

FINAL REPORT TO
SCIENTIFIC INQUIRY INTO HYDRAULIC FRACTURING IN THE NORTHERN TERRITORY
OCTOBER 2017

THE ECONOMIC IMPACTS OF A POTENTIAL SHALE GAS DEVELOPMENT IN THE NORTHERN TERRITORY





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Interpreting this report

ACIL Allen Consulting ('ACIL Allen') was engaged by the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory ('the Inquiry') to conduct an economic study into the impacts and risk of an unconventional shale gas industry in the Northern Territory. As one part of its scope of works, ACIL Allen has conducted a series of modelling tasks, including the development of a commercial financial model.

All economic modelling is subject to uncertainty, and should be treated with caution. ACIL Allen Consulting ('ACIL Allen') considers the modelling presented in this report is subject to higher than usual uncertainty. This is because of the unusual nature of the task ACIL Allen has undertaken.

The development of a shale gas industry in the Northern Territory is at the very earliest possible stages. To date, there has been one fracture stimulated horizontal well that has been tested in a near-production setting – Origin Energy's Amungee NW-1H well, in the Beetaloo Sub-Basin of the McArthur Basin. While the well delivered a positive production test result, significant further testing is required to determine the precise scale, scope and qualities of shale gas production potential in this sub-basin alone, let alone the remainder of the Northern Territory.

However, in order to conduct economic impact assessment modelling, it has been necessary for ACIL Allen to develop a commercial financial model of an industry in the Northern Territory. This model has been built using a range of assumptions, and does not represent an assessment of the commercial viability of a shale gas industry development in the Northern Territory. It is not possible to conduct such modelling at this point in the industry's life cycle, as even the most basic information regarding the quantity and quality of gas in situ is unknown.

Ultimately, ACIL Allen was engaged by the Inquiry to articulate the potential **economic** benefits, impacts and risks of a shale gas industry in the Northern Territory. We have done this using our best estimates of what a successful development may look like, based on:

- the views of the Northern Territory Government, potential industry operators, non-gas industry stakeholders, Traditional Owners and native title holders, non-government organisations, and representative bodies;
- our own expertise in gas market and economic impact modelling;
- the experience of shale gas industry development in analogous regions across the world; and
- the latest research, data and insights of shale gas industry economics.

ACIL Allen has developed a framework that has allowed it to deal with the uncertain nature of our task, which is presented in Chapter II of this report. However, as a result of the significant information limitations, ACIL Allen advises those who read this report to treat the results with higher than usual caution. The modelling prepared and results presented in this report should be treated as what they are – **an estimate of the economic impacts of a shale gas industry development** – and not for what they are not – an assessment of the commercial viability of a shale gas industry development in the Northern Territory.



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EXECUTIVE SUMMARY

The Inquiry

Hydraulic fracturing for onshore unconventional gas has been subject to significant debate in the Northern Territory in recent years. Following a change of government in 2016, the Northern Territory Government announced a moratorium on hydraulic fracturing of onshore unconventional reservoirs including the use of hydraulic fracturing for exploration, extraction, production and including Diagnostic Fracture Injection Testing (DFITs).

On 3 December 2016 the Northern Territory Government announced an independent Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs in the Northern Territory. The Inquiry is investigating the environmental, social and economic risks and impacts of hydraulic fracturing ('fracking') of onshore unconventional gas reservoirs and associated activities in the Northern Territory.

ACIL Allen Consulting ('ACIL Allen') was appointed on 24 May 2017 to assist the Inquiry understand the potential economic benefits, impacts and risks of the development of an onshore unconventional gas industry in the Northern Territory. An abbreviated version of the scope of works is presented below, and the full terms of reference included in Appendix A.

ACIL Allen has been engaged by the Inquiry and this, our Final Report, has been released for public consumption.

Our scope of works

ACIL Allen Consulting has been appointed by the Inquiry to assess the actual and potential direct and indirect economic benefits, risks and impacts of fracking on the Northern Territory under the current regulatory regime.

To facilitate this, ACIL Allen's scope of works gives regard to three distinct scenarios:

1. Scenario 1, or the baseline scenario, where the moratorium on hydraulic fracturing of unconventional shale gas reservoirs remains in place (the 'base case')
2. Scenario 2, which involves the development of the onshore unconventional shale gas industry in the Northern Territory (the 'unconstrained case')
3. Scenario 3, which involves the development of unconventional shale gas reservoirs in the Beetaloo sub-basin only.

In order to do this, ACIL Allen will complete two main tasks:

- **Conduct economic impact assessment modelling, using ACIL Allen's suite of in-house economic models**, including models of the national gas and electricity markets. To complete this

task, ACIL Allen will develop credible, evidenced-based scenarios for the development of shale gas projects in the Northern Territory under a set of assumptions which are agreed by the Inquiry. The outcome of this task will be quantitative economic impact assessment results under each of the three scenarios listed above.

- **Research, analyse, articulate and discuss the potential impacts on the Northern Territory economy's other industries**, including but not limited to tourism, agriculture, horticulture and pastoral. This will centre on findings of stakeholder consultation and a review of relevant international literature and case studies. The outcome of this task will be a chapter or chapters in the final report of this engagement that outlines the economic risks and provides suggestions on policy initiatives the Inquiry may recommend to the Northern Territory Government in the Inquiry report.

Scope variation – 18 July

Following the completion of its initial research and round of stakeholder consultation in the Northern Territory, ACIL Allen presented the Inquiry with a proposal to vary its scope of works.

The key finding of our initial research and consultation was that it was not possible to conduct economic modelling giving regard to the three scenarios as requested by the Inquiry in its scope of works. This was primarily due to lack of information about the size or scope of commercial shale gas reserves in the Northern Territory (both in the Beetaloo sub-basin and in the Northern Territory more broadly), and the embryonic stage of the industry's life cycle. The scenarios as described by the Inquiry implied a precision which ACIL Allen was not comfortable providing.

ACIL Allen proposed to conduct modelling on the basis of **five** scenarios, briefly outlined below and explained further in this report.

1. **"Baseline"**: The moratorium remains in place
2. **"Shale CALM"**: The moratorium is lifted, and exploration and appraisal activity occurs. However, the results of testing indicate the resource is not commercial, and no further activity takes place.
3. **"Shale BREEZE"**: The moratorium is lifted, and exploration and appraisal activity occurs. A relatively small scale development occurs, targeting production of 100 terajoules (TJ) per day.
4. **"Shale WIND"**: The moratorium is lifted, and exploration and appraisal activity occurs. A moderate scale development occurs, targeting production of 400 TJ/day.
5. **"Shale GALE"**: The moratorium is lifted, and exploration and appraisal activity occurs. A relatively large scale development occurs, targeting production of 1000 TJ/day.

Complementing these scenarios is a qualitative probability matrix, which is intended to articulate the subjective likelihood that a given scenario would come to fruition under a series of moratorium lifting scenarios. This is presented at the end of this summary.

ACIL Allen considered that the scenarios as described above would achieve the objectives of the scope of works while also dealing with the lack of information and articulating the significant uncertainty which currently exists regarding the prospects of a shale gas industry in the Northern Territory.

No other aspects of the engagement were proposed to change. The Inquiry agreed to the scope variation post this meeting, and these are the scenarios ACIL Allen has adopted for its economic modelling and policy analysis tasks.

Our methodology

ACIL Allen has completed two discrete but related tasks to meet the objectives of this scope of works.

Economic impact assessment modelling

We have completed **an economic impact assessment** on the five scenarios above, where the four "Shale" scenarios are compared to a baseline assessment of the modelled growth of the Northern Territory economy absent the development of a shale gas industry. In order to complete the economic impact assessment, ACIL Allen conducted an iterative process of modelling across four models:

1. **Gas Market Modelling:** Understanding the supply and demand for gas from a Northern Territory shale gas industry under each scenario, to determine the volume of gas that could be placed in the market at market prices each year of the study. This task was completed using ACIL Allen's *GasMark* model of the east coast gas market.
2. **Project Development Modelling:** Understand the production and infrastructure requirements to meet the volume of gas to be placed in the market, using a bespoke shale well production schedule model. This model required two major inputs: an assumed single average type curve of a hypothetical shale well (different for each scenario) and a series of assumptions regarding the infrastructure required to enable production to occur (wells, pads, gathering pipes, roads, water, camps, labour). This occurred in two streams:
 - a) "ProjectCo": the hypothetical development company responsible for exploring, appraising and developing the shale gas industry in the Northern Territory.
 - b) "PipelineCo": the hypothetical builder, owner and operator of new pipeline infrastructure required to facilitate the sale of ProjectCo shale gas to market.

ProjectCo and PipelineCo are separate entities, but interact via tariffs paid by ProjectCo to PipelineCo for the provision of pipelines to transport gas to market.
3. **Project Cash Flow Modelling:** Understanding the financial implications of the development using assumptions regarding the cost of development of ProjectCo and PipelineCo, and volume and price data derived from *GasMark*. ACIL Allen has built a bespoke discounted cash flow model that takes into account all features of ProjectCo's finances, including estimates of taxation. PipelineCo is built as a simple discounted cash flow model with capital investment, ProjectCo tariffs revenue and operating expenditure.
4. **Economic Impact Assessment Modelling:** The summary inputs and outputs of the ProjectCo and PipelineCo cash flow modelling are converted to a national accounting framework and processed through ACIL Allen's *TasmanGlobal* computable general equilibrium (CGE) model. The four development scenarios are compared to the baseline assessment of the future growth of the Northern Territory economy to produce estimates of the potential economic impacts of each development scenario as a discrete set of outputs.

Outputs are presented at the Northern Territory and Australia level, under the Australian Bureau of Statistics National Accounting framework for income, expenditure and output – including at ANZSIC major industry level. This ensures a comprehensive understanding of both positive and negative impacts of an industry. This process is described at length in Sections II and III of this report.

Perspectives on economic policy issues

We have also completed a qualitative research exercise centred on understanding the potential economic policy implications of a shale gas industry in the Northern Territory. This is informed somewhat by the outputs of the economic impact assessment modelling, as these articulate the potential "pressure points" that may emerge at an industry level.

ACIL Allen has completed this in two chapters of this report.

1. A **literature review** centred on current academic research and practical insights of sustainable resources industry development, with an Australian bent.
2. A **discussion of six key policy issues** that were raised during stakeholder consultation. We have included examples of onshore gas industry development and other resources industry development in other jurisdictions, as our literature review indicates resources-related developments have similar benefits and costs.

ACIL Allen has not sought to develop a policy reform program to help capture benefits and mitigate risks, as this is beyond the scope of works we have been asked to complete.

Economic impact assessment summary

ACIL Allen has conducted this economic impact assessment under five scenarios; a base case, and four scenarios which are independent deviations from this base case.

The base case is ACIL Allen's assessment of the future growth of the Northern Territory and Australian economies under current policy settings, which is effectively an assessment of the economy if the moratorium on fracking was to remain in place. The four scenarios are in line with the cash flow modelling results presented in this report.

In line with ACIL Allen's scope of works, the modelling outputs have been presented for three regions: Northern Territory, Rest of Australia, and Australia (which is the sum of the first two regions), and under the following macroeconomic variables:

- Real income (Gross Real Income)
- Real output (Gross State Product and Gross Domestic Product, and change in industry output from the base case)
- Real final demand (State Final Demand and Domestic Final Demand)
- Real investment (Business Investment)
- Real exports (for the Northern Territory, international and interstate; for Australia, international only)
- Real employment (FTE employment and employment by industry)
- Real wages
- Population
- Taxation (by major heads of taxation)

Base case

In order to assess the economic impact of a potential shale gas industry, it has been necessary to define what the Northern Territory economy will look like without a shale gas industry in the future. This is known as the "base case" scenario, which projects the long term growth of the Northern Territory economy.

The Northern Territory's recent economic performance has been driven by the impact of INPEX's Ichthys offshore gas and LNG facility development. To this point, the impact has been mostly centred on the initial surge and subsequent fall in construction activity, with the lift in production and export still on the horizon. ACIL Allen has included a projection of the impact of Ichthys' production phase on the Northern Territory economy in its base case.

Other foreseen events for the Northern Territory included in the base case include:

- The impact of the Northern Territory Government's **10 Year Infrastructure Plan**
- **Project Seadragon**, and the significant impact on the Northern Territory Government's aquaculture industry
- The highly likely development of an offshore gas project to support the **backfill of DLNG** as existing supplies deplete
- An **expanded horticulture sector**, in line with research presented by NT Farmers and the perspective of Northern Territory Government stakeholders

In Gross Territory Product (GTP) terms, ACIL Allen's base case projects the Northern Territory economy will grow by an average of 2.9 per cent over the forecast period (2018-2043) (Figure ES1, Panel 1). This is lower than the average GTP growth of four per cent recorded over the past decade, which was mostly influenced by the impact of first the DLNG project and then the Ichthys LNG project.

Growth is forecast to spike in the short term, with GTP growth of eight per cent forecast in 2019 on account of the ramp up in Ichthys LNG production. This manifests as an increase in the Petroleum sector's output, and a lift in the real export base of the Northern Territory economy. As LNG production ramps up and then reaches a steady-state level of production, this is only anticipated to have a one year impact on the Territory's growth rate.

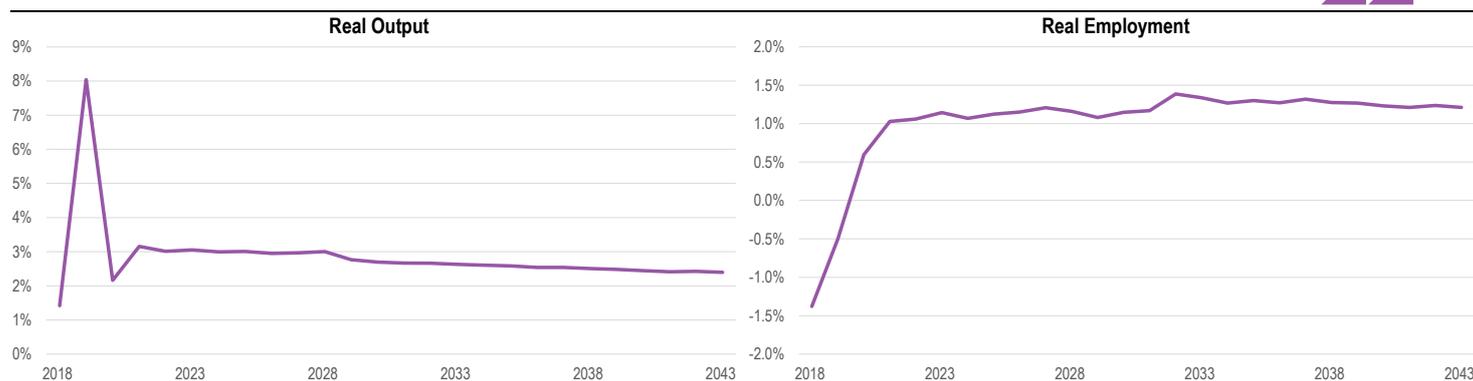
Following the ramp up of Ichthys LNG Project, ACIL Allen forecasts there will be a period of slightly above average growth through the 2020s, as the Territory's aquaculture and horticulture industries grow faster than the rest of the economy, and the Northern Territory Government's 10 Year Infrastructure Plan plays out. The impact of the new offshore gas development to back fill DLNG is somewhat limited, as much of the supplies and services for an offshore development are by necessity

imported. This manifests in a strong increase in Business Investment (and therefore State Final Demand), but a commensurate increase in imports, therefore a near-zero impact on overall GTP.

Beyond the 2020s, ACIL Allen projects the Northern Territory economy will grow in line with population growth, labour force participation and productivity growth. All up, the Northern Territory economy is projected to grow from a \$23.4 billion economy (2018 dollars) in 2018 to a \$47.9 billion economy by the end of the forecast period.

ACIL Allen's base case assumes total employment in the Northern Territory economy will grow by an average of one per cent per annum over the forecast period (Figure ES1, Panel 2). Short term employment growth follows the trajectory of the unwinding of the remainder of the Ichthys LNG project, with employment forecast to fall by 1.4 per cent in 2018 and 0.5 per cent in 2019. Thereafter, total employment is forecast to grow by an average of 1.2 per cent per annum.

FIGURE ES 1 BASE CASE HEADLINE RESULTS, REAL OUTPUT AND REAL EMPLOYMENT, ANNUAL PERCENTAGE CHANGE, FORECAST



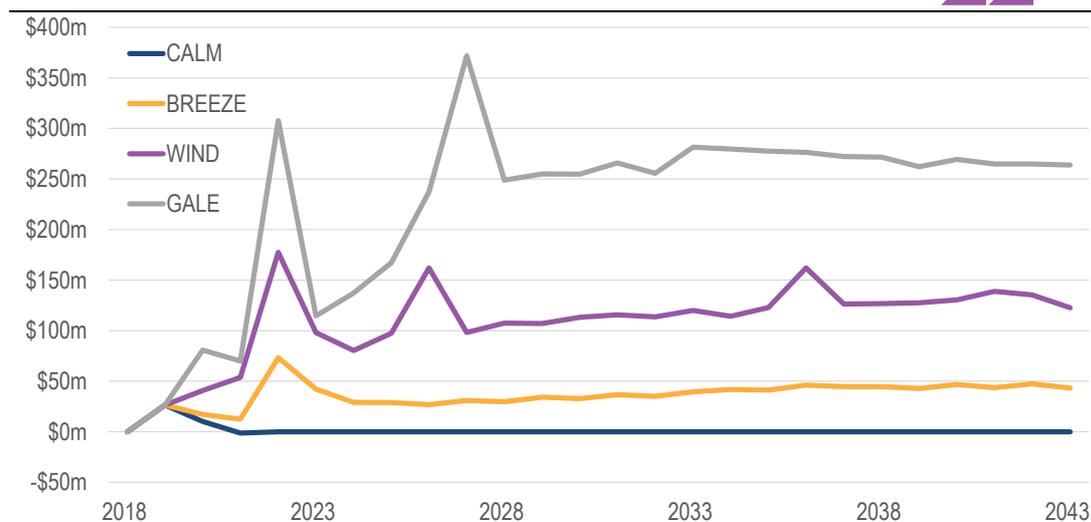
SOURCE: ACIL ALLEN CONSULTING

Economic impact assessment results

ACIL Allen's economic impact assessment illustrates the potential economic upsides and downsides in the event of small, medium and large scale shale gas industry developments in the Northern Territory, and the flow on effects to the rest of the Australian economy. While the base case and CALM scenarios, where no shale gas industry development occurs, show the Northern Territory economy is set to grow in the years ahead, the development scenario modelling shows the shale gas industry could have an overall net positive impact on the future growth of the Northern Territory economy.

ACIL Allen projects a shale gas industry development could result in a net real income (a measure of the overall wealth impact of the industry's development) increase of between \$937.2 million (BREEZE), \$2.8 billion (WIND) and \$5.8 billion (GALE) for the Northern Territory over the modelling period, or between \$36 million, \$108.4 million and \$222.2 million per annum. This equates to a net real income per capita increase of \$146, \$439 to \$903 per capita (based on the Northern Territory's 2018 population) over the modelling period, which is mostly caused by increased Northern Territory Government revenue. The rest of Australia also sees a lift in real income, of between \$3.4 billion (BREEZE), \$9.1 billion (WIND) and \$12.5 billion (GALE) over the modelling period, on account of the flow on impact of lower gas prices across the economy and the increase in Commonwealth taxes associated with the development (refer to Figure ES 2).

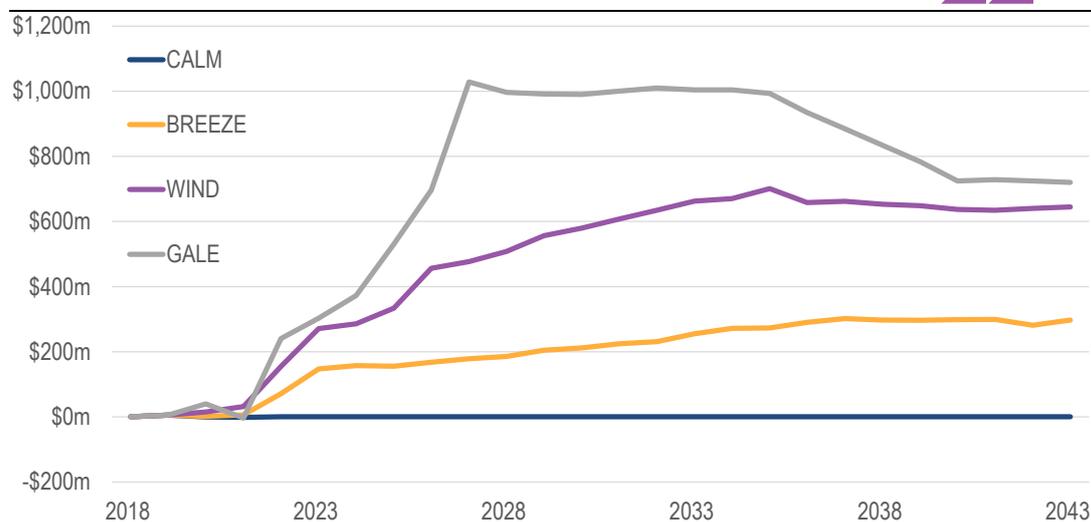
FIGURE ES 2 REAL INCOME, ANNUAL DEVIATION FROM BASE CASE, A\$ MILLION, REAL TERMS



SOURCE: ACIL ALLEN CONSULTING

The net economic benefit (in terms of increase to the Northern Territory’s Real Gross Territory Product) to the Northern Territory ranges from \$5.1 billion in the BREEZE scenario (\$196.5m per annum), to \$12.1 billion (\$466.4m per annum) in the WIND scenario, to \$17.5 billion (\$674.4m per annum) in the GALE scenario, in real 2018 dollar terms. In annual average terms, this is the equivalent of an additional 0.8 per cent, 1.9 per cent to 2.9 per cent of the Northern Territory’s forecast Gross Territory Product in 2018 (Figure ES 3).

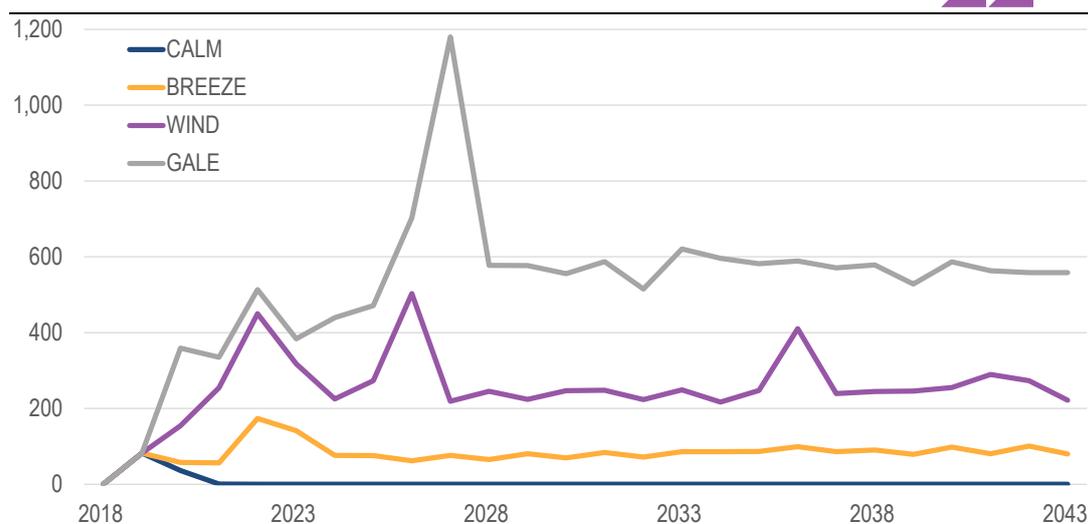
FIGURE ES 3 REAL OUTPUT, ANNUAL DEVIATION FROM BASE CASE, A\$ MILLION, REAL TERMS



SOURCE: ACIL ALLEN CONSULTING

This additional economic activity will generate employment opportunities for Territorians, with an estimated 2,154 FTE jobs (BREEZE), to 6,559 FTE jobs (WIND) to 13,611 FTE jobs (GALE) generated by the various development scenarios over the forecast period – over and above the existing employment growth ACIL Allen has forecast in its base case (Figure ES 4). This equates to between 82 FTEs, 252 FTEs, and 524 FTEs of net employment growth in each year on average. This includes indirect employment generated by the local spending of the industry. While modest in the context of the overall Northern Territory labour market, this represents the capital intensive nature of the shale gas industry and modelling assumptions (see Section 6).

FIGURE ES 4 REAL EMPLOYMENT, FTE JOB YEARS, REAL TERMS, BY SCENARIO

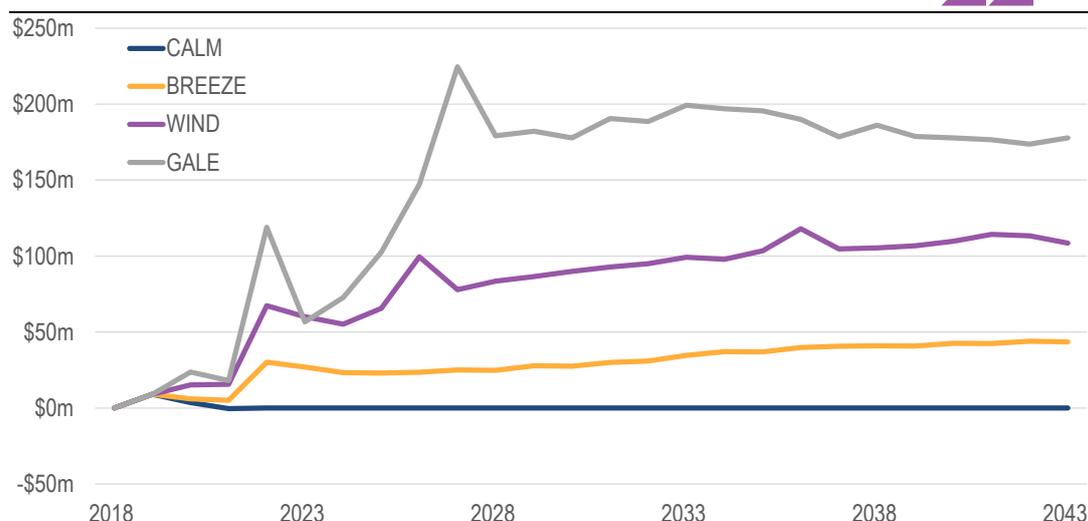


SOURCE: ACIL ALLEN CONSULTING

For Territorians, the most visible channel of economic impact likely to be seen is an increase to Territory Government revenue. ACIL Allen estimates a successful shale gas industry development could generate between \$757 million (BREEZE), \$2.1 billion (WIND) and \$3.7 billion (GALE) in additional revenue for the Northern Territory Government over the 25 year modelling period, or between \$29.1 million, \$80.6 million, and \$143.2 million per annum (Figure ES 5). In the larger case, this represents a sizeable increase to the Northern Territory’s recurrent revenue base of 2.2 per cent, or more than eight per cent if Commonwealth Government grants are excluded. ACIL Allen has modelled royalty revenue, payroll tax and implied GST raised in the Northern Territory.

ACIL Allen’s analysis shows a shale gas industry could also deliver windfall growth in Commonwealth revenue, even as the cascading impact of reduced gas prices from the development reduces the income earned by the gas sector outside of the Northern Territory. ACIL Allen has modelled company income tax, personal income tax and PRRT revenue.

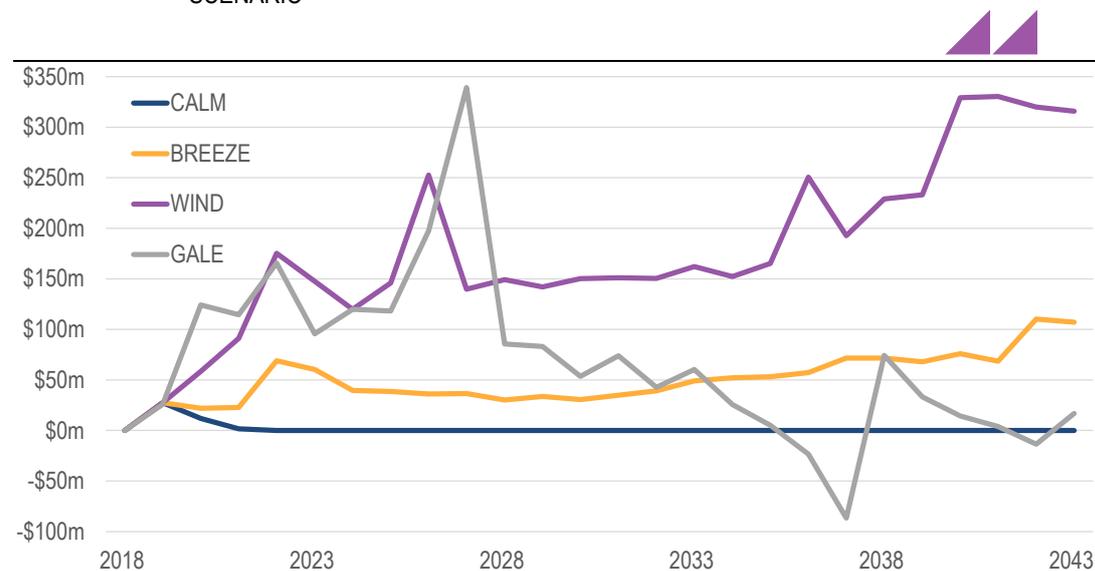
FIGURE ES 5 REAL TAXATION, NORTHERN TERRITORY GOVERNMENT, A\$ MILLION, REAL TERMS, BY SCENARIO



SOURCE: ACIL ALLEN CONSULTING

ACIL Allen estimates the Commonwealth Government could expect to raise between \$1.3 billion (BREEZE), \$4.6 billion (WIND), and \$5.5 billion (GALE) in income and profits based taxation over the forecast period, or \$50.2 million, \$176.2 million and \$210.4 million per annum (Figure ES 6).

FIGURE ES 6 REAL TAXATION, COMMONWEALTH GOVERNMENT, A\$ MILLION, REAL TERMS, BY SCENARIO



SOURCE: ACIL ALLEN CONSULTING

Project development probability matrix, and key development assumptions

As discussed in Section 4, the shale gas industry in the Northern Territory is at such an early stage that the modelling conducted in this engagement is subject to more than the usual uncertainty. Below, ACIL Allen has presented a subjective probability matrix to represent the qualitative likelihood of each scale of development occurring (Figure ES 7).

On the basis of the financial modelling undertaken on the each development scenario, ACIL Allen has assessed the probability of a shale gas industry developing in the Northern Territory in each case. This is based on the outcomes of the financial modelling, the uncertainty regarding the size of the Northern Territory's commercial reserves, and the challenges associated with producing gas at a price which the market will accept. As the development scales up, these challenges will become greater, leading to a reduced likelihood that any given scale of development can be realised.

ACIL Allen has also formed a view that the probability of a shale gas industry developing in the Northern Territory will improve the greater the potential area for exploration and appraisal. This is in line with international experience, which shows that it is often developments which occur following an initial discovery and development that prove to be the most commercial.

For example, under the GALE scenario, ACIL Allen has assessed, on current information, the likelihood of a shale gas industry that will begin to scale to 1000 terajoules per day (TJ/day) of gas production at an average price of \$4.01 per gigajoule (GJ) within the next five years as low, assuming the moratorium is lifted in full across the Northern Territory. If there is only a partial lift in the moratorium, this becomes a very low probability, because there is less of an ability for a potential shale gas industry to find the most commercial shale gas deposits.

In the context of the probability matrix, ACIL Allen notes that it has made a critical assumption that the shale gas developments modelled in this report are a "dry gas play". That is, the hydrocarbons produced in a development do not include higher value liquid hydrocarbons such as ethane, propane, butane or crude oil. A "liquids rich" shale gas play results in a very small increase in operating costs (associated with increased processing to separate the higher value hydrocarbons from the lower value hydrocarbons), and a very large increase in potential production revenue. This improves the

commercial viability of a shale gas development, to the point where a larger development may have a higher probability of occurring versus a dry gas play.

For further information on the development scenarios, refer to Section 4.

To be clear, this matrix is not an assessment of the commercial prospects of a shale gas industry in the Northern Territory, as ACIL Allen has not been engaged to assess this, and it is too early in the industry's development to make such a determination.

FIGURE ES 7 ACIL ALLEN DEVELOPMENT SCENARIO PROBABILITY MATRIX

INDUSTRY DEVELOPMENT SCENARIO	Production Profile	Production Cost Regime	POLICY SCENARIO PROBABILITY MATRIX		
			PERMANENT MORATORIUM	PARTIAL LIFT	FULL LIFT
BASELINE	Nil Shale Production	N/A	CERTAIN	MODERATE	LOW
SHALE CALM	Exploration occurs Failure to commercialise	N/A	ZERO	VERY HIGH	VERY HIGH
SHALE BREEZE	Scenario 1 Target production: 36PJ per annum	High cost	ZERO	MODERATE	HIGH
SHALE WIND	Scenario 2 Target production: 150PJ per annum	Moderate cost	ZERO	LOW	MODERATE
SHALE GALE	Scenario 3 Target production: 365PJ per annum	Low cost	ZERO	VERY LOW	LOW

SOURCE: ACIL ALLEN CONSULTING



Structure of this report

As this is a complex engagement, ACIL Allen has structured its report in a logical fashion, with overarching Chapters and a series of Sections underneath. The contents of each remaining Chapter and Section is briefly outlined below (excluding this introductory chapter).

Chapter I: Preliminary Information

Section 2: Economic context. This section provides relevant contextual information regarding the structure and recent performance of the Northern Territory economy, the Australian economy, Australia's gas and electricity markets (including a brief discussion of recent policy initiatives) and the Northern Territory's energy markets.

Section 3: Unconventional gas and hydraulic fracturing. This section provides relevant contextual information regarding unconventional gas and hydraulic fracturing techniques, a brief overview of unconventional gas extraction in Australia, and the recent experience of hydraulic fracturing for shale gas in the Northern Territory prior to the moratorium.

Chapter II: Shale Gas Industry Development Scenarios

Section 4: Project Assumptions and Development Scenarios. This section outlines the process used to derive the industry development scenarios discussed above, including a full explanation of the target and realised gas sales and prices, single average type curve assumptions and production and supporting infrastructure requirements. This includes the timing of development under each scenario.

Section 5: Project Cash Flow Modelling. This section outlines the ProjectCo and PipelineCo financial models, including all assumptions relating to the cost of development and overall financial position of ProjectCo under each set of assumptions outlined in Section 4.

Chapter III: Economic Impact Assessment

Section 6 through 11: Economic Impact Assessment Results. This section outlines the economic forecasting results of the baseline scenario, before articulating the economic impact assessment results of the four scenarios under the criteria established.

Section 12: Economic Impact Assessment Summary. This section briefly outlines the results of the economic impact assessment chapter of the report in a brief, easy to understand format centred on the highest level economic outputs and a narrative style description of the exercise.

Chapter IV: Economic Policy Considerations

Section 13: Shale Gas Economics Literature Review. This section contains a thorough review of contemporary academic literature regarding the benefits and costs of shale gas industry development, and measures that can be taken to ensure sustainable economic development.

Section 14: Perspectives on Policy. This section uses domestic and international case studies and feedback from stakeholder consultation to articulate some of the key policy issues likely to emerge should a shale gas industry successfully develop in the Northern Territory. This section does not include ACIL Allen's perspective on measures the Northern Territory Government should adopt, as this is outside of our scope of works.

Appendices

Appendices Part One: Information relevant to the engagement that has not been included in the body of the report but which ACIL Allen believes is important to ensure transparency.

Appendices Part Two: Information regarding the structure and processes of ACIL Allen's economic and gas market models.

Glossary of terms and abbreviations

Throughout this report, ACIL Allen has used a number of technical terms related to both the economic and energy market modelling tasks it has completed. These terms are outlined below.

Term	Definition
"Fracking"	In this report, ACIL Allen will specifically define "fracking" as the process of hydraulically fracturing shale formations for the purposes of targeting hydrocarbons.
Employment	The number of full time equivalent job years created as a result of a project or expenditure in the economy, which includes direct and indirect (flow-on) employment.
Exchange rate	The exchange rate is expressed as the AUD/USD exchange rate unless otherwise stated and is denoted as A\$ throughout the document.
Exports	The value of goods exported and amounts receivable from non-residents for the provision of services by residents.
Gross product or real economic output	<i>A measure of the size of an economy</i> Gross product is a measure of the output generated by an economy over a period of time (typically a year). It represents the total dollar value of all finalised goods and services produced over a specific time period and is considered as a measure of the size of the economy. At a national level, it is referred to as Gross Domestic Product (GDP); at the state level, Gross State Product (GSP); while at a regional level, Gross Regional Product (GRP).
Gross value added	<i>A measure of the value of goods and services produced in an industry or sector of an economy.</i> Gross Value Added (GVA) is the output of an industry or sector minus intermediate consumption. GVA therefore represents the value of all goods and services produced, minus the cost of all inputs and raw materials used to produce that good or service. Unlike Gross Product, GVA does not include the value of taxes minus subsidies.

Term	Definition
Imports	The value of goods imported to a region and amounts payable to non-residents for the provision of services to residents.
Job years	Real employment is measured in job years. A job year is employment of one full time equivalent (FTE) person for one year. Alternatively it can be expressed as one 0.5 FTE person for two years.
Millions, billions and trillions of standard cubic feet	<p>In this report, ACIL Allen Consulting will make use of units of measurement for hydrocarbons in millions, billions and trillions of cubic feet (mmscf, BCF and TCF). These units of measurement are an order of magnitude apart:</p> <p>1,000mmscf = 1 BCF 1,000BCF = 1 TCF</p> <p>These units of measurement are the industry standard for measurement of gas produced at the wellhead of a development. ACIL Allen Consulting will refer to “BCF” produced per well.</p>
Net Real Income, Net Gross Territory Product and other “Net” Prefixes	The economic modelling outputs in this report are presented in “net” terms, unless otherwise stated. This is a representation of the aggregated economic impact on the particular variable, being the gross benefit of an investment less the crowding out effect on other sectors.
Net present value (NPV)	<p>The value of a future stream of income (or expenses) converted into current terms by an assumed annual discount rate. The underlying premise is that receiving, say, \$100 in 10 years is not ‘worth’ the same (i.e. is less desirable) than receiving \$100 today.</p> <p>For the purposes of this study, NPV calculations have been made based on a discount rate of 10 per cent. The discount rate has been selected as a balance between a typical commercial financial discount rate (12-15 per cent) and a typical social discount rate (seven per cent).</p>
Real and nominal dollars	<p>Nominal dollars are dollars that are expressed in the actual dollars that are spent or earned in each year, including inflation effects. Real dollars have been adjusted to exclude any inflationary effects and therefore allow better comparison of economic impacts in different years. Over time, price inflation erodes the purchasing power of a dollar thereby making the comparison of a dollar of income in 2063 with a dollar of income in 2016 invalid. Adjusting nominal dollars into real dollars overcomes this problem.</p> <p>All values are expressed in real dollar terms with a base year of 2016, unless otherwise stated.</p>
Real income	<p><i>A measure of the welfare of residents in an economy through their ability to purchase goods and services and to accumulate wealth</i></p> <p>Although changes in real economic output are useful measures for estimating how much the output of the economy may change due to the Project, changes in real income are also important as they provide an indication of the change in economic welfare of the residents of a region through their ability to purchase goods and services.</p> <p>Real income measures the income available for final consumption and saving after adjusting for inflation. An increase in real income means that there has been a rise in the capacity for consumption as well as a rise in the 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 the economic welfare of residents within an economy.</p>

Term	Definition
State final demand	<p><i>A measure of the value of goods and services in an economy</i></p> <p>The aggregate obtained by summing government final consumption expenditure, household final consumption expenditure, private gross fixed capital formation and the gross fixed capital formation of public corporations and general government. It is conceptually equivalent to the Australia level aggregate domestic final demand.</p>
Terajoules and petajoules	<p>Terajoules and petajoules are a standardised unit of energy measurement, used in the energy and pipeline sectors. In this report, ACIL Allen will refer to energy production in terms of terajoules per day (TJ/day) and petajoules per annum (PJ/annum).</p> <p>One terajoule (TJ) = ~0.001 petajoules (PJ)</p>
Working age population	<p>All usual residents of Australia aged 15 years and over except members of the permanent defence forces, certain diplomatic personnel of overseas governments customarily excluded from census and estimated population counts, overseas residents in Australia, and members of non-Australian defence forces (and their dependants) stationed in Australia.</p>

LIST OF ACRONYMS

Abbreviation	Full name
ABS	Australian Bureau of Statistics
AUD/ A\$ or \$	Australian dollars
BCF	Billions of cubic feet of gas
Billion	Billion measured by 1×10^9 (or 1,000 million) as per the US convention
CAPEX	Capital expenditure
CGE	Computable general equilibrium (model)
CPI	Consumer Price Index
FIFO	Fly in-fly out work practice
FTE	Full time equivalent
GDP	Gross Domestic Product
GSP	Gross State Product
GST	Goods and services tax
GTP	Gross Territory Product
GVA	Gross Value Added
LNG	Liquefied natural gas
Million	Million measured by 1×10^6 (or 1,000 thousand) as per the US convention
mmscf	Millions of cubic feet
NPV	Net present value
OPEX	Operational expenditure
PJ	Petajoules
PJ/day	Petajoules per day
PRRT	Petroleum Resources Rent Tax
TCF	Trillion cubic feet
TJ	Terajoules

Abbreviation	Full name
TJ/day	Terajoules per day
USD or US\$	United States dollars
WPI	Wage Price Index

Stakeholder consultation

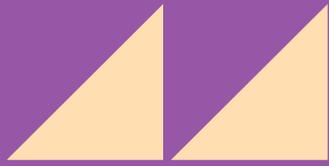
While our own independent research has helped form much of the inputs into our methodology, ACIL Allen also conducted an extensive program of stakeholder consultation in the first month of the engagement. ACIL Allen met with the following groups as part of its structured program of stakeholder consultation, and held follow up meetings with a range of stakeholders to gather additional information as the engagement progressed. Stakeholders were provided with a Consultation Guide prepared by ACIL Allen, and comprehensive verbatim notes of the consultation sessions were taken by ACIL Allen. A copy of the Consultation Guide has been included in Appendix B.

Stakeholders have been presented in alphabetical order.

TABLE 1.1 ACIL ALLEN STAKEHOLDER CONSULTATION

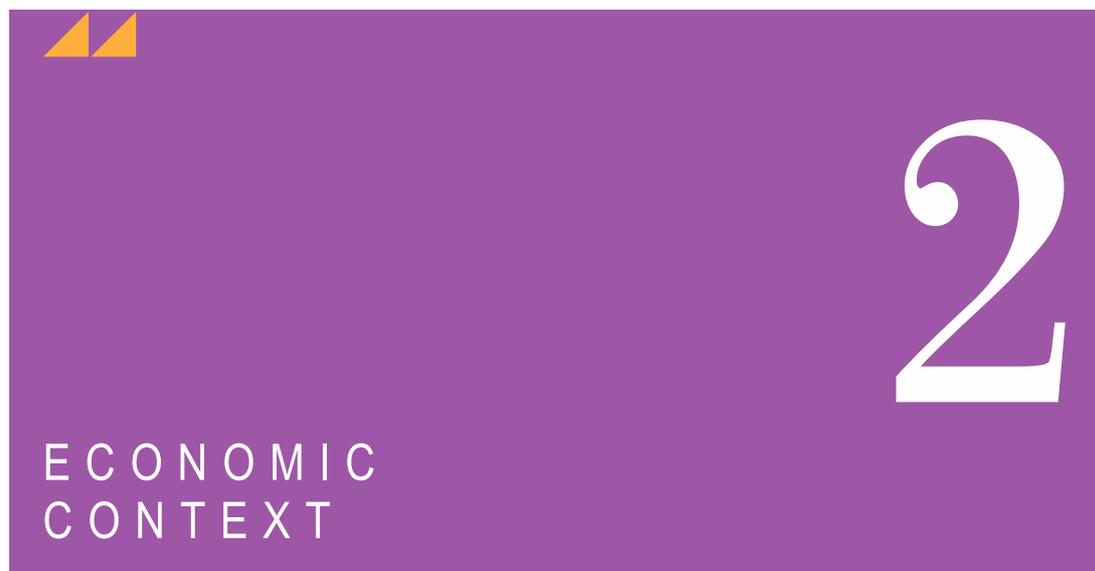
Stakeholder Organisation	Method of Meeting	Stakeholder Group
Australian Petroleum Production & Exploration Association	Face to face	Non-Government Organisation
Central Land Council	Teleconference	Traditional Owner representative
Lock the Gate Alliance & The Australia Institute	Face to face (Lock the Gate) and teleconference (The Australia Institute)	Non-Government Organisation
MS Contracting	Teleconference	Industry operators
Northern Land Council	Face to face	Traditional Owner representative
NT Cattlemen's Association	Face to face	Non-Government Organisation
NT Department of Business, Trade and Innovation	Face to face	Government
NT Department of Primary Industry and Resources	Face to face	Government
NT Department of Primary Industry and Resources (follow up)	Teleconference	Government
NT Farmers	Face to face	Non-Government Organisation
NT Treasury	Face to face	Government
NT Treasury (follow up)	Teleconference	Government
NT Treasury (second follow up)	Teleconference	Government
Origin Energy	Face to face and teleconference	Industry operators
Origin Energy (follow up)	Face to face	Industry operators
Pangaea Pty Ltd	Teleconference	Industry operators
Pangaea Pty Ltd (follow up)	Teleconference	Industry operators
Santos	Face to face	Industry operators
Santos (follow up)	Teleconference	Industry operators

In addition to the consultation sessions above, ACIL Allen received a variety of material from all stakeholders throughout the engagement, and drew on submissions made to the Inquiry by the full range of stakeholders.



I

PRELIMINARY
INFORMATION

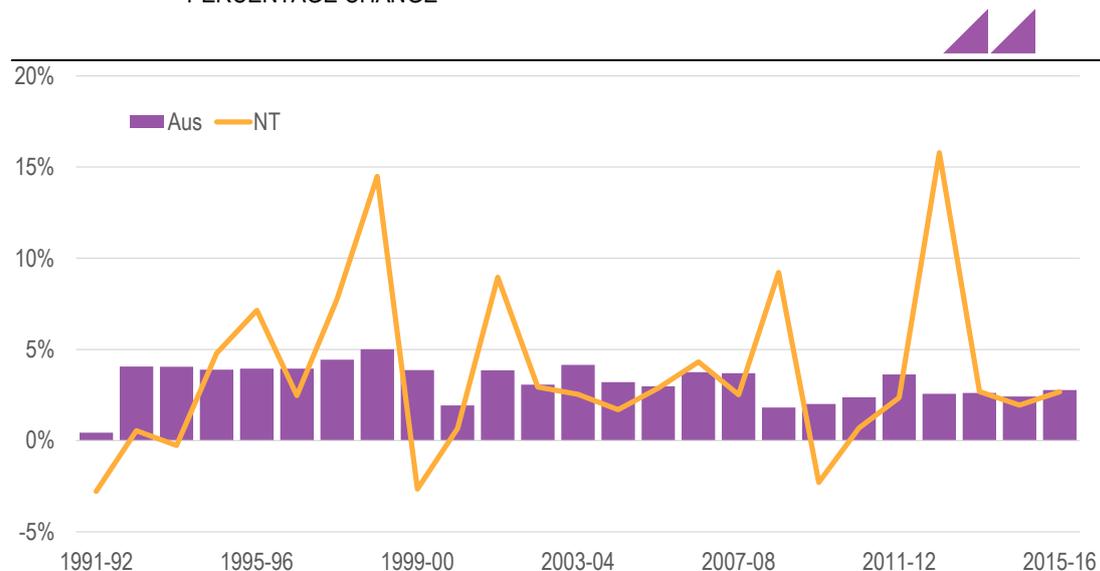


2.1 Economic trends

The Northern Territory economy is a regional economy, which generated \$23 billion in Gross State Product (GSP) in 2015-16, accounting for 1.4 per cent of Australia's Gross Domestic Product (A\$1.6 trillion). Northern Territory is an emerging economic centre, with average annual rates of growth in the economy exceeding five per cent per annum over the past five years (around double the rates of growth recorded in the national economy over the same period).

Economic growth in the Northern Territory is fairly volatile due to its small size and narrow economic base. As a result, major investments can have a disproportionately large impact on overall growth. The development of the Ichthys LNG Project has had a substantial impact on the Northern Territory economy, driving growth (as measured by Gross Territory Product) to a high of 15.8 per cent in 2012-13 as investment activity accelerated. While investment activity levels have remained at historically high levels, as the pace of growth in investment has slowed this has had a corresponding impact on the broader measures of growth in the Northern Territory.

FIGURE 2.1 REAL ECONOMIC GROWTH, NORTHERN TERRITORY AND AUSTRALIA, ANNUAL PERCENTAGE CHANGE

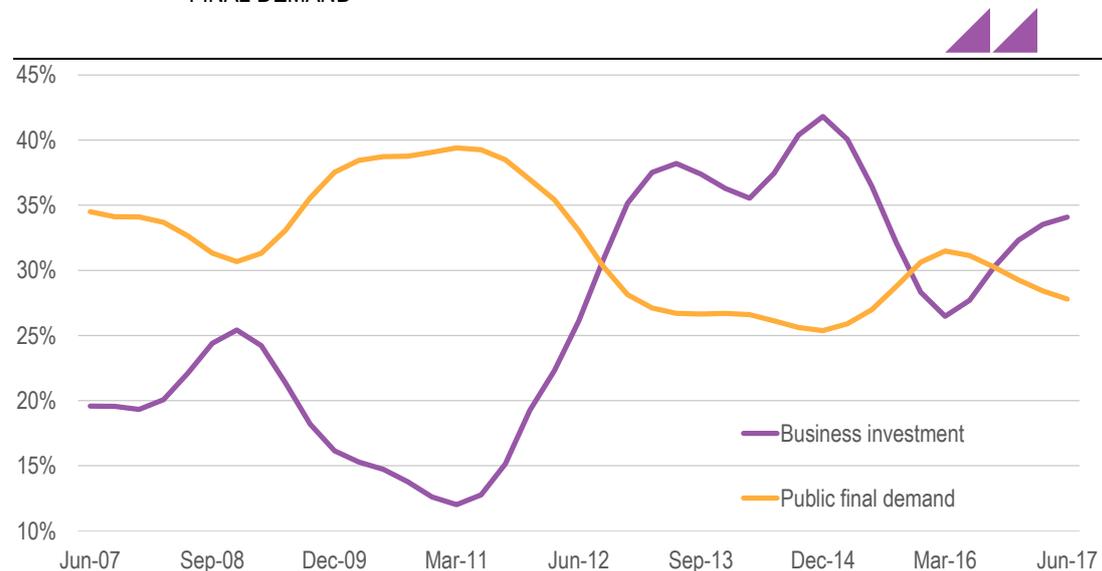


SOURCE: ACIL ALLEN CONSULTING, ABS CAT. 5220.0

Business investment has driven overall levels of growth in the Northern Territory economy in recent years, due to the impact of the development of the Ichthys LNG Project. Business investment has

averaged 31 per cent per annum on average since the commencement of the Project, and has accounted for 34 per cent of all domestic economic activity, as measured by State Final Demand. This has seen business investment overtake government spending and investment activity in the Territory (as measured by Public Final Demand) as the key driver of domestic economic growth (see Figure 2.2 below).

FIGURE 2.2 NT BUSINESS INVESTMENT AND PUBLIC FINAL DEMAND AS A SHARE OF TOTAL FINAL DEMAND



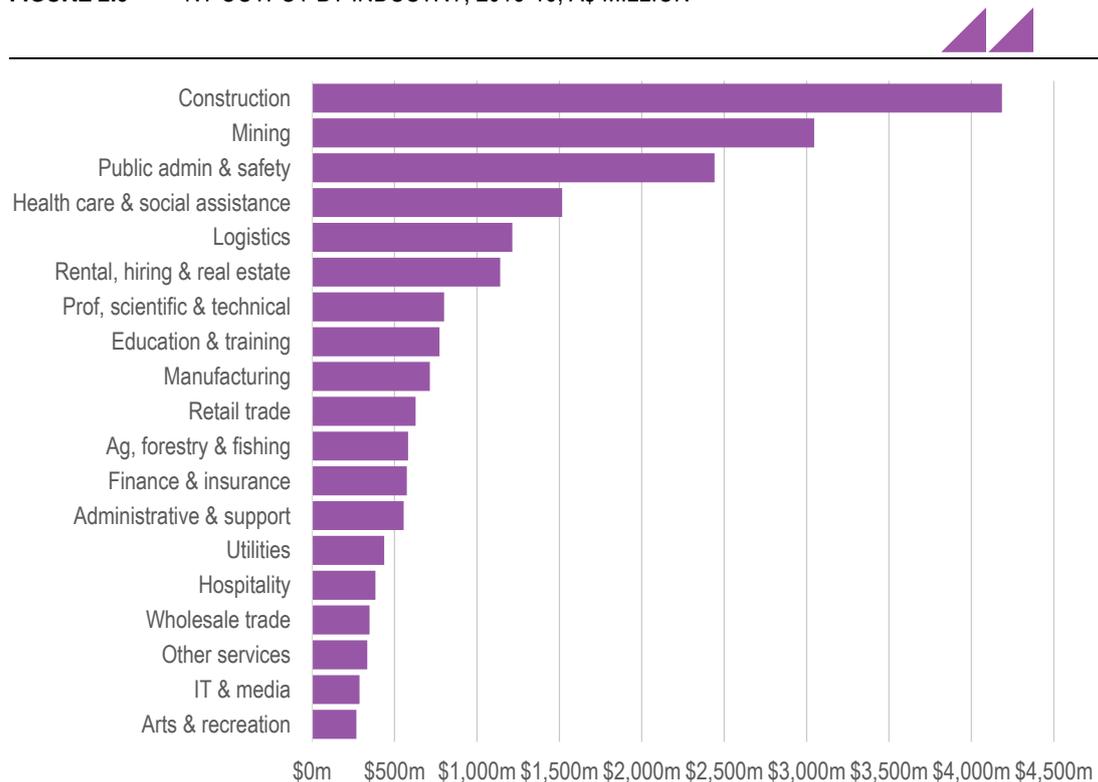
SOURCE: ACIL ALLEN CONSULTING, ABS CAT. 5242.0

Historically, it has been government that has been the dominant sector of the Northern Territory economy, due in large part to the Commonwealth's large defence presence. However, in recent years significant development in the resources sector has seen it overtake the public sector as the driver of the Territory's economy. The substantial developments in the resources sector has in turn stimulated construction activity, which became the largest contributor to the Territory economy in 2015-16.

By value add, the largest industries in the Northern Territory in 2015-16 were Construction (\$4.2 billion or 21 per cent of the economy), Mining (\$3 billion or 15 per cent of the economy), and Public Administration and Safety (\$2.4 billion or 12 per cent of the economy) (refer to Figure 2.3).

However, ACIL Allen estimates that as the Ichthys LNG Project transition from construction to production, this will see the Mining industry overtake the Construction industry to become the largest industry in the Northern Territory.

FIGURE 2.3 NT OUTPUT BY INDUSTRY, 2015-16, A\$ MILLION

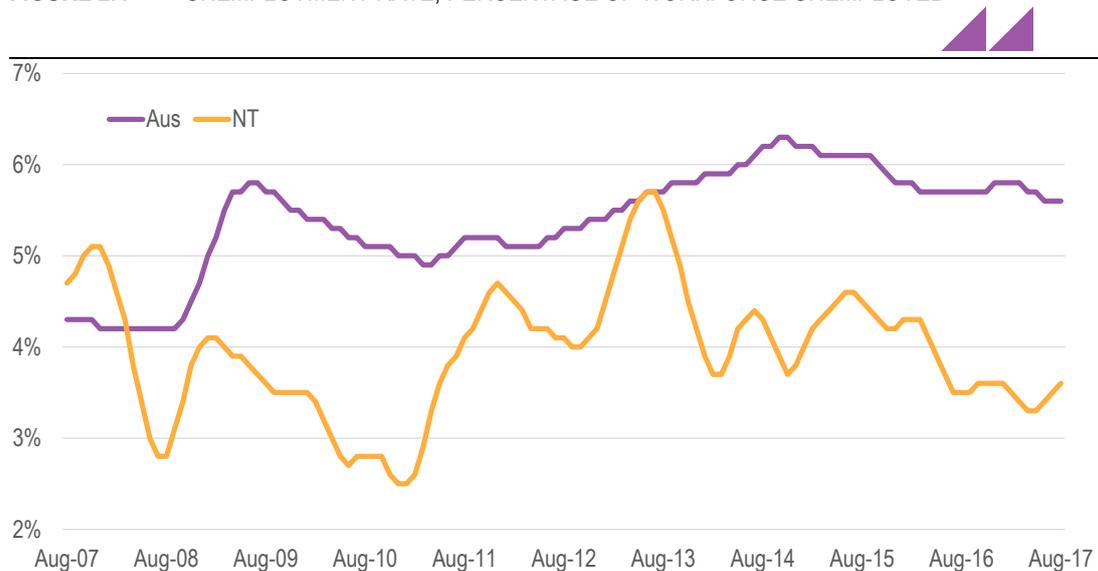


SOURCE: ACIL ALLEN CONSULTING, ABS CAT. 5220.0

2.2 Labour market trends

The Northern Territory historically has had high levels of labour force utilisation. Overall levels of labour force participation have averaged 74 per cent over the past decade, which is well above the national average of 65 per cent. Employment opportunities have in turn meant that the average rates of unemployment are well below those recorded in another other part of Australia (refer to Figure 2.4 below).

FIGURE 2.4 UNEMPLOYMENT RATE, PERCENTAGE OF WORKFORCE UNEMPLOYED

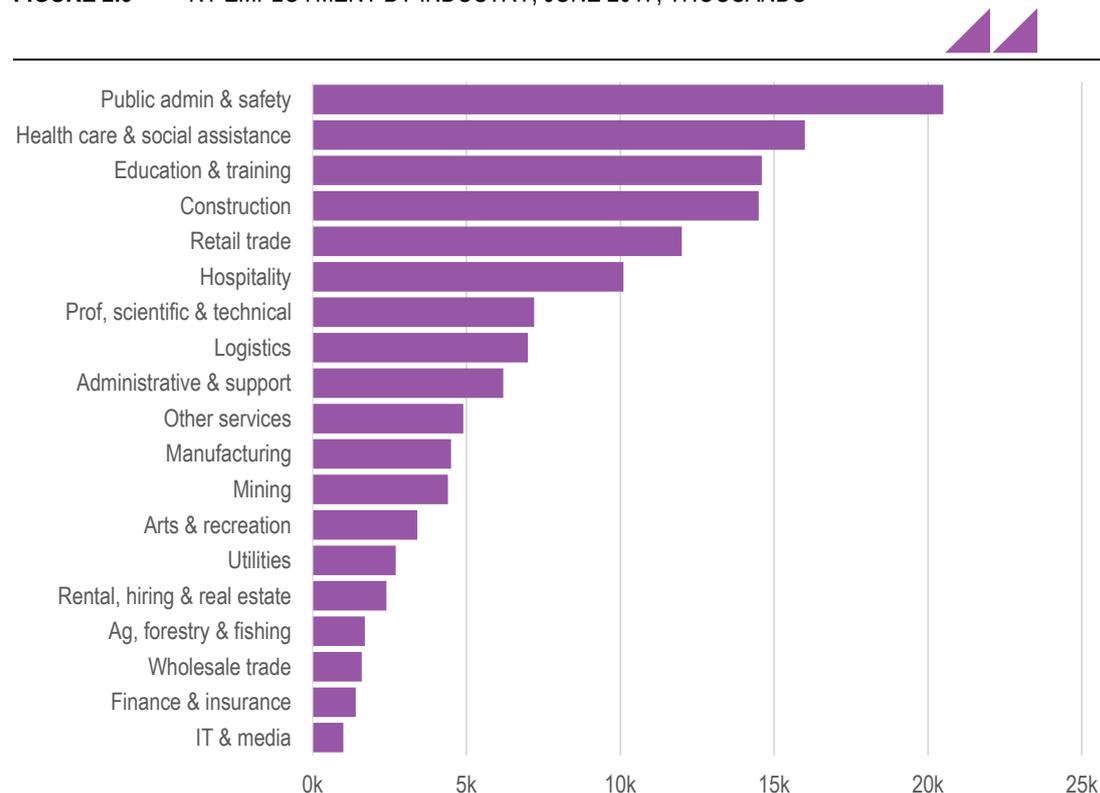


SOURCE: ACIL ALLEN CONSULTING, ABS CAT. 6202.0

Total employment in the Northern Territory was 132,200 in August 2017, which was just below the record high of 139,900 in February 2017. Over the five years to August 2017, total employment has increased by 5,600 or 4.4 per cent.

Employment trends in the Northern Territory have been largely driven jobs growth in government and in construction, which has increased its capacity in line with developments in the resources sector. Over the past five years, there has been 5,100 new jobs created in government, with a further 2,900 new jobs created in construction. Against these trends, the largest decreases in employment have been seen in agriculture (4,700) and wholesale trade (1,700).

FIGURE 2.5 NT EMPLOYMENT BY INDUSTRY, JUNE 2017, THOUSANDS



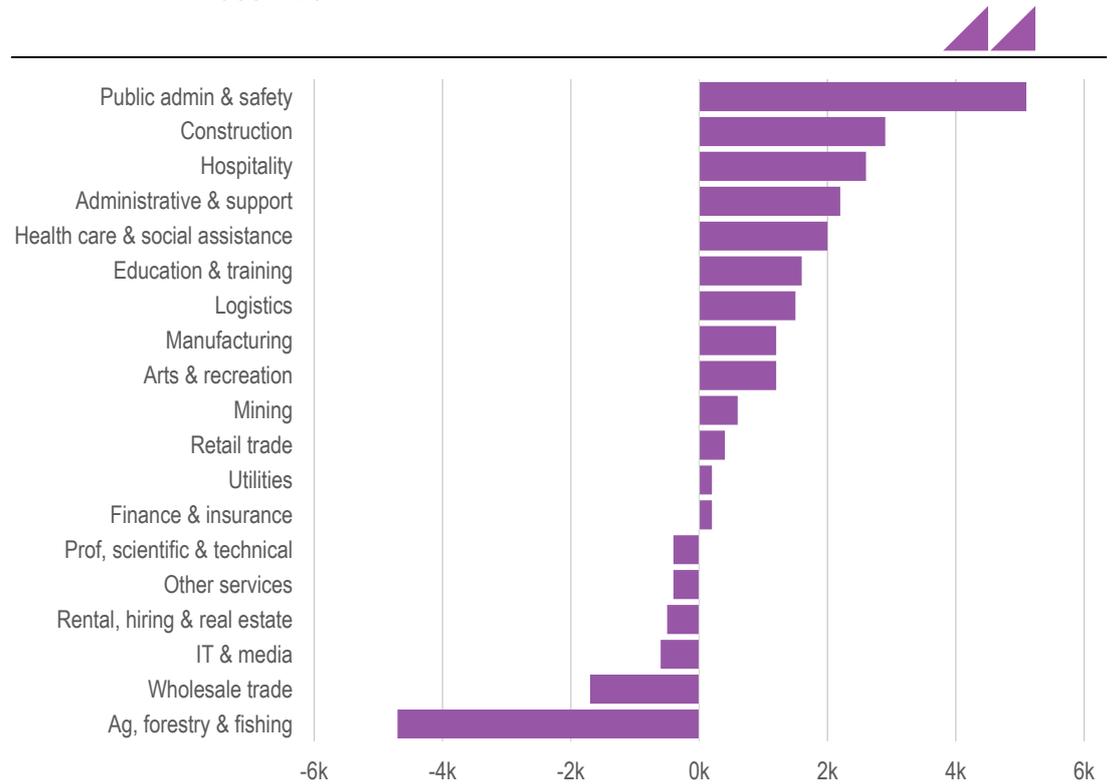
SOURCE: ACIL ALLEN CONSULTING, ABS CAT. 6202.0

Wage trends in the Northern Territory have typically followed broader wage trends across the national economy in recent years. Despite robust labour market conditions in the Territory, wages growth (as measured by the Wage Price Index (WPI)) has trended lower in recent years, due to the combination of the unwinding of the resources boom, structural factors such as lower levels of productivity, and the low inflation environment.

Over the year to June 2017, wages growth in the Territory averaged 2.1 per cent, which is well down on the most recent high of 4.2 per cent in December 2011 during the height of the resources boom. Across the public and private sectors, significant variances emerge, with public sector wages growing by three per cent over the year to June 2017, compared to just 1.7 per cent in the private sector.

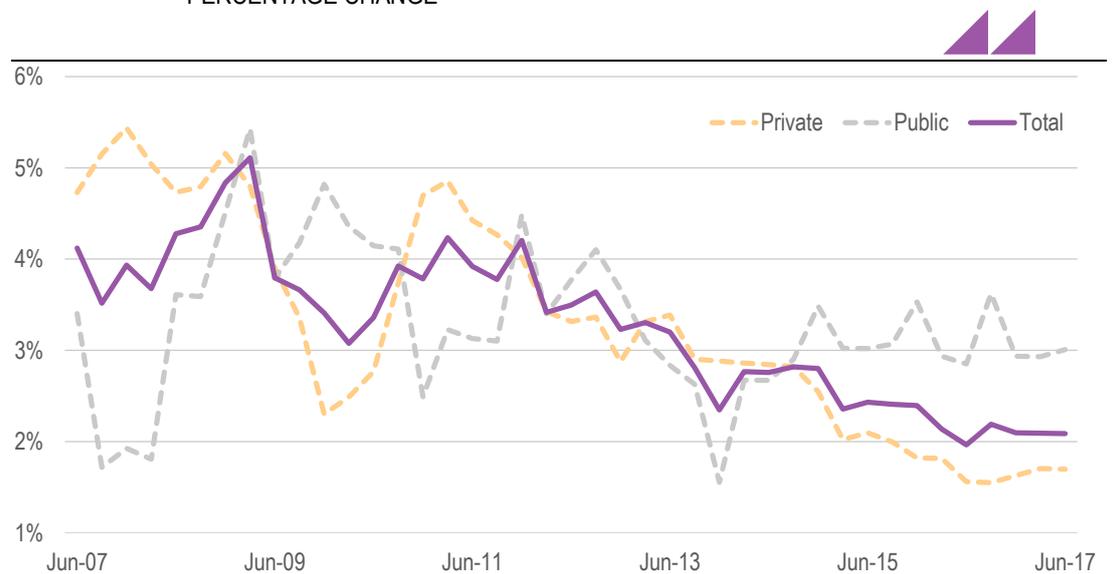
These trends are broadly consistent with the trends across the national economy, where the WPI rose by 1.9 per cent over the year to June 2017.

FIGURE 2.6 NT EMPLOYMENT BY INDUSTRY, CHANGE BETWEEN JUNE 2012 & JUNE 2017, THOUSANDS



SOURCE: ACIL ALLEN CONSULTING, ABS CAT. 6202.0

FIGURE 2.7 NT WAGE PRICE INDEX, PUBLIC SECTOR, PRIVATE SECTOR AND TOTAL, ANNUAL PERCENTAGE CHANGE



SOURCE: ACIL ALLEN CONSULTING, ABS CAT. 6345.0

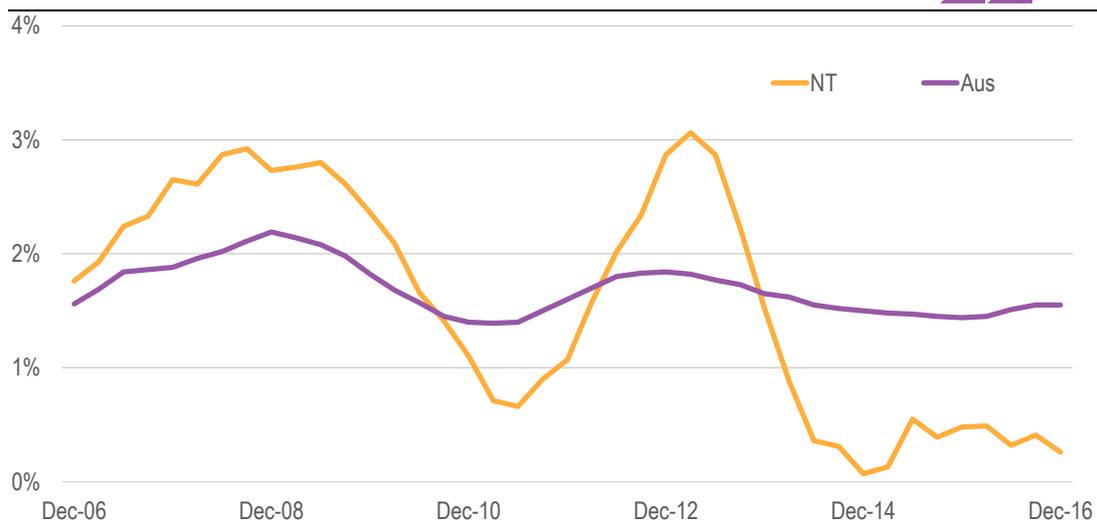
2.3 Population trends

In recent years, population growth in the Northern Territory has slowed significantly relative to the demographic trends in other parts of Australia. Over the 12 months to December 2016, the population

of the Northern Territory grew by just 0.3 per cent, which was the slowest rate of growth of any state or territory in Australia, and well down on the most recent high of 3.1 per cent in March 2013.

By contrast, population trends across Australia have been relatively stable, with the estimated resident population in Australia increasing by an annual rate 1.6 per cent by the end of 2016. The constancy of Australia's population trends reflects the relatively stronger rates of population in the larger states of New South Wales (annual growth 1.5 per cent by the end of 2016) and Victoria (annual growth of 2.4 per cent), offsetting the slowing rates of population growth in the resources states like Western Australia (annual growth of 0.7 per cent by the end of 2016), Queensland (1.5 per cent) and the Northern Territory.

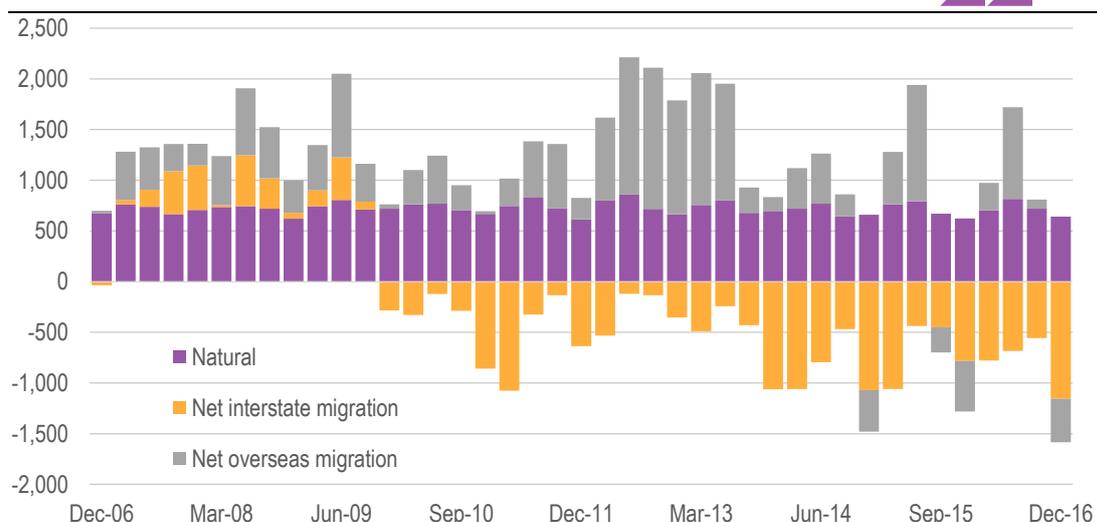
FIGURE 2.8 POPULATION GROWTH, ANNUAL PERCENTAGE CHANGE



SOURCE: ACIL ALLEN CONSULTING, ABS CAT. 3101.0

The end of the resources boom has had a pronounced impact on the population trends in the predominately mining states and territories in Australia. For the Northern Territory, this has seen the levels of overseas migration fall significantly (see Figure 2.9), as potential overseas migrants seek to settle in other parts of Australia where their job prospects are stronger.

FIGURE 2.9 COMPOSITION OF NT POPULATION GROWTH



SOURCE: ACIL ALLEN CONSULTING, ABS CAT. 3101.0

2.4 Northern Territory Government finances

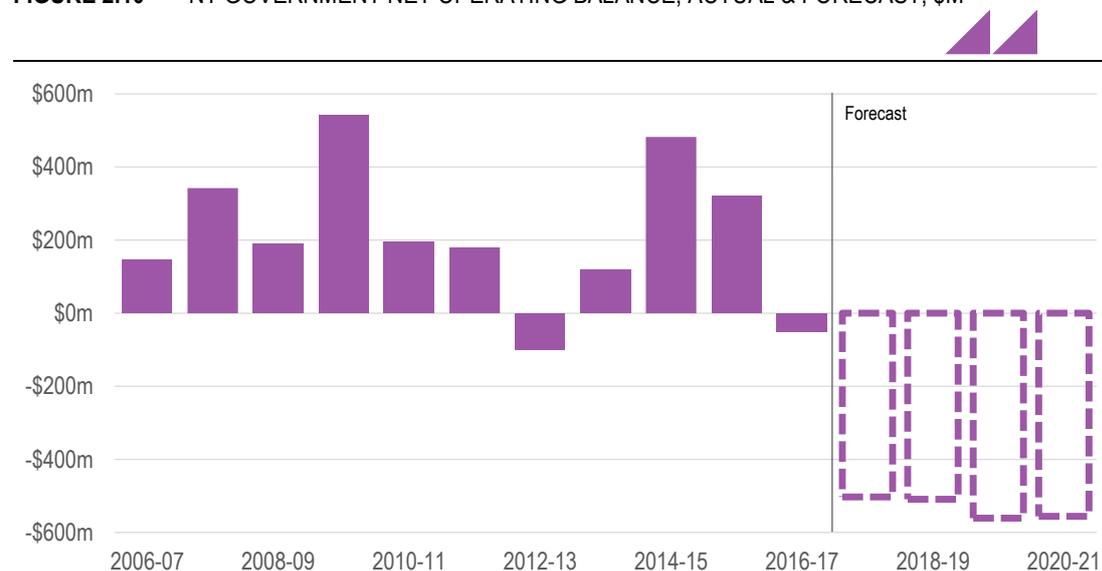
The Northern Territory's 2017-18 Budget, released on in May 2017, projects five consecutive net operating deficits for the Territory's General Government sector (the arm of government that provides most services to the community), with net debt rising from \$2.4 billion to \$5.5 billion between 2016-17 and 2020-21. The Northern Territory non-financial public sector raised \$1.9 billion in revenue from its own sources in 2016-17, and recorded total operating expenditure of \$6.5 billion.

The Goods and Services Tax, including redistribution effects, is the Northern Territory Government's largest source of revenue, accounting for 49 per cent of the Territory's revenue in 2016-17 (the last year of actual data). With a large land mass and low population density, the delivery of government services is a challenge in the Northern Territory. The Commonwealth Grants Commission's formula for distributing the GST assessed the Northern Territory Government requires between four and five times the hypothetical equal per capita distribution of GST revenue.¹

Expenditure challenges are writ large across all elements of Northern Territory public finances. The high share of the Northern Territory's population that is Aboriginal or Torres Strait Islander, remoteness and regional costs, higher wage costs, and lack of administrative scale all result in the Commonwealth Grants Commission assessing the Territory as requiring significant assistance from the GST to help in the provision of services, vis-à-vis the other States and Territories. The Northern Territory has been a significant recipient State in the GST distribution system since its inception.

However, the Northern Territory's broader public finance challenges are a relatively recent phenomenon. This is because as a result of the release of the 2016 Census the Australian Bureau of Statistics believes the population of the Northern Territory is smaller than previously thought, while the Commonwealth Grants Commission believes the Northern Territory requires less GST per capita than previously thought to compensate it for structural spending challenges.² NT Treasury considers this is a structural shock to the Territory's finances.

FIGURE 2.10 NT GOVERNMENT NET OPERATING BALANCE, ACTUAL & FORECAST, \$M



SOURCE: AUSTRALIAN BUREAU OF STATISTICS, CONSECUTIVE NT BUDGETS

2.5 Recent Australian energy market developments

Over time, the individual energy markets across Australia's eastern states have become joined up through a series of policy changes and asset investments. The system is referred to as the "National Electricity Market", or NEM for short. Broadly speaking, it encompasses the full supply chain from the

¹ Commonwealth Grants Commission. 2017. *2017-18 Update Report*. Accessed online at <http://www.cgc.gov.au>

² NT Treasury. 2017. *2017-18 State Budget, Northern Territory*. Accessed online at <http://www.budget.nt.gov.au>

extraction of hydrocarbons and other fossil fuels through to the consumption of electricity, gas and other fuels by domestic consumers and processing for export.

A series of significant developments in Australia's energy market have emerged in recent years, driven by rapid technological change, the pressing need for action to address climate change, and the development of new onshore and offshore hydrocarbon industries targeting both domestic and international sales of petroleum products.

Broadly speaking, these issues have manifested in significant uncertainty regarding the future direction of energy policy in Australia; higher wholesale gas prices, which feed through the entire NEM supply chain; and pressures to rapidly adjust to low emissions energy technologies.

The principal short term issue is an elevated level gas market uncertainty in eastern Australia. The long-anticipated transition of the east coast domestic gas market as a result of the development of six large export LNG trains at Gladstone has reached a critical point, with the last three trains having been commissioned between December 2015 and September 2016. The full extent of the dislocation in the domestic gas market caused by the LNG projects is now being felt as production ramps up and the market moves to a new equilibrium state.

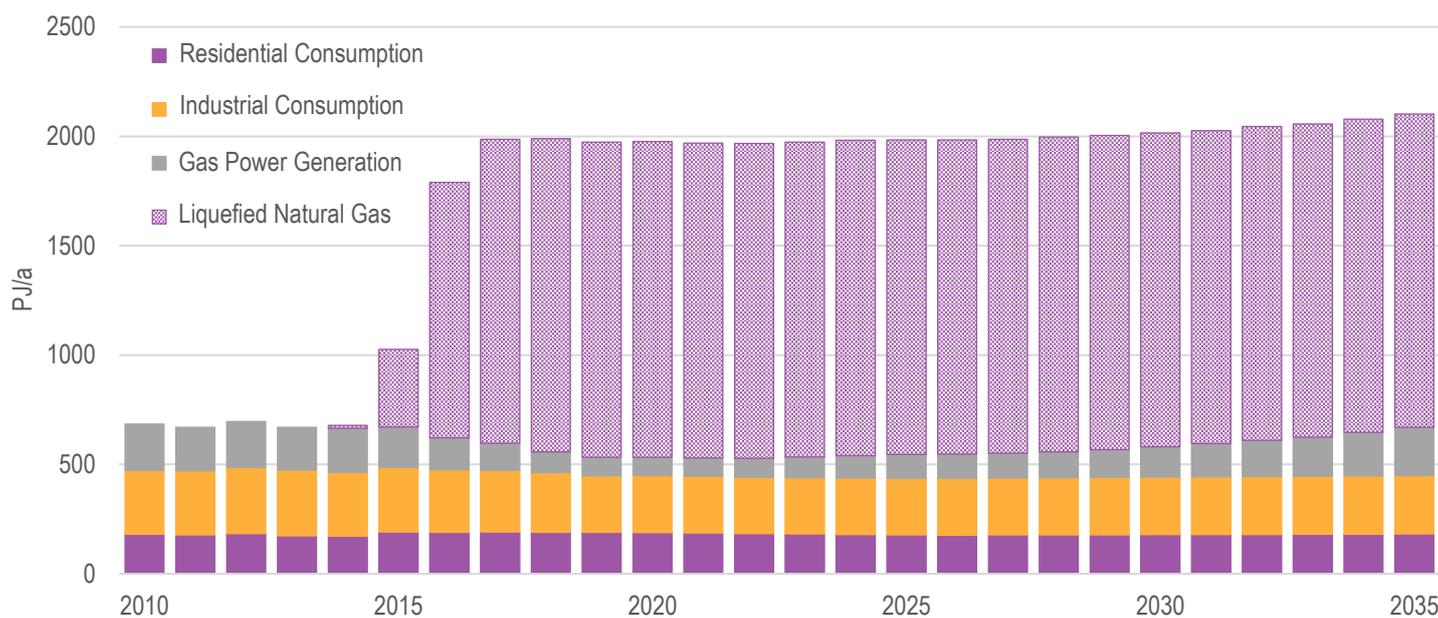
A number of other risk factors have become more prominent in recent times. A relatively severe winter in 2016 combined with constraints on the electricity interconnector between Victoria and South Australia resulted in high electricity and gas prices which caused distress for large industrial users and brought a renewed political focus on the idea of an electricity interconnector between South Australia and New South Wales.

2.5.1 Eastern Australia gas demand and the LNG export transformation

Over the past six years there has been an unprecedented transformation of the eastern Australia 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 in excess of 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) released its 2016 National Gas Forecasting Report (NGFR) in December 2016. Figure 2.11 shows 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) under AEMO's Neutral scenario. This shows a tripling of total gas demand in eastern Australia, driven by the rapid expansion of LNG production from the six LNG trains now operational at Gladstone in central Queensland.

FIGURE 2.11 HISTORICAL AND FORECAST GAS DEMAND IN EASTERN AUSTRALIA



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

These LNG projects have had impacted on the domestic gas market by reducing the availability of gas to supply domestic markets; affected the price of domestic gas and the ways in which gas prices are determined; and affected levels of domestic gas consumption, particularly in the power generation sector.

Gas for power generation was, for a number of years, expected to be a driver of strong growth in demand for gas in eastern Australia. Gas-fired power generation was commonly seen as offering a cleaner energy transition pathway to a lower emissions future. However, in practice, the role of gas-fired generation in the eastern Australian market has evolved very differently.

With large amounts of large-scale renewable energy (mostly wind) being added to the system to meet mandated renewable energy targets, and strong uptake of subsidised rooftop solar photovoltaic systems, the demand for centrally-generated electricity in the National Electricity Market has fallen and average wholesale electricity prices have been suppressed. In these circumstances, and with tight gas supply and rising gas prices, a number of large gas-fired generators have been mothballed or de-rated. This has allowed them to profit by using their contractual gas entitlements to sell gas to LNG and/or other domestic gas buyers, rather than using it to generate electricity. The Tamar Valley (Tasmania)³ and Swanbank E (Queensland) combined cycle gas turbine (CCGT) generators have been mothballed, and the Pelican Point CCGT in Adelaide has cut back its operations and on-sold much of its gas entitlements⁴.

The overall result has been to drive a significant reduction in recent and projected gas demand in the eastern Australian domestic market. This is shown in Figure 2.12. Overall domestic demand is expected to decline from 700 PJ per annum in 2012 to around 530 PJ per annum by 2019. Most of the decline will occur in the gas-fired power generation sector, with gas use by large industrial consumers also expected to fall. In the retail residential and commercial sectors consumption is expected to remain relatively flat, with increasing customer numbers (driven by demographic growth) offset by

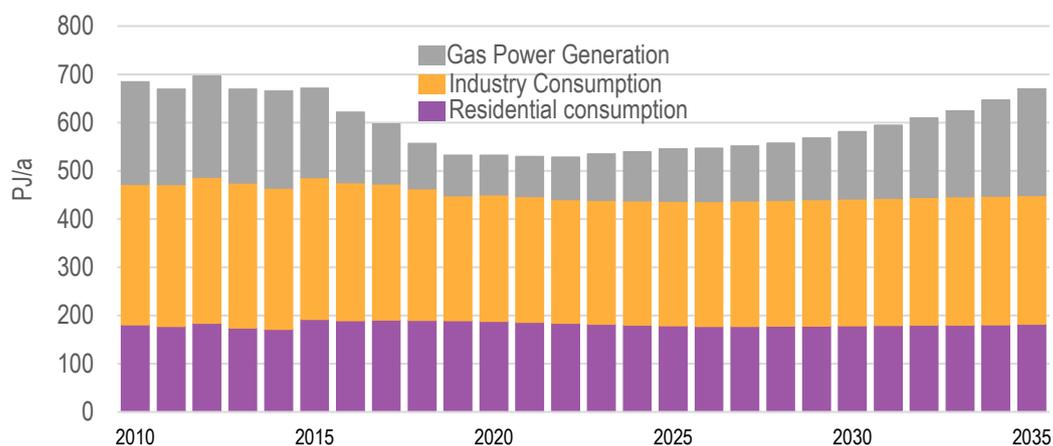
³ Tamar Valley was temporarily returned to service in 2016 in response to an extended outage on the Basslink electricity interconnector between Victoria and Tasmania.

⁴ In March 2017, the owner of Pelican Point (Engie) announced that it would recommission its second turbine by July 2017, returning the station to full capacity. This decision followed a deal in which Origin Energy agreed to provide gas to Pelican Point and to enter into an offtake agreement covering 240 MW of capacity from the station. The deal follows critical power shortages and blackouts in South Australia in late 2016 and early 2017, and is designed to improve the security of the grid in South Australia following closure of coal-powered generation at Port Augusta.

declining average consumption per customer (as a result of improved appliance efficiency, better building standards and increased penetration of electric reverse-cycle air-conditioning).

The steep decline in gas-fired power generation reflects a number of factors: abnormally high levels of gas-fired generation in the recent past (particularly in 2013 and 2014) driven by readily-available and low cost gas from the ramp-up of coal seam gas (CSG) production in Queensland; rising gas prices resulting in lower levels of economic dispatch of gas-fired generators; and increased penetration of renewable generation sources displacing marginal gas-fired generation.

FIGURE 2.12 HISTORICAL AND FORECAST DOMESTIC GAS DEMAND IN EASTERN AUSTRALIA



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

Implications for eastern Australia gas supply

The structural transformation of the eastern Australia gas market brought about by the establishment of the Queensland LNG industry has seen a large increase in the demand for east coast natural gas with a consequent tightening of supply to domestic gas buyers. At the same time, the LNG developments have seen the rapid expansion of gas production from CSG fields in Queensland. The LNG export developments have been the primary driver for this increased production, although some of this gas has been (and continues to be) supplied to the domestic gas market.

It is nevertheless the case that a large part of the gas production capacity in eastern Australia has been committed, on a long-term basis, to support LNG production activities. The affected production sources include not only the Queensland CSG projects controlled by the LNG proponents who have prioritised delivery to the LNG facilities over domestic market sales. It has also seen the commitment of large volumes of third-party gas supply, under long-term contract arrangements, to supply additional gas to the LNG projects. There is anecdotal evidence that, for at least some of the Queensland CSG fields intended to support LNG production, production performance has been below design expectations and the costs of production higher than anticipated. As a result, LNG project proponents have turned to third-party producers—traditionally suppliers to the domestic market—to seek incremental gas supply.

While the LNG projects have increased demand for gas in eastern Australia, they have also led to development of large tracts of gas, and has increased the number of potential suppliers to the domestic gas market. These newly developed sources of gas could, depending on market conditions, supply the domestic gas market. Indeed, data published by AEMO on the Natural Gas Services Bulletin Board confirms that, during the severe southern winter in July 2016, QCLNG diverted some gas supply from its Gladstone operations into the southern states domestic market.

2.5.2 Northern Gas Pipeline

Jemena is currently constructing the Northern Gas Pipeline (NGP) between Tennant Creek in the Northern Territory and Mount Isa in north-west Queensland. The NGP is designed to allow gas from the Northern Territory to be delivered into the Eastern Australian market from late 2018. To the extent that the project succeeds in allowing substantial quantities of competitively priced gas from the Northern Territory to enter the East Coast market, the project represents a competitive threat to other sources of gas supply in eastern Australia.

Jemena took delivery of the first batch of pipe for the NGP in October 2016 and has commenced construction. However the size of the project has been scaled back, reflecting a lack of customer commitment. The diameter of the pipeline has been reduced to 12" (from the 14" diameter pipe originally planned), with a corresponding reduction in throughput capacity from 120 TJ/d to 90 TJ/d.

Given the current scarcity of gas available for commitment into new long-term contracts in the east coast market, this lack of customer support strongly suggests that the issue facing the NGP project relates to a lack of proven gas reserves available to support firm gas sales agreements, rather than a lack of demand from end-user customers. Apart from the gas being sold into the project by the Northern Territory government from its Blacktip entitlements, no other gas supply has yet been committed to the project. The Blacktip gas has effectively been committed to the Mount Isa market in Queensland (which has an annual gas requirement comparable to the annualised throughput capacity of the NGP in its current configuration).

Under current policy settings, NGP does not appear likely to deliver large quantities of competitively priced gas into the east coast market.

2.5.3 Australian Domestic Gas Security Mechanism

In response to the current tight gas supply situation, sharply rising prices and forecasts of potential supply shortages, the Australian Government has moved to bolster domestic gas supply by introducing the Australian Domestic Gas Security Mechanism (ADGSM) which will rely on the Australian Government's constitutional powers in relation to export controls. The ADGSM has been described by the government as a 'targeted, temporary measure ... to repair markets and allow Australian users to compete on a level playing field'. The objective of the policy is to ensure that there is a secure supply of gas to meet the forecast needs of Australian gas consumers by requiring, if necessary, LNG producers that are drawing gas from the domestic market to limit their exports or to find offsetting sources of new gas.

The ADGSM came into effect on 1 July 2017. Operational details are set out in Guidelines dated 30 June 2017. In summary the ADGSM will operate as follows:

1. Export controls may be triggered on an annual basis if the Minister determines that there is likely to be shortage of domestic gas supply in the next year, and that LNG exports are likely to contribute to that shortfall.
2. If such a trigger occurs, LNG exporters would provide information to determine if they are 'net-deficit' projects that are withdrawing more gas from the domestic market than they are contributing to it. LNG exporters assessed as being 'no effect' or 'net suppliers to the domestic market' will not face any export restrictions.
3. The extent of any export restrictions will depend on the 'Total Market Security Obligation' (TMSO) determined by the Minister and the proportion of the gas shortfall attributable to net-deficit LNG projects.
4. 'Net deficit' exporters will be required to contribute to the achievement of the TMSO on a pro-rata basis according to the extent of their market deficits. This will be done by restricting Export Permissions for these exporters.
5. Each 'net deficit' exporter will be required to meet its individual Exporter Market Security Obligation either by restricting exports, or by increasing domestic production.

The Guidelines restrict the scope of 'domestic suppliers' by excluding suppliers that developed gas for the primary purpose of export. The tests also involve the concept of 'own gas', with a source of gas to the LNG plants being considered 'own gas' rather than gas obtained from domestic suppliers if it is

owned by an LNG joint venture, or by one of the joint venture partners who developed and contracted the gas for LNG export sale. These provisions will reduce significantly the amount of gas deemed to be diverted from domestic markets by the LNG project.

Assessment

On the basis of what is set out in the Guidelines it appears that the only party likely to be caught under the ADGSM arrangements is the Santos-operated Gladstone LNG project, which is heavily reliant on third party gas. However, depending on how the definitions of 'third party gas' and 'own gas' are interpreted, even GLNG's obligations may be relatively limited. We are aware of several 'third party' sales contracts under which GLNG has access to gas supply totalling between 475 and 635 TJ/day. However, a number of these contracts are likely to meet the test for 'own gas' and/or 'export compatible third party gas'.

GLNG is likely to be the only liable party, and its net deficit is likely to be relatively small for the reasons mentioned above. Even if the Minister declares a domestic shortage and imposes an Export Market Security Obligation on GLNG, questions remain regarding the price at which that gas would be offered to the market, how it would be sold, and what would happen to any gas offered for sale but not taken up. The Guidelines are largely silent on the matter of the price or terms upon which any gas withheld from export under the ADGSM would be offered for sale to domestic consumers.

On balance, we think that the ADGSM is unlikely to result in any large quantities of additional gas being supplied into the domestic market, nor is it likely to result in significant downward pressure on domestic gas prices.

2.5.4 Regulatory reform: the Vertigan Inquiry

In June 2017 the Gas Market Reform Group, chaired by Dr Michael Vertigan AC, published a final design recommendation for a 'Gas Pipeline Information Disclosure and Arbitration Framework'.

The overarching objective of the new information disclosure and arbitration framework is to facilitate access on reasonable terms to services provided by 'non-scheme' (that is, currently unregulated) pipelines, including SEA Gas.

The information disclosure requirements and arbitration processes proposed by Vertigan are set out in changes to the *National Gas Law* that recently passing through the South Australian parliament.

The arbitration process covers disputes on any matter (including price or other terms and conditions). It may be triggered by either the prospective shipper or the pipeline operator. While the arbitration mechanism is a key element of the new framework, it is intended that commercial negotiation will continue as the principal means by which access terms and conditions are determined and that the arbitration mechanism will rarely be triggered. That is, it is intended that the threat of arbitration will be sufficient to encourage the parties to reach a commercial agreement.

The arbitration design involves a three stage process:

Stage 1: Shipper considers whether to seek access having regard to basic information published by pipeline operator

Stage 2: Shipper requests access and enters into commercial negotiations with pipeline operator. Negotiations informed by further information exchanges

Stage 3: If negotiations fail, either party may seek arbitration. Arbitrator to make decision having regard to the arbitration principles

Under the new framework, existing and prospective new shippers may be less inclined to agree to commercially negotiated terms for pipeline services and more inclined to have recourse to arbitration. This is because, while the arbitration process is said to be 'binding', the shipper is not in fact bound to enter into a gas transport services agreement on the terms set out in the arbitrator's decision. The shipper can elect (within 30 days) not to proceed in which case it is still able to continue to negotiate for transport. Under this scenario, the only downside from the shipper's perspective is that it foregoes the right to trigger a new arbitration process (for a similar service) for 12 months. In effect, the

prospective shipper has a free option to see if it can get a better outcome under arbitration than it would achieve by accepting commercially negotiated terms.

2.5.5 The Finkel Review

The Independent Review into the Future Security of the National Electricity Market (the 'Finkel Review', named after the Review's Chair Dr Alan Finkel) was commissioned by the Council of Australian Governments (COAG), in order to address the security and reliability challenges faced by the National Electricity Market in the context of transitioning policy imperatives and emerging and evolving technologies.

The report primarily addresses key issues in the National Electricity Market – such as the balance of security and reliability, affordability and reduced emissions, as well as new technology integration and rising gas prices rendering stations unviable – and provides guidance on measures to address current and future challenges.

Finkel believed energy policy in Australia should be calibrated to deliver four central objectives:

- increased security
- future reliability
- rewarding consumers, and
- lower emissions

The principal recommendation of the review is that technological change is occurring rapidly in the energy sector, and the way forward is to provide certainty to both the energy sector and Australians more broadly as to how Australia will meet its international emissions reduction commitments. In this respect, security references the National Electricity Market's ability to respond to disturbances, which with the inclusion of variable renewable energy generation will require more attention than with more traditional, fossil fuel methods of electricity generation.

Underpinning these are three pillars promoting an "orderly transition" to the future energy mix, better system planning and stronger governance. An orderly transition is upheld by the recommendation of a Clean Energy Target, and the recommendation for a mandatory three years' notice prior to closure of a generator. Improved system planning seeks a system wide grid plan that informs investment decisions and improved reporting and analysis in regards to reliability and security. Stronger governance is recommended to be delivered through a new energy security board, and strengthened market bodies.

The Finkel Review outlines a blueprint of recommendations for the transition that makes special mention of the increased requirement for flexible, gas-fired generation to support the variable renewable energy generation. Finkel also noted that in the short to medium term tightening gas supply, and therefore rising prices, threaten the economics of such generators.

Despite the clear findings and roadmap provided by the Finkel Review, there remains significant uncertainty regarding the direction of energy policy in Australia.

2.6 The Northern Territory's gas industry and energy markets

The Department of Industry, Science and Innovation suggest the Northern Territory consumed 46.2PJ of natural gas in 2014-15, making it the largest source of energy for the Territory.⁵ This gas is used to produce electricity and to fuel industry, as well as being used in the processing of Liquefied Natural Gas (LNG) that is exported through the Darwin LNG Plant (which does not show up in the Department's statistics as it is not consumed in the NT).

The majority of the Territory's gas is provided by three fields: ENI's Blacktip Gas Field, in the Bonaparte Basin off the north west coast of the Northern Territory⁶ (predominantly for domestic consumption), ConocoPhillips' Bayu-Undan field in the Australia-Timor-Leste Joint Petroleum

⁵ Department of Industry, Science and Innovation, 2016. *Australian Energy Statistics 2016, Table D*. Accessed online at <http://www.industry.gov.au>

⁶ ENI Australia. 2016. *ENI in Australia*. Accessed online at <http://www.eni.com/>

Development Area⁷ (predominantly for LNG exports) and from fields in the Amadeus Basin to the east of Alice Springs, with the Mereenie Oil and Gas Field the major producing play⁸. The Ichthys LNG project, owned and operated by Japanese energy company INPEX, produces LNG at a facility in the Port of Darwin, but extracts gas from the Browse Basin off the north west coast of Western Australia.

The major players in the Northern Territory energy market are NT Power and Water Corporation ('PowerWater'), the State-owned transmission and network company, and Territory Generation, the wholesale provider of electricity. The two entities were formerly one vertically integrated entity but were structurally separated in 2014 as part of a broader program of electricity market reform.⁹ PowerWater and Territory Generation represent a significant share of the residential and small scale commercial/industrial energy markets in the Territory. The Territory has a contestable market for residential and small scale commercial users.

⁷ ConocoPhillips. 2017. *Our Business Activities – Bayu-Undan*. Accessed online at <http://www.conocophilips.com.au/>

⁸ Central Petroleum. 2017. *Mereenie Oil and Gas Field*. Accessed online at <http://www.centralpetroleum.com.au/>

⁹ Territory Generation. 2017. *Territory Generation: About Us*. Accessed online at <http://www.territorygeneration.com.au>



3.1 What is Hydraulic Fracturing?

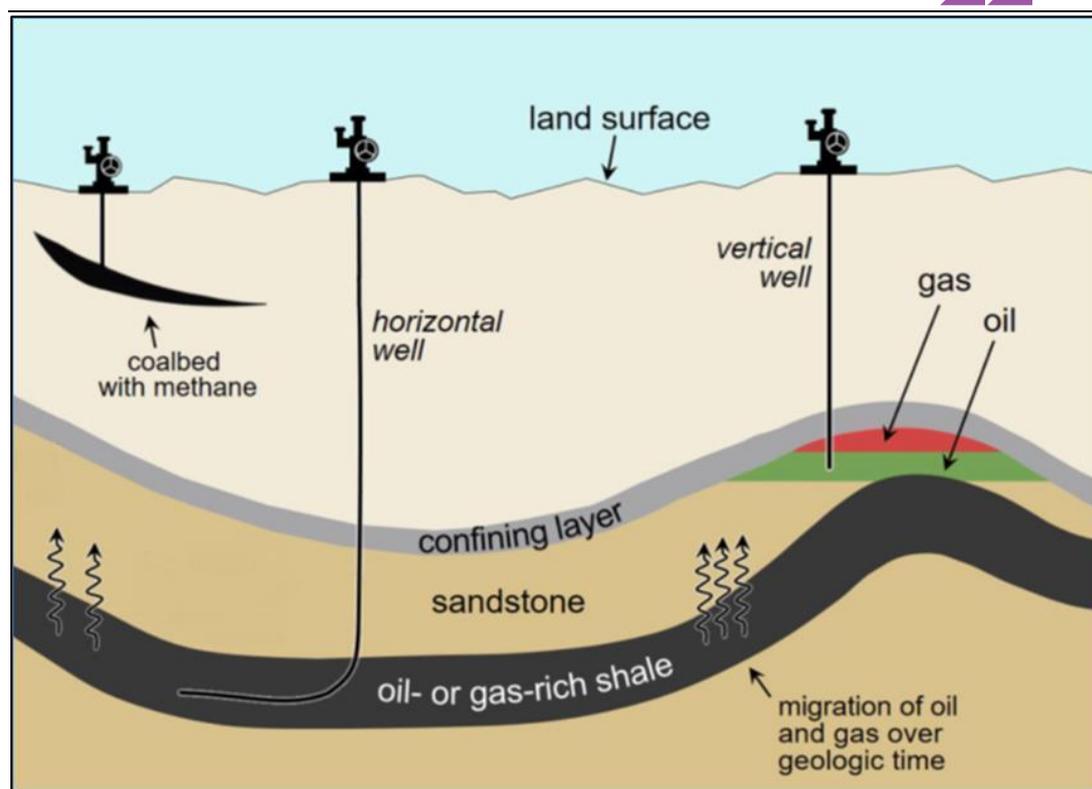
There are two broad types of gas reserves: conventional and unconventional. Conventional gas reserves accumulate in confined areas with well-connected pore spaces in a sedimentary basin. This allows for effective drainage of reserves with well-placed vertical wells. By contrast, unconventional gas reserves accumulate in a larger area amongst more tightly bound and less porous sedimentary basins, which are typically lower in the ground. A visual representation of conventional and unconventional gas accumulations and some of the extraction techniques is provided in Figure 3.1 (overleaf).

Artificial stimulation is typically required to make the gas in unconventional reservoirs flow through a well. One commonly used technique to achieve this is called hydraulic fracturing, commonly known as 'fracking'. Fracking basically involves pumping a mixture of water, sand and chemical additives ('fracking fluid') into the production well, under pressure, so that the rocks containing the gas resources crack. This allows the gas contained in the tight reservoir to flow more freely.

3.1.1 Shale gas versus coal seam gas (CSG)

Fracking is used to extract both coal seam gas (CSG) and shale gas. The two types of resources differ significantly.

- CSG is typically extracted from wells that are much closer to the land surface (300m – 1,000m) than shale wells (1,500m – 4,000m)
- CSG is typically much closer to the surface, and therefore closer to potable water sources such as aquifers. Shale gas is not typically located near aquifers
- CSG is most often extracted using vertical wells, while shale gas is extracted using a combination of vertical and horizontal drilling techniques
- CSG wells are typically low productivity and require a larger number of wells, where shale gas wells produce more energy per well. However, shale wells use more water per well, and operate across a larger underground footprint.
- The land surface area of CSG wells and shale gas wells is largely the same.

FIGURE 3.1 DIFFERENT TYPES OF PETROLEUM ACCUMULATIONS AND DEVELOPMENT

SOURCE: THE INQUIRY, VIA U.S. ENVIRONMENTAL PROTECTION AGENCY.

3.1.2 The fracking process

Shale gas is mainly methane (often with associated liquid hydrocarbons) that is trapped within clay-rich sedimentary rock at depths greater than 1,500 metres. The low permeability of the rock means that gas, either absorbed or in a free state, in the pores of the rock, is unable to flow easily.

To extract shale gas, wells are drilled anywhere from 1,500 – 4,000 metres deep through various layers of rock to access the shale. The wells are lined with various steel casings, which are cemented using fit-for-purpose cement designed to protect groundwater from contamination.

To maximise shale gas recovery a technique called horizontal drilling is used. This technique typically involves the well changing from a vertical to a horizontal direction deep underground.

Before gas can be extracted from the shale gas reservoir, hydraulic fracturing must occur. Hydraulic fracturing is a technique used to enhance the production of the gas. Hydraulic fracturing refers to the injection of fluid (comprising approximately 99.5% water and proppant (sand) and approximately 0.5% chemical additives) at high pressure into targeted sections of the layers of gas-bearing rocks. This creates localised networks of fractures that unlock gas and allow it to flow into the well and up to the surface. An average of 20 to 30 megalitres (ML) of water is used per fracked horizontal well over the life of the well.

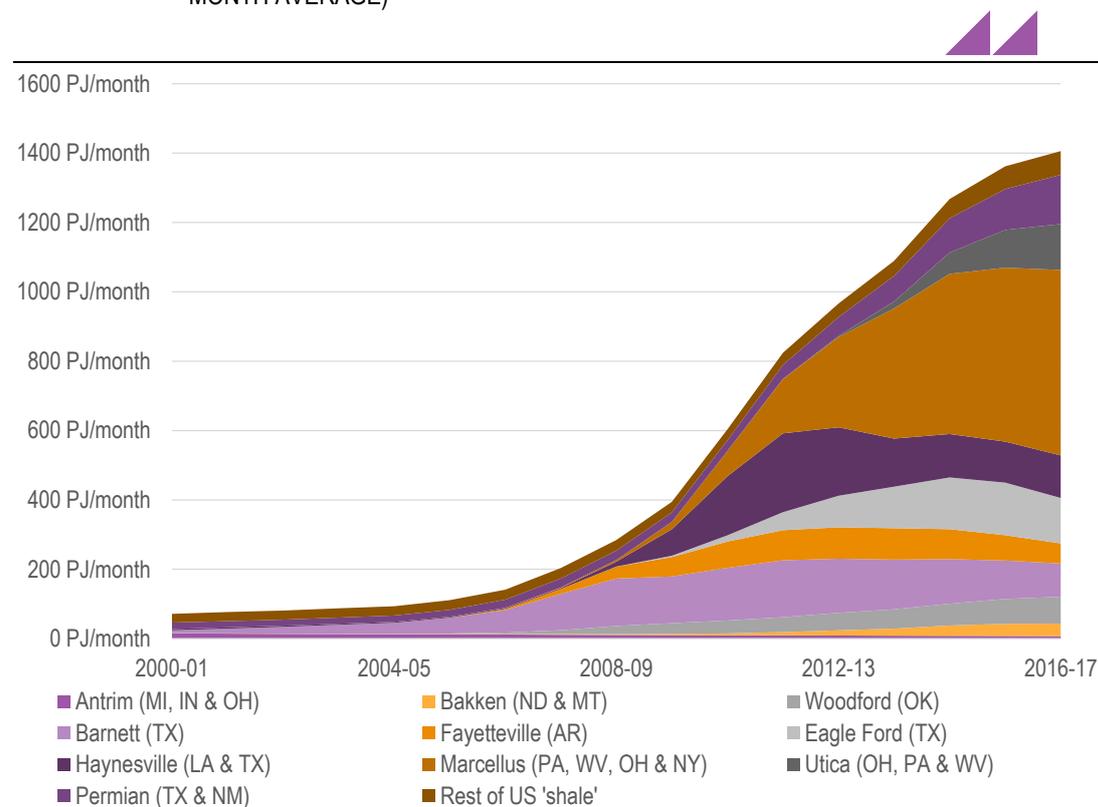
After fracturing, the hydraulic pressure is released and most of the 'frack fluid' is pumped back out of the well. Typically gas production from the well builds up over a period of days or weeks as the frack fluid is recovered (a process known as 'well clean-up'). Much of the sand remains in the well, propping open the cracks so that gas flow is maintained (hence 'proppant').

3.2 The “Shale Revolution”

Fracking is not a particularly new or novel technique for accessing petroleum deposits. However, rapid technological improvements and a period of very high natural gas prices in the United States led to a significant wave of exploration and investment targeting shale gas with horizontal drilling techniques. The result has been a so-called “shale revolution”, which has put significant downward pressure on energy prices in the United States and across the world.¹⁰

Production of petroleum products from US shales has grown exponentially between 2007 and 2017, and the shale gas industry deepens and continues to learn the most economic ways to target and extract oil and gas from shales. According to the US Energy Information Administration, the volume of dry shale gas produced in the United States has increased 15-fold between 2005-06 and 2016-17, from an average of 110.8 PJ per month to 1405.3 PJ per month (Figure 3.2).¹¹

FIGURE 3.2 DRY SHALE GAS PRODUCTION, UNITED STATES, BY MAJOR PLAY, PJ/MONTH (12 MONTH AVERAGE)



SOURCE: ACIL ALLEN CONSULTING, US EIA

US producers have been able to extract more gas per well each year for the past 10 years, as technology advancements like longer horizontal drilling, improved fracturing techniques, and increased knowledge of the geology of formations have led to surging productivity. These conspire to reduce the average cost of establishing a single petroleum well, which is the single largest influence on the wellhead cost of gas produced.¹² More than anything though, there is a strong negative relationship between the total number of wells drilled in a shale gas play and the overall average cost per well drilled in said play (that is, the more wells drilled the lower the marginal cost of establishing a well).

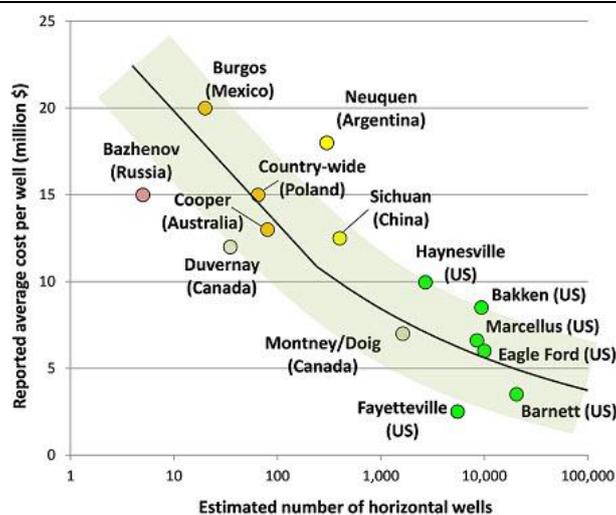
¹⁰ European Commission. 2017. *Shale gas production costs: historical developments and outlook*. Accessed online at <http://www.insightenergy.org/>

¹¹ US Energy Information Administration. 2017. *US dry shale gas production, monthly data*. Accessed online at <http://www.eia.gov>

¹² ACOLA. 2013. *Engineering Energy: Unconventional Gas Production in Australia, A study of shale gas in Australia*. Accessed online at <http://www.acola.org.au/>

This “learning effect”, where the incremental cost of delivering a unit of gas has been shown to fall substantially over time, has been the catalyst behind the shale revolution, and the ability for the shale industry in the United States to deliver gas at increasingly lower prices (Figure 3.3).

FIGURE 3.3 THE INTERNATIONAL SHALE LEARNING CURVE



SOURCE: US EIA

3.3 Shale gas in the Northern Territory

Given the significant uncertainty regarding the shale gas potential of the Northern Territory, ACIL Allen Consulting has prepared this brief summation based on information presented by the Inquiry in its Interim Report, released in July 2017.

There are a range of estimates available regarding the shale gas potential of the Northern Territory. Geoscience Australia believes there is 257,276 PJ of potential gas resource trapped in shale formations across the Territory – the vast majority of this concentrated in the Beetaloo Sub-Basin of the McArthur Basin, in northern central Northern Territory. The US Energy Information Administration’s 2015 *Technically Recoverable Shale Oil and Shale Gas Resources* report for Australia estimated approximately 262 TCF of shale gas was in situ in the Northern Territory’s two most explored basins, Beetaloo and Georgina.¹³

Additional resource is thought to exist to the south (the Amadeus Basin, which is currently subject to conventional gas production), north west (an onshore portion of the predominately offshore Bonaparte Basin), south east (the Georgina Basin) and south-south east (the Pedrika Basin). However, the majority of the effort of potential industry operators has been spent better understanding the geology and petroleum potential of the Beetaloo Sub-Basin.

A map of the Northern Territory’s known and approximated source rocks for hydrocarbons is presented in Figure 3.4 (page 27).

According to the Department of Primary Industry and Resources,¹⁴ there have been eight hydraulically fractured wells targeting unconventional shale gas in the Northern Territory. Four such wells have been drilled in the Georgina Basin, and four in the Beetaloo Sub-Basin.

The most significant well drilled to date is Origin Energy’s (‘Origin’) Amungee NW-1H well, which completed a 57 day production test prior to the moratorium taking effect.¹⁵ The well was a 1,100m

¹³ US EIA. 2015. *Technically Recoverable Shale Oil and Shale Gas Resources: Australia*.

¹⁴ Scientific Inquiry. 2017. *Scientific Inquiry into Hydraulic Fracturing in the Northern Territory: Interim Report, July 2017*. Accessed online at <http://www.frackinginquiry.nt.gov.au/>

¹⁵ Origin Energy. 2017. *Notice to market: Beetaloo Basin drilling results indicate material gas resource, 15 February 2017*. Accessed online at <http://www.asx.com.au/>

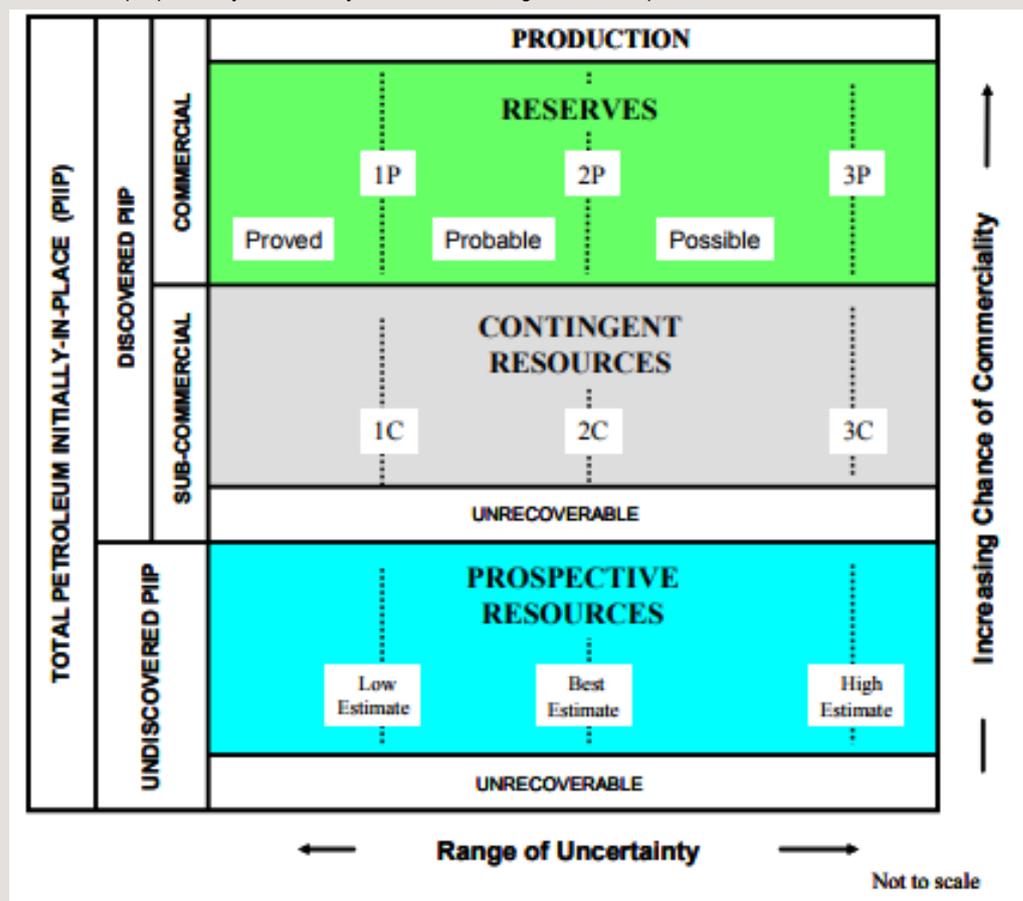
long horizontal fracture stimulated well with 11 fracture stages, targeting the so-called “Velkerri B shale” layer within the basin. Origin reported a positive production test, and in conjunction with additional geological data gathered over its exploration program to date lodged a notice with the Petroleum Resource Management System (PRMS) that identified a “Contingent Resource” of 6.6 TCF of technically recoverable gas (the PRMS system is outlined briefly in Box 3.1). A 6.6 TCF discovery is significant; it is 50 per cent larger than the “Pluto” onshore LNG project in Western Australia, which cost an estimated \$15 billion to develop (including liquefaction facilities).

BOX 3.1 THE PETROLEUM RESOURCE MANAGEMENT SYSTEM

The Petroleum Resource Management System is the system used to classify the commerciality of conventional and unconventional hydrocarbon discoveries in a clear, consistent and transparent manner as it relates to companies listed on the Australian Stock Exchange. All publicly listed Australian companies are required to report on the outcomes of their exploration activities using this framework.

It is a framework that allows companies to determine the quantity of petroleum thought to be in place in a particular area using probabilistic modelling and an assessment of commerciality contingent on the ability to deliver the petroleum to market.

Petroleum deposits effectively move through a codified lifecycle, starting out as prospective resources, progressing to contingent resources – which are deposits with confirmed petroleum in place, but with questions over the commerciality of the deposit – and finally to commercial reserves and eventual production. This framework, prepared by the Society of Petroleum Engineers, is reproduced below.



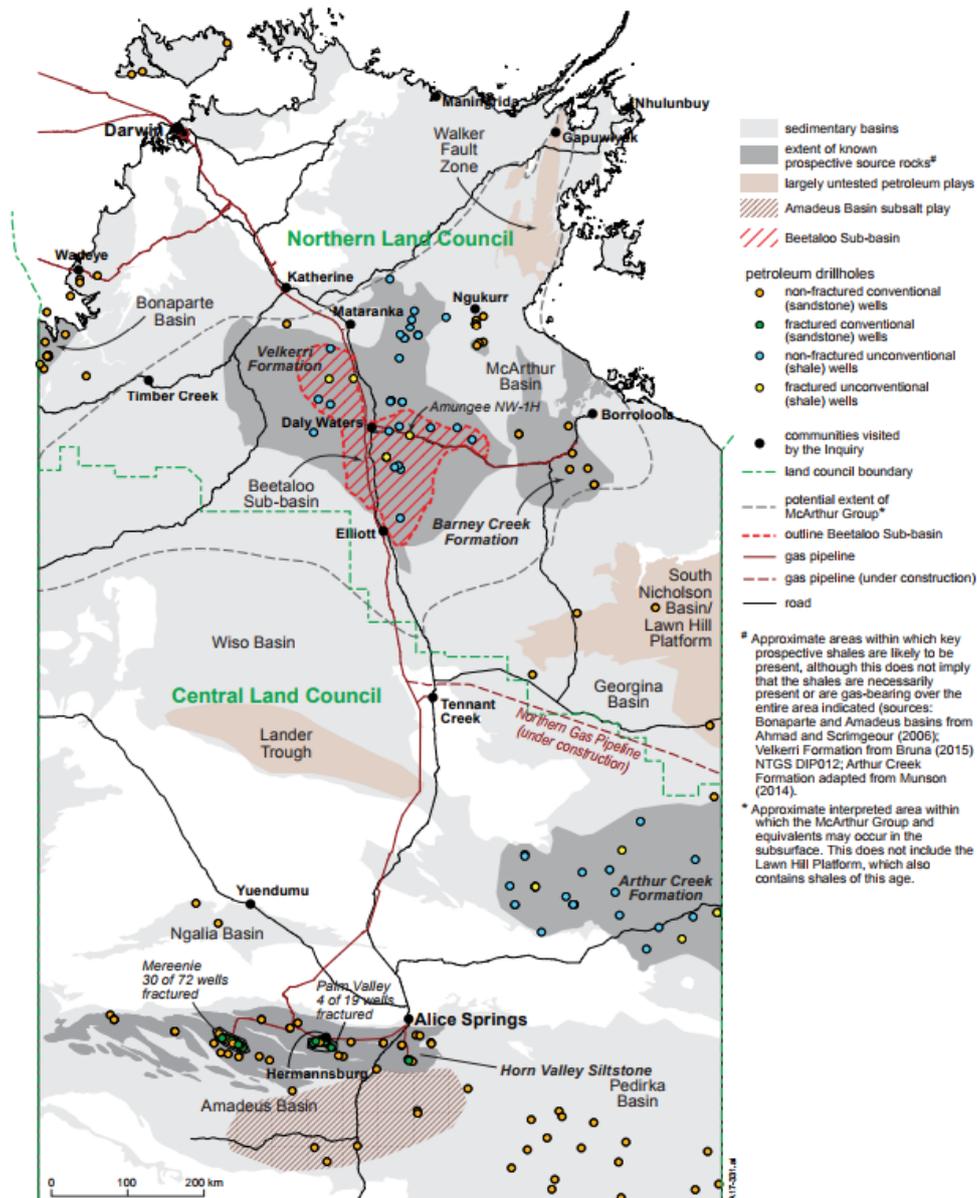
SOURCE: SOCIETY OF PETROLEUM ENGINEERS PETROLEUM RESOURCE MANAGEMENT SYSTEM

Origin Energy’s discovery in the Beetaloo Sub-Basin has been assessed by Origin as a 2C grade contingent resource. In lay terms, this means Origin is fairly certain there is commercial scale

petroleum in place, but requires further testing to confirm this, and still has significant commercial hurdles to overcome to progress to determination of a commercial reserve.

Origin's contingent resource is the only material discovery made so far. While the Northern Territory is thought to have significant shale gas, it is a mostly unknown proposition and requires significant further exploration, testing and appraisal to ascertain a more defined estimate of its potential. There are three lead industry proponents seeking to undertake exploration and appraisal of shale gas deposits in the Beetaloo Sub-Basin and beyond. These are Origin Energy Ltd (an ASX-listed energy company), Pangaea Resources Pty Ltd (a privately held exploration company) and Santos Ltd (an ASX-listed energy company). These three companies are the lead operators in the region, with a range of other companies holding shares in exploration and appraisal projects. There are also a raft of companies which hold exploration permits covering mostly unexplored regions of the Northern Territory.

FIGURE 3.4 POSSIBLE SHALE GAS DEPOSITS, NORTHERN TERRITORY



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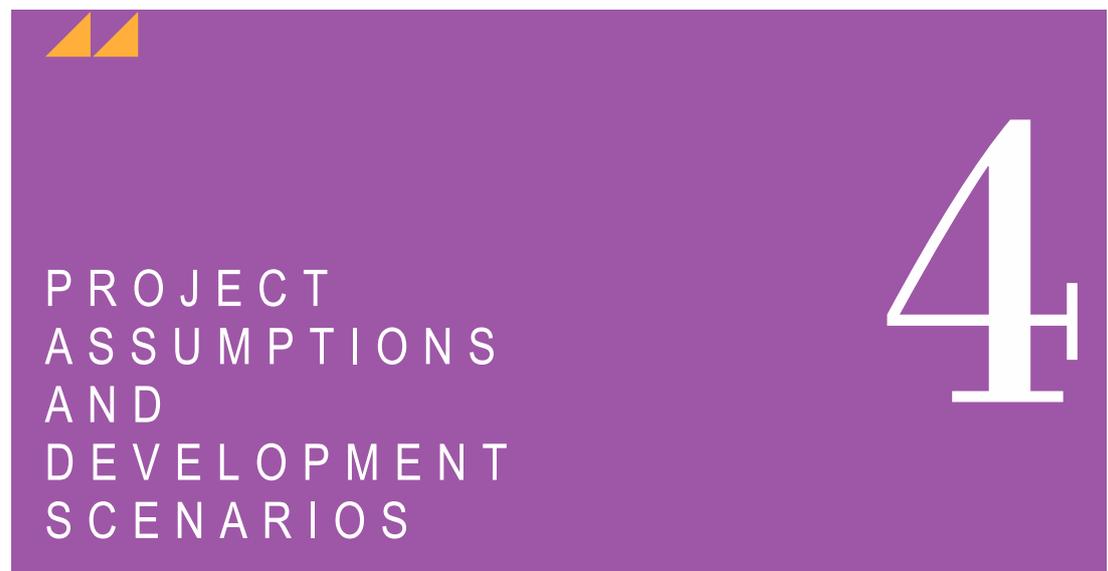


SOURCE: SCIENTIFIC INQUIRY INTO HYDRAULIC FRACTURING



SHALE GAS
INDUSTRY
DEVELOPMENT
SCENARIOS

II



4.1 Introduction

The shale gas industry in the Northern Territory is in a pre-embryonic stage of development. To date, there has been one fracked well which has progressed to a 57 day production test. In the Marcellus Basin in the United States State of Pennsylvania, more than 2,000 wells are drilled every year. Information on the potential of the industry, and how it may develop in Northern Territory, is scant.

The results of our modelling are subject to higher than usual uncertainty and should be treated as what they are – an estimate of the impacts of a hypothetical development – and not for what they are not – a prediction of what will actually happen in the future. As a result of this lack of defined information, ACIL Allen sought approval from the Scientific Inquiry to modify its scope of works slightly.

ACIL Allen's original scope of works was to complete economic modelling under three scenarios:

1. The moratorium on fracking remained in place in perpetuity ('Baseline')
2. The moratorium on fracking is lifted for the entire Northern Territory ('full lift')
3. The moratorium on fracking is lifted in the Beetaloo Sub-Basin only ('Beetaloo only')

This was the premise with which ACIL Allen conducted its program of stakeholder consultation in the Northern Territory. This implication of these scenarios is that it was possible to develop a model of what *would* happen should the moratorium be lifted at some point in the future.

However, as we began to gather more information from government agencies, industry operators, and conducted our own research, it became clear that there was no way of knowing what *would* happen, as was the original intent of our scope of works.

With the endorsement of the Scientific Inquiry, ACIL Allen has modified the initial scope of works to instead complete economic modelling on five scenarios. These scenarios make a broad assumption that the quantity of shale gas in the Northern Territory is not a constraint, but instead the constraint on the size of a potential development is on the demand side and contingent on the development of a quantity of gas that can meet certain price points in the market. These are discussed below.

In addition to the uncertainty regarding the scale of commercial quality shale gas reserves, ACIL Allen was confronted with a significant challenge to develop a set of underlying assumptions that would allow it to "build" a shale gas industry in the Northern Territory. Typically, economic modelling is conducted using a project or industry-level financial model; the development of a shale gas industry in the Northern Territory is so early stage that such information was scant and largely held in commercial confidence by potential industry operators.

ACIL Allen has sought to be as transparent as possible in this process. This section details every assumption made in regards to the development of an industry financial model, including a rationale

for the assumption and a source where one is available. We have not been able to independently source evidence for every assumption required to build the financial model; some assumptions regarding the cost of particular elements of a hypothetical development have by necessity been sourced as “industry operators”.

The sum total of this scope variation is ACIL Allen now completing its economic modelling task using information that is our assessment of what a successful shale gas industry *could* look like in the Northern Territory. The Scientific Inquiry agrees that this fulfils the overall objectives of the economic advisory services we have been asked to provide, which is to articulate for Territorians the potential economic impacts, benefits and risks to them should an industry develop in the future.

The chapter of our report outlines:

1. The five industry development scenarios (baseline, exploration only, and three production scenarios)
2. The process of determining the inputs and outputs of the industry development scenarios
3. The overlaying assumptions used to determine gas prices, sales and production volumes in each of the production scenarios
4. The underlying assumptions used to build the financial models of an industry
5. The financial models of gas industry development in the three production scenarios
6. The financial models of gas pipeline development in the three production scenarios

4.2 Modelling process

ACIL Allen has undertaken a comprehensive exercise to build the assumptions set and associated inputs and outputs used to facilitate the cash flow and economic modelling required to complete our scope of works. The modelling occurred in four sequential phases, outlined below.

1. **Gas Market Modelling:** Understanding the supply and demand for gas from a Northern Territory shale gas industry under each scenario, to determine the volume of gas that could be placed in the market at market prices each year of the study. This was completed using ACIL Allen’s *GasMark* gas market model. A description of the manner in which ACIL Allen’s *GasMark* deals with new sources of supply is provided in Box 4.1, and a full outline of *GasMark*’s underlying system and processes is provided in F.

The task of gas market modelling was different to a normal modelling task, as ACIL Allen typically knows the quantity, target sales price and underlying cost structure of a new gas development prior to attempting to place it into the market in *GasMark*. Due to the early stage of development, there is no information regarding the underlying cost structure of the gas present in the Northern Territory, even a very limited understanding of the quantity and quality of the gas itself. To make up for this information gap, in this engagement, ACIL Allen first had to determine how much gas could be sold to the market, to then understand the infrastructure required to facilitate the extraction of gas, and ultimate cost structure of the gas.

At first, ACIL Allen developed target levels of gas production under the three scenarios: 100. These target production levels were input into *GasMark* iteratively, with \$0.25 incremental price increase (starting at \$2.00/GJ) per iteration. *GasMark* then determined how much gas could be placed in the market at each price point in each year of the study (through 2035). ACIL Allen then conducted a simple NPV calculation using a 10 per cent discount rate to determine the price and volume quantities that should be adopted for ProjectCo to maximise its revenue. These price and volume calculations were adopted as the actual values for modelling.

2. **Project Development Modelling:** Understand the production and infrastructure requirements to meet the volume of gas to be placed in the market, using a bespoke shale well production schedule model.

This model required two major inputs: an assumed single average type curve of a hypothetical shale well (different for each scenario) and a series of assumptions regarding the infrastructure required to enable production to occur (wells, pads, gathering pipes, roads, water, camps, labour). This occurred in two streams:

- a) “ProjectCo”: the hypothetical development company responsible for exploring, appraising and developing the shale gas industry in the Northern Territory.

BOX 4.1 ACIL ALLEN'S GASMARK MODEL AND NEW DEVELOPMENTS

ACIL Allen's *GasMark* model is built from the bottom up using both real world supply and demand sources and pipelines which link supply to demand. When considering the right size of new sources of supply and transport, ACIL Allen considers:

- Current and projected future pipeline capacities across the national gas grid, and transport costs based on actual tariffs (for regulated pipelines) or estimated tariffs (for unregulated pipelines)
- Current and projected future supply from currently producing and committed sources of gas, as well as yet-to-be-discovered gas, by taking publicly available information on reserve size, depletion rate and estimated production costs
- Current and projected future demand from households, industry, electricity generation and LNG export facilities, based on publicly available information and internally generated projections, cross-checked against forecasts prepared by the Australian Energy Market Operator (National Gas Forecasting Report).

The model takes this information and attempts to clear the market in the most efficient manner possible, taking into account effective final prices (ex-field, processing and transport inclusive).

When considering a new production project, ACIL Allen will typically incorporate assumptions about the volume of new gas supply that will be made available to the market. ACIL Allen instructs the model to offer the new gas into the market at a particular price point or in accordance with a specified supply cost curve, and the market finds a new equilibrium – which may include reducing the production of existing fields or stopping the development of planned fields if they are made uncompetitive versus the new supply. The model will only dispatch the new gas offered into the market to the extent that it is able to competitively meet demand at the price offered.

As discussed above (Page 22), this engagement requires a somewhat different approach because, given the early stage of shale gas exploration in the Northern Territory, there is a lack of reliable information regarding the size of the gas resource and its costs of production. We assume the existence of a significant shale gas resource in the Northern Territory and to use the gas model to determine the hypothetical cost of production (and consequently, the minimum ex-field selling prices) needed in order to achieve market penetration at the levels implied by the three staged market development scenarios.

SOURCE: ACIL ALLEN CONSULTING

b) "PipelineCo": the hypothetical builder, owner and operator of new pipeline infrastructure required to facilitate the sale of ProjectCo shale gas to market.

ProjectCo and PipelineCo are separate entities, but interact via tariffs paid by ProjectCo to PipelineCo for the provision of pipelines to transport gas to market.

3. **Project Cash Flow Modelling:** Understanding the financial implications of the development using assumptions regarding the cost of development of ProjectCo and PipelineCo, and volume and price data derived from *GasMark*.

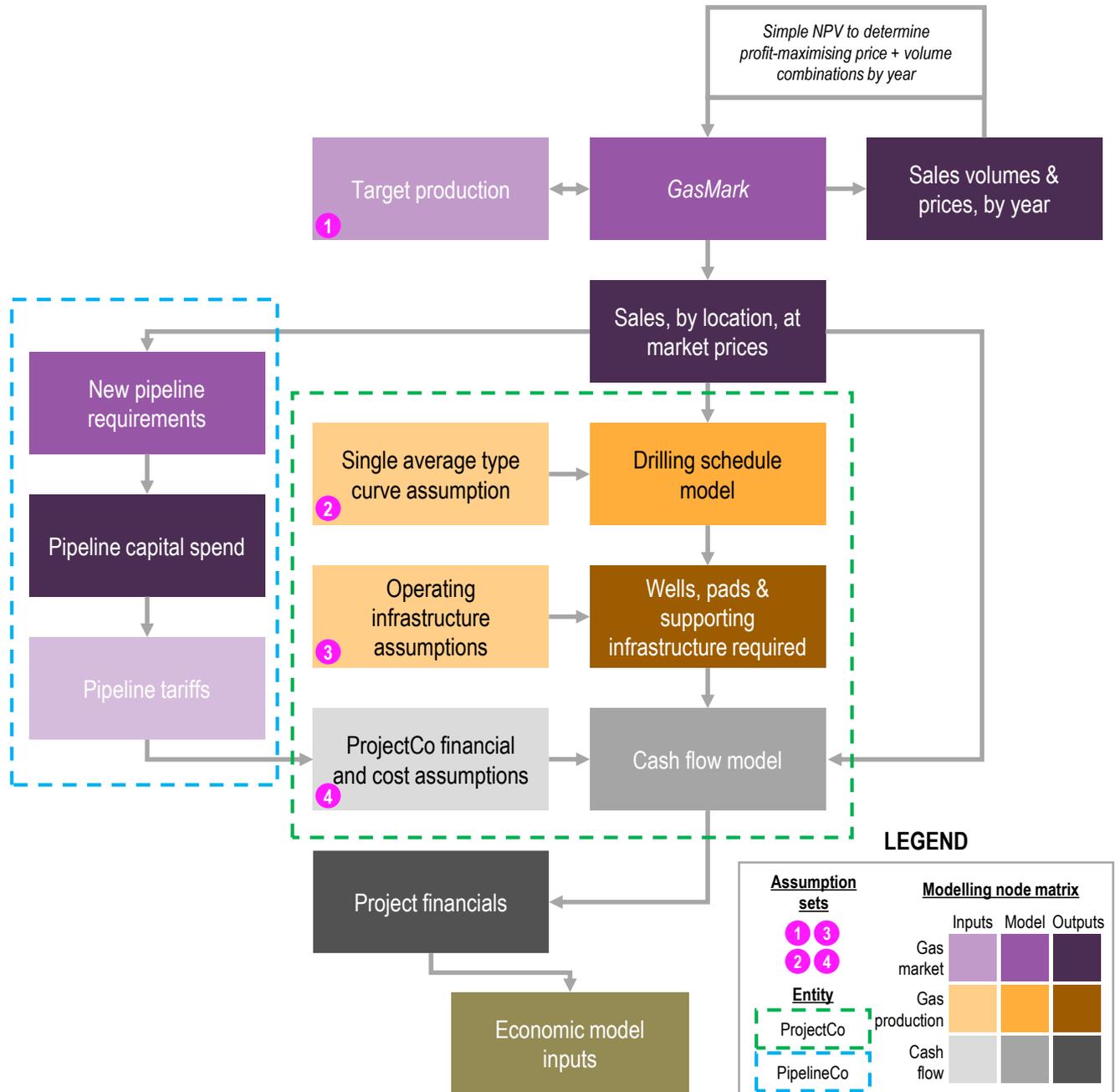
ACIL Allen has built a bespoke discounted cash flow model that takes into account all features of ProjectCo's finances, including estimates of taxation. PipelineCo is built as a simple discounted cash flow model with capital investment, ProjectCo tariffs revenue and operating expenditure.

4. **Economic Impact Assessment Modelling:** The summary inputs and outputs of the ProjectCo and PipelineCo cash flow modelling are converted to a national accounting framework and processed through ACIL Allen's *TasmanGlobal* computable-general equilibrium (CGE) model. The four development scenarios are compared to the baseline assessment of the future growth of the Northern Territory economy to produce estimates of the potential economic impacts of each development scenario as a discrete set of outputs.

Outputs are presented at the Northern Territory and Australia level, under the Australian Bureau of Statistics National Accounting framework for income, expenditure and output – including at ANZSIC major industry level. This ensures a comprehensive understanding of both positive and negative impacts of an industry.

This is a complex and iterative process. The process is outlined in the flow chart below (Figure 4.1). Specific details regarding the models and modelling techniques described above can be found the appendix of this report. The remainder of this chapter outlines the process of modelling, the assumptions used, and the outputs of each phase of modelling.

FIGURE 4.1 ACIL ALLEN MODELLING FLOW CHART



SOURCE: ACIL ALLEN CONSULTING

4.3 Shale gas industry development scenarios

ACIL Allen's three onshore gas industry development scenarios

1. **BREEZE Scenario:** Target production of 100 TJ/day of gas into existing pipeline infrastructure, the net effect being an increase in the amount of Northern Territory gas flowing through the Northern Gas Pipeline (NGP) into the East Coast market. This was selected as the “small” scale development following consultation with industry stakeholders and a review of their submissions to the Inquiry.
2. **WIND Scenario:** Target production of 400 TJ/day into newly constructed pipeline infrastructure, to fill short term gap in East Coast industrial and power generation, and penetrate the Northern Territory market (post-Blacktip) thereafter. This was selected as the “medium” scale development following consultation with industry stakeholders and a review of their submissions to the Inquiry.
3. **GALE Scenario:** Target provision of 1000 TJ/day into the existing Darwin LNG facility and additional East Coast supply (for power generation and LNG), replacing the Bayu-Undan feed stock as it depletes in the middle of the next decade. This was selected as the “large” scale development as a development of such scale would allow for scale economies to embed significantly into the project, and allow ProjectCo to provide the scale of gas feed into LNG production.

The rationale and supporting evidence for each scale of development is outlined below. As discussed above, at this stage these volumes of gas production are only “target” rates which have been fed into ACIL Allen's *GasMark* model for the purposes of determining what can be realistically sold into the market at particular price points. A second stage of modelling is conducted to determine how much gas ProjectCo will provide to the market in order to maximise its revenue generating capacity.

Critical assumption: A dry gas development

One critical and overarching assumption in ACIL Allen's development scenarios is the play that is developed is a 100 per cent “dry gas” play. That is, there are no higher value hydrocarbons, such as butane, ethane, propane or crude oil targeted for extraction, nor extracted, by ProjectCo. A “liquids rich” shale gas play results in a very small increase in operating costs (associated with increased processing to separate the higher value hydrocarbons from the lower value hydrocarbons), and a very large increase in potential production revenue. As a result, the net effect of a liquids rich development is to significantly improve total project economics.

ACIL Allen has assumed a dry gas play for two reasons. As discussed in Section 3.2, Origin Energy's Amungee NW-1H well produced dry gas from the Velkerri B shale, the shale which has been the target play of operators that have explored in the Beetaloo Sub-Basin. While operators are of the view there is likely to be a liquids rich shale in the sub-basin, it is too early to estimate the types or quantities of liquids available for extraction. Given this uncertainty, ACIL Allen has not sought to model any liquids.

In addition, ACIL Allen's scope of works requires a conservative assessment of the potential. Given the significant boost to project economics associated with a liquids rich development, ACIL Allen is more comfortable excluding the potential from its modelling. We can confidently state however that should a liquids rich development occur, the overall project economics will be significantly more positive, and the value of the shale gas industry to the Northern Territory would be significantly larger.

4.3.2 BREEZE Scenario: Target 100TJ/day scale

Based on ACIL Allen's assessment of the Northern Territory gas market in Section 2.6, there is currently a surplus of gas in the Northern Territory for the purposes of domestic consumption. This, and the potential for future on and offshore gas developments in the Northern Territory, has spurred the development of a gas pipeline linking Tennant Creek and Mt Isa in Queensland to the East Coast Gas Market – the Northern Gas Pipeline.

In 2006, Northern Territory Power and Water, the Territory's State-owned utility provider, entered into a 25 year off take agreement with ENI to take between 23 PJ/year and 37 PJ/year of gas from an onshore processing facility on the Territory coast.¹⁶ However, it appears the current agreement results

¹⁶ Ibid

in the provision of more gas than is required by the Territory, with NT Power and Water effectively underwriting the initial development of the NGP through the on-sale of Blacktip gas to a major industrial user in Queensland.¹⁷

The current 12-inch diameter specification of the NGP allows for the provision of up to 90 terajoules per day (TJ/day) of gas to the East Coast market.¹⁸ As it stands, there is likely to be significant unutilised capacity on the pipeline upon commissioning, with the on-sale of Blacktip gas referred to above utilising only about one-third of the available capacity.

The Blacktip gas field has an estimated remaining life of 18 years, based on current reserves and assuming a flat production profile of 87.4 TJ/day (about 32 PJ/year). Under current estimates of NT domestic demand, there is unlikely to be a need for a major new source of gas for NT domestic consumption over the forecasting period of *GasMark* (2017 – 2035). However, the entry of NT Power and Water into the national gas market via the Northern Gas Pipeline affords it an opportunity to become a larger player in the provision of gas to East Coast markets.

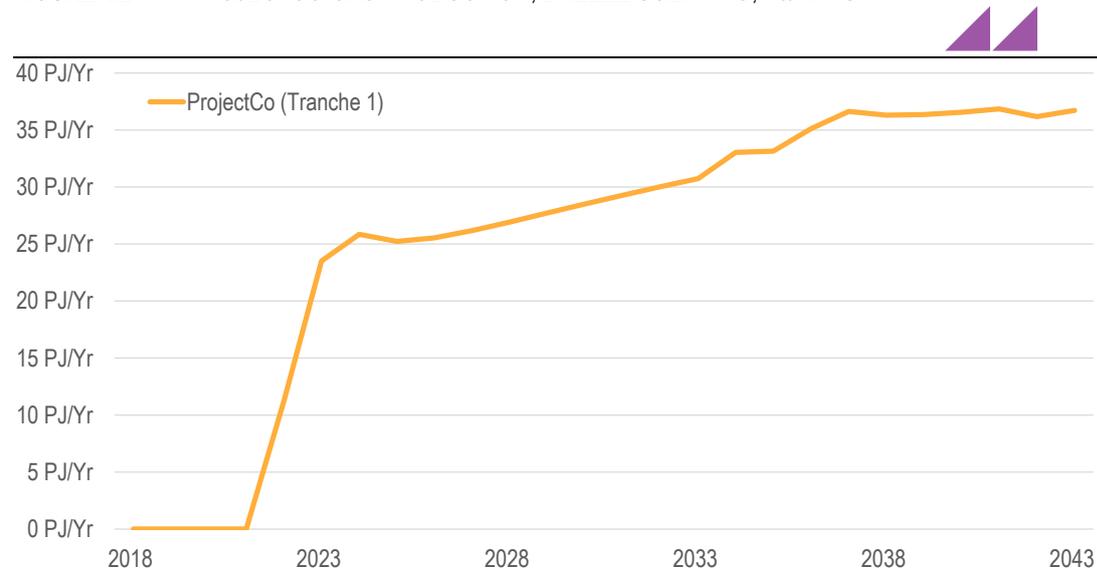
Our preliminary analysis using ACIL Allen's *GasMark* model shows that on the basis of growth in NT demand and potential to supply the East Coast market through the current specification of the NGP, there is room for between 24 and 34 PJ/year of new gas to enter the market at current prices between 2018 and 2035. It is assumed that ProjectCo will meet this demand.

Under the first scenario, it is assumed ProjectCo begins to produce shale gas in FY2022, with the current moratorium on activities lifting at the end of FY2018 and the exploration/appraisal phase of development occurring in FY2019, FY2020 and FY2021. At the tail end of FY2021, ProjectCo begins to build the facilities required to tie into the Amadeus Gas Pipeline, which at that time will be linked to the East Coast market via the NGP. ProjectCo produces gas at an initial rate of 33.4 TJ/day in 2022, ramping up to 90 TJ/day in 2034 as the Blacktip field begins to wind down production.

The model assumes the price of gas from ProjectCo is set at a level that allows for competitive supply into the East Coast market without displacing production of Blacktip gas that is contractually committed to NT Power and Water. Initially, all of the gas produced by ProjectCo flows to the East Coast gas market. After 2030 some ProjectCo gas starts to be delivered to the Northern Territory market, backfilling the decline in production from Blacktip. However, as *GasMark* is only able to produce estimates to 2035, ACIL Allen has assumed production remains constant from 2036 to 2043.

The profile of gas production by ProjectCo in BREEZE is below (Figure 4.2).

FIGURE 4.2 PROJECTCO GAS PRODUCTION, BREEZE SCENARIO, PJ/ANNUM



SOURCE: ACIL ALLEN CONSULTING

¹⁷ NT Power and Water. 2017. *Power and Water positioned to enter the Australian gas market*. Accessed online at <http://www.powerandwater.com.au/>

¹⁸ Australian Energy Market Operator. 2017. *Gas Statement of Opportunities, March 2017*. Accessed online at <http://www.aemo.com.au/>

4.3.3 WIND Scenario: Target 400TJ/day scale

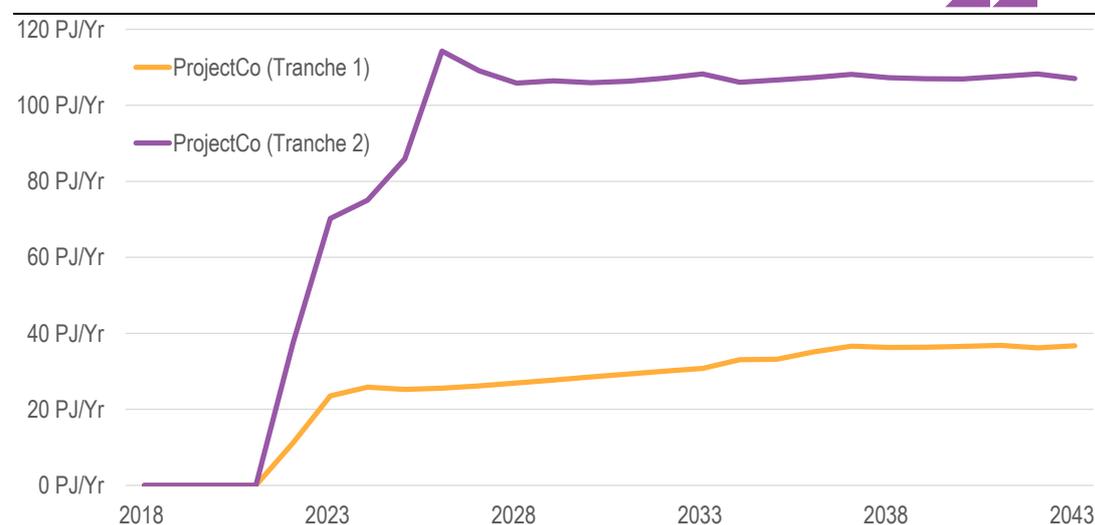
The WIND scenario assumes ProjectCo is further able to deliver commercial gas into the NGP and East Coast market. After a successful initial development, ProjectCo seeks to build its market share on the East Coast via production efficiencies to take advantage of push and pull factors in East Coast gas markets associated with the development of higher cost coal seam gas (CSG) production and the backfill requirements of existing LNG facilities in Queensland.

ProjectCo's target production rate for this scenario is 400TJ/day – or an additional 300TJ/day over the BREEZE scenario. Modelling indicates that under the optimal price/volume strategy adopted, the maximum amount of gas that could flow to the East Coast market under current market assumptions is an incremental 244 TJ/day peak in 2026 (total gas produced 315 TJ/day), with a long term equilibrium of 210 TJ/day by 2035 (total gas produced 300 TJ/day).

The majority of this gas is placed into the East Coast market, requiring additional pipeline infrastructure be developed as the capacity of the existing NGP is 100 per cent subscribed by ProjectCo. Pipeline-related assumptions are outlined in Section 4.5.1.

The production profile of ProjectCo in the WIND scenario is presented in Figure 4.3.

FIGURE 4.3 PROJECTCO GAS PRODUCTION, WIND SCENARIO, PJ/ANNUM



SOURCE: ACIL ALLEN CONSULTING

4.3.4 GALE Scenario: Target 1000TJ/day scale

The Darwin LNG plant (DLNG) is currently supplied feed gas from the Bayu-Undan gas project in off the coast of the Northern Territory in the Australia Timor-Leste Joint Petroleum Development Area. DLNG has a single production train¹⁹, producing up to 3.7 million tonnes of LNG per annum for sales to Japan²⁰. To produce 3.7 million tonnes of LNG, the plant requires approximately 225 PJ/year of feed gas.

As it stands, Bayu-Undan provides 100 per cent of the feed in gas to the plant. The field is set to reach maturity in 2022-23, and will progressively reduce its production. Unless replacement gas is found DLNG will cease production some time towards the end of the next decade. Acknowledging this, the owners of the Bayu-Undan joint venture have begun independently investigating new sources of gas for the plant, at this stage focussed on a new large scale offshore development off the coast of the Northern Territory.²¹

¹⁹ ConocoPhillips. 2017. *Our Business Activities – DLNG*. Accessed online at <http://www.conocophillips.com.au/>

²⁰ Santos. 2017. *Bayu-Undan/Darwin LNG Joint Venture*. Accessed online at <http://www.santos.com/>

²¹ Energy News Bulletin. 2017. *Barossa development begins*. Accessed online at <http://www.energynewsbulletin.net/>

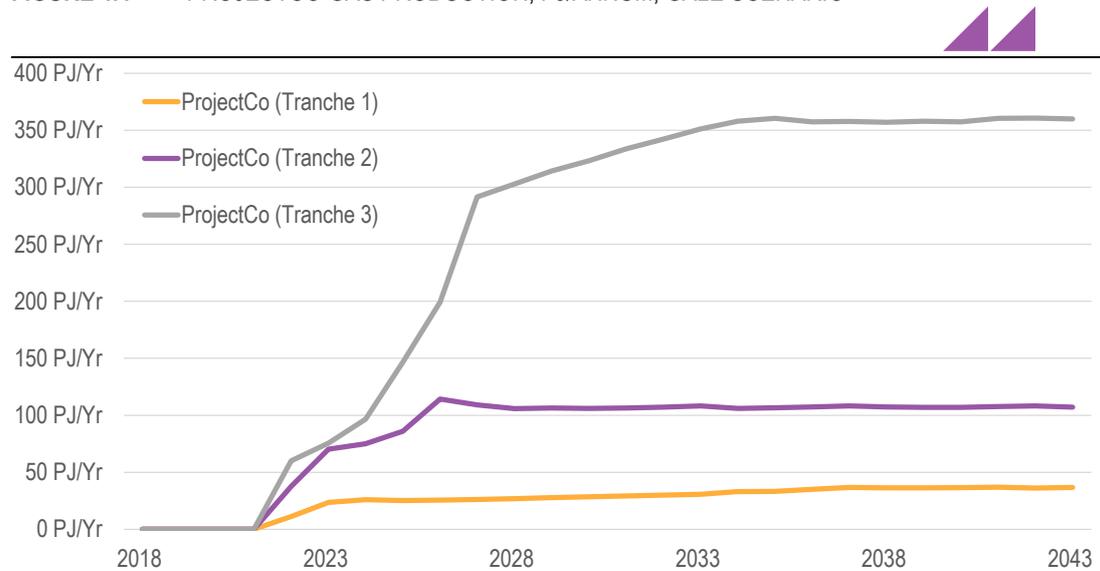
ACIL Allen assumes ProjectCo is able to build to a scale that would allow it to progressively replace the Bayu-Undan gas field as the feed in gas for DLNG, allowing the existing train to continue production beyond 2022-23 at current rates. This necessitates investment to expand the Amadeus Gas Pipeline to allow more gas to flow north to DLNG.

For the purposes of economic modelling, it is assumed that DLNG will continue to produce LNG at its current rate with or without ProjectCo gas. In the base case, it is assumed one of the new offshore developments discussed above comes to pass and this gas backfills DLNG. This is a critical assumption, as it means there is no incremental value associated with LNG production attributable to ProjectCo gas – the incremental value is any change to the production profile, profitability and local content of gas required to backfill DLNG in an onshore scenario versus an offshore scenario. This is discussed further in Section 6.

It is also assumed that due to ProjectCo’s increasing scale economies, its cost of production falls below the rate of the WIND scenario, allowing for further gas sales into the East Coast gas market – potentially including partial backfill of an LNG train at Gladstone. In any event, the cascading effect of ProjectCo’s gas results in a reduction in the wholesale price of gas in the East Coast market, with the “ripple” effect of injection of more gas flowing west to east leading to less gas produced in Queensland fields moving south. Similarly to DLNG, there is no incremental value associated with LNG backfill.

As such, this necessitates further investment in the NGP and Carpentaria Gas Pipeline over and above the investment assumed to be required to meet WIND East Coast exports. As a result, ProjectCo is able to fulfil its full target production of 1000 TJ/day by 2035. Economies of scale in production allowing it to increase its penetration of the East Coast market over the WIND scenario. The production profile of ProjectCo under these assumptions is shown below (Figure 4.4).

FIGURE 4.4 PROJECTCO GAS PRODUCTION, PJ/ANNUM, GALE SCENARIO



SOURCE: ACIL ALLEN CONSULTING

4.3.5 Final volumes and prices

The final volumes and selling prices for ProjectCo gas under each scenario are presented below, in real 2017 terms, inclusive of transport costs. Details on the stratified sales of gas by market (domestic NT, East Coast and DLNG) are presented in Appendix C.

TABLE 4.1 PROJECTCO FINAL GAS VOLUMES AND PRICES, BY SCENARIO, \$/GJ & PJ/ANNUM

Year	BREEZE		WIND		GALE	
	Volume PJ/annum	Price \$/GJ	Volume PJ/annum	Price \$/GJ	Volume PJ/annum	Price \$/GJ
2018	-	-	-	-	-	-

Year	BREEZE		WIND		GALE	
	Volume	Price	Volume	Price	Volume	Price
	PJ/annum	\$/GJ	PJ/annum	\$/GJ	PJ/annum	\$/GJ
2019	-	-	-	-	-	-
2020	-	-	-	-	-	-
2021	-	-	-	-	-	-
2022	11.3	7.37	37.7	5.65	60.1	6.12
2023	23.5	7.64	70.2	6.07	75.6	6.12
2024	25.9	7.64	75.0	6.09	96.5	6.12
2025	25.2	7.69	85.9	6.12	146.6	5.96
2026	25.5	8.16	114.3	6.19	199.3	5.88
2027	26.2	8.37	109.1	6.79	291.5	5.88
2028	26.9	8.48	105.9	7.33	302.8	5.82
2029	27.7	8.94	106.5	7.74	314.4	5.77
2030	28.5	9.04	106.0	7.97	323.2	5.73
2031	29.3	9.24	106.3	8.19	333.7	5.70
2032	30.0	9.32	107.2	8.43	342.2	5.67
2033	30.7	9.89	108.2	8.55	351.3	5.65
2034	33.0	9.81	106.1	8.80	357.9	5.63
2035	33.2	9.84	106.6	9.05	360.4	5.61
2036	35.1	9.84	107.3	9.05	357.5	5.55
2037	36.6	9.84	108.1	9.05	357.7	5.48
2038	36.3	9.84	107.3	9.05	357.0	5.42
2039	36.4	9.84	107.0	9.05	358.0	5.35
2040	36.6	9.84	107.0	9.05	357.4	5.28
2041	36.9	9.84	107.6	9.05	360.6	5.28
2042	36.2	9.84	108.3	9.05	360.7	5.28
2043	36.7	9.84	107.1	9.05	360.0	5.28

SOURCE: ACIL ALLEN CONSULTING

4.4 Adopting single average type curves

To progress from the volume of gas to be sold to the cost of production, ACIL Allen has formulated a series of assumptions regarding the quality of the gas reserve available to ProjectCo in each of the scenarios. The manifestation of this is what is known as a “type curve”, which shows how much gas is produced from a single well at any one point in time (in this case per annum).

ACIL Allen has developed its own type curves, rather than using estimated type curves for gas fields in the Northern Territory. This is because there has been one successful horizontally drilled shale gas well for production testing in the Northern Territory: Origin Energy’s Amungee NW-1H. The results of this test were positive, but cannot be used for our type curve assumption for three reasons:

- The well only involved 11 “frack” stages (number of fracture stimulation points from the well). A typical horizontal well will have at least 20 frack stages, and in most cases many more.

- The well's production profile was atypical, with a very low initial production rate and an almost perfectly flat production curve.²² A typical shale gas well has a high initial production in the first year or two relative to the average production over the well life, and lower than average production over the well life thereafter. Nonetheless, ACIL Allen has attempted to adopt the “flatter” characteristic of the Amungee NW-1H well in its type curve
- The well underwent production testing for 57 days. This is less than two months, making development of an estimated type curve problematic

ACIL Allen has adopted a “single average type curve” for the purposes of modelling. In reality, every well will produce a different type curve, relating to the location the well is drilled, the specific geology of the formation, and the particular techniques used. However, ACIL Allen considered it impractical to develop multiple type curves, and considers that the ultimate production in a given development can be summarised by a single average type curve regardless.

A typical shale gas type curve is a hyperbolic decline function, where the production of a well in the first period (typically reported in months) is very high relative to the average monthly production over the life of the well. A well's production declines rapidly from this initial production rate, and continues to produce for a long period of time at very low levels.

There are four key pieces of information required to develop a type curve:

- Initial production rate (IP): the volume of gas produced in the first month of the well's life
- Decline rate (in two parts: exponent and rate): the speed in which the well's production declines per month
- Estimated Ultimate Recovery (EUR): the ultimate volume of gas that will be extracted from the well over its useful life, measured in petajoules (PJ)
- Well life (an exogenous figure): the useful production life of each well

ACIL Allen has developed a single average type curve for each of the three shale gas development scenarios in the Northern Territory. We have built our type curves using a variety of sources – on the advice of potential shale gas operators and the Northern Territory Government – and used the operators' collective assumption that a shale gas well in the Northern Territory would have a useful life of 20 years.

Much of the information used is related to the Marcellus Basin shale gas play, in the United States of America State of Pennsylvania. The rationale for the Marcellus analogue is that both Marcellus and Beetaloo basin plays are thought exhibit similar geological characteristics: assumed to be a mostly dry gas play, similar shale formation, similar depths and similar geology.²³

The parameters of ACIL Allen's development type curve assumptions are below Table 4.2.

TABLE 4.2 ACIL ALLEN TYPE CURVE ASSUMPTIONS

Scenario	Initial Production (mmscf/month)	Decline exponent	Decline rate (% per month)	EUR (Petajoules per well)	Well life (years)
BREEZE	160	1.0	5.3%	8.4	20
WIND	160	1.0	3.8%	10.6	20
GALE	240	1.0	5.4%	12.7	20

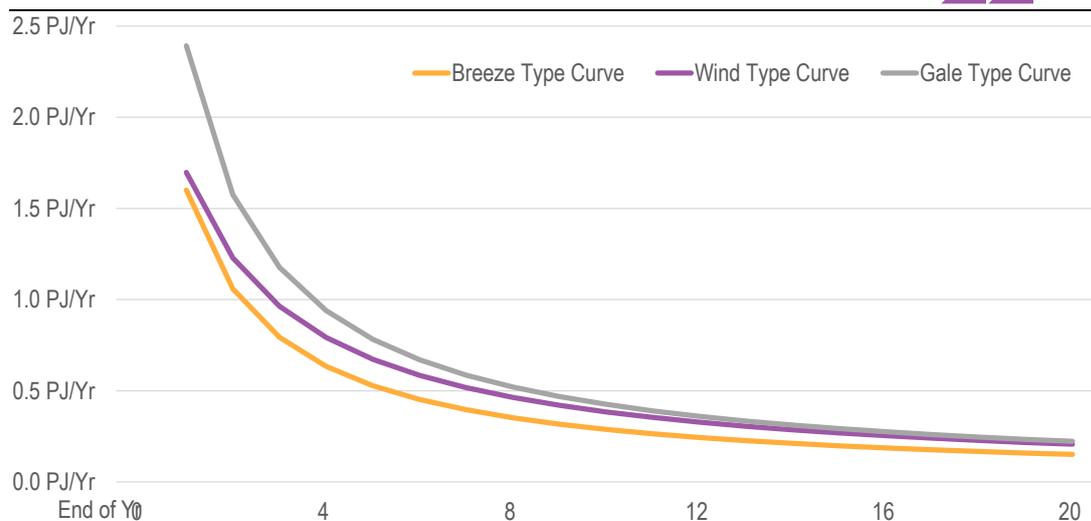
SOURCE: ACIL ALLEN CONSULTING, DERIVED USING VARIOUS SOURCES BELOW

ACIL Allen's type curves are presented below, in annual production terms. The type curves essentially “graduate” in each scenario (each curve produces more gas at every point in time), as a proxy measure for the fact that better project economics are required for ProjectCo to progress from one scenario to the next.

²² Origin Energy. 2017. Submission to the Inquiry, #272. Accessed online at <http://www.frackinginquiry.nt.gov.au>

²³ Consensus view sourced from Origin Energy, Santos and Department of Primary Industry and Resources submissions to the Scientific Inquiry into Hydraulic Fracturing Issues Paper.

FIGURE 4.5 PROJECTCO SINGLE AVERAGE TYPE CURVES, BY SCENARIO, ANNUAL PRODUCTION (PJ)



SOURCE: ACIL ALLEN CONSULTING

The type curve is a critical assumption, as it governs the number of wells required to meet target production rates, which flows through to capital and operating costs as well as the economic impact (as this is fundamentally driven by total expenditure). The rationale for ACIL Allen’s type curve assumptions are below.

4.4.1 Initial Production Rate (IP)

ACIL Allen initially developed its type curve assumption from a report prepared by petroleum engineer Gary Swindell, titled *Marcellus Shale in Pennsylvania: A 3,800 Well Study of Estimated Ultimate Recovery (EUR)*. The table in this report has been reproduced below (Figure 4.6).

FIGURE 4.6 SWINDELL REPORT DATA

The increase in initial production rate during the early years of the Marcellus development may be related to an increase in the horizontal length during the same period. For a subset of 2,168 wells where an estimate of the horizontal length was able to be made, the average horizontal section increased from 2,280 ft in 2008; 2,890 ft. in 2009; 3,800 ft in 2010; 4,100 ft. in 2011; 4,500 ft. in 2012 and 4,751 in the 2013 vintage wells.

Average decline profiles for the whole state, vintaged by the year of first production are summarized in **Table 1**.

Vintage	Average initial production Mcf/month	Average initial decline rate - %	Hyp b factor	Average EUR Statewide - Bcfe
2008	43,263	43.87	0.65	2,032.69
2009	71,768	43.21	0.55	3,327.25
2010	121,248	48.52	0.65	4,873.21
2011	121,339	49.02	0.66	4,531.52
2012	129,302	48.38	0.51	4,201.77
2013	172,787	46.22	0.39	5,397.40

Table 1. Average decline profiles for the Pennsylvania Marcellus.

SOURCE: SWINDELL, G. 2016. MARCELLUS SHALE IN PENNSYLVANIA: A 3,800 WELL STUDY OF ESTIMATED ULTIMATE RECOVERY (EUR)

As the target of the Swindell study is estimating average EUR, his study does not include contemporary information regarding initial production rates. The study used data from the Pennsylvania Department of Environmental Protection, which mandates that producers in the State must report monthly production figures for all shale wells drilled in the Marcellus shale.

This is a regulatory requirement to assist the Department manage the industry and its impact on the environment. However, the Department also publishes all of this data on the internet, allowing for precise analysis of shale gas production from wells drilled in the Marcellus Basin. ACIL Allen initially sought out this data to verify the findings of this report, but after understanding the depth of data available instead used the data to determine an appropriate initial production rate for its type curves.

ACIL Allen extracted well level production data from 2012 to 2016. Data for 2012 to 2014 was reported on a six-monthly basis, while 2015 and 2016 was monthly data. Initially, ACIL Allen converted production data to monthly mmscf by dividing total production in the period by the number of days in the period, multiplying this by 365.25 days (a standard year) and divided this by 12.

ACIL Allen then filtered out well data that was not dry gas and was not a horizontally drilled well. This resulted in 171,611 individual data points over 7,925 wells for analysis.

ACIL Allen then determined the time which each well initially came online by applying a formula that looked up the first time a Well ID Number appeared in the database. If this was in the first six months of 2012, this data was ignored as it was the first time Well ID Numbers appears for many wells which may have been producing for some time. Applying this filter allowed ACIL Allen to determine the average IP rate for wells drilled in particular years. These are presented in a table below.

TABLE 4.3 INITIAL PRODUCTION RATES OF SHALE GAS WELLS DRILLED IN MARCELLUS BASIN BY YEAR

Period	Initial Production (TJ/month)	# of Wells in Sample
2012 (2H2012 only)	134.7	746
2013	177.3	1402
2014	209.6	1217
2015	184.6	1004
2016	233.3	672

SOURCE: ACIL ALLEN CONSULTING, PA DEPARTMENT OF ENVIRONMENTAL REGULATION

This data suggests the IP rate of horizontal dry shale gas wells drilled in the Marcellus Basin has increased over time, from 127.7 mmscf/month (134.7 TJ/month) in the second half of 2012 to 221.1 mmscf/month (233.3 TJ/month) in 2016. The increase has not been linear, with a decline in 2015.

ACIL Allen adopted an IP rate of 160 mmscf/month (168.8 TJ/month) for its BREEZE and WIND scenarios, and an IP rate of 240 mmscf/month (253.2 TJ/month) in its GALE scenario. ACIL Allen has adopted these as conservative estimates, noting:

- technological progress in the shale gas industry is rapid, so adopting IP rates that are two to five years behind the analogue shale is conservative
- the anticipated geology of the most prospective areas of the Northern Territory is conducive to the development of long horizontal wells, which tend to have higher IP rates.

It is noted that this IP rate is higher than the Amungee NW-1H well (33.5 mmscf/month or 35.3TJ/month), and higher than the most comprehensive previous study of the economics of shale gas developments in Australia, the Australian Council of Learned Academics report *Unconventional Gas Production: A study of shale gas in Australia* (the 'ACOLA report'), of 446Mscf per day (13.6 mmscf/month or 14.3TJ/month). ACIL Allen has not adopted the well profile of NW-1H for the reasons identified above. ACIL Allen has not adopted the well profile of the hypothetical shale gas development presented in the ACOLA report as we are of the view it is now out of date, given it is based on the findings of a 2012 US Energy Information Agency report, which itself was based on data that is two years older again, and is not certain that it represents the experience of the Marcellus shale given the significant discrepancy between it and data prepared by the Government of Pennsylvania.

4.4.2 EUR and Well Life

Determining the EUR of a well is a difficult exercise, even when information is fully available. It can only be known once a well has reached the end of its useful life, which in the case of the current shale

gas industry in the United States is not possible. It is possible to determine probabilistic measurements of well EUR, but ACIL Allen does not have access to the requisite information to do so.

The EUR is a central assumption, as it is the variable in the type curve that provides the most sensitivity to the number of wells required to facilitate the volume of production under each scenario, and the expenditure on supporting infrastructure. ACIL Allen was unable to source adequate analogue data to adopt like for like for a modelling assumption, and so was left to piece together evidence for credible EUR assumptions from a range of sources. These are discussed below.

EUR is a function of the quality of the geology of the shale, the length of the horizontal section of the well being drilled, the precision of the drilling activity taking place, and the number of fracking stages per unit of lateral length. Research presented to the Inquiry and ACIL Allen by industry operators shows that shale gas operators in the United States are drilling increasingly long horizontal wells with the aim of increasing the EUR per well and thus lowering their development costs.²⁴

There is some conjecture regarding the relationship between lateral drilling length and the volume of gas extracted per well, to the extent that EUR per 1,000 feet of lateral drilling (the industry definition of well productivity) increases as the horizontal well length increases. A recent paper by Yuan et al, published in the Society of Petroleum Engineers, found there was no additive effect of gas recovery per 1,000 foot of horizontal drilling in the Barnett Basin (in Texas), but that there was a clear relationship between the length of drilling and early production.²⁵ In addition to the above factors, EUR is thought to be partially a function of initial production rates per well, to the extent it reflects the quality of the shale targeted and the ultimate productivity of the well drilled. Therefore, EUR per well is likely to exhibit a positive relationship with the length of the horizontal section of a well.

This is reinforced by academic literature, such as in the Swindell report referenced in Section 4.4.1. The Swindell report found the mean EUR per well across the study period (wells spudded between 2008 and 2013) was 5.0PJ per well, with approximately 80 per cent of wells exhibiting an EUR per well of 6.3 PJ or less.²⁶ The Swindell data suggests the average lateral length of wells drilled in the Marcellus Basin has increased from 2,280 feet (694 metres) in 2008 to 4,751 feet (1,448 metres) in 2013 – more than doubling over this time.²⁷ The Swindell report does show average EUR per well by year of well spudding has increased over time, from 2.1 PJ in 2008 to 4.7 PJ in 2011, and to 5.7 PJ in 2013. Assuming a steady compound annual growth rate from 2011 to 2013 (9.5 per cent per annum), the PJ per well in the Marcellus Basin could have increased to 8.2 PJ per well on average in 2017.

The latest report on US shale gas industry performance prepared by the US Energy Information Administration, which ACIL Allen has relied upon for other assumptions in this report, found EUR in the Marcellus Basin had increased from 4.6PJ per well in 2010 to 6.8 PJ per well in 2014.²⁸ Assuming a steady compound annual growth rate (11.9 per cent per annum), the PJ per well in the Marcellus Basin could have increased to 9.5 PJ per well on average in 2017.

A second piece of research prepared by the US EIA suggested the average EUR of wells spudded in the Marcellus Basin has increased from 0.4 PJ in 2008 to 5.4 PJ in 2010, and 6.8 PJ in 2013.²⁹ Assuming a steady compound annual growth rate from 2010 to 2013 (7.5 per cent), the PJ per well in the Marcellus Basin could have increased to 9.0 PJ per well on average in 2017.

While useful, these estimates are based wholly on the continuation of historic growth rates in PJ per well, without assuming any technological progress which has occurred in the United States in recent years. This also illustrates the inherent difficulty in assessing EUR, as even in one of the most widely studied basins there is significant uncertainty.

Outside of these two papers, ACIL Allen was unable to source academic literature that was able to strike a balance between rigorous academic analysis and the contemporary experience of the shale gas industry in the United States. The published data produced above contained data for wells that

²⁴ See Origin (2017), Santos (2017) and Pangaea (2017).

²⁵ Yuan, G. et al. 2017.

²⁶ Swindell, G. 2016. *Marcellus Shale in Pennsylvania: A 3,800 well study of estimated Ultimate Recovery (EUR)*. Accessed online at <http://www.gswindell.com/>

²⁷ Contemporary industry information suggests the average horizontal drilling length in the Marcellus Basin has increased to 7,000 feet (2,133 metres) in 2016.

²⁸ US EIA. 2016. *Trends in US Oil and Natural Gas Upstream Costs*. Accessed online at <http://www.eia.gov/>

²⁹ Staub, J. 2015. *The growth of US natural gas: An uncertain outlook for US and world supply*. Accessed online at <http://www.eia.gov/>

was at least three years old, and given the rapid productivity increases of the industry (see Section 3.2), is considered the best available conservative estimate of contemporary shale gas industry practices.

To compensate for this, ACIL Allen accessed a series of reports prepared by US shale gas industry operators for the Securities and Exchange Commission.³⁰ These reports indicated a strong trend of increasing EUR in the Marcellus Basin over time, and projections of further increases into the future. These reports were supportive of EURs in excess of 21.1 PJ per well at the leading edge of developments in the Marcellus Basin.

Operators provided a very large range of EUR per well that could be expected in the Northern Territory, of 4.2 - 21.1 PJ per well. For instance, Santos, in a submission to the Inquiry, indicated it was expecting an EUR of 12.2 PJ to 21.5 PJ of raw gas per well (raw gas suggesting it includes components which would be stripped out following extraction such as carbon dioxide).³¹ Origin provided a range of between 5.2 PJ and 15.8 PJ per well in one of its submissions to the Inquiry.³² Pangaea did not provide a range of expected EUR in its exploration areas, but it did cite evidence of 21.1+ PJ per well EUR outcomes in the United States.³³

As a conservative assumption, ACIL Allen has adopted a graduated EUR for each scenario, starting with an 8.4 PJ per well in the BREEZE scenario in line with ACIL Allen's simple extrapolation analysis presented above. EUR rates of 10.6 PJ per well and 12.7 PJ per well are adopted for WIND and GALE scenarios, reflecting that to progress to increasingly large development ProjectCo would be required embed technological improvements or the quality of the shale would have to improve. This strikes the balance between ACIL Allen's requirement to take conservative assumptions, consider the most relevant contextual information of contemporary practice in the shale gas industry, and deliver economic modelling results on the economic impact of the industry (as opposed to delivering an assessment of the economics of the shale itself). This assumption also reflects the relationship between longer lateral lengths and PJ per well observed in the literature.

Operators suggested an average well life of 20 years, which ACIL Allen understands is in line with international experience. ACIL Allen has adopted this across the three scenarios.

4.4.3 Decline rates

ACIL Allen has assumed a decline rate and decline exponent that allows for the delivery of the target EUR of gas in each scenario over a 20 year well life, assuming the IP rate of either 160 mmscf/month (168.8 TJ/month) or 240 mmscf/month (253.2 TJ/month). ACIL Allen has adopted a decline exponent of 1.0, given there is no compelling reason to adopt a decline exponent of greater than or less than 1.0 – the exponent varies significantly across plays. Therefore in effect, the decline rates adopted are a residual calculation based on assumed IP, EUR and well life.

As discussed in Section 4.4, ACIL Allen has sought to qualitatively reflect the relatively low decline rate experienced in the NW-1H well drilled and spudded by Origin. This can be seen below, with the BREEZE type curve versus a hypothetical average decline curve developed from the data presented in Swindell report and the ACOLA report.

The assumed single average type curves for each scenario are applied to the production volumes modelled in Section 0 to determine the scale of the development required. The process of combining these two outputs, and the assumptions used to determine the scale of the development, are discussed in the next section.

³⁰ ACIL Allen accessed material prepared by US shale companies Cabot, Antero, Eclipse Resources, EQT, Gulfport Resources, Rice Energy, Southwestern Energy, and Tourmaline Corp, which were mostly in the form of SEC-compliant investor presentations. These reports contain the historic and projected future productivity of wells drilled in the Marcellus Basin. While these reports are not prepared according to the scientific method of academic research, they represent a body of evidence that is contemporary and based on the current experience of independent operators in the United States.

³¹ Santos. 2017. *Submission to the Scientific Inquiry into Hydraulic Fracturing, Submission #232*. Accessed online at <http://www.frackinginquiry.nt.gov.au>

³² Origin. 2017. *Submission to the Scientific Inquiry into Hydraulic Fracturing, Submission #272*. Accessed online at <http://www.frackinginquiry.nt.gov.au>

³³ Pangaea. 2017. *Submission to the Scientific Inquiry into Hydraulic Fracturing, Submission #427*. Accessed online at <http://www.frackinginquiry.nt.gov.au>

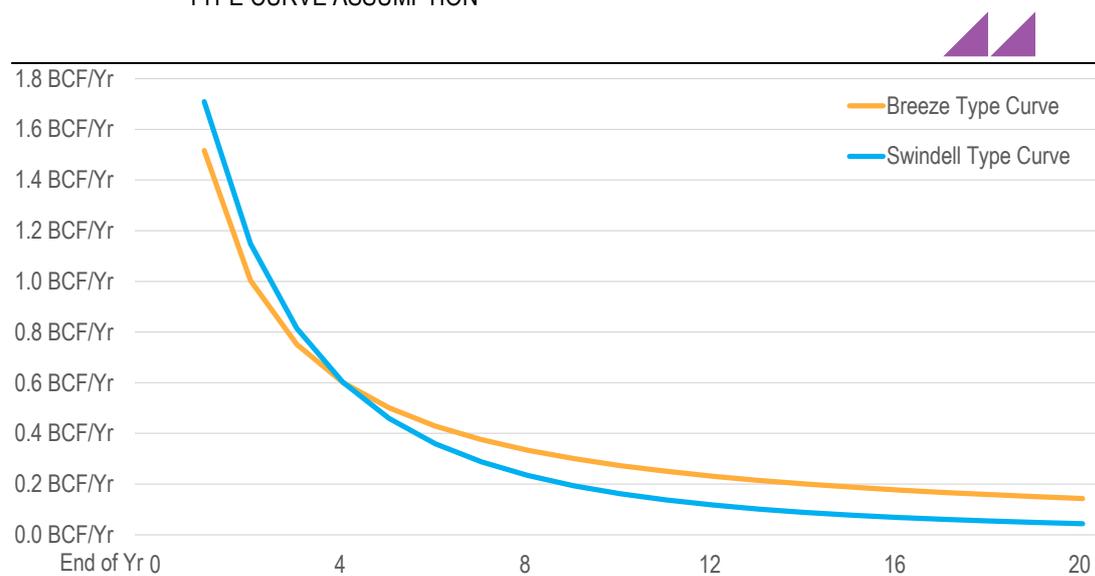
4.5 ProjectCo drilling schedule and supporting infrastructure

This section details how ACIL Allen estimated the number of wells required to meet the production profile of each production scenario presented in Section 0. The estimation of the number of wells under each production scenario enabled ACIL Allen to estimate the supporting infrastructure requirements, including:

- number of pads;
- required length of connecting roads; and
- required length of gathering pipes.

The process used by ACIL Allen to estimate the required number of wells and these infrastructure requirements is detailed below.

FIGURE 4.7 HYPOTHETICAL DECLINE RATE, OBSERVED IN MARCELLUS BASIN VS ACIL ALLEN TYPE CURVE ASSUMPTION



SOURCE: PA DEPARTMENT OF ENVIRONMENTAL REGULATION, ACIL ALLEN CONSULTING

4.5.1 Number of wells required

To estimate the required number of wells to meet each development scenario's production profile, ACIL Allen required estimates of:

- sales volumes (as estimated by *GasMark* and presented in Section 0); and
- single average type curve assumptions (presented in Section 4.4).

Combining these two inputs allowed ACIL Allen to estimate the number of new wells required over time to meet the production profile estimated by *GasMark*. This is a two-step process, involving new wells and existing wells.

Existing wells are wells which have been constructed in previous periods, and which are still producing gas. Each year, there are a number of new wells commissioned, which decline in production on an annual basis in line with ACIL Allen's assumed single average type curve. New wells are wells which are required to be built in a given year to make up for a gap between required production and existing well production. The number of new wells required is calculated by subtracting required production from existing production, and dividing by the annual initial production rate of a new well. This excludes Year One of production, as there is no existing production, and 100 per cent of required production must be met by new wells.

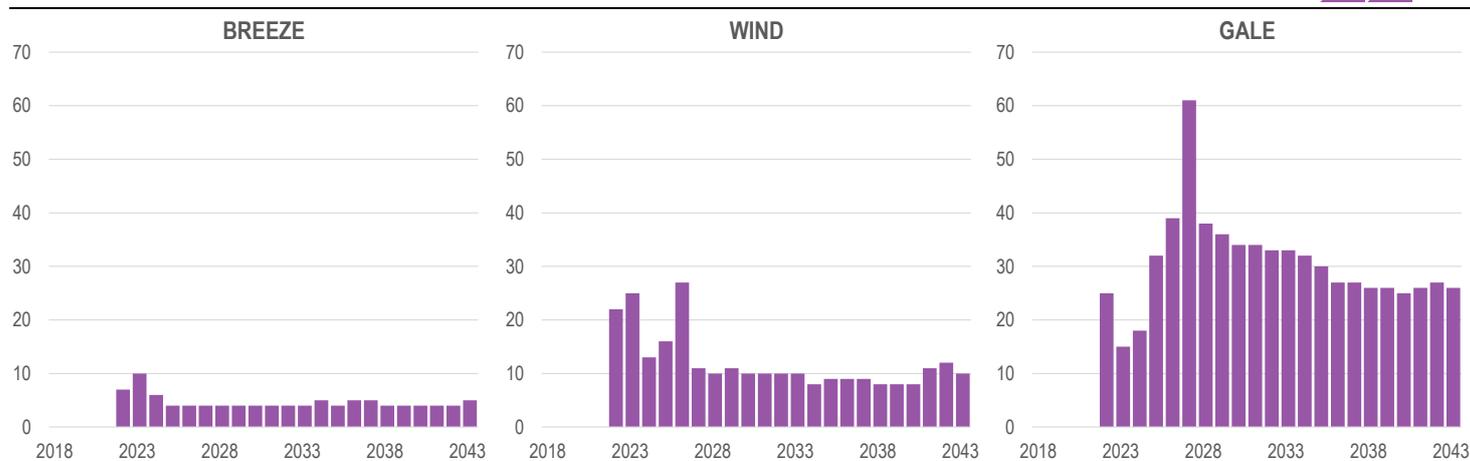
Figure 4.8 highlights the number of new wells required to be drilled per annum to meet the production profile in each development scenario.

Over the study period, ACIL Allen has estimated that a total of; 103 wells will be drilled (at an average of four wells drilled per annum) under the BREEZE development scenario, 167 new wells under the WIND development scenario (at an average of 10.3 wells drilled per annum) and 670 new wells under the GALE development scenario (at an average of 25.8 wells drilled per annum); to meet each scenario’s production profile.

Figure 4.9 presents the total number of wells that are operating per annum by development scenario. Towards the end of the study period, the number of wells that are operating under each development scenario begins to level off as production profile of each development scenario hits its target level of production.

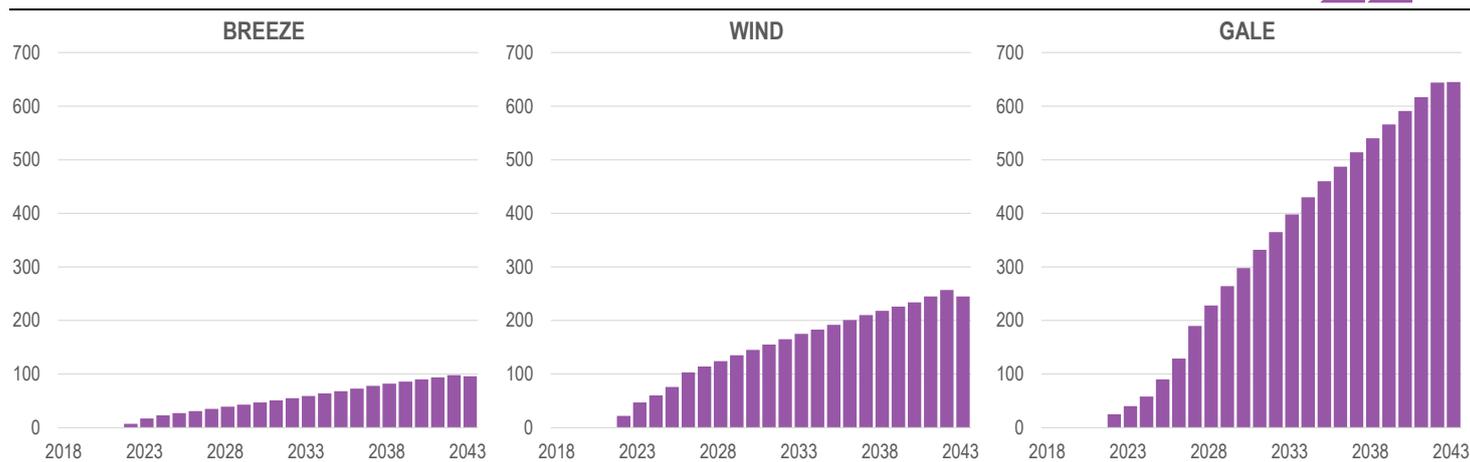
Through the study period, the number of wells in operation peaks at 98 in 2042 under the BREEZE development scenario, and 257 in the WIND development scenario. The number of wells in operation peaks one year later at 645 for the GALE development scenario.

FIGURE 4.8 DRILLING SCHEDULE, NUMBER OF WELLS DRILLED PER ANNUM, BY DEVELOPMENT SCENARIO



SOURCE: ACIL ALLEN CONSULTING

FIGURE 4.9 NUMBER OF OPERATING WELLS PER ANNUM, BY DEVELOPMENT SCENARIO



SOURCE: ACIL ALLEN CONSULTING

4.5.2 Supporting infrastructure

In addition to the number of wells, there is a range of supporting infrastructure required to enable gas to be extracted, processed, and sent to market. ACIL Allen has developed a simplified supporting

infrastructure regime using a series of ratios, presented in Table 4.4. Supporting infrastructure requirements are a function of the number of wells built in a given year.

TABLE 4.4 SUPPORTING INFRASTRUCTURE REQUIREMENTS

Supporting Infrastructure	Assumption	Source
Pads	Every eight wells drilled requires one new pad. If nine wells are drilled, two pads are required, and a new pad is not required until the number of new wells drilled exceeds 16.	ACIL Allen estimate based on industry consultation
Roads	For every one pad, 1.7km of roads are required for connection purposes.	ACIL Allen estimate based on industry consultation
Gathering pipes	For every one pad, 1km of 5 inch piping is required for gathering purposes.	ACIL Allen estimate based on industry consultation

These values for supporting infrastructure are fed into ProjectCo's financial model, and are costed in line with assumptions presented in Section 5.1.

4.6 Development prospect matrix

The above development scenarios are hypothetical, based on what a development could look like should ProjectCo discover a commercial quality shale gas reserve in the Northern Territory. This is subject to significant uncertainty, because there has been such little exploration activity that it is not possible to determine the extent to which a development is likely to occur.

With this in mind, ACIL Allen has developed a qualitative matrix to represent the prospect of each development occurring (Figure 4.10). On the basis of the financial modelling undertaken on the each development scenario, ACIL Allen has assessed the probability of a shale gas industry developing in the Northern Territory in each case. This is based on the outcomes of the financial modelling, the uncertainty regarding the size of the Northern Territory's commercial reserves, and the challenges associated with producing gas at a price which the market will accept. As the development scales up, these challenges will become greater, leading to a reduced likelihood that any given scale of development can be realised.

ACIL Allen has also formed a view that the probability of a shale gas industry developing in the Northern Territory will improve the greater the potential area for exploration and appraisal. As discussed in Section 3.2, international experience suggests that the ability to deliver large scale commercial quantities of petroleum products from prospective shale gas resources is a function of the volume of exploration and activity which has occurred, and the area available for exploration and activity to occur. This is driven by institutional learning, the ability to find better quality reserves over time, and economies of scale and scope.

For example, under the GALE scenario, ACIL Allen has assessed, on current information, the likelihood of a shale gas industry that will begin to scale to 1000 terajoules per day (TJ/day) of gas production at an average price of \$4.01 per gigajoule (GJ) within the next five years as low, assuming the moratorium is lifted in full across the Northern Territory. If there is only a partial lift in the moratorium, this becomes a very low probability, because there is less of an ability for a potential shale gas industry to find the most commercial shale gas deposits.

In the context of the probability matrix, ACIL Allen notes that it has made a critical assumption that the shale gas developments modelled in this report are a "dry gas play". That is, the hydrocarbons produced in a development do not include higher value liquid hydrocarbons such as ethane, propane, butane or crude oil. A "liquids rich" shale gas play results in a very small increase in operating costs (associated with increased processing to separate the higher value hydrocarbons from the lower value hydrocarbons), and a very large increase in potential production revenue. This improves the

commercial viability of a shale gas development, to the point where a larger development may have a higher probability of occurring versus a dry gas play.

FIGURE 4.10 ACIL ALLEN POLICY SCENARIO PROBABILITY MATRIX

			POLICY SCENARIO PROBABILITY MATRIX		
INDUSTRY DEVELOPMENT SCENARIO	Production Profile	Production Cost Regime	PERMANENT MORATORIUM	PARTIAL LIFT	FULL LIFT
BASELINE	Nil Shale Production	N/A	CERTAIN	MODERATE	LOW
SHALE CALM	Exploration occurs Failure to commercialise	N/A	ZERO	VERY HIGH	VERY HIGH
SHALE BREEZE	Scenario 1 Target production: 36PJ per annum	High cost	ZERO	MODERATE	HIGH
SHALE WIND	Scenario 2 Target production: 150PJ per annum	Moderate cost	ZERO	LOW	MODERATE
SHALE GALE	Scenario 3 Target production: 365PJ per annum	Low cost	ZERO	VERY LOW	LOW

SOURCE: ACIL ALLEN CONSULTING

4.7 PipelineCo development assumptions

To get ProjectCo's gas to market, it will need to be transmitted on a series of major gas transmission pipelines. As discussed in Section 0, there is limited capacity available on existing gas transmission pipelines. As a result, new pipelines must be developed.

PipelineCo is the builder, owner and operator of new major transmission pipeline infrastructure required to facilitate the development of ProjectCo's gas fields in each of the three scenarios. The development of PipelineCo is significantly simpler than ProjectCo, as PipelineCo simply builds pipelines of the requisite size to convey ProjectCo's gas to market over the life of the modelling period. PipelineCo is modelled as a typical pipeline owner-operator, with a relatively low required rate of return on its investments reflecting the relative safety of investment in pipeline infrastructure.

The key assumptions used to develop PipelineCo are presented below.

- PipelineCo builds all of its pipelines in the two years prior to the first flow of ProjectCo gas, to a specification that will allow it to carry the peak load of ProjectCo gas in the modelling period.
- PipelineCo has a 40 year investment horizon, and sets tariffs at a level that allow it to generate a six per cent pre-tax internal rate of return in a simple DCF model.
- PipelineCo's operating costs are set at 1.25 per cent of its total up front capital costs, and begin accruing from one year post the commencement of construction.
- Finally, part of PipelineCo's capital investment is stratified into initial investment in pipelines, which can carry a certain volume of uncompressed gas, and ongoing smaller capital investments required to build compression stations on the pipeline network as transmission requirements increase.

There are five distinct pipelines that are required to be built or duplicated over the three development scenarios, with the diameter of the pipe changing in each scenario depending on the volume of gas requiring transmission. The below matrix outlines the diameter of each pipe on PipelineCo's network in each scenario.

TABLE 4.5 PIPELINECO PIPELINE SPECIFICATIONS

Pipeline (length)	Breeze diameter	Wind diameter	Gale diameter
Tie into Amadeus pipeline (50km)	12 inch	19 inch	22 inch

Pipeline (length)	Breeze diameter	Wind diameter	Gale diameter
Amadeus duplication (300km)	10 inch	18 inch	22 inch
Northern Gas Pipeline (NGP) duplication (622km)	N/A	16 inch	21 inch
Carpentaria Gas Pipeline (CGP) duplication (841 km)	N/A	15 inch	21 inch
DLNG Feed Pipeline (new pipeline) (550km)	N/A	N/A	20 inch

Note: For simplicity, ACIL Allen assumed the processing facility built by ProjectCo is approximately 50 kilometres away from the Amadeus pipeline, and 550km away from the DLNG facility. Outside of this, ACIL Allen has not assumed a location for the development

SOURCE: ACIL ALLEN CONSULTING

ACIL Allen has not considered the mooted Moomba-Alice Springs gas pipeline in this analysis for two reasons. First, it is simpler to assume that existing pipeline routes are expanded or duplicated rather than developing an entirely new pipeline from scratch, as existing pipeline lengths, routes and cost estimates are available. Second, the Moomba-Alice Springs pipeline has been discussed for some time, and is yet to progress beyond the pre-feasibility study stage, albeit the Federal Government committed to fund a more detailed feasibility study earlier this year.³⁴ At face value, the Moomba-Alice Springs gas pipeline would represent a viable route to market for gas produced by a Northern Territory shale gas development.

³⁴ NT News. 2017. *Federal Government to investigate feasibility of north-south gas pipeline*, 2 April 2017. Accessed online at <http://www.ntnews.com.au/>



5

PROJECT DEVELOPMENT FINANCIAL MODEL

After shaping the development, using a series of modelling tasks, ACIL Allen has converted ProjectCo and PipelineCo's development plans in each scenario into three separate financial models. The financial models for ProjectCo are prepared as discounted cash flow ('DCF') model as if ProjectCo was a standalone corporate entity with a relatively simple financial structure. This requires a series of assumptions, which are outlined in Section 5.1. The outcome of the DCF modelling for ProjectCo is presented in Section 5.2. Recognising the role that assumptions can play in the results of DCF modelling, ACIL Allen has presented a series of sensitivity analysis on key inputs under each scenario. The results of this are presented in Section 5.3. Finally, the simple financial model for PipelineCo is outlined in Section 5.4.

5.1 ProjectCo financial inputs and assumptions

This section details the remaining key inputs and assumptions used to populate the cash flow model for each development scenario.

5.1.1 Overall inputs and assumptions

The inputs and assumptions used to populate the framework of the cash flow model are presented in the table below.

Input or Assumption	Value	Source
Reporting year	Financial year	ACIL Allen
Cash flow model start date	2018	ACIL Allen
Discount rate start date	2018	ACIL Allen
Discount rate	10 per cent	ACIL Allen

5.1.2 Financial inputs and assumptions

The inputs and assumptions used to estimate ProjectCo's non capital, operating and taxation expenses are presented in the table below.

Input or Assumption	Value	Source
Share of capital funded by debt	66.7 per cent	ACIL Allen estimate based on industry standards
Share of capital funded by equity	33.3 per cent	ACIL Allen estimate based on industry standards

Input or Assumption	Value	Source
Term length of debt	20 years	ACIL Allen estimate based on industry standards
Amortisation of debt	Yes	ACIL Allen based on industry standards
Native Title payments, exploration	3 per cent of proponent exploration cost	Stakeholder consultation
Native Title payments, operations	10 per cent of royalty payments	Stakeholder consultation
Pastoralist payments, operations	\$250,000 per pad	Stakeholder consultation
Exploration permit	\$4,927 per permit	NT Government ³⁵
Exploration permit renewal	\$1,642 per permit	NT Government*
Production permit	\$18,000 per block	NT Government*
Production permit renewal	\$1,642 per permit	NT Government*
Environmental bond	Estimated cost of abandonment	Stakeholder consultation

5.1.3 Capital inputs and assumptions

The inputs and assumptions used to estimate ProjectCo's capital expenditure are presented in the table below.

Input or Assumption	Value	Source
Cost, drilling construction (well-related civil work, surface hole preparation, drilling, fracture stimulation, completion, connection. This includes implicit costs of water extraction and sand acquisition for proppant) (also include implicit capital cost of a processing facility as a cost per 8.4-10.6-12.7PJ of gas. ACIL Allen could not determine the cost of a standalone processing facility)	\$18 million per well	ACIL Allen estimate based on: <ul style="list-style-type: none"> – US Department of Energy, <i>Trends in US Oil and Natural Gas Upstream Costs</i>, March 2016; – ACOLA, <i>Engineering Energy: Unconventional Gas Production, A study of Shale Gas in Australia, Final Report</i>, June 2013; and – industry consultation.
Costs, pad construction	\$3.7 million per pad	ACIL Allen estimate based on industry consultation
Number of wells drilled per pad	8 wells per pad	ACIL Allen estimate based on industry expectations
Costs, gathering pipes construction	\$350,000 per km	ACIL Allen estimate based on industry consultation assuming a 5 inch diameter pipe at \$70,000 per inch kilometre
Costs, road construction	\$450,000 per 1.7km	Cummings Economics, <i>Submission to Infrastructure Australia</i> , 2012
Costs, camp construction	\$8 million per camp	ACIL Allen, based on: <ul style="list-style-type: none"> – Estimated cost per bed of INPEX Ichthys camp, when applied to 150 bed camp structure = \$11.1m.³⁶ – Stakeholder consultation

³⁵ <https://nt.gov.au/industry/mining-and-petroleum/petroleum-titles/petroleum-titles-fees-and-rents>

³⁶ INPEX. 2013. *ICHTHYS LNG PROJECT'S MANIGURR-MA VILLAGE OPEN FOR BUSINESS*. Accessed online at <http://www.inpex.com/>

Input or Assumption	Value	Source
Useful life, drilling	20 years	ACIL Allen based on standard ATO practice
Useful life, pad	20 years	ACIL Allen based on standard ATO practice
Useful life, gathering pipes	20 years	ACIL Allen based on standard ATO practice
Useful life, road	20 years	ACIL Allen based on standard ATO practice
Useful life, camp	20 years	ACIL Allen based on standard ATO practice
Abandonment, well	\$250,000 per well	ACIL Allen based on industry consultation
Abandonment, pad	\$100,000 per pad	ACIL Allen based on industry consultation

5.1.4 Operating inputs and assumptions

The inputs and assumptions used to estimate the operating cost of ProjectCo are presented in the table below.

Input or Assumption	Value	Source
All-in costs <i>(downhole maintenance and monitoring, extraction processing, labour, overheads, compliance, insurance)</i>	\$1.50 per GJ	ACIL Allen estimate based on: – US Department of Energy, <i>Trends in US Oil and Natural Gas Upstream Costs</i> , March 2016; and – industry consultation.
Gathering and compression costs <i>(operations and maintenance for gathering pipelines, processing for sale)</i>	\$0.75 per GJ	ACIL Allen estimate based on: – US Department of Energy, <i>Trends in US Oil and Natural Gas Upstream Costs</i> , March 2016; and – industry consultation.
Avoided cost of fuel <i>(included in 'all-in' costs and gathering and compression costs which reduces operating cost per GJ. Cost saving is mostly associated with diesel fuel hauling and storage costs)</i>	\$0.90 per GJ	Industry consultation
Camp operating cost	\$10 million per camp per annum	Industry consultation

5.1.5 Learnings inputs and assumptions

The inputs and assumptions used to estimate the learnings the ProjectCo will achieve over its economic life are presented in the table below.

Input or Assumption	Value	Source
Drilling construction costs	15 per cent, cap at 40 per cent per annum	ACIL Allen estimate based on: <ul style="list-style-type: none"> – US Department of Energy, <i>Trends in US Oil and Natural Gas Upstream Costs</i>, March 2016; – ACOLA, <i>Engineering Energy: Unconventional Gas Production, A study of Shale Gas in Australia, Final Report</i>, June 2013; and – industry consultation.
Pad construction costs	15 per cent, cap at 40 per cent per annum	ACIL Allen estimate based on: <ul style="list-style-type: none"> – US Department of Energy, <i>Trends in US Oil and Natural Gas Upstream Costs</i>, March 2016; – ACOLA, <i>Engineering Energy: Unconventional Gas Production, A study of Shale Gas in Australia, Final Report</i>, June 2013; and – industry consultation.
All-in operating costs	7.5 per cent, cap at 20 per cent per annum	ACIL Allen estimate based on: <ul style="list-style-type: none"> – US Department of Energy, <i>Trends in US Oil and Natural Gas Upstream Costs</i>, March 2016; – ACOLA, <i>Engineering Energy: Unconventional Gas Production, A study of Shale Gas in Australia, Final Report</i>, June 2013; and – industry consultation.
Gathering and compression operating costs	7.5 per cent, cap at 20 per cent per annum	ACIL Allen estimate based on: <ul style="list-style-type: none"> – US Department of Energy, <i>Trends in US Oil and Natural Gas Upstream Costs</i>, March 2016; – ACOLA, <i>Engineering Energy: Unconventional Gas Production, A study of Shale Gas in Australia, Final Report</i>, June 2013; and – industry consultation.

5.1.6 Labour inputs and assumptions

The inputs and assumptions used to estimate the labour component of ProjectCo are presented in the table below.

Input or Assumption	Value	Source
Average construction salary	\$150,000 per FTE	ACIL Allen
Average operations salary	\$150,000 per FTE	ACIL Allen
Field construction	35 FTEs per pad	Industry consultation
Camp construction	15 FTEs per camp	Industry consultation
Field operations	8 FTEs per pad	Industry consultation
Field abandonment	10 FTEs per pad	Industry consultation
Camp operations	20 FTEs per camp	Industry consultation

5.1.7 Pipeline tariffs

ACIL Allen anticipates ProjectCo will be able to utilise some latent capacity on existing gas transmission pipelines. The assumed tariffs for these are below. ACIL Allen has taken a conservative assumption and bought capacity at the quoted spot rate by pipeline owners, noting that realised tariffs are likely to be lower. Tariffs for new pipelines developed by PipelineCo are presented in Section 0.

Input or Assumption	Value	Source
Amadeus Gas Pipeline	\$0.58 per GJ	APA Group
Northern Gas Pipeline (NGP)	\$1.45 per GJ	Jemena Group
Carpentaria Gas Pipeline (CGP)	\$1.56 per GJ	APA Group

5.1.8 Water inputs and assumptions

The inputs and assumptions used to estimate ProjectCo's total water requirements are presented in the table below.

Input or Assumption	Value	Source
Water requirements	41ML per frack	ACIL Allen estimate based on: <ul style="list-style-type: none"> – ACOLA, <i>Engineering Energy: Unconventional Gas Production, A study of Shale Gas in Australia, Final Report</i>, June 2013; and – industry consultation. As a conservative estimate, ACIL Allen has doubled its expected water use projection.
Water recycle rate	0 per cent recycled	ACIL Allen estimate
Number of fracking stages	20 fracks and 1 hydraulic fracture stimulation program per well	ACIL Allen estimate based on industry consultation
Water charges	\$0/ML	NT Government, there is currently no policy to charge users of groundwater for the use of groundwater resources. The cost of extracting ground water is implicit in ACIL Allen's well cost assumption

5.1.9 Macroeconomic inputs and assumptions

The macroeconomic inputs and assumptions that impact on ProjectCo's net cash flows are presented in the table below.

Input or Assumption	Value	Source
Long-term bond rate	3.5 per cent	ACIL Allen
Interest rate	6 per cent	ACIL Allen
Inflation	Real terms	ACIL Allen

5.1.10 Taxation inputs and assumptions

The taxation inputs and assumptions used in this cash flow assessment of ProjectCo are presented in the table below.

Input or Assumption	Value	Source
Payroll tax rate, Northern Territory	5.5 per cent	NT Department of Treasury and Finance http://www.treasury.nt.gov.au/TaxesRoyaltiesAndGrants/PayrollTax/Pages/Payroll-Tax-Rates-and-Thresholds.aspx
Payroll tax threshold, Northern Territory	\$1.5 million	NT Department of Treasury and Finance http://www.treasury.nt.gov.au/TaxesRoyaltiesAndGrants/PayrollTax/Pages/Payroll-Tax-Rates-and-Thresholds.aspx
Company tax rate	30 per cent	ATO
Quarantine losses	Yes	ACIL Allen based on standard ATO practice
PRRT rate	40 per cent	ATO
PRRT general expenditure growth rate	4 per cent	ACIL Allen
Oil and gas royalty rate, Northern Territory	10 per cent of well head value	NT Department of Treasury and Finance

5.2 ProjectCo cash flow modelling results

Based on the set of inputs and assumptions detailed in the previous sections, the estimated net cash flows of ProjectCo for each development stage is presented below.

ACIL Allen estimated the net cash flows of each development scenario using a bottom-up approach. This involved estimating costs for capital, operations, other operating costs and direct taxation payments made by ProjectCo and the resulting margin under each development scenario (refer to Table 5.1 and Figure 5.1 overleaf).

TABLE 5.1 AVERAGE COST BETWEEN 2022 AND 2043 OF EACH PROJECTCO DEVELOPMENT SCENARIO, FINANCIAL YEAR, REAL TERMS, A\$ PER GJ

Cost	BREEZE	WIND	GALE
CAPEX	\$2.20/GJ	\$1.74/GJ	\$1.45/GJ
Interest	\$1.20/GJ	\$0.86/GJ	\$0.55/GJ
OPEX	\$1.77/GJ	\$1.59/GJ	\$1.46/GJ
Taxation	\$0.75/GJ	\$0.71/GJ	\$0.45/GJ
Other costs	\$0.16/GJ	\$0.13/GJ	\$0.09/GJ
Total costs (ex-field)	\$6.07/GJ	\$5.03/GJ	\$4.01/GJ
Market price (ex-transport tariff)	\$6.84/GJ	\$5.11/GJ	\$3.75/GJ
Margin	\$0.77/GJ	\$0.09/GJ	-\$0.26/GJ

Note: Market prices presented are ex-transport tariff.

SOURCE: ACIL ALLEN CONSULTING

The largest components of ProjectCo's cost structure are the costs associated with capital expenditure. For example, under the BREEZE development scenario, the cost of capital averages \$2.20 per GJ, with the resulting average interest costs associated with financing capital expenditure of \$1.20 per GJ. The costs of capital and interest reduce in the subsequent WIND and GALE

development scenarios due to improved learnings and the economies of scale achieved under a larger production scenario.

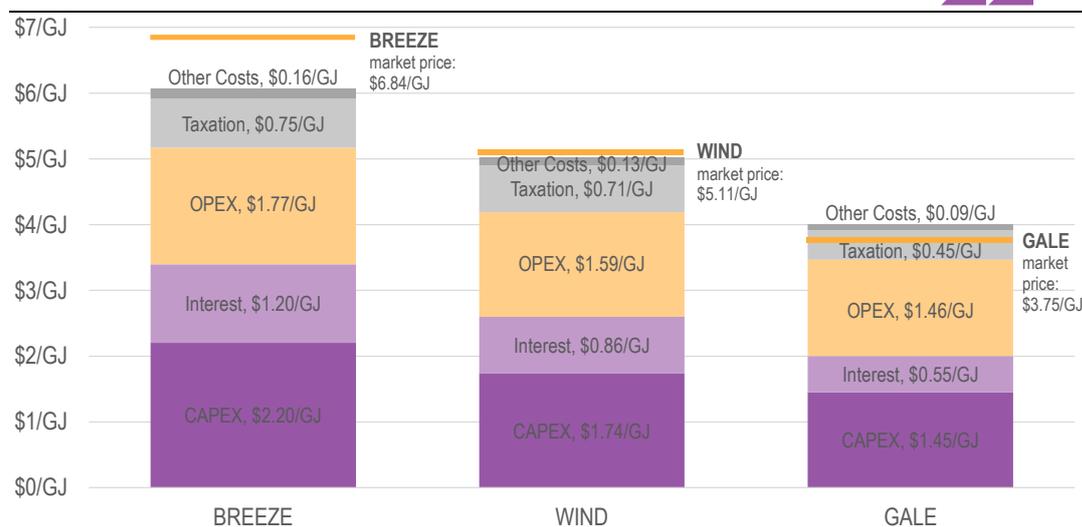
Ex-field costs associated with ProjectCo’s production phase are the next biggest share of its total cost structure. For example, under the BREEZE development stage, operating costs average \$1.78 per GJ, reducing to an average of \$0.55 per GJ under the GALE development scenario as a result of the improved learnings and economies of scale benefits.

Taxation payments made by ProjectCo are dependent on the economics of each development stage. Based on the margins generated under each development scenario, the tax payments are expected to range from \$0.74 per GJ under the BREEZE development scenario to \$0.45 per GJ under the GALE development scenario.

Based on the 20 year study period, this does not allow enough time for ProjectCo to return a substantial dividend on its capital expenditure. However, beyond the study period and over the economic life of the Project, the dividends increase and the Project’s taxation payment increase.

Ex-field all other costs include costs for abandonment, payments to native title owners and pastoralists, and licensing. On average, other costs make up a very small proportion of ProjectCo’s cost structure under each development scenario.

FIGURE 5.1 AVERAGE COST BETWEEN 2022 AND 2043 OF EACH PROJECTCO DEVELOPMENT STAGE, FINANCIAL YEAR, REAL TERMS, A\$ PER GJ



Note: Market prices presented are ex-transport tariff.

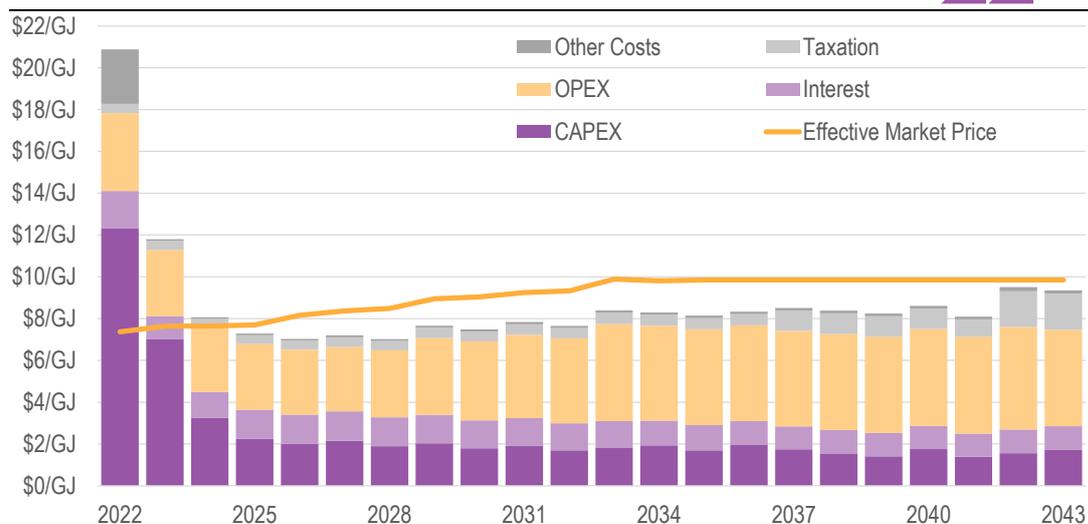
SOURCE: ACIL ALLEN CONSULTING

The figures presented in Figure 5.1 represent averages over the period between 2022 and 2043, and therefore do not necessarily represent the operating position of each development scenario at any one time. It is for this reason in Figure 5.1 that the GALE development scenario shows an operating loss over the study period.

Figure 5.3 below presents the operating position of the BREEZE development scenario each year over the study period. At the start of the development, the capital requirements of ProjectCo are significant, but as ProjectCo reaches a steady state of production, the level capital required to maintain steady state production significantly falls. This results in ProjectCo operating at a loss in the early years of the development (when capital costs are high), with a positive margin being generated once steady state production is reached (due to lower capital requirements).

This is consistent across all development scenarios.

FIGURE 5.2 AVERAGE COST BETWEEN 2022 AND 2043 OF BREEZE DEVELOPMENT SCENARIO, FINANCIAL YEAR, REAL TERMS, A\$ PER GJ



Note: Market prices presented are ex-transport tariff.

SOURCE: ACIL ALLEN CONSULTING

5.2.1 CALM

The CALM scenario is the scenario that sees ProjectCo undertake a three year program of exploration and appraisal, but fail to progress beyond this due to an inability to find a commercial quality shale gas reserve. The CALM scenario is also the basis for the first four years (in Year 0, nothing occurs as the moratorium is lifted) of the production scenarios discussed below, but instead of an assumption that no commercial quality shale gas is discovered, the assumption is a requisite scale commercial shale gas reserve is discovered.

ACIL Allen has assumed in the first year of the exploration and appraisal program, ProjectCo builds eight production wells, and the associated infrastructure to support the program. This is valued at \$315.9 million. In Year two of the exploration and appraisal program, testing, commercial analysis and other services are purchased to allow ProjectCo to understand the shale it is testing. This is valued at \$166.9 million. In Year three, residual exploration expenditure occurs, as ProjectCo decommissions its exploration and appraisal program due to a failure to find a commercial shale gas reserve. This is valued at \$4.2 million.

In the CALM scenario, this is the extent of ProjectCo's financial model. The total cost of the exploration and appraisal program is \$500 million. It is assumed ProjectCo does not earn any revenue from its operations, meaning the discounted net cash flows of ProjectCo are estimated to total -\$440 million over the study period (refer to Figure 5.3 overleaf).

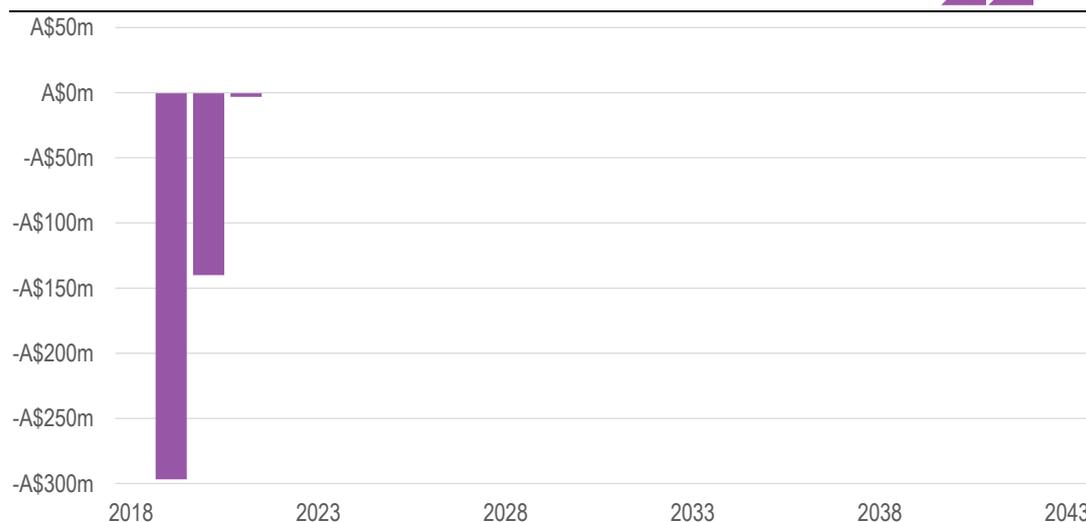
In the BREEZE, WIND and GALE scenarios, the expenditure associated with CALM is the starting point of the cash flow model, and is recovered progressively over the modelling period as ProjectCo moves into production and begins to generate positive cash flows.

5.2.2 BREEZE

Based on the production profile and the associated drilling schedule developed by ACIL Allen, it is estimated the capital requirements of ProjectCo under the BREEZE development scenario over the study period would total \$2 billion, at an average of \$76 million per annum.

The cost of drilling and associated pad costs are estimated to total \$1.5 billion over the study period, making them the largest component of total capital expenditure. The remainder of the capital expenditure consists of supporting infrastructure, such as gathering pipes, roads and camp construction costs.

FIGURE 5.3 CALM NET CASH FLOWS, FINANCIAL YEAR, DISCOUNTED, REAL TERMS, A\$ MILLION



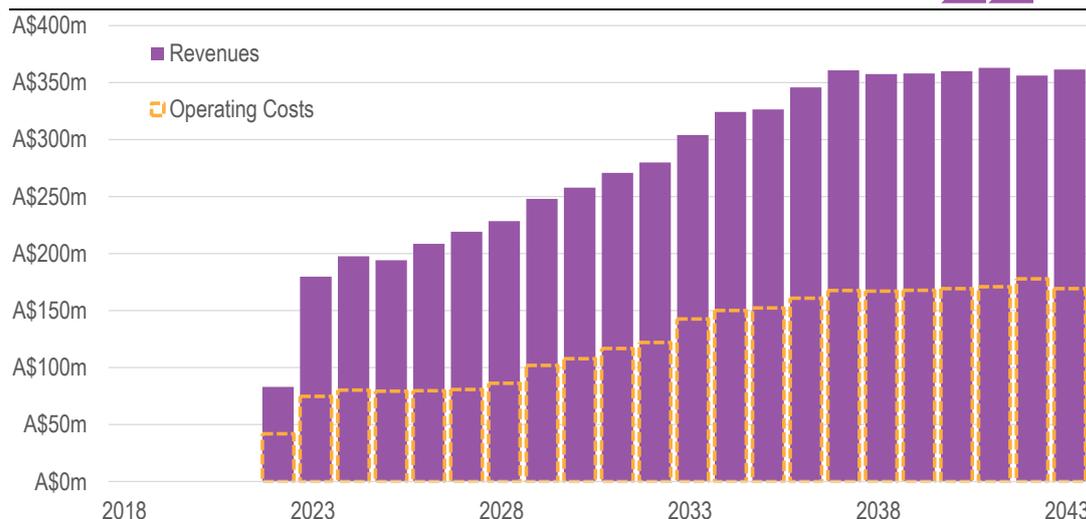
SOURCE: ACIL ALLEN CONSULTING

The operating costs of ProjectCo reach a steady state of around \$170 million per annum in 2037 (refer to Figure 5.4 overleaf). Over the study period, operating costs total \$2.8 billion at an average of \$107 million per annum. Transport costs total \$1.6 billion over the study period, and are the largest component of ProjectCo’s total operating cost structure.

The capital expenditure and operating costs generate a steady state of revenue of around \$350 million per annum by 2037. Over the study period, the revenues are estimated to total \$6.2 billion at an average of \$238 million per annum.

Once ProjectCo becomes liable for PRRT payments, PRRT payments overtake company taxation payments as the major profits based tax.

FIGURE 5.4 BREEZE OPERATING POSITION, FINANCIAL YEAR, PRESENT VALUE, REAL TERMS, A\$ MILLION



SOURCE: ACIL ALLEN CONSULTING

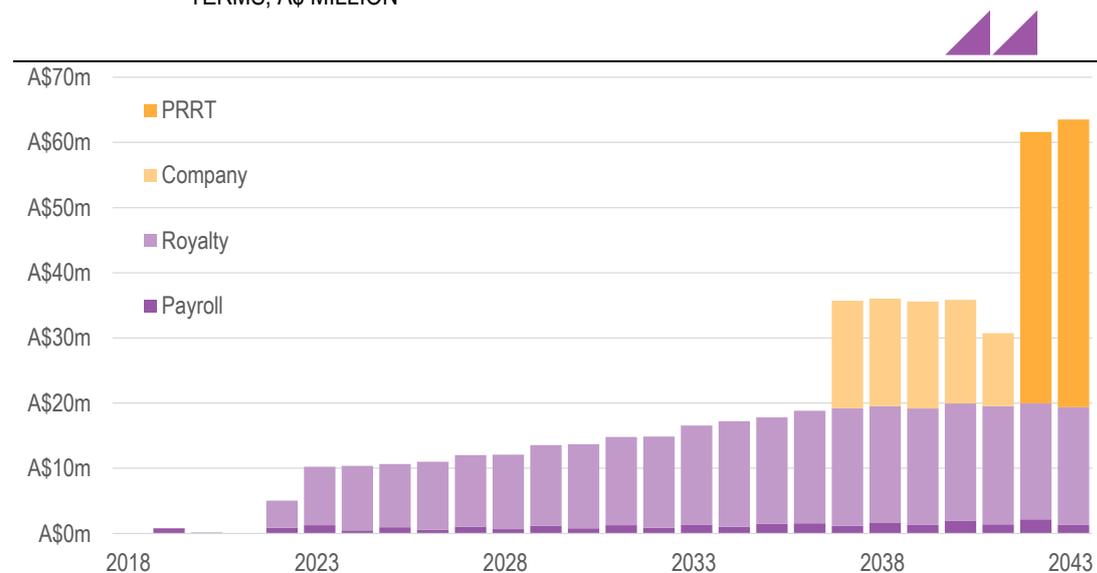
Figure 5.4 presents the major heads of taxation ProjectCo is liable to pay over the study period. Under the BREEZE development scenario, it is estimated that ProjectCo becomes liable for profit based taxation payments from 2037.

Company taxation payments to the Commonwealth are estimated to be first payable in 2037 and total \$76.5 million at an average of \$2.9 million per annum over the study period. As the taxable income of ProjectCo increases over time and the Project's PRRT credits are fully consumed, ProjectCo becomes liable for PRRT payments in 2042, and total \$85.8 million over the study period.

Over the study period, the Northern Territory Government will be the primary beneficiary of taxation payments made by ProjectCo. This will largely occur through the form of royalty payments, which are estimated to total \$309 million over the study period or \$11.9 million per annum.

The Northern Territory Government will also receive payroll taxation payments from ProjectCo, which are estimated to total \$27.2 million over the study period, or on average \$1.1 million per annum.

FIGURE 5.5 BREEZE DIRECT TAXATION PAYMENTS, FINANCIAL YEAR, PRESENT VALUE, REAL TERMS, A\$ MILLION



SOURCE: ACIL ALLEN CONSULTING

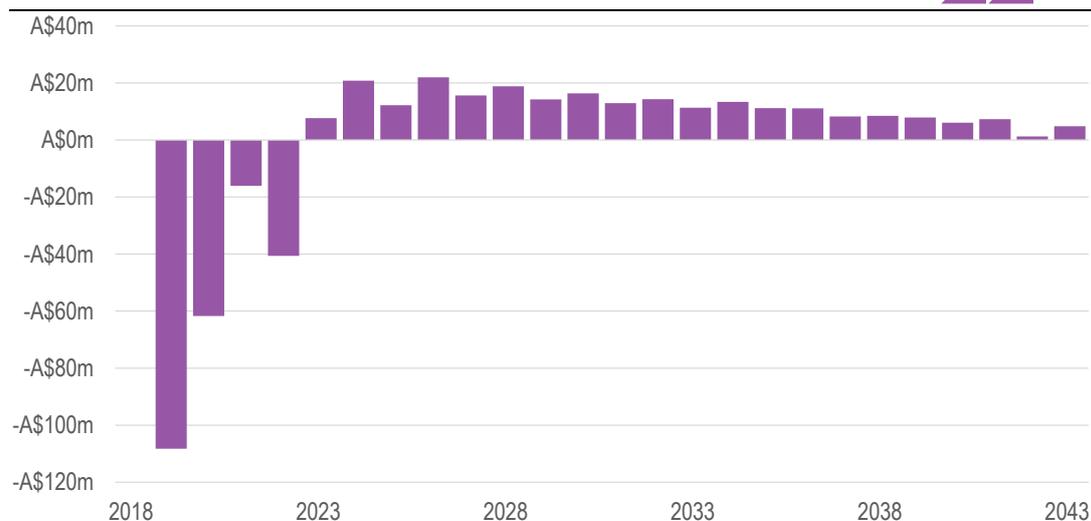
The level of taxation receipts collected by both Commonwealth and Territory governments are dependent on the magnitude of net cash flows generated by ProjectCo, which are of course highly sensitive to the inputs and assumptions that underpin the cash flow model.

Over the study period, the discounted net cash flows of ProjectCo are estimated to total \$19.4 million, at an average of \$0.8 million per annum. Under the set of inputs and assumptions presented above, interest payments on the debt required to fund ProjectCo's capital expenditure, and the cost of PRRT payments first being realised in 2042, are major determinants of the Project's overall economic viability from a discounted cash flow prospective.

This is because the cash flow model has been developed to fund capital expenditure via debt (66.6 per cent), equity (33.3 per cent) and/or by positive cash flows. Greater positive net cash flows generated by ProjectCo in the early years reduce the level of debt the Project is required to take on, which reduces interest payments and further increases the Project's net cash flows.

However, as taxation expenses increase when ProjectCo's taxable income increases towards the end of the study period, positive net cash flows are reduced, resulting in ProjectCo's financing more of its capital expenditure by debt, which increases interest payments and further reduces net cash flows.

FIGURE 5.6 BREEZE NET CASH FLOWS, FINANCIAL YEAR, DISCOUNTED, REAL TERMS, A\$ MILLION



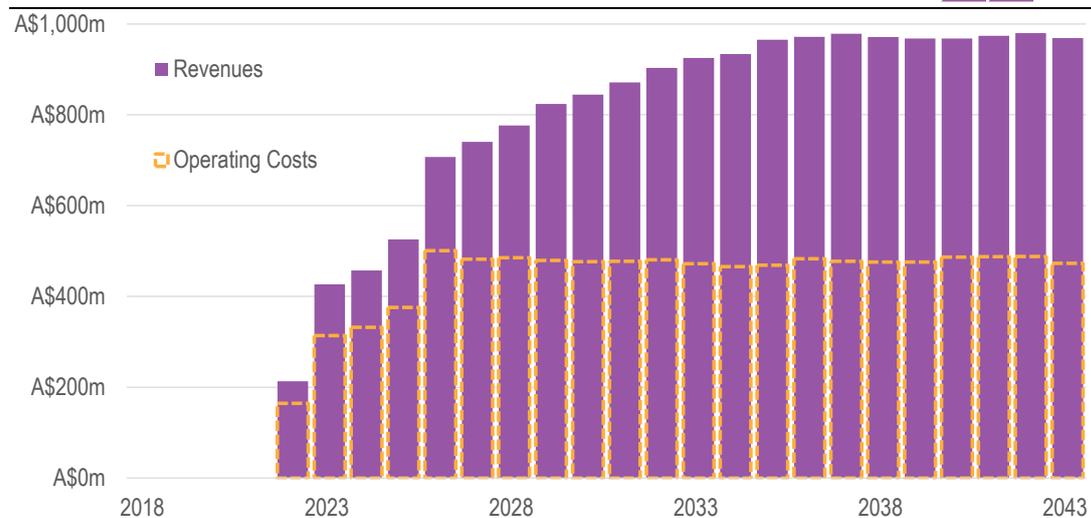
Note: Discount rate of 10 per cent per annum.
 SOURCE: ACIL ALLEN CONSULTING

5.2.3 WIND

Based on the production profile and the associated drilling schedule developed by ACIL Allen, it is estimated the capital requirements of ProjectCo under the WIND development scenario over the study period would total \$4.3 billion, at an average of \$167 million per annum. The cost of drilling and associated pad costs are estimated to total \$3.5 billion over the study period, making them the largest component of total capital expenditure. The remainder of the capital expenditure consists of supporting infrastructure, such as gathering pipes, roads and camp construction costs.

The operating costs of ProjectCo reach a steady state of around \$480 million per annum in 2027 (refer to Figure 5.7). Over the study period, operating costs total \$9.8 billion at an average of \$379 million per annum. Transport costs total \$6.3 billion over the study period, and are the largest component of ProjectCo’s total operating cost structure.

FIGURE 5.7 WIND OPERATING POSITION, FINANCIAL YEAR, PRESENT VALUE, REAL TERMS, A\$M



SOURCE: ACIL ALLEN CONSULTING

The capital expenditure and operating costs generate a steady state of revenue of around \$970 million per annum by 2035. Over the study period, the revenues are estimated to total \$17.9 billion at an average of \$688 million per annum.

Figure 5.8 presents the major heads of taxation ProjectCo is liable to pay over the study period. Under the WIND development scenario, it is estimated that ProjectCo becomes liable for profit based taxation payments from 2037.

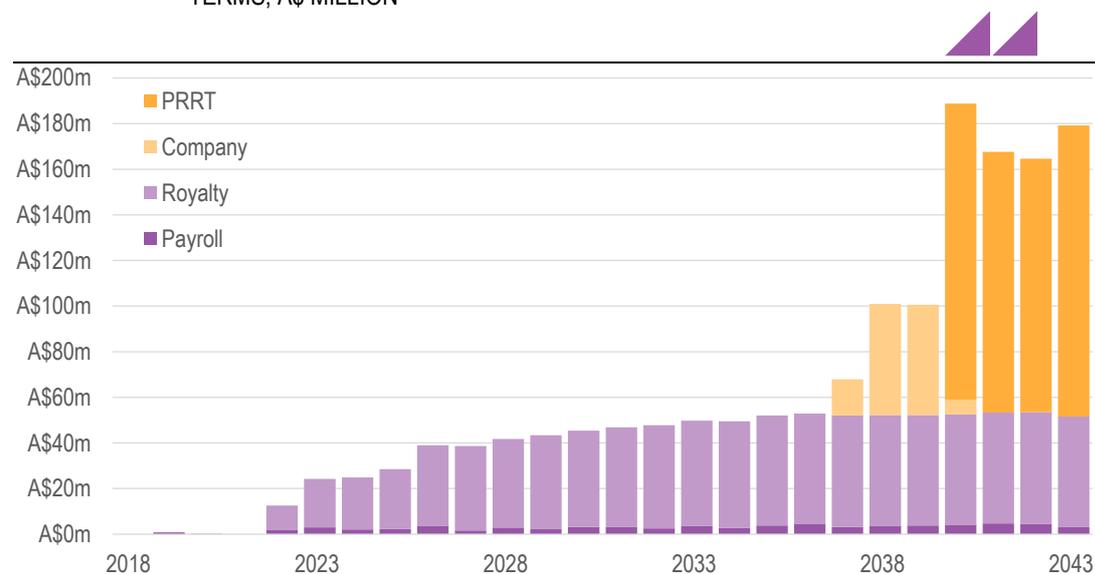
Company taxation payments to the Commonwealth are estimated to be first payable in 2037 and total \$119 million at an average of \$4.6 million per annum over the study period. As the taxable income of ProjectCo increases over time and the Project's PRRT credits are fully consumed, ProjectCo becomes liable for PRRT payments in 2040, and total \$483 million over the study period.

Once ProjectCo becomes liable for PRRT payments, PRRT payments overtake company taxation payments as the major profits based tax.

Over the study period, the Northern Territory Government will be the primary beneficiary of taxation payments made by ProjectCo. This will largely occur through the form of royalty payments, which are estimated to total \$875 million over the study period or \$34.4 million per annum.

The Northern Territory Government will also receive payroll taxation payments from ProjectCo, which are estimated to total \$71.1 million over the study period, or on average \$2.7 million per annum.

FIGURE 5.8 WIND DIRECT TAXATION PAYMENTS, FINANCIAL YEAR, PRESENT VALUE, REAL TERMS, A\$ MILLION



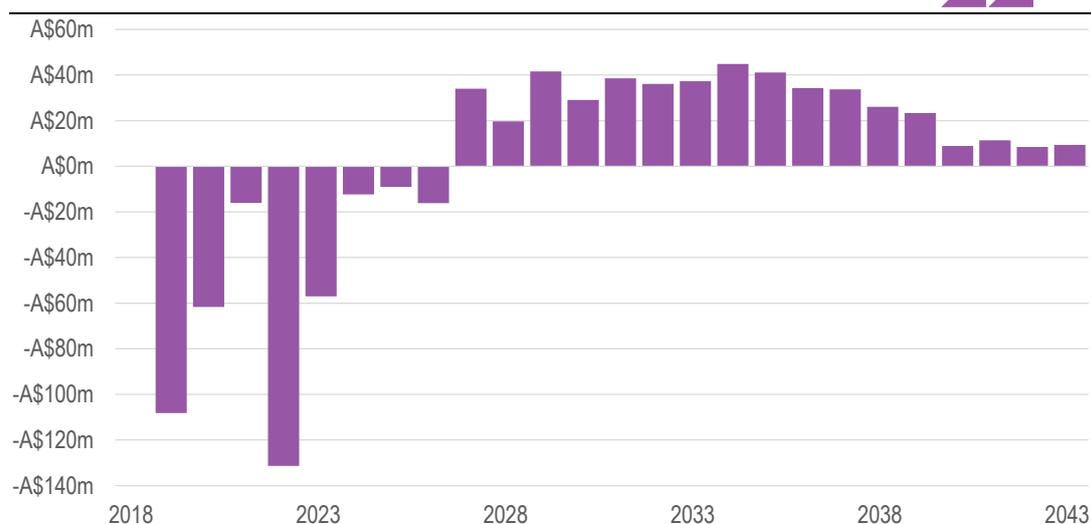
SOURCE: ACIL ALLEN CONSULTING

The level of taxation receipts collected by both Commonwealth and Territory governments are dependent on the magnitude of net cash flows generated by ProjectCo, which are of course highly sensitive to the inputs and assumptions that underpin the cash flow model.

Over the study period, the discounted net cash flows of ProjectCo are estimated to total \$65.9 million, at an average of \$2.5 million per annum. Under the set of inputs and assumptions presented above, interest payments on the debt required to fund ProjectCo's capital expenditure, and the cost of PRRT payments first being realised in 2040, are major determinants of the Project's overall economic viability from a discounted cash flow prospective.

This is because the cash flow model has been developed to fund capital expenditure via debt (66.6 per cent), equity (33.3 per cent) and/or by positive cash flows. Greater positive net cash flows generated by ProjectCo in the early years reduce the level of debt the Project is required to take on, which reduces interest payments and further increases the Project's net cash flows.

FIGURE 5.9 WIND NET CASH FLOWS, FINANCIAL YEAR, DISCOUNTED, REAL TERMS, A\$ MILLION



Note: Discount rate of 10 per cent per annum.

SOURCE: ACIL ALLEN CONSULTING

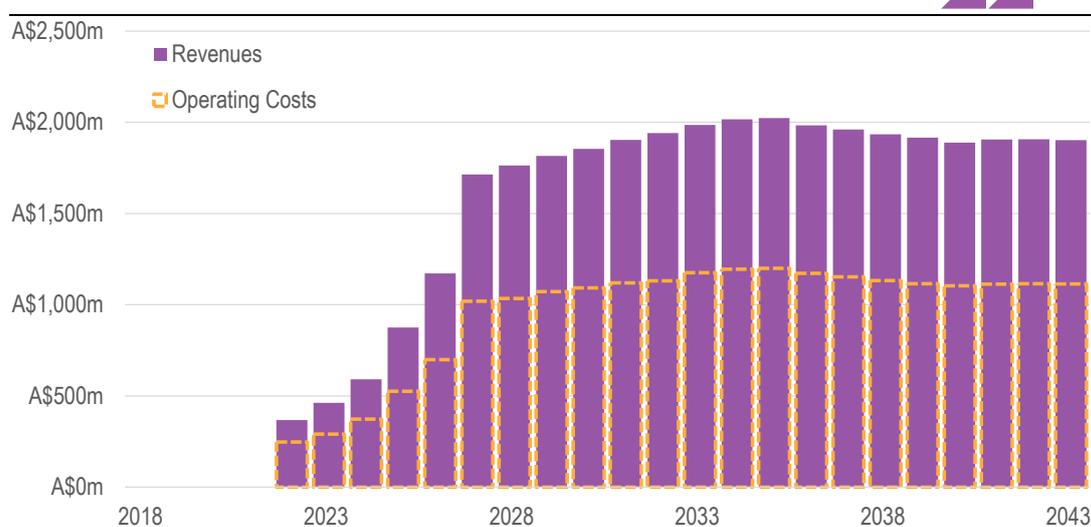
However, as taxation expenses increase when ProjectCo’s taxable income increases towards the end of the study period, positive net cash flows are reduced, resulting in ProjectCo’s financing more of its capital expenditure by debt, which increases interest payments and further reduces net cash flows.

5.2.4 GALE

Based on the production profile and the associated drilling schedule developed by ACIL Allen, it is estimated the capital requirements of ProjectCo under the GALE development scenario over the study period would total \$9.8 billion, at an average of \$378 million per annum. The cost of drilling and associated pad costs are estimated to total \$8.5 billion over the study period, making them the largest component of total capital expenditure. The remainder of the capital expenditure consists of supporting infrastructure, such as gathering pipes, roads and camp construction costs.

The operating costs of ProjectCo reach a steady state of around \$1.1 billion per annum in 2027 (refer to Figure 5.10).

FIGURE 5.10 GALE OPERATING POSITION, FINANCIAL YEAR, PRESENT VALUE, REAL TERMS, A\$M



SOURCE: ACIL ALLEN CONSULTING

Over the study period, operating costs total \$21 billion at an average of \$816 million per annum. Transport costs total \$11.8 billion over the study period, and are the largest component of ProjectCo’s total operating cost structure. The capital expenditure and operating costs generate a steady state of revenue of around \$1.9 billion per annum by 2030. Over the study period, the revenues are estimated to total \$35.9 billion at an average of \$1.4 billion per annum.

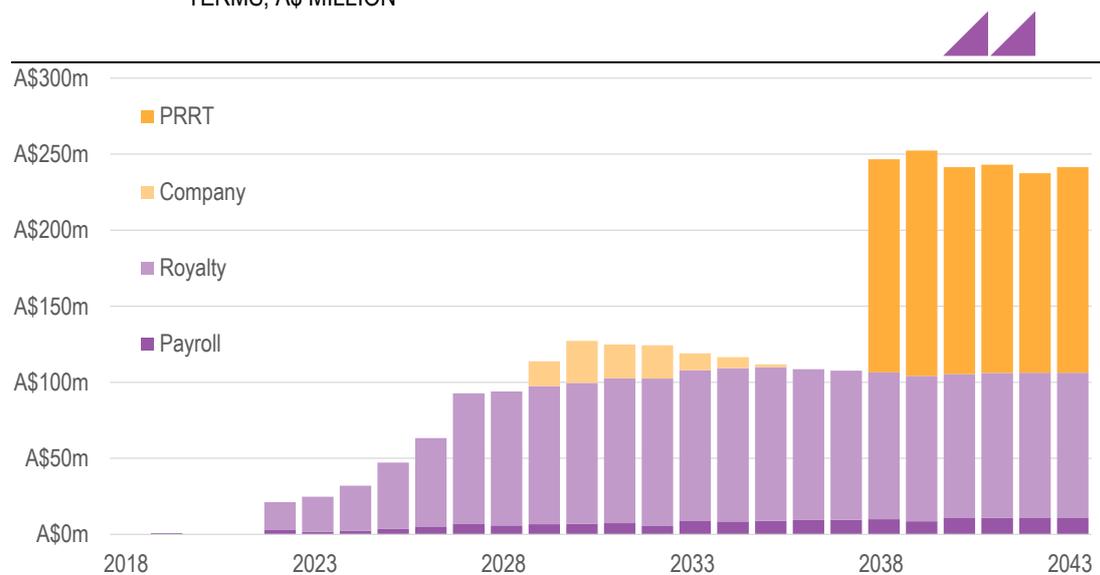
Figure 5.11 presents the major heads of taxation ProjectCo is liable to pay over the study period. Under the GALE development scenario, it is estimated that ProjectCo becomes liable for profit based taxation payments from 2029.

Company taxation payments to the Commonwealth are estimated to be first payable in 2029 and total \$108 million at an average of \$4.2 million per annum over the study period. As interest payments increase over time, the taxable income of ProjectCo decreases, as results in no company taxation payments in 2036 and 2037. However, as ProjectCo’s taxable income for PRRT calculations increases, and over time and the Project’s PRRT credits are fully consumed, ProjectCo will become liable for PRRT payments in 2038, totalling \$828 million over the study period.

Over the study period, the Northern Territory Government will be the primary beneficiary of taxation payments made by ProjectCo. This will largely occur through the form of royalty payments, which are estimated to average \$1.8 billion over the study period or \$69 million per annum.

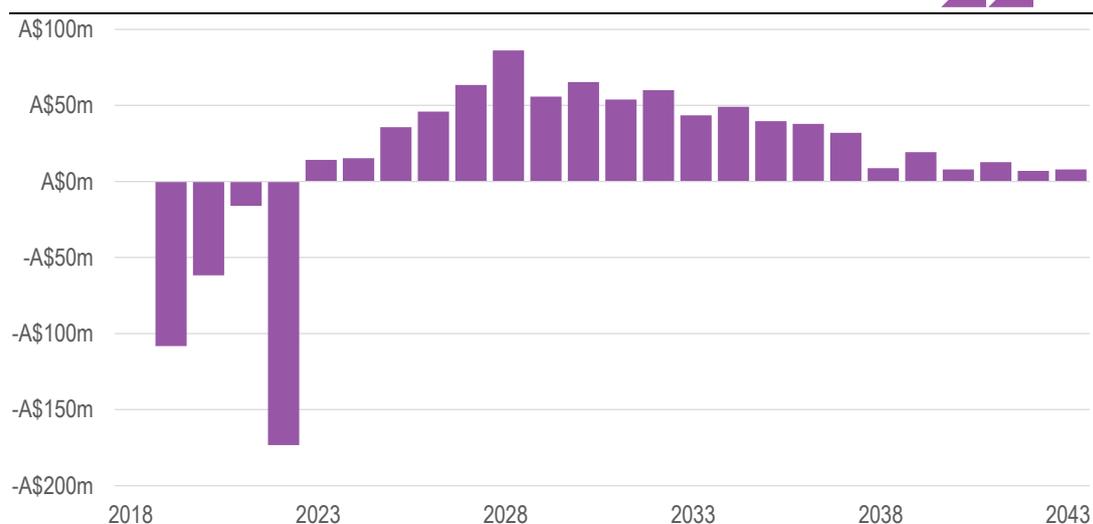
The Northern Territory Government will also receive payroll taxation payments from ProjectCo, which are estimated to total \$163 million over the study period, or on average \$6.3 million per annum.

FIGURE 5.11 GALE DIRECT TAXATION PAYMENTS, FINANCIAL YEAR, PRESENT VALUE, REAL TERMS, A\$ MILLION



SOURCE: ACIL ALLEN CONSULTING

The level of taxation receipts collected by both Commonwealth and Territory governments are dependent on the magnitude of net cash flows generated by ProjectCo, which are of course highly sensitive to the inputs and assumptions that underpin the cash flow model.

FIGURE 5.12 GALE NET CASH FLOWS, FINANCIAL YEAR, DISCOUNTED, REAL TERMS, A\$ MILLION

Note: Discount rate of 10 per cent per annum.

SOURCE: ACIL ALLEN CONSULTING

Over the study period, the discounted net cash flows of ProjectCo are estimated to total \$403 million, at an average of \$15.5 million per annum. Under the set of inputs and assumptions presented above, interest payments on the debt required to fund ProjectCo's capital expenditure, and the cost of PRRT payments first being realised in 2038, are major determinants of the Project's overall economic viability from a discounted cash flow prospective.

This is because the cash flow model has been developed to fund capital expenditure via debt (66.6 per cent), equity (33.3 per cent) and/or by positive cash flows. Greater positive net cash flows generated by ProjectCo in the early years reduce the level of debt the Project is required to take on, which reduces interest payments and further increases the Project's net cash flows. However, as taxation expenses increase when ProjectCo's taxable income increases towards the end of the study period, positive net cash flows are reduced, resulting in ProjectCo financing more of its capital expenditure by debt, which increases interest payments and further reduces net cash flows.

5.3 Sensitivity analysis – ProjectCo cash flow modelling results

The overall economics of ProjectCo are highly sensitive to a number of key assumptions presented in the above sections. In order to highlight the degree of sensitivity of ProjectCo to the inputs and assumptions used in this study, ACIL Allen has undertaken sensitivity analysis for four key inputs and assumptions, and have presented the results as the discounted net cash flows of each development scenario.

The key variables ACIL Allen has presented sensitivity analysis on are:

- EUR: +/- 3.8 PJ from the base case;
- interest rate: +/- 1 percentage point from the base case;
- market price: +/- 20 per cent from the base case; and
- learnings: +/- 20 per cent from the base case.

5.3.1 BREEZE

A summary of the change in total and average annual discounted net cash flows of ProjectCo are presented in Table 5.2 and Figure 5.13.

TABLE 5.2 SUMMARY OF SENSITIVITY ANALYSIS, BREEZE NET CASH FLOWS, DISCOUNTED, REAL TERMS, A\$ MILLION

Sensitivity	Total	Average
EUR		
Base case, 8.4 PJ	\$19.4 million	\$0.8 million
High case, 12.7 PJ	\$135 million	\$5.2 million
Low case, 4.2 PJ	-\$83.6 million	-\$3.2 million
Interest Rate		
Base case, 6 per cent	\$19.4 million	\$0.8 million
High case, 7 per cent	-\$11 million	-\$0.4 million
Low case, 5 per cent	\$45.4 million	\$1.8 million
Market Price		
Base case	\$19.4 million	\$0.8 million
High case, +20 per cent	\$154 million	\$5.9 million
Low case, -20 per cent	-\$154 million	-\$5.9 million
Learnings		
Base case	\$19.4 million	\$0.8 million
High case, +20 per cent	\$30.3 million	\$1.2 million
Low case, -20 per cent	-\$8.6 million	-\$0.3 million

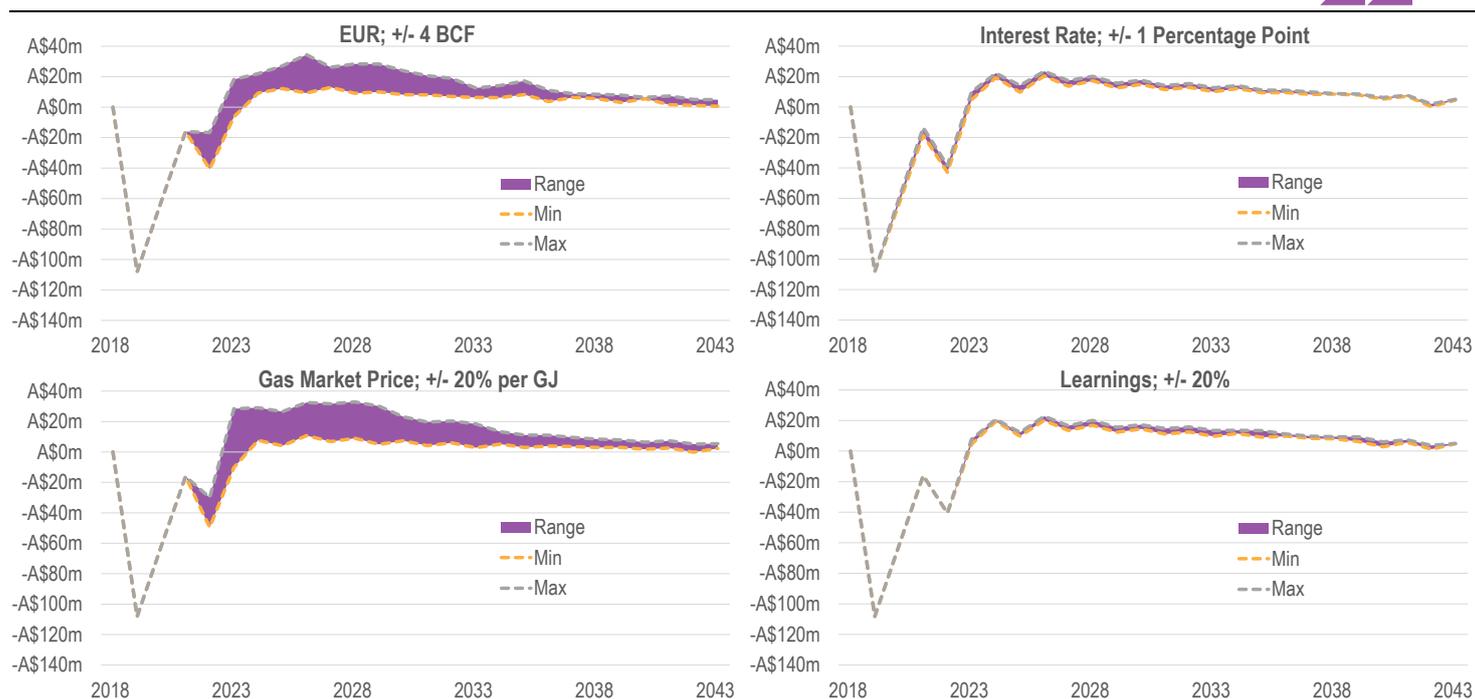
SOURCE: ACIL ALLEN CONSULTING

Table 5.2 and Figure 5.13 demonstrate that a change to the market price has the greatest variability on the discounted net cash flows of ProjectCo, while a change in the EUR also has a significant impact on the variability of ProjectCo's cash flows.

When the market price is increased by 20 per cent, the discounted net cash flows of ProjectCo increase from \$19.4 million to \$154 million. Similarly, when the EUR is increased to 12.7 PJ, the discounted net cash flows increase to \$135 million.

The variability of the cash flows to changes in the interest rate or learnings are less pronounced, but still significant. For example, when the interest rate increases by one percentage point, total discounted net cash flows decrease from \$19.4 million to -\$11 million, and if the rate of learnings are decreased by 20 per cent, the discounted net cash flows fall to -\$8.6 million.

Similar to the base case discount net cash flow results presented in Section 5.2, this variance is due to how the cash flow model has been developed, where capital expenditure is financed by debt (66.6 per cent), equity (33.3 per cent) and/or by positive cash flows. Greater positive net cash flows generated by ProjectCo reduce the level of debt the Project is required to take on to finance its capital requirements, which reduces interest payments and further increases the Project's net cash flows. However, as net cash flows are reduced, the Project is required to finance more of its capital expenditure by debt, which increases interest payments and further reduces the Project's net cash flows.

FIGURE 5.13 SENSITIVITY ANALYSIS, BREEZE NET CASH FLOWS, FINANCIAL YEAR, DISCOUNTED, REAL TERMS, A\$ MILLION

SOURCE: ACIL ALLEN CONSULTING

5.3.2 WIND

A summary of the change in total and average annual discounted net cash flows of ProjectCo are presented in Table 5.3 and Figure 5.14.

TABLE 5.3 SUMMARY OF SENSITIVITY ANALYSIS, WIND NET CASH FLOWS, DISCOUNTED, REAL TERMS, A\$ MILLION

Sensitivity	Total	Average
EUR		
Base case, 10.6 PJ	\$65.9 million	\$2.5 million
High case, 14.8 PJ	\$352 million	\$13.5 million
Low case, 6.3 PJ	-\$82.4 million	-\$3.2 million
Interest Rate		
Base case, 6 per cent	\$65.9 million	\$2.5 million
High case, 7 per cent	\$2.1 million	-\$0.1 million
Low case, 5 per cent	\$129 million	\$5 million
Market Price		
Base case	\$65.9 million	\$2.5 million
High case, +20 per cent	\$484 million	\$18.6 million
Low case, -20 per cent	-\$492 million	-\$18.9 million
Learnings		
Base case	\$65.9 million	\$2.5 million
High case, +20 per cent	\$117 million	\$4.5 million
Low case, -20 per cent	-\$31.5 million	-\$1.2 million

Sensitivity	Total	Average
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SOURCE: ACIL ALLEN CONSULTING

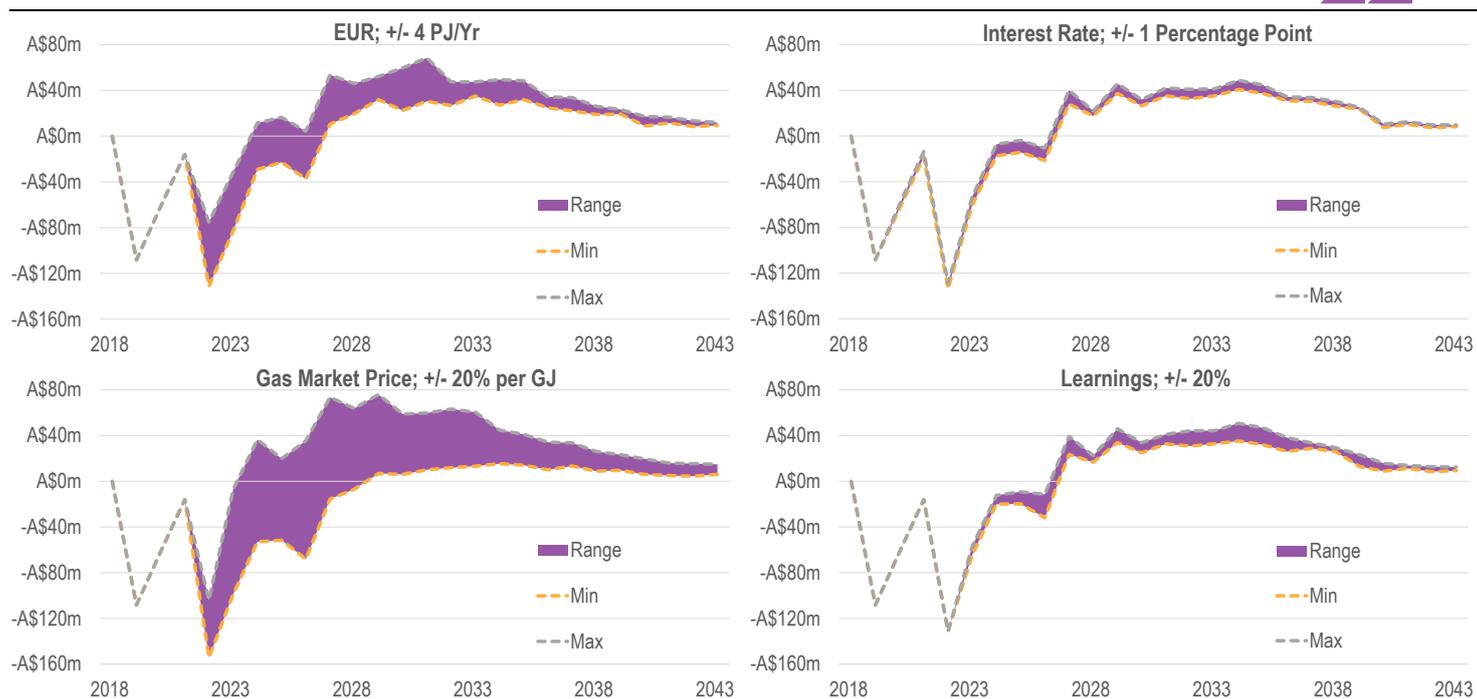
Table 5.3 and Figure 5.14 demonstrate that a change to the market price has the greatest variability on the discounted net cash flows of ProjectCo, while a change in the PJ also has a significant impact on the variability of ProjectCo's cash flows.

When the market price is increased by 20 per cent, the discounted net cash flows of ProjectCo increase from \$65.9 million to \$484 million. Similarly, when the BFC is increased to 14.8 PJ, the discounted net cash flows increase to \$352 million.

The variability of the cash flows to changes in the interest rate or learnings are less pronounced, but still significant. For example, when the interest rate increases by one percentage point, total discounted net cash flows decrease from \$65.9 million to \$2.1 million, and if the rate of learnings are decreased by 20 per cent, the discounted net cash flows fall to -\$31.5 million.

Similar to the base case discount net cash flow results presented in Section 5.2, this variance is due to how the cash flow model has been developed, where capital expenditure is financed by debt (66.6 per cent), equity (33.3 per cent) and/or by positive cash flows. Greater positive net cash flows generated by ProjectCo reduce the level of debt the Project is required to take on to finance its capital requirements, which reduces interest payments and further increases the Project's net cash flows. However, as net cash flows are reduced, the Project is required to finance more of its capital expenditure by debt, which increases interest payments and further reduces the Project's net cash flows.

FIGURE 5.14 SENSITIVITY ANALYSIS, WIND NET CASH FLOWS, FINANCIAL YEAR, DISCOUNTED, REAL TERMS, A\$ MILLION



SOURCE: ACIL ALLEN CONSULTING

5.3.3 GALE

A summary of the change in total and average annual discounted net cash flows of ProjectCo are presented in Table 5.4 and Figure 5.15.

TABLE 5.4 SUMMARY OF SENSITIVITY ANALYSIS, GALE NET CASH FLOWS, DISCOUNTED, REAL TERMS, A\$ MILLION

Sensitivity	Total	Average
EUR		
Base case, 12.7 PJ	\$403 million	\$15.5 million
High case, 16.9 PJ	\$777 million	\$29.9 million
Low case, 8.4 PJ	\$420 million	\$16.2 million
Interest Rate		
Base case, 6 per cent	\$403 million	\$15.5 million
High case, 7 per cent	\$322 million	\$12.4 million
Low case, 5 per cent	\$483 million	\$18.5 million
Market Price		
Base case	\$403 million	\$15.5 million
High case, +20 per cent	\$1,041 million	\$40 million
Low case, -20 per cent	-\$593 million	-\$22.8 million
Learnings		
Base case	\$403 million	\$15.5 million
High case, +20 per cent	\$474 million	\$18.3 million
Low case, -20 per cent	\$224 million	\$8.6 million

SOURCE: ACIL ALLEN CONSULTING

Table 5.4 and Figure 5.15 demonstrate that a change to the market price has the greatest variability on the discounted net cash flows of ProjectCo, while a change in the PJ also has a significant impact on the variability of ProjectCo's cash flows.

When the market price is increased by 20 per cent, the discounted net cash flows of ProjectCo increase from \$403 million to \$1 billion. Similarly, when the PJ is increased to 16.9 PJ, the discounted net cash flows increase to \$777 million.

Over the study period, the variability of the cash flows to changes in the interest rate or learnings are less pronounced, and less pronounced than the BREEZE and WIND development scenarios. However, over the economic life of ProjectCo under the GALE development scenario, changes to the base case interest rate and learnings are significant.

Over the study period, when the interest rate increases by one percentage point, total discounted net cash flows decrease from \$403 million to \$322 million, and if the rate of learnings are decreased by 20 per cent, the discounted net cash flows falls to \$224 million.

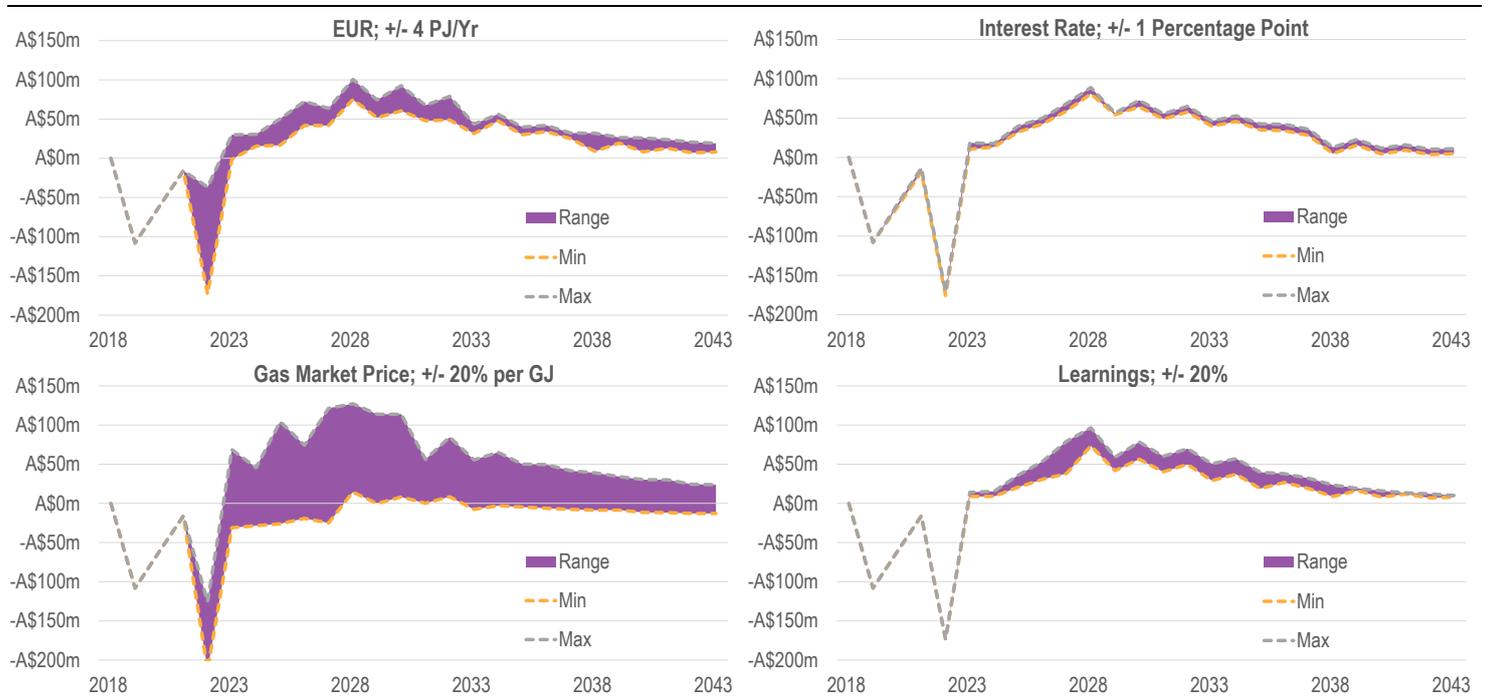
It should be noted, however, under the low case EUR sensitivity, when the PJ is lowered to 8.4, the discounted net cash flows of ProjectCo are higher than the base case. This is due to the impact that payments for PRRT have on the economics of ProjectCo. Under a lower EUR, ProjectCo's taxable income is less, resulting PRRT payments being payable in later years. Over the economic life of ProjectCo, the base case total discounted net cash flows are greater than total discounted net cash flows of the lower EUR sensitivity.

The total discounted net cash flows under the lower sensitivities for the GALE development scenario are also positive, compared to the BREEZE and WIND development scenarios over the study period. However, over the economic life of ProjectCo under the GALE development scenario, total discounted net cash flows are negative, as is the case in the other development scenarios.

Similar to the base case discount net cash flow results presented in Section 5.2, this variance is due to how the cash flow model has been developed, where capital expenditure is financed by debt (66.6 per cent), equity (33.3 per cent) and/or by positive cash flows. Greater positive net cash flows generated by ProjectCo reduce the level of debt the Project is required to take on to finance its capital

requirements, which reduces interest payments and further increases the Project's net cash flows. However, as net cash flows are reduced, the Project is required to finance more of its capital expenditure by debt, which increases interest payments and further reduces the Project's net cash flows.

FIGURE 5.15 SENSITIVITY ANALYSIS, GALE NET CASH FLOWS, FINANCIAL YEAR, DISCOUNTED, REAL TERMS, A\$ MILLION



SOURCE: ACIL ALLEN CONSULTING

5.4 PipelineCo financial model

PipelineCo is modelled using a simple DCF model with a series of assumptions regarding the cost of development and operation, required pre-tax internal rate of return. Using the assumed pipeline diameters developed in Section 4.6, and the gas sales volumes of ProjectCo in each scenario developed in Section 0, PipelineCo aims to deliver its pipeline project in each scenario to an NPV = \$0 after 40 years (the useful life of the pipeline infrastructure), using a six per cent discount rate (the pre-tax internal rate of return).

To do this, it sets a flat real tariff equal to the amount that will allow it to deliver on its financial target. These tariffs are presented below. The tariffs are charged to ProjectCo, where they accrue as an operating cost. This requires a special treatment in the economic impact assessment modelling, which is discussed in the next Chapter.

TABLE 5.5 PIPELINECO PIPELINE TARIFFS

Pipeline	Breeze tariff (\$/GJ)	Wind tariff (\$/GJ)	Gale tariff (\$/GJ)
Tie into Amadeus pipeline (50km)	0.2479	0.1651	0.1884
Amadeus duplication	2.0060	0.4471	0.3719
Northern Gas Pipeline (NGP) duplication	N/A	0.9350	0.6458
Carpentaria Gas Pipeline (CGP) duplication	N/A	1.3563	0.8601
DLNG Feed Pipeline (new pipeline)	N/A	N/A	0.6882

SOURCE: ACIL ALLEN CONSULTING



ECONOMIC
IMPACT
ASSESSMENT





ECONOMIC IMPACT ASSESSMENT INTRODUCTION

6

This section of the reports explores the economic impacts of the development of a shale gas industry in the Northern Territory, through the lens of ProjectCo as it has been defined in Chapter II of this report. The tool for this exploration is ACIL Allen's in-house Computable General Equilibrium (CGE) model, *TasmanGlobal*. The model and critical underlying assumptions are outlined in Appendix E.

The modelling period lines up with cash flow modelling period outlined in previous sections: 2018 to 2043. The 25 year modelling period allows for an articulation of the initial capital intensive phase of a development, and a period of operation where capital intensity is lower, and means any economic impacts articulated are conservative relative to presenting a 50 or 100 year modelling period – which is subject to additional uncertainty.

In line with ACIL Allen's scope of works, the modelling outputs have been presented for three regions: Northern Territory, Rest of Australia, and Australia (which is the sum of the first two regions), and under the following macroeconomic variables:

- Real income (Gross Real Income)
- Real output (Gross State Product and Gross Domestic Product, and change in industry output from the base case)
- Real final demand (State Final Demand and Domestic Final Demand)
- Real investment (Business Investment)
- Real exports (for the Northern Territory, international and interstate; for Australia, international only)
- Real employment (FTE employment and employment by industry)
- Real wages
- Population
- Taxation (by major heads of taxation)

ACIL Allen has conducted this economic impact assessment under five scenarios; a base case, and four scenarios which are independent deviations from this base case.

The base case is ACIL Allen's assessment of the future growth of the Northern Territory and Australian economies under current policy settings, which is effectively an assessment of the economy if the moratorium on fracking was to remain in place. The four scenarios are in line with the cash flow modelling results presented in this report.

The results of the base case are presented in annual percentage change terms, where the scenarios are presented as a deviation in the base case, in millions of real dollars or FTE job years as relevant.

In order to complete this task, ACIL Allen has made a series of assumptions regarding the base case and the channel of economic impacts in the four scenarios. These are outlined below. The remainder of this chapter presents the results of the economic impact assessment in the base case and under each of the four scenarios.

6.1 Base case assumptions

Typically, ACIL Allen would model the base case of an economic impact assessment as a function of the continuation of recent economic trends in the particular regions being studied. During its research and stakeholder consultation, ACIL Allen discovered a series of additional assumptions to include in its base case assessment of the Northern Territory economy, which mostly centred on adding realism and nuance to the short and medium term outlook.

6.1.1 NT Government 10 year infrastructure plan

In June 2017, the Northern Territory Government released its 10 Year Infrastructure Plan, a document intended to guide the public and private sector's expectations regarding planned infrastructure investments to be made by the Northern Territory Government.³⁷ The Plan discusses a number of matters, but critically provides some quantitative guidance regarding the future infrastructure spending plans of the Northern Territory Government. ACIL Allen has attempted to give regard to the direction of infrastructure spending presented in this report in its base case, but has stopped short of including all planned investments as there is significant uncertainty regarding which projects will be funded, when they will commence, and who will fund them.

6.1.2 INPEX Ichthys LNG project

INPEX's LNG project is assumed to begin production in the fourth quarter of 2017-18, ramping up to 8.6 million tonnes 2018-19 before plateauing at 8.9 million tonnes a year from 2019-20 onwards. The start of operations results in a significant increase in the Northern Territory's Gross Territory Product (GTP) over this period, which can be seen in the significant growth in the Northern Territory's real exports in 2018-19.

6.1.3 Darwin LNG

As discussed in Section 4.3.4, the Darwin LNG facility is currently supplied feed gas from the Bayu Undan field. Although gas from the Bayu Undan field is anticipated to decline as the field reaches its end of life, Darwin LNG is assumed to continue LNG production of 3.7 million tonnes a year over the forecast period using gas sourced from the development of an alternative gas field or fields. As outlined previously, there is already significant exploration activity underway off the coast of the Northern Territory.

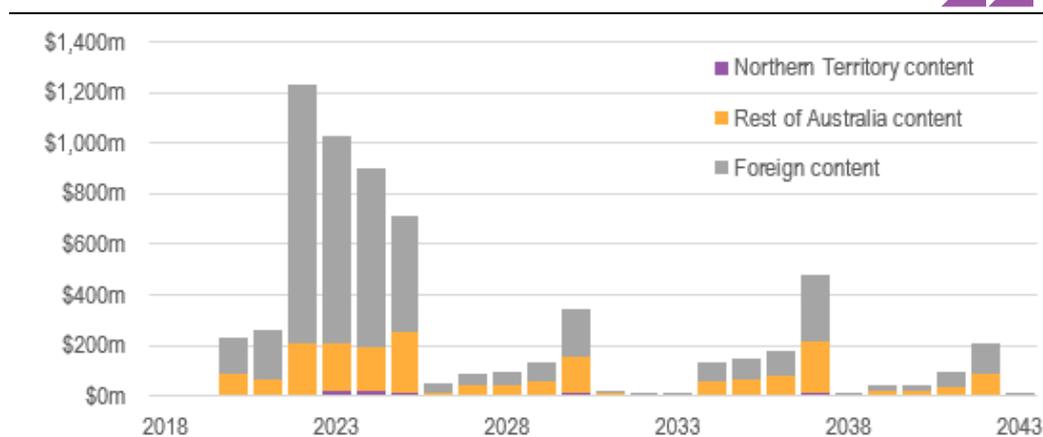
To model this, the base case includes explicit capital (\$6.8 billion) and operating costs to construct and operate the necessary offshore infrastructure and a new subsea pipeline to facilitate this development. In the Gale production scenario, it is assumed that the onshore gas production replaces production from the offshore development, thereby eliminating the need to undertake much of the capital and operations expenditure, particularly from 2023 onwards. The capital and operating expenditure component of this assumed offshore development is provided in Figure 6.1.

ACIL Allen has produced these estimates based on previous confidential work associated with large scale offshore gas developments, and has right-sized the facility to provide enough feed gas to supply DLNG only. As the figure indicates, there is a high degree of imported content in this development, in line with the experience of recent major developments in Australia.

The critical implication of this assumption is there is **no incremental increase in LNG production** facilitated by the shale gas industry development.

³⁷ Department of Infrastructure, Planning and Logistics. 2017. *10 Year Infrastructure Plan*. Accessed online at <http://www.dipl.nt.gov.au>

FIGURE 6.1 NEW OFFSHORE DEVELOPMENT TO FEED DLNG, CAPITAL AND OPERATING EXPENDITURE, BY JURISDICTION OF SPENDING, \$M



SOURCE: ACIL ALLEN CONSULTING

6.1.4 Project Sea Dragon

Project Sea Dragon is a large-scale, integrated, land-based prawn aquaculture project in northern Australia designed to produce high-quality, year-round reliable volumes for export markets. At the time of the modelling, environmental approvals for Stage 1 of the project had progressed with approval of the project being recommended by the Northern Territory Environment Protection Authority (NT EPA).³⁸ In the reference case it has been assumed that production from Stage 1 begins in 2019-20 with further approvals and ramp-up to the full planned project by the early 2030's. Stage 1 will comprise approximately 1,080 ha of prawn farming capacity plus associated infrastructure onsite with the full scale Project reaching 10,000 ha of prawn farming capacity with production of 165,000 tonnes a year and revenues of over \$3 billion a year.

6.1.5 Horticulture industry

During stakeholder consultation in the Northern Territory, ACIL Allen was presented with a report prepared for NT Farmers which articulated the value of the horticulture industry in the Northern Territory. NT Farmers provided a view to ACIL Allen that the Australian Bureau of Statistics significantly understated the value of the horticulture industry. This view was supported by other stakeholders, including NT Treasury.

ACIL Allen modified the base level of horticulture industry output, land use and employment using this report, which resulted in an increase to the size of agriculture industry relative to the standard definition used.

6.2 Scenario assumptions

ACIL Allen has made a series of assumptions regarding the transmission of economic benefits and costs in the policy scenarios, which are outlined below. These are in addition to the more standard assumptions like the CPI, currency and industry interactions, which are outlined throughout this document.

6.2.1 Local content

It is necessary to assume a level of local content provision in the delivery of the development scenarios, as there is no information regarding the actual or planned volume of local purchasing that ACIL Allen is able to rely upon. Broadly speaking, ACIL Allen assumed two dimensions to local

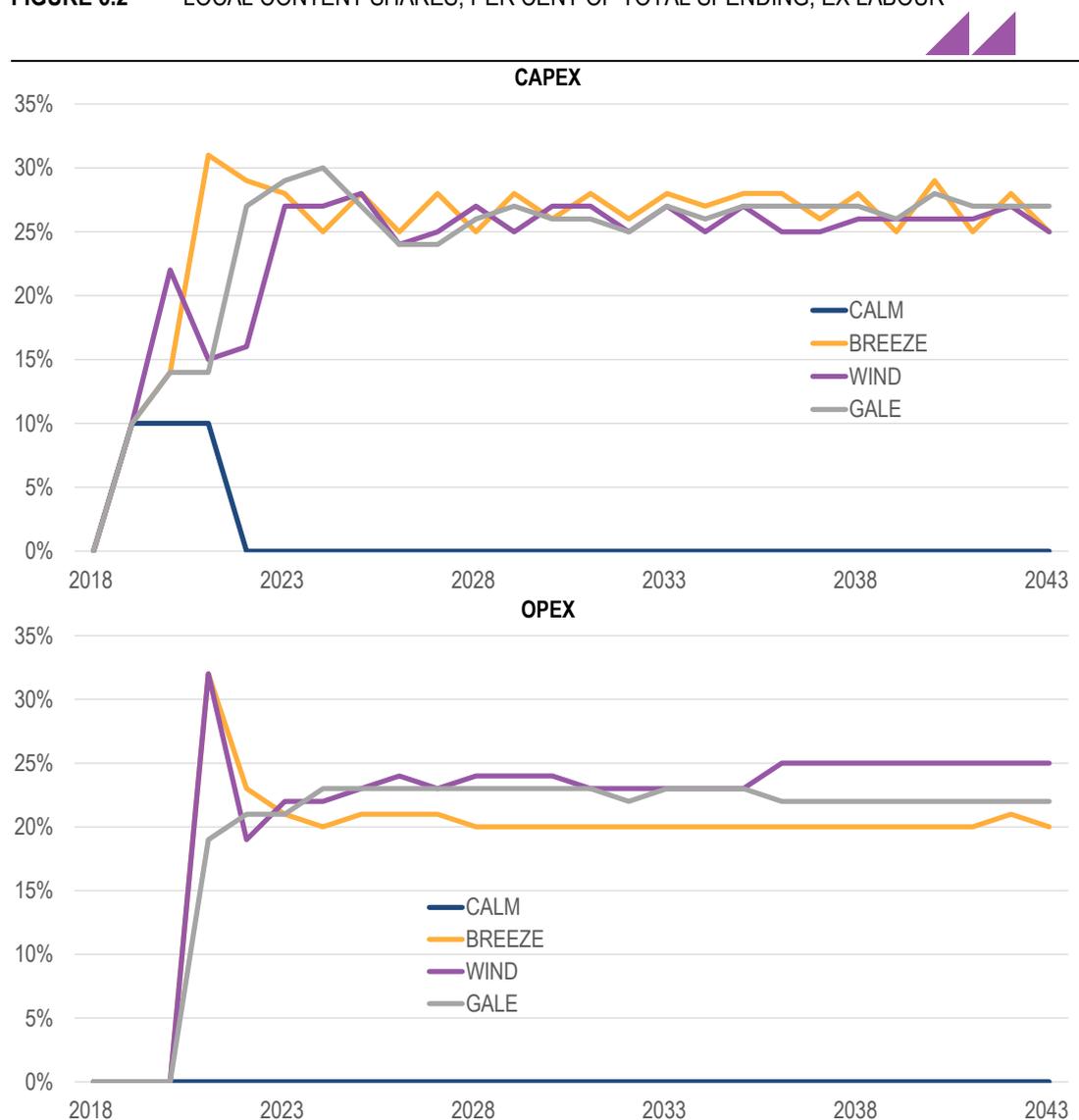
³⁸ Seafarms. 2017. *Project Seadragon: Project Status*. Accessed online at <http://seafarms.com.au/project-status/>

content penetration: there would be an increasing share of supplies and services provided by Northern Territory firms over time, and there would a step change increase under each scenario.

In the case of an increased share over time, this is to reflect the plans of industry to engage local suppliers to assist in the industry’s development, but also to reflect it is not as simple as suppliers being able to supply products and services from day one of the development. In the case of a step change increase under each scenario, this reflects ACIL Allen’s view that the larger an industry gets, the more opportunities there are to deliver local providers opportunities as scale economies can develop. This manifests in a slightly lower share of local content in the GALE scenario compared to the WIND scenario, but the larger size of the GALE scenario means the value of local content in the project in dollar terms is larger.

ACIL Allen’s assumed local content shares in the provision of capital and operating goods (excluding labour) is outlined in the tables below.

FIGURE 6.2 LOCAL CONTENT SHARES, PER CENT OF TOTAL SPENDING, EX LABOUR



SOURCE: ACIL ALLEN CONSULTING

6.2.2 Gas producers – price impact

Due to the complex nature of the gas market modelling undertaken for this task, ACIL Allen has made a simplifying assumption that there is no net change to the supply of or demand for gas in the national gas market resulting from the development of ProjectCo. Instead, the channel of impact is through a

reduction in the prices paid by consumers, and a commensurate reduction in margins across the supply chain. The value of these quantum of these reductions is presented in Appendix C.

ACIL Allen adopted this assumption as there is significant uncertainty regarding national energy policy, and it was difficult to determine a credible way to treat which suppliers may choose to turn off their supply in the case of ProjectCo's development. To do this would have required a second round of gas market modelling, which could have then resulted in additional gas sales opportunities for ProjectCo, which would have then required a third round of gas market modelling and so on. Instead, by channelling the impact through prices, the modelling results articulate how a shale gas industry in the Northern Territory may impact on real incomes, real consumption and Commonwealth taxation revenue.

In reality, if a shale gas industry was able to penetrate the market to the degree assumed in this modelling task, it is possible some producers would exit the market. However it is difficult to determine who, when and where, and what the flow on effects may be given the uncertainty regarding both the industry development scenarios ACIL Allen has developed and the current state of the national market.

6.2.3 Employment – no net growth in Australia

As a conservative assumption, ACIL Allen assumed there would be no net employment growth in the Australian economy as whole resulting from the shale gas industry's development in the Northern Territory. This is because the Inquiry is mostly concerned with the potential impacts on the Northern Territory rather than the Australian economy as a whole, and the approach ACIL Allen has adopted with regards to the gas industry (ie no incremental increase in LNG production, and restricting gas industry impacts to price only) means adopting this assumption generates more conservative results.

In reality, it is likely there would be some net increase in employment outside of the Northern Territory, particularly in the development of pipeline infrastructure, the impact on Commonwealth finances, and the second round impacts of lower gas prices on consumer and business spending.

6.2.4 Agriculture – area of disturbance approach

ACIL Allen has made a broad assumption that no shale gas industry development will be allowed to occur:

- on or near sacred Aboriginal sites,
- on or near prime horticultural land,
- in proximate distance to major towns or cities
- on or near any major tourist attractions or locations
- on or near nature reserves, national parks and other land-based natural resources

Given this, ACIL Allen considers it highly unlikely there will be any impact on industries or stakeholders associated with these land uses in the event the industry develops, insofar as a reduced availability of land or conflicting land use goes.

However, it is possible, and indeed highly likely, that a shale gas industry will develop on pastoral properties, which cover approximately 45 per cent of the Northern Territory's land mass.³⁹ For example, Origin's exploration permit areas encompass 18,512km² of pastoral lease property.⁴⁰

In order to model this, ACIL Allen has developed area of disturbance calculations under each scenario, centred on calculations of the land use associated with each element of a shale gas industry's development. We have calculated a gross square meterage of disturbance under each scenario using the table below and applying it to the volume of infrastructure developed, and then doubling it as a conservative assumption. The total area of disturbance under each scenario is presented in Table 6.1.

ACIL Allen then assumed this land would become unavailable for the pastoral industry to raise cattle. To determine the impact, ACIL Allen calculated the average value per hectare of the cattle industry in

³⁹ Pastoral Land Board. 2016. *Pastoral Land Board Annual Report: 2015-16*. Accessed online at <http://www.denr.nt.gov.au/>

⁴⁰ Origin. 2017. *Environmental Plan Summary, Beetaloo Sub-Basin*. Accessed online at <http://www.dpir.nt.gov.au/>

the Northern Territory, multiplied this by the loss in land available for pastoral industry activities, and subtracted this from the future growth of the industry.

TABLE 6.1 TOTAL AREA OF LAND DISTURBANCE, BY SCENARIO

Scenario	Disturbance (km ²)
BREEZE	67.7
WIND	231.7
GALE	475.9



This section provides the results of ACIL Allen's base case economic modelling for the Northern Territory over the period from 2018 to 2043. This includes outputs for key macroeconomic variables only, and does not include real income and real taxation, which are calculated as levels in the scenarios only.

7.1 Scenario description

As discussed in Section 2, the Northern Territory's recent economic performance has been driven by the impact of INPEX's Ichthys offshore gas and LNG facility development. To this point, the impact has been mostly centred on the initial surge and subsequent fall in construction activity, with the lift in production and export still on the horizon. As discussed in Section 6, ACIL Allen has included a projection of the impact of Ichthys' production phase on the Northern Territory economy in its base case.

Other foreseen events for the Northern Territory included in the base case include:

- The impact of the Northern Territory Government's 10 Year Infrastructure Plan
- Project Seadragon, and the significant impact on the Northern Territory Government's aquaculture industry
- The highly likely development of an offshore gas project to support the backfill of DLNG as existing supplies deplete
- An expanded horticulture sector, in line with research presented by NT Farmers and the perspective of Northern Territory Government stakeholders

Other than the above modifications, the base case assumes that as a starting point the structure of the Northern Territory economy is as it is today. For instance, the largest employing sector is Government Services, with 47,390 employees in 2018.

7.2 Real output – total

In Gross Territory Product (GTP) terms, ACIL Allen's base case projects the Northern Territory economy will grow by an average of 2.9 per cent over the forecast period (2018-2043) (Figure 7.1). This is lower than the average GTP growth of four per cent recorded over the past decade, which was mostly influenced by the impact of first the DLNG project and then the Ichthys LNG project.

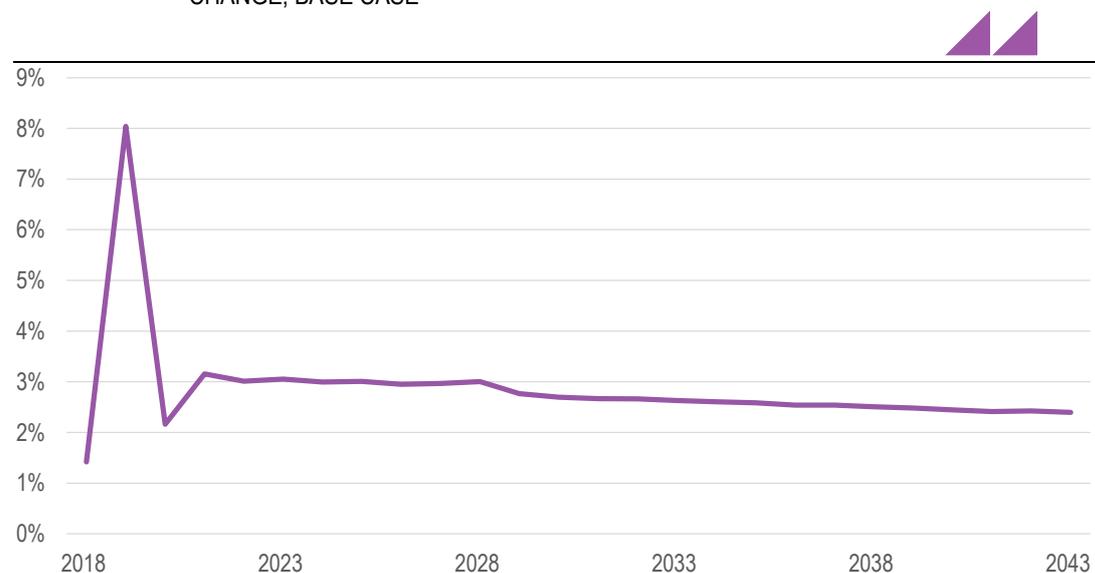
Growth is forecast to spike in the short term, with GTP growth of eight per cent forecast in 2019 on account of the ramp up in Ichthys LNG production. This manifests as an increase in the Petroleum sector's output, and a lift in the real export base of the Northern Territory economy. As LNG

production ramps up and then reaches a steady-state level of production, this is only anticipated to have a one year impact on the Territory's growth rate.

Following the ramp up of Ichthys LNG Project, ACIL Allen forecasts there will be a period of slightly above average growth through the 2020s, as the Territory's aquaculture and horticulture industries grow faster than the rest of the economy, and the Northern Territory Government's 10 Year Infrastructure Plan plays out. The impact of the new offshore gas development to back fill DLNG is somewhat limited, as much of the supplies and services for an offshore development are by necessity imported. This manifests in a strong increase in Business Investment (and therefore State Final Demand), but a commensurate increase in imports, therefore a near-zero impact on overall GTP.

Beyond the 2020s, ACIL Allen projects the Northern Territory economy will grow in line with population growth, labour force participation and productivity growth. All up, the Northern Territory economy is projected to grow from a \$23.4 billion economy (2018 dollars) in 2018 to a \$47.9 billion economy by the end of the forecast period.

FIGURE 7.1 GROSS TERRITORY PRODUCT, NORTHERN TERRITORY, ANNUAL PERCENTAGE CHANGE, BASE CASE



SOURCE: ACIL ALLEN CONSULTING

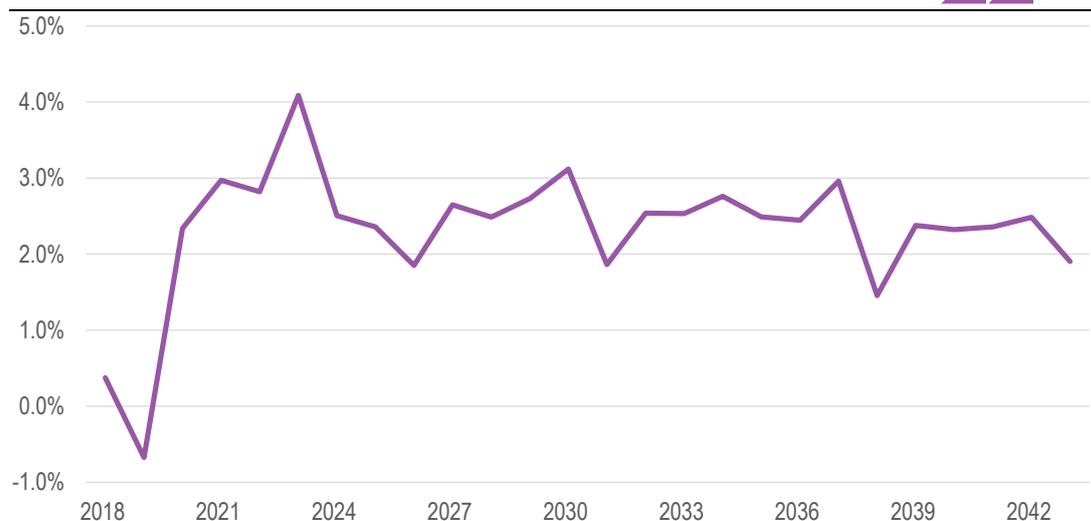
7.2.1 State Final Demand

ACIL Allen's base case projects the Northern Territory's State Final Demand will grow by an average of 2.3 per cent over the forecast period. This compares to growth of 4.4 per cent over the previous decade, where State Final Demand both grew and declined in excess of 10 per cent per annum on three separate occasions as a result of investments in LNG processing facilities.

ACIL Allen has not assumed the development of new onshore LNG processing facilities in its base case, and so the Northern Territory's State Final Demand is projected to be less volatile in the years ahead. Notwithstanding, State Final Demand is projected to be relatively flat over the next two years as the remainder of the uplift associated with the Ichthys LNG project comes out of the economy.

State Final Demand growth is projected to be strongest in the years leading up to 2023, as a result of the impact of the development of the new offshore gas extraction facility to backfill the DLNG facility. State Final Demand growth is forecast to hit 4.1 per cent in 2023, before easing to 1.9 per cent in 2026 (Figure 7.2).

FIGURE 7.2 STATE FINAL DEMAND, NORTHERN TERRITORY, ANNUAL PERCENTAGE CHANGE, BASE CASE



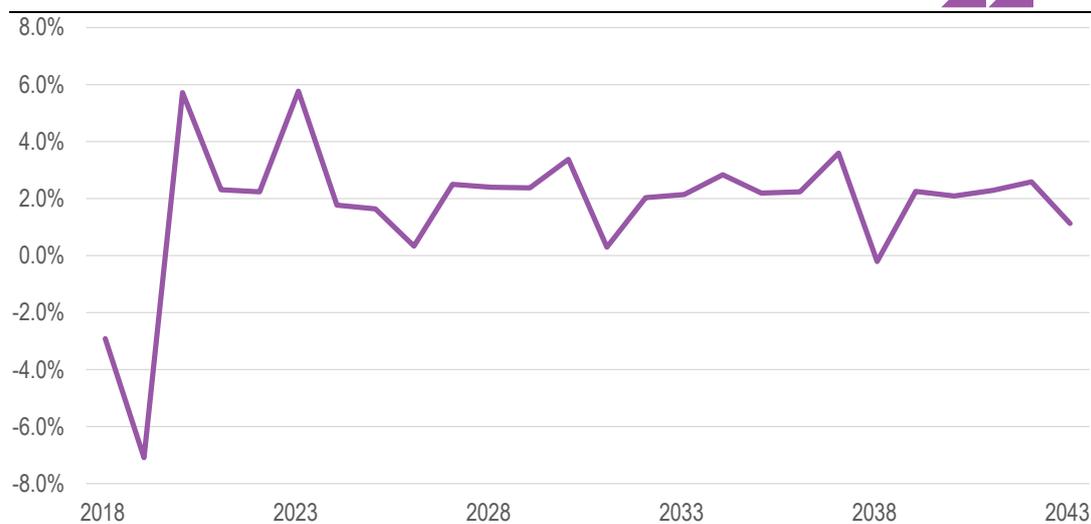
SOURCE: ACIL ALLEN CONSULTING

Business investment

The biggest driver of changes in State Final Demand on an annual basis is business investment, which is often subject to large, lumpy periods of spending by the private sector. This has been the experience of the Northern Territory economy in recent years, as discussed in Section 2.

ACIL Allen’s base case forecasts two more years of declining business investment in the Northern Territory associated with the final stages of the Ichthys LNG project. Thereafter, business investment is forecast to grow by an average of four per cent per annum between 2020 and 2023, as the new offshore gas industry development progresses and other investments in aquaculture and horticulture progress. Over the full forecast period (2018 to 2043), business investment is forecast to grow by 1.8 per cent per annum (Figure 7.3). This is slower than the average growth of eight per cent per annum over the past decade, which was characterised by two years of 35 per cent and 65 per cent growth in investment in 2012 and 2013, respectively.

FIGURE 7.3 BUSINESS INVESTMENT, NORTHERN TERRITORY, ANNUAL PERCENTAGE CHANGE, BASE CASE

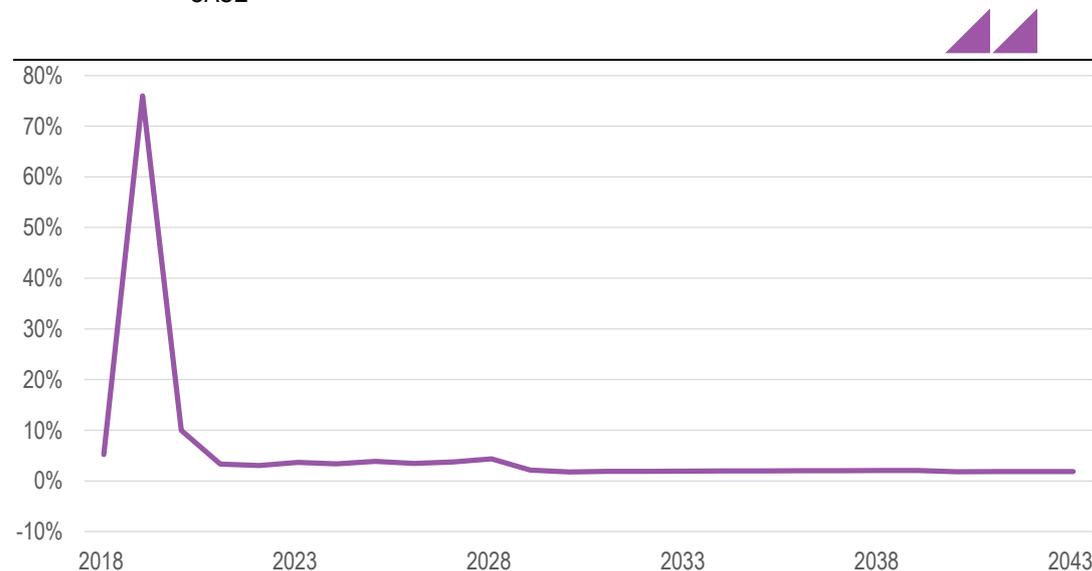


SOURCE: ACIL ALLEN CONSULTING

7.2.2 Real Exports

In ACIL Allen's base case, the Northern Territory's export outlook is dominated by the impact of the progression of the Ichthys LNG project to full production in 2019. In this year alone, the base case forecasts the Northern Territory's real exports will increase by 76 per cent (Figure 7.4).

FIGURE 7.4 REAL EXPORTS, NORTHERN TERRITORY, ANNUAL PERCENTAGE CHANGE, BASE CASE



SOURCE: ACIL ALLEN CONSULTING

This is effectively a structural increase in the Northern Territory's real exports base, as the Ichthys LNG project is projected to produce at its steady state level 8.9 million tonnes of LNG per annum. Excluding this one off increase, ACIL Allen's base case forecasts real exports from the Northern Territory will increase by 2.8 per cent per annum, largely on account of the increased activity associated with the Territory's horticulture and aquaculture industries.

7.3 Real output – industry

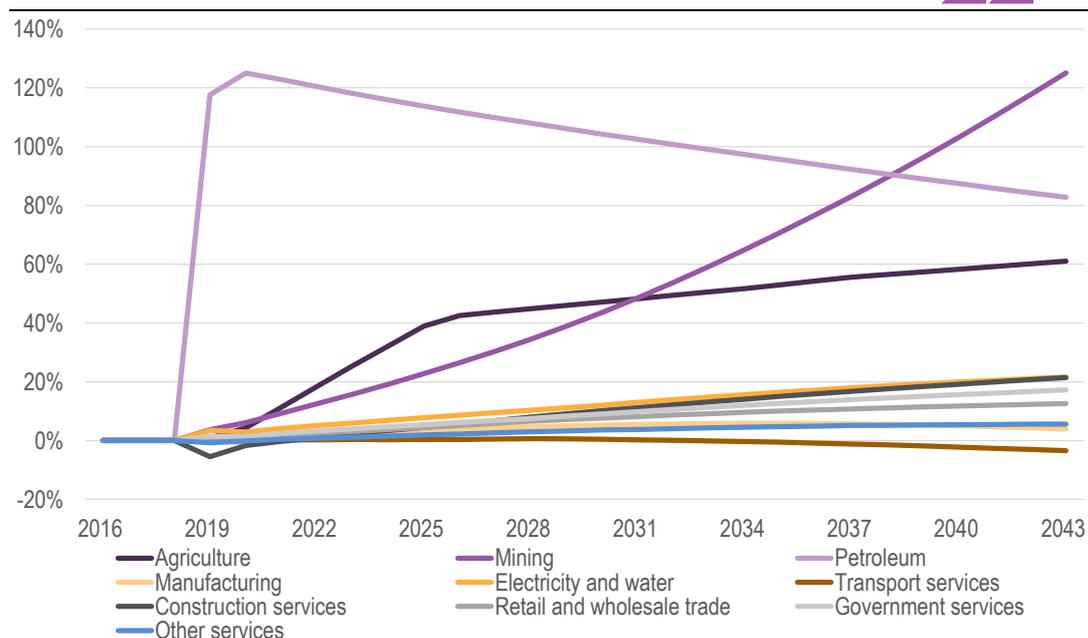
ACIL Allen produced estimates of future industry output growth on the basis of growth or decline from a starting level observed in actual Australian Bureau of Statistics data (2016). To progress these estimates to the modelling period, ACIL Allen has rebased its industry growth projections to the 2018 year and presented the results as a cumulative change in output from the 2018 year.

The fastest growing industry in the base case is Agriculture, which is forecast to grow by 9.1 per cent over the modelling period. This is on account of the impact of Project Seadragon, the rebased estimates of the size and growth potential of the Northern Territory's horticulture industry, and the Northern Territory Government's policies to improve the prospects of the whole agriculture industry (including pastoral industries).

The petroleum industry is also projected to grow faster than average, albeit all of the growth occurs in the first three years of the study period of account of the lift in production from the Ichthys LNG project. Direct industry output from the petroleum industry does not show the same characteristics as export growth for the Northern Territory as a whole as most of the industry output component of the petroleum industry occurs in the extraction of hydrocarbons, which in this case occurs off the coast of Western Australia rather than the Northern Territory. In a similar vein, the addition of a new offshore gas development assumed in the base case simply replaces otherwise lost industry output rather than adding new industry output.

Most other sectors are projected to grow around the same pace as the Northern Territory economy more broadly (Figure 7.5).

FIGURE 7.5 REAL OUTPUT, INDUSTRY LEVEL, NORTHERN TERRITORY, CUMULATIVE PERCENTAGE CHANGE FROM BASE YEAR (2018), BASE CASE

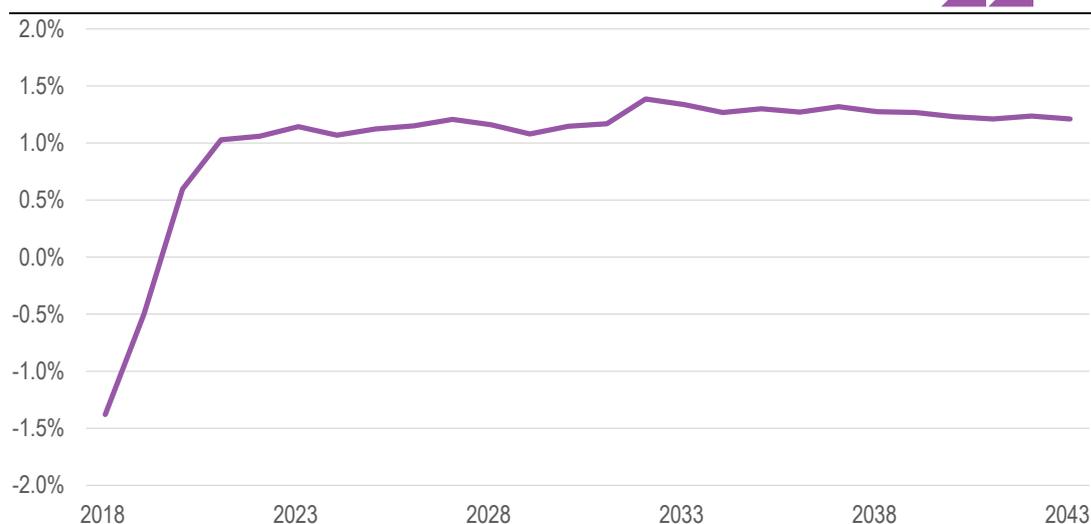


SOURCE: ACIL ALLEN CONSULTING

7.4 Labour market

7.4.1 Total employment

ACIL Allen’s base case assumes total employment in the Northern Territory economy will grow by an average of one per cent per annum over the forecast period (Figure 7.6). Similar to the State Final Demand and Business Investment variables, short term employment growth follows the trajectory of the unwinding of the remainder of the Ichthys LNG project, with employment forecast to fall by 1.4 per cent in 2018 and 0.5 per cent in 2019. Thereafter, total employment is forecast to grow by an average of 1.2 per cent per annum.

FIGURE 7.6 REAL EMPLOYMENT, NORTHERN TERRITORY, ANNUAL PERCENTAGE CHANGE, BASE CASE

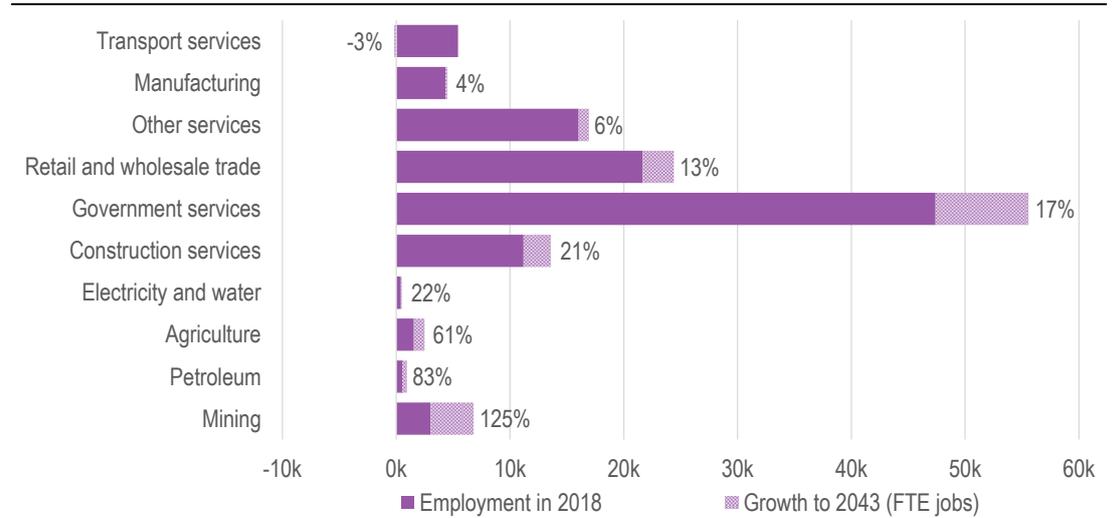
SOURCE: ACIL ALLEN CONSULTING

7.4.2 Industry employment

While total employment growth is forecast to remain relatively stable, ACIL Allen's base case forecasts a shift in the composition of employment in the Northern Territory. Employment growth is forecast to be largest in the Government Services sector, with an additional 8,181 FTE jobs created over the study period. This sector accounts for almost half of total FTE employment growth in the Northern Territory over the period. The other two sectors recording large growth in FTE numbers are similarly already large: retail and wholesale trade (2,729 FTE jobs) and construction (2,397 FTE jobs). However, in percentage change terms these sectors produce relatively modest results (between 13 per cent and 21 per cent, respectively).

The three sectors forecast to see large percentage increases in employment growth are mining (125 per cent), petroleum (83 per cent) and agriculture (61 per cent). In total FTE job terms however, these three sectors are forecast to deliver just over one third of the total employment growth of the three largest employing sectors in the Northern Territory (Figure 7.7).

FIGURE 7.7 REAL EMPLOYMENT, INDUSTRY CHANGES, NORTHERN TERRITORY, ANNUAL PERCENTAGE CHANGE, BASE CASE

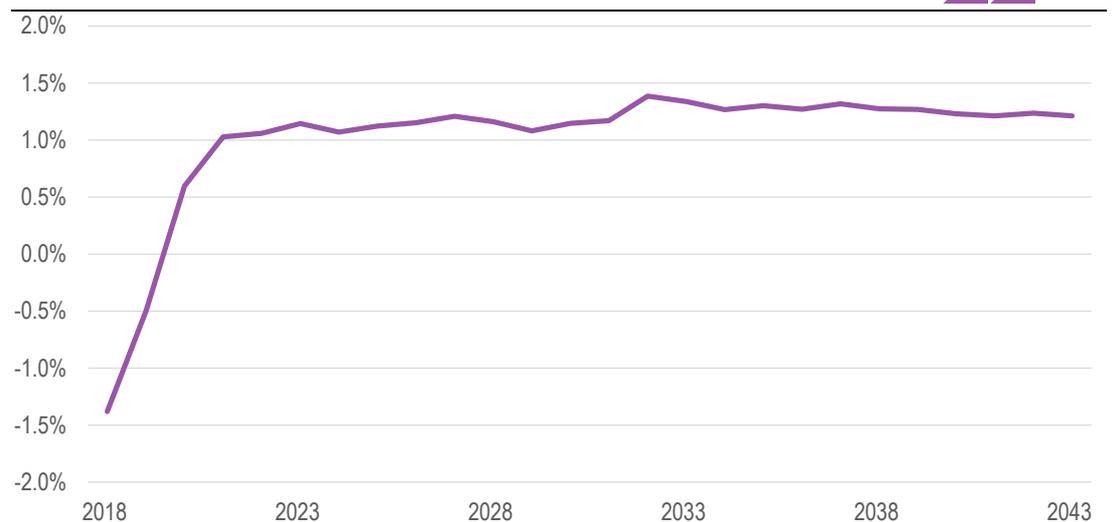


SOURCE: ACIL ALLEN CONSULTING

7.5 Population

ACIL Allen forecasts the Northern Territory’s population will shrink modestly in the first two years of the forecast period, on account of the impact of the wind down of the construction phase of the Ichthys LNG project on the Northern Territory economy. Thereafter, ACIL Allen forecasts the Northern Territory’s population will grow by an average of 1.2 per cent per annum, reaching 334,037 in 2043 (Figure 7.8)

FIGURE 7.8 POPULATION GROWTH, NORTHERN TERRITORY, ANNUAL PERCENTAGE CHANGE, BASE CASE



SOURCE: ACIL ALLEN CONSULTING

7.6 Summary

Table 7.1 presents a summary of the base case economic forecasts presented in this section.

TABLE 7.1 ACIL ALLEN BASE CASE, SUMMARY OF ECONOMIC MODELLING RESULTS

	2018 level	2043 level	Annual Average Percentage Change
Real output			
Northern Territory	\$23,402m	\$47,852m	2.9%
Real Final Demand			
Northern Territory	\$28,457m	\$51,318m	2.3%
Real investment			
Northern Territory	\$10,027m	\$16,149m	1.8%
Northern Territory real exports			
Northern Territory	\$6,299m	\$21,575m	5.7%
Real Output, Industry Growth (Index; 2018 = 100)			
Agriculture	100	109.1	
Mining	100	102.9	
Petroleum	100	103.0	
Manufacturing	100	102.0	
Electricity and water	100	102.0	
Transport services	100	102.1	
Construction services	100	101.9	
Retail and wholesale trade	100	102.0	
Government services	100	101.6	
Other services	100	102.0	
Real employment (total)			
Northern Territory	131,310	173,018	1.0%
Real employment by industry (FTE)			
Agriculture	1,546	2,489	1.9%
Mining	3,017	6,789	3.3%
Petroleum	518	947	4.0%
Manufacturing	4,325	4,497	0.2%
Electricity and water	400	487	0.8%
Transport services	5,425	5,237	-0.1%
Construction services	11,189	13,586	0.8%
Retail and wholesale trade	21,664	24,393	0.5%
Government services	47,390	55,571	0.6%
Other services	16,024	16,924	0.2%

	2018 level	2043 level	Annual Average Percentage Change
Real population			
Northern Territory	245,872	334,037	1.2%

SOURCE: ACIL ALLEN CONSULTING



This section explores the broader economic impacts of development of an onshore unconventional shale gas industry, as represented in the previous sections as ProjectCo and PipelineCo. The economic impact will be assessed over the period from 2018 to 2043 for the Northern Territory and Rest of Australian economies on the following terms:

- the impact on **real incomes** (a measure of economic welfare or standard of living);
- the impact on **real output** (as measured in terms of Gross Domestic Product, Gross State/Territory Product, National/State Final Demand, Business Investment and Exports),
- the impact on **employment** (as measured on a full time equivalent job basis);
- the impact on **real wages growth**;
- the impact on **population growth**; and
- the impact on **total taxation payments** (those taxes directly paid by the industry, and the indirect taxes paid as a result of the activity generated from the industry).

For purposes of the reporting, the economic impact of ProjectCo and PipelineCo will be referred to as the “Onshore Unconventional Gas Industry” or “the Industry”.

The economic impact of the development of the Industry under the CALM development scenario, as detailed in Section 6, was assessed using ACIL Allen’s *Tasman Global* CGE model. Further details on *Tasman Global* are presented in Appendix E.

8.1 Scenario description

As discussed in Section 4.3, The CALM scenario is the scenario that sees ProjectCo undertake a three year program of exploration and appraisal, but fail to progress beyond this due to an inability to find a commercial quality shale gas reserve. The CALM scenario is also the basis for the first four years (in Year 0, nothing occurs as the moratorium is lifted) of the production scenarios discussed below, but instead of an assumption that no commercial quality shale gas is discovered, the assumption is a requisite scale commercial shale gas reserve is discovered.

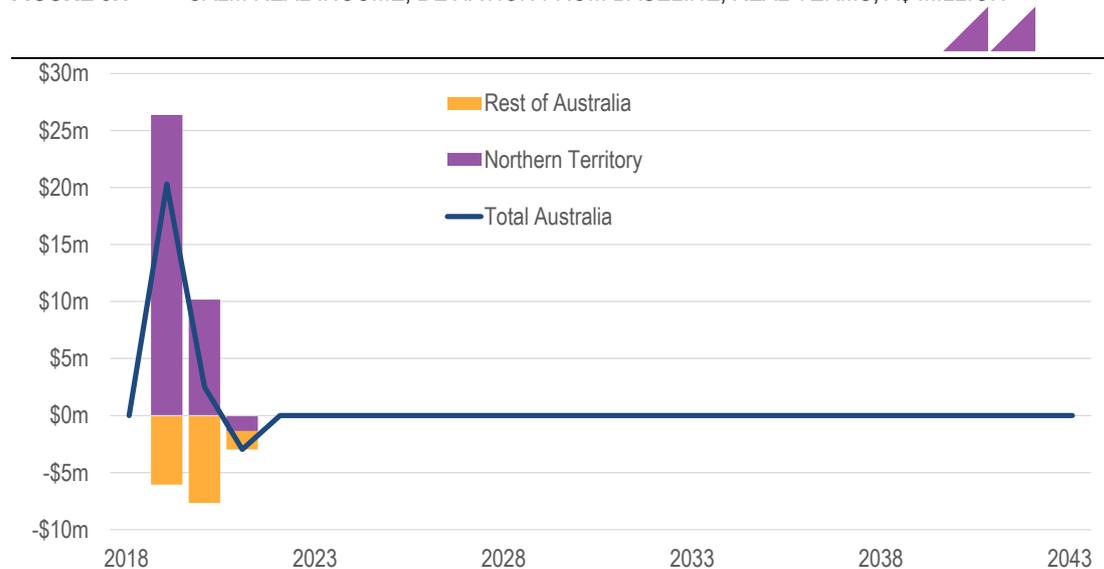
8.2 Real income

Real income impacts are realised in the Territory through increased employment, payroll taxation payments made to the Northern Territory Government and payments made to pastoralists and native title owners.

In total, the real income impact of the Industry is estimated to total \$19.8 million at over the study period (refer to Figure 8.1). In the Northern Territory, real income is estimated to total \$35.2 million,

while in the Rest of Australia real income will fall by \$15.4 million, as a result of a reallocation of labour to the Territory for the Industry's appraisal phase.

FIGURE 8.1 CALM REAL INCOME, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION



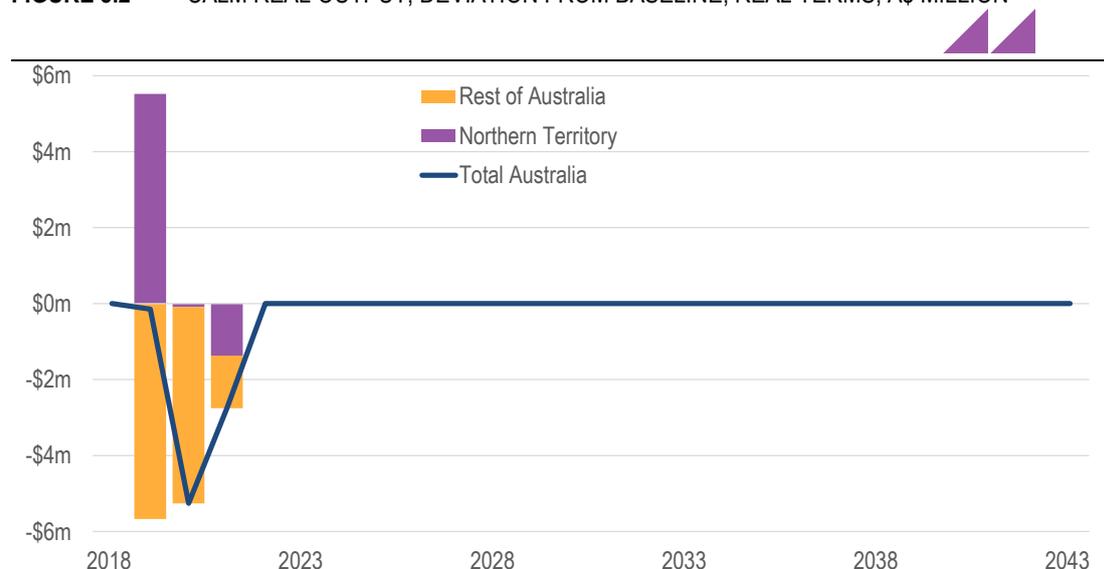
SOURCE: ACIL ALLEN CONSULTING

8.3 Real output

The real output impact of the Industry is different to the real income impact because output does not include increases to welfare that is generated through additional employment and wages growth.

Under the CALM development scenario, real output is estimated to fall by a total of \$8.2 million (refer to Figure 8.2). In the Northern Territory, it is estimated real output will increase by \$4.1 million and fall by \$12.2 million across the Rest of Australia (the result of a reallocation of labour to the Territory for the Industry's appraisal phase) over the study period.

FIGURE 8.2 CALM REAL OUTPUT, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION

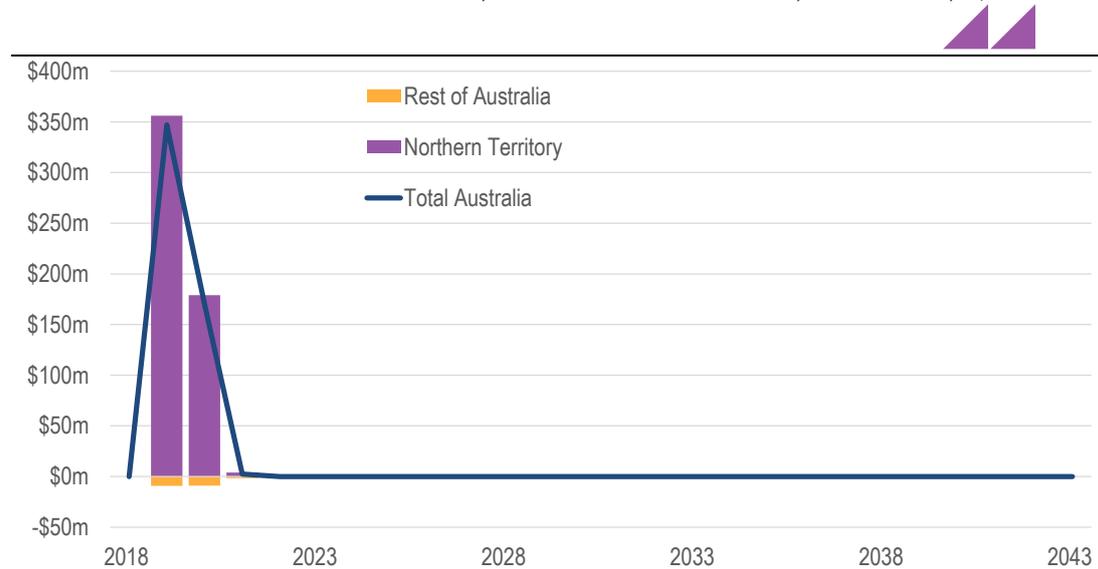


SOURCE: ACIL ALLEN CONSULTING

8.3.1 Real Final Demand

Final Demand is the component of real output that accounts for all domestic economic activity. As it does not include exports or imports, the magnitude and timing of the impacts on Final Demand differ from the broader measure of real output. In total, the real Final Demand impact of development under the CALM scenario is estimated to total \$519 million over the study period (refer to Figure 8.3). In the Northern Territory it is estimated real Final Demand will increase by \$539 million and fall by \$19.7 million across the Rest of Australia (the result of a reallocation of labour to the Territory for the Industry’s appraisal phase) over the study period.

FIGURE 8.3 CALM REAL FINAL DEMAND, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION

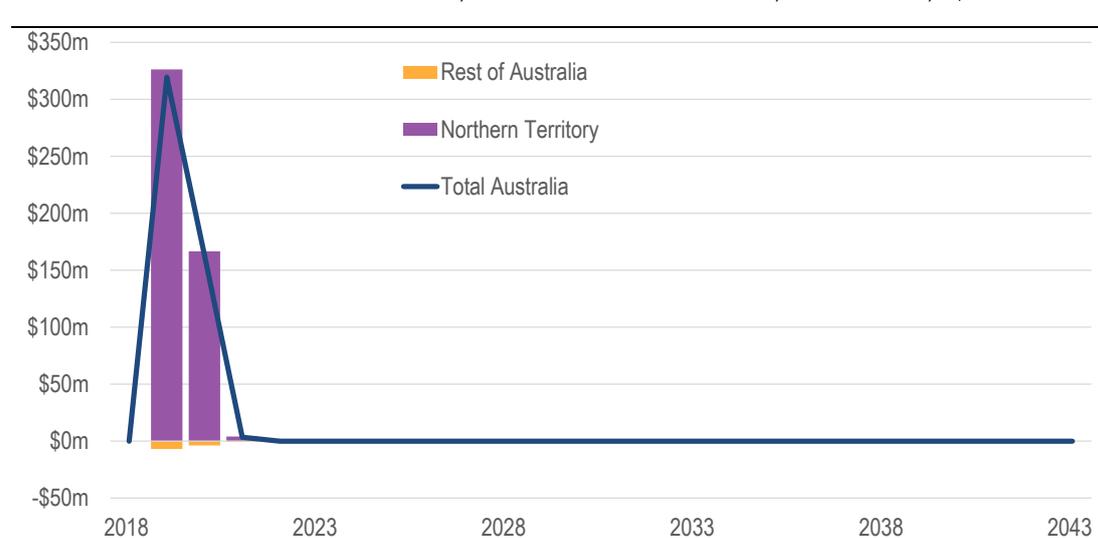


SOURCE: ACIL ALLEN CONSULTING

Real investment

In the Northern Territory, the major component of the Industry’s real Final Demand impact is in relation to investment. The real investment impact of the Industry is estimated to total \$486 million over the study period (refer to Figure 8.4). In the Northern Territory it is estimated real investment will increase by \$497 million and fall by \$11.4 million across the Rest of Australia (the result of a reallocation of labour to the Territory’s appraisal phase) over the study period.

FIGURE 8.4 CALM REAL INVESTMENT, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION



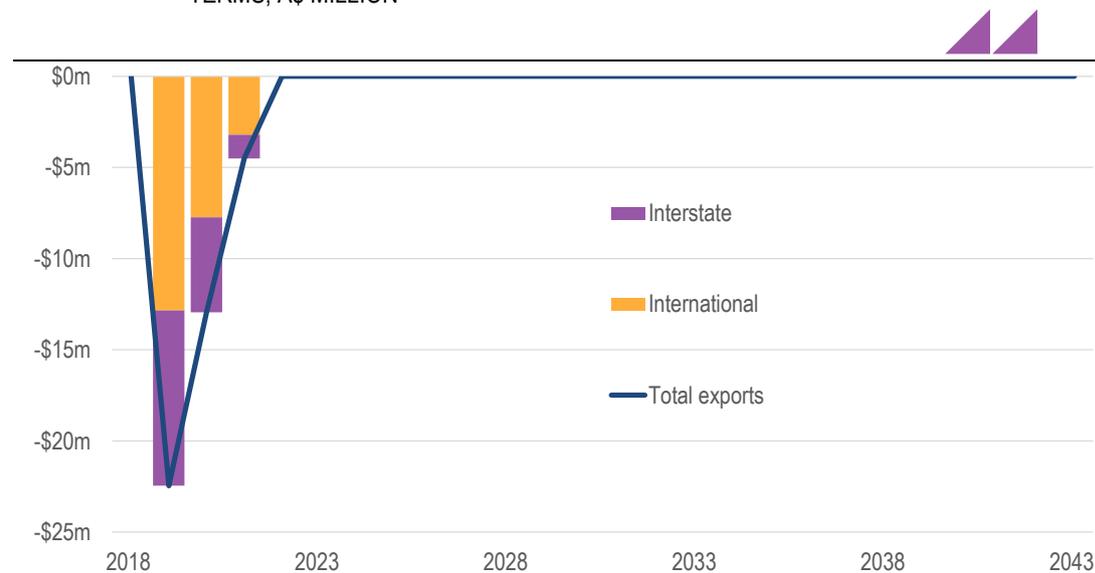
SOURCE: ACIL ALLEN CONSULTING

8.3.2 Real exports

The reallocation of labour resources to the Northern Territory under the CALM development scenario for the appraisal of the Industry results in labour not generating export revenue in other industries in the economy, which results in a net loss to exports in the Territory (refer to Figure 8.5).

In total, the *Tasman Global* CGE model estimates that real exports in the Territory will contract by \$39.9 million. The majority of this will be lost from international exports (\$23.8 million), with \$16.1 million from interstate exports.

FIGURE 8.5 CALM NORTHERN TERRITORY REAL EXPORTS, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION



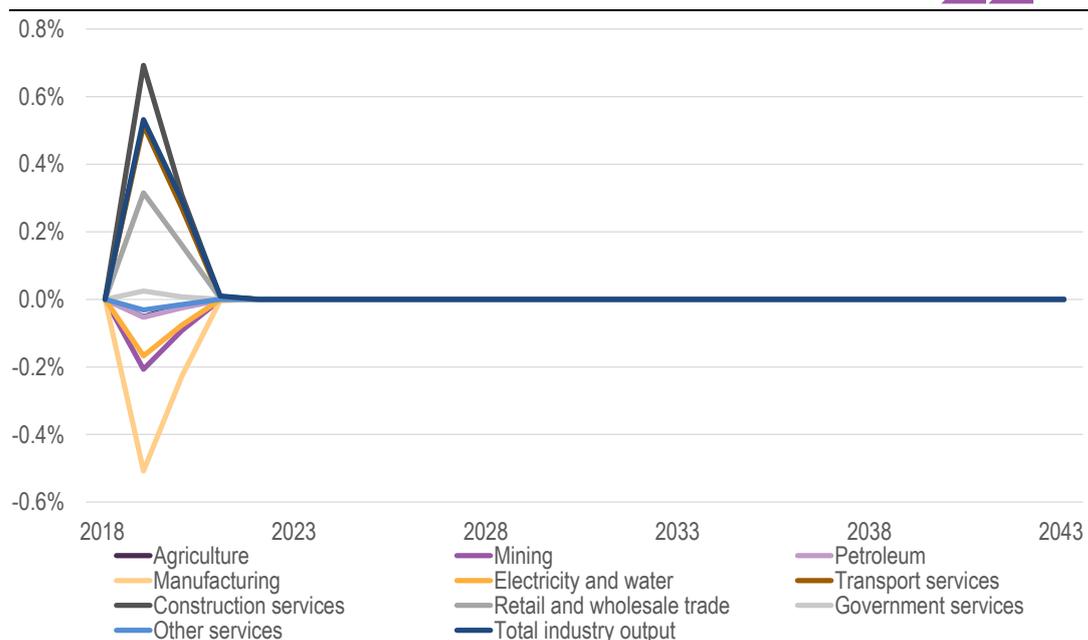
SOURCE: ACIL ALLEN CONSULTING

8.4 Real output – industry

Figure 9.7 displays the impact the Industry has on the real output by industry in the Northern Territory. Under the CALM development scenario, the largest impact will be realised in the Construction Services industry, which between 2019 and 2021 will generate average growth over and above the base case by 0.34 per cent per annum. The Transport Services industry also will generate additional growth of 0.26 per cent per annum between 2019 and 2021 over and above the base case.

The largest negative impact of the Industry under the CALM development scenario is estimated to occur in the Manufacturing industry, which is estimated to contract by 0.25 per cent per annum between 2019 and 2021 relative to the base case. For the remaining Northern Territory industries, the impact of the Industry under the CALM development scenario is negligible.

FIGURE 8.6 CALM NORTHERN TERRITORY REAL OUTPUT BY INDUSTRY, PERCENTAGE CHANGE FROM BASELINE, REAL TERMS, PERCENTAGE



SOURCE: ACIL ALLEN CONSULTING

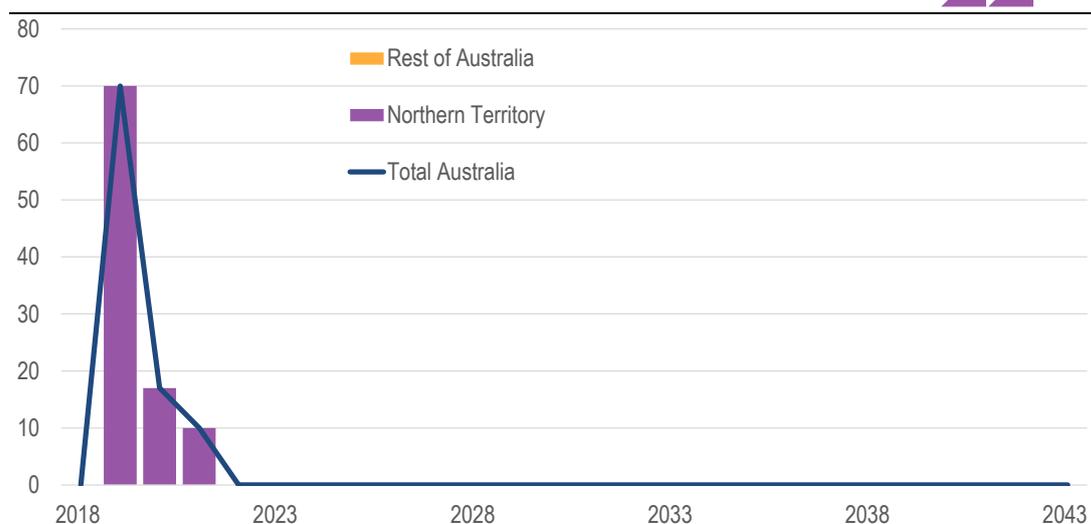
8.5 Labour market

8.5.1 Employment

Under the CALM development scenario, the Industry is expected to require some short term employment opportunities.

Over the study period, it is estimated the development of the Industry will require direct employment of 97 FTE jobs, there is no labour requirements after 2021 (refer to Figure 8.7). Overall, it is estimated that the Industry under the CALM scenario will generate total direct and indirect jobs of 119 FTE jobs over the study period.

FIGURE 8.7 CALM DIRECT EMPLOYMENT, DEVIATION FROM BASELINE, REAL TERMS, FTES, THOUSANDS



SOURCE: ACIL ALLEN CONSULTING

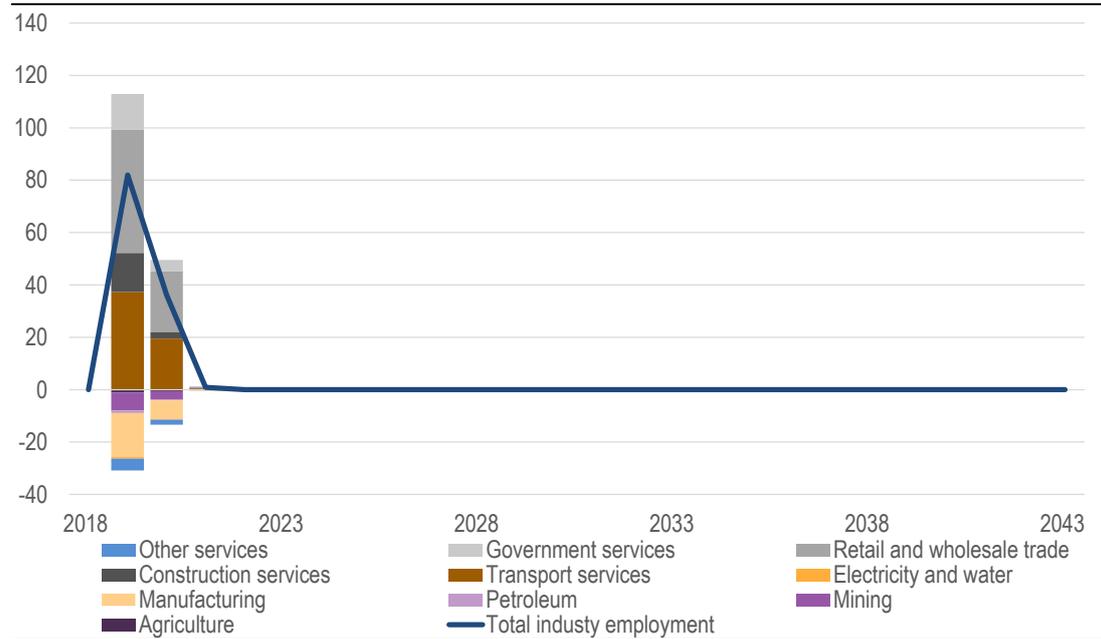
8.5.2 Industry real employment

While the development of the Industry under the CALM development scenario results in the reallocation of some labour resources from other industries, on average the real employment impact is significantly positive for the Territory. Figure 9.9 displays the impact the Industry has on direct and indirect employment by industry in the Northern Territory. Under the CALM development scenario, the largest impact will be realised in the Retail and Wholesale Trade industry, which between 2019 and 2021 will generate total additional jobs over and above the base case of 71 FTE jobs, and is a result of the consumption impacts arising from the boost to real incomes in the Territory.

The Transport Services (57 FTE jobs), Government Services (18 FTE jobs) and Construction Services Industry (17 FTE jobs) will also receive a boost to employment over and above the base case over the study period.

The largest negative impact of the Industry under the CALM development scenario is estimated to occur in the Manufacturing industry, which is estimated to contract by 24 FTE jobs over the study period relative to the base case. For the remaining Northern Territory industries, the impact of the Industry under the CALM development scenario is negligible.

FIGURE 8.8 CALM NORTHERN TERRITORY DIRECT AND INDIRECT EMPLOYMENT BY INDUSTRY, DEVIATION FROM BASELINE, REAL TERMS, FTES, THOUSANDS

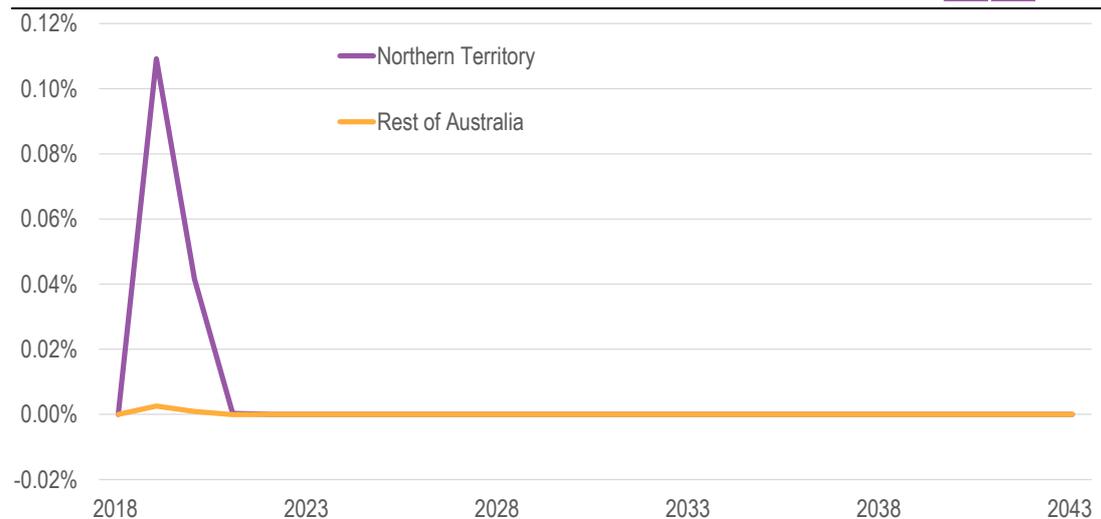


SOURCE: ACIL ALLEN CONSULTING

8.5.3 Real wages

The development of the Industry is estimated to provide a temporary boost to real wages in the Northern Territory between 2019 and 2021 of 0.05 per cent per annum. The impact across the Rest of Australia is negligible, given that there is no job creation under the CALM scenario (refer to Figure 8.9).

FIGURE 8.9 CALM REAL WAGE GROWTH, DEVIATION FROM BASELINE, REAL TERMS, PERCENTAGE

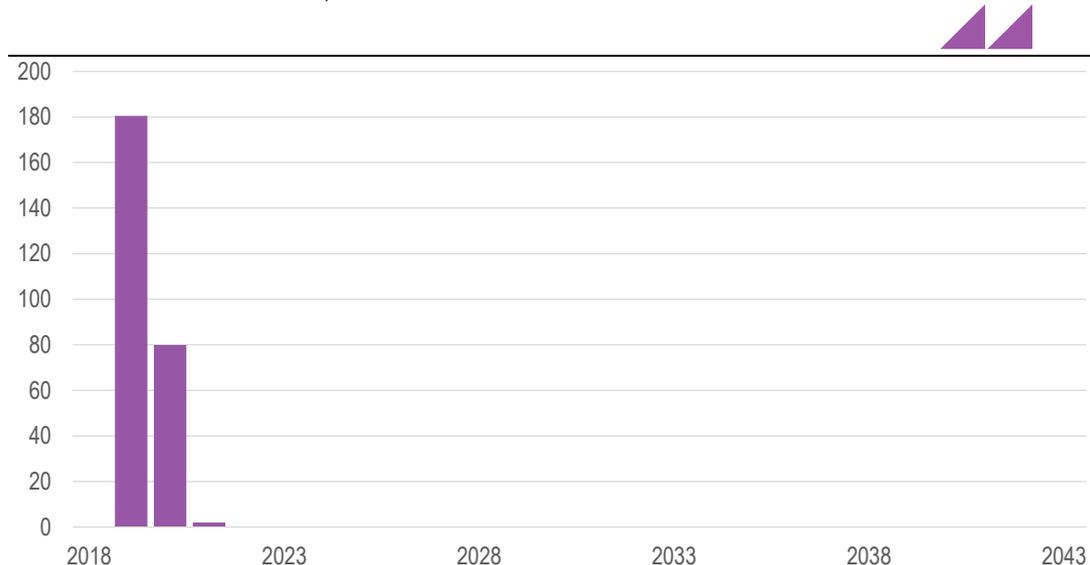


SOURCE: ACIL ALLEN CONSULTING

8.6 Population

The development of the Industry is estimated to provide a temporary boost to population in the Northern Territory of 180 persons in 2019, 80 persons in 2020 and two persons in 2021. After 2021 there is no impact on the Territory's population.

FIGURE 8.10 CALM NORTHERN TERRITORY REAL POPULATION, DEVIATION FROM BASELINE, REAL TERMS, NUMBER

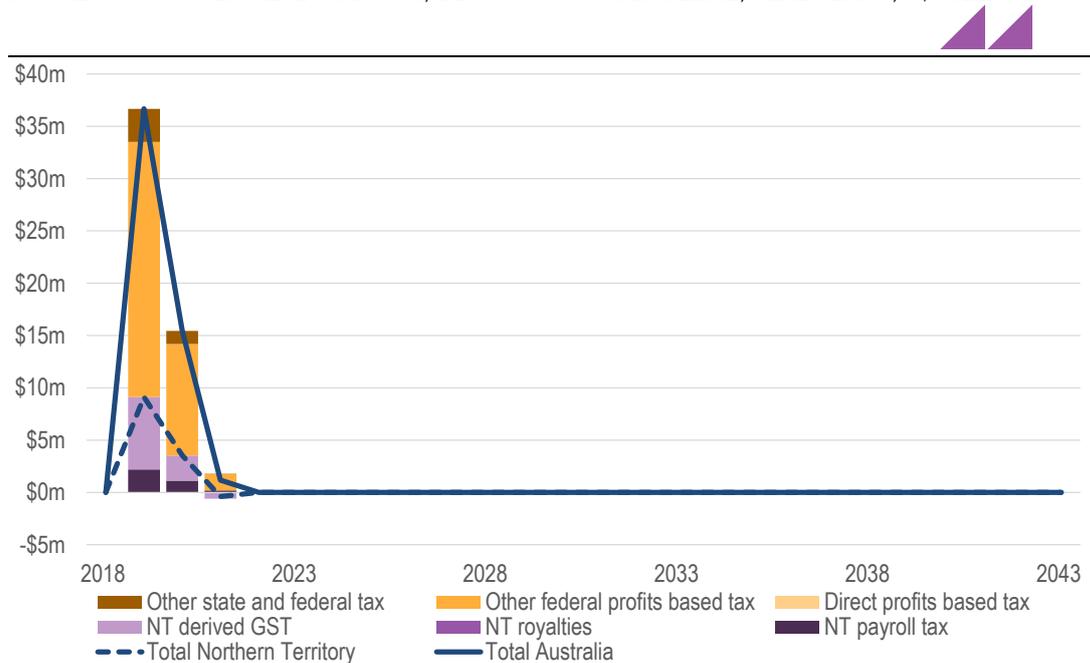


SOURCE: ACIL ALLEN CONSULTING

8.7 Real taxation

The development of the Industry under the CALM scenario will generate a short term taxation benefits to the Northern Territory and the Commonwealth Governments, primarily in the form of indirect profits based taxes and GST (refer to Figure 8.11).

FIGURE 8.11 CALM REAL TAXATION, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION



SOURCE: ACIL ALLEN CONSULTING

Between 2019 and 2021, it is estimated the Commonwealth Government will be in receipt of \$36.6 million of indirect company taxation payments, and a further \$8.7 million is estimated to be generated in GST collections.

The Industry under the CALM development scenario will also generate \$3.5 million in payroll taxation payments to the Northern Territory Government, while \$4.5 million is expected to be generated in other state and federal taxes (such as personal income, excises, fringe benefits and capital gains tax receipts).

8.8 Summary

Table 8.1 presents a summary of the economic modelling results presented in the section.

TABLE 8.1 CALM DEVELOPMENT SCENARIO, SUMMARY OF ECONOMIC IMPACT RESULTS

	Total	Average	NPV (7 per cent)
Real income			
Northern Territory	\$35.2m	\$1.4m	\$30.3m
Rest of Australia	-\$15.4m	-\$0.6m	-\$12.8m
Total Australia	\$19.8m	\$0.8m	\$17.5m
Real output			
Northern Territory	\$4.1m	\$0.2m	\$3.7m
Rest of Australia	-\$12.2m	-\$0.5m	-\$10.2m
Total Australia	-\$8.2m	-\$0.3m	-\$6.5m
Real Final Demand			
Northern Territory	\$539.1m	\$20.7m	\$460.2m
Rest of Australia	-\$19.7m	-\$0.8m	-\$16.5m
Total Australia	\$519.4m	\$20.0m	\$443.7m
Real investment			
Northern Territory	\$496.9m	\$19.1m	\$424.0m
Rest of Australia	-\$11.4m	-\$0.4m	-\$9.6m
Total Australia	\$485.5m	\$18.7m	\$414.4m
Northern Territory real exports			
International	-\$23.8m	-\$0.9m	-\$20.0m
Interstate	-\$16.1m	-\$0.6m	-\$13.6m
Total	-\$39.9m	-\$1.5m	-\$33.6m
Real employment			
Northern Territory	119 FTEs	5 FTEs	
Rest of Australia	-119 FTEs	-5 FTEs	
Total Australia	0 FTEs	0 FTEs	
Real employment by industry			
Agriculture	-2 FTEs	0 FTEs	
Mining	-10 FTEs	0 FTEs	

	Total	Average	NPV (7 per cent)
Petroleum	-1 FTEs	0 FTEs	
Manufacturing	-24 FTEs	-1 FTEs	
Electricity and water	-1 FTEs	0 FTEs	
Transport services	57 FTEs	2 FTEs	
Construction services	17 FTEs	1 FTEs	
Retail and wholesale trade	71 FTEs	3 FTEs	
Government services	18 FTEs	1 FTEs	
Other services	-6 FTEs	0 FTEs	
Total industry employment	119 FTEs	5 FTEs	
Real population			
Northern Territory	262 persons	10 persons	
Real taxation			
Northern Territory			
Payroll tax	\$3.5m	\$0.1m	\$3.0m
Royalties	\$0.0m	\$0.0m	\$0.0m
Derived GST	\$8.7m	\$0.3m	\$7.5m
Total Northern Territory	\$12.2m	\$0.5m	\$10.5m
Commonwealth			
Direct profits based tax	\$0.0m	\$0.0m	\$0.0m
Other federal profits based tax	\$36.6m	\$1.4m	\$31.2m
Other state and federal tax	\$4.5m	\$0.2m	\$3.8m
Total Commonwealth	\$41.1m	\$1.6m	\$35.0m
Total Australia	\$53.3m	\$2.0m	\$45.5m

SOURCE: ACIL ALLEN CONSULTING



This section explores the broader economic impacts of development of an onshore unconventional shale gas industry, as represented in the previous sections as ProjectCo and PipelineCo. The economic impact will be assessed over the period from 2018 to 2043 for the Northern Territory and Rest of Australian economies on the following terms:

- the impact on **real incomes** (a measure of economic welfare or standard of living);
- the impact on **real output** (as measured in terms of Gross Domestic Product, Gross State/Territory Product, National/State Final Demand, Business Investment and Exports),
- the impact on **employment** (as measured on a full time equivalent job basis);
- the impact on **real wages growth**;
- the impact on **population growth**; and
- the impact on **total taxation payments** (those taxes directly paid by the industry, and the indirect taxes paid as a result of the activity generated from the industry).

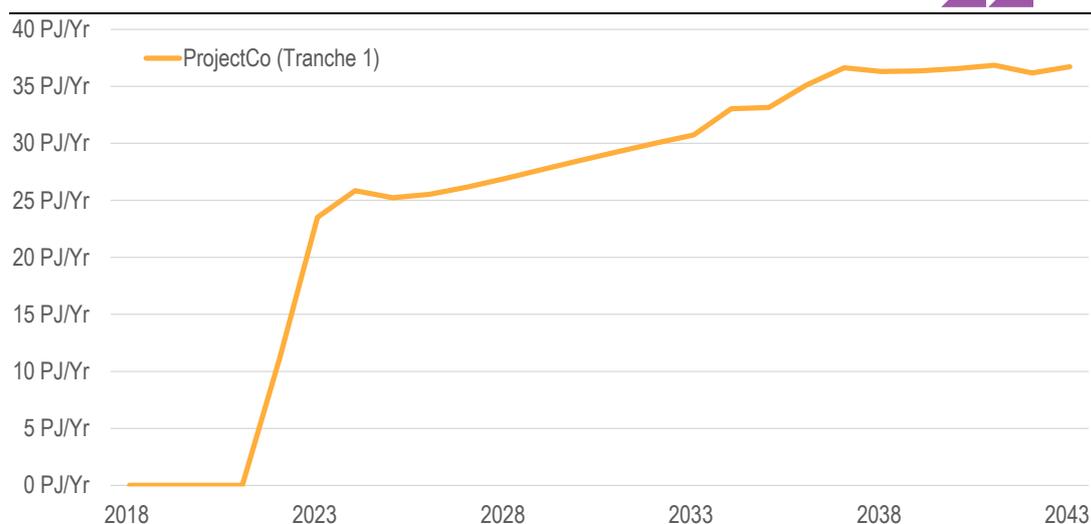
For purposes of the reporting, the economic impact of ProjectCo and PipelineCo will be referred to as the “Onshore Unconventional Gas Industry” or “the Industry”.

The economic impact of the development of the Industry under the BREEZE development scenario, as detailed in Section 4.3.2, was assessed using ACIL Allen’s *Tasman Global* CGE model. Further details on *Tasman Global* are presented in Appendix E.

9.1 Scenario description

As discussed in Section 4.3.2, under the BREEZE development scenario it is assumed shale gas production commences in FY2022, with the current moratorium on activities lifting at the end of FY2018 and the exploration/appraisal phase of development occurring in FY2019, FY2020 and FY2021. At the tail end of FY2021, facilities required to tie into the Amadeus Gas Pipeline are built and then linked to the East Coast market via the NGP. Gas is produced at an initial rate of 33.4 TJ/day in 2022, ramping up to 90 TJ/day in 2034.

The profile of gas production by ProjectCo in BREEZE is below in Figure 9.1.

FIGURE 9.1 GAS PRODUCTION, BREEZE SCENARIO, PJ/ANNUM

SOURCE: ACIL ALLEN CONSULTING

9.2 Real income

The development of the Industry has a significant impact on the real income of Australia. Real income is a measure of the economic welfare (or standard of living) improvement as a result of the developments. The change in real income captures the effect of net foreign income transfers associated with ownership of the capital along with changes in the purchasing power of Australian residents.

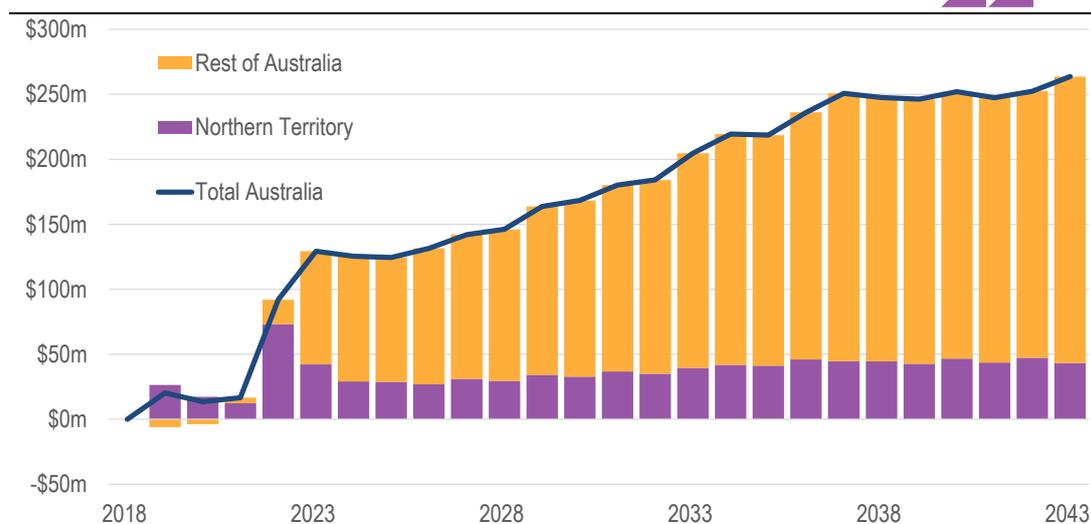
The real income impact of the Industry is largely accrued through the profits generated by the Industry once it is operational, which also determines the level of profits based taxation paid by the Industry. Overall, the majority of the real income impact of the development under the BREEZE scenario is transferred from the Northern Territory to the Rest of Australia, in the form of Commonwealth Government taxes and because the equity ownership of the Industry is assumed to be largely on the east coast of Australia.

Real income impacts are still realised in the Territory, through increased employment and a redistribution of the profits based taxation payments from the Commonwealth back to the Territory. Royalty and payroll taxation payments made to the Northern Territory Government and payments made to pastoralists and native title owners also contribute to the real income impact in the Territory.

In total, the real income impact of the Industry is estimated to total \$4.3 billion at an average of \$165 million per annum over the study period (refer to Figure 9.2). The real income impact reaches a steady state of around \$250 million per annum in 2037, once the Industry reaches its steady state of production.

Over the study period, the real income impact in the Northern Territory is estimated to total \$937 million, at an average of \$36.1 million per annum. Real incomes are expected to peak at \$73.2 million in 2022, which coincides with peak employment and peak wages growth in the Territory. Once the Industry reaches its steady state level of production, the real income impact in the Territory averages around \$44.7 million per annum.

The real income impact is largely felt on the east coast of Australia, which is estimated to total \$3.3 billion at an average of \$128 million per annum over the study period. Real incomes are expected to peak in 2043 at \$220 million, as the Industry reaches peak production.

FIGURE 9.2 BREEZE REAL INCOME, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION

SOURCE: ACIL ALLEN CONSULTING

9.3 Real output

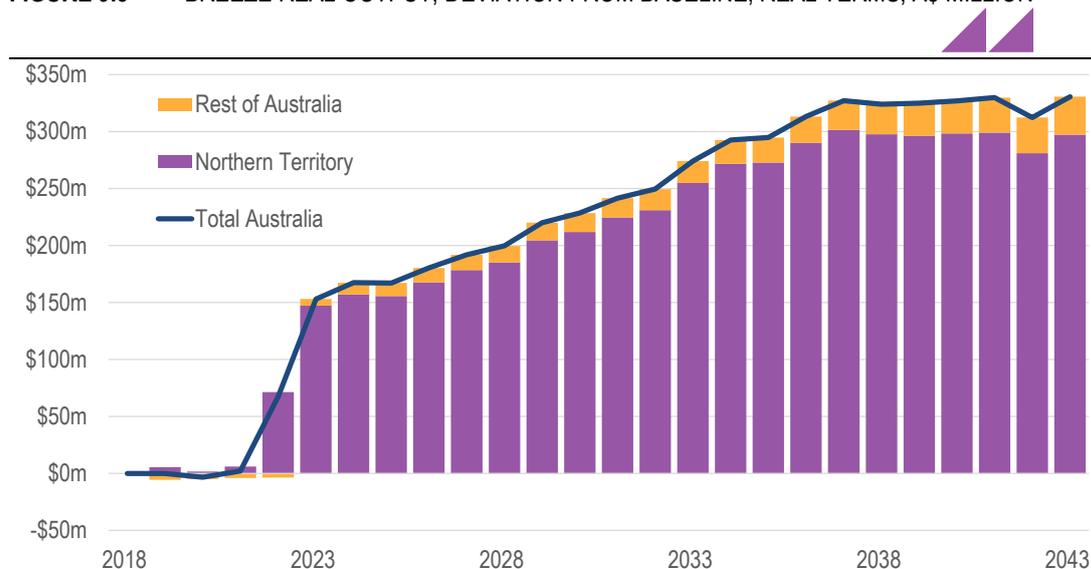
The real output impact is largely accrued through the impact the Industry has on investment in the Northern Territory and the value of the gas exported from the Territory to the Rest of Australia. The real output impact of the Industry is different to the real income impact because, in an output sense, the value of the gas exported is realised in the Territory, whereas in an income sense, the value of the gas exported is realised through profits generated and taxation payments, which largely accrue on the east coast of Australia.

Under the BREEZE development scenario, real output is estimated to total \$5.5 billion at an average of \$205 million per annum over the study period (refer to Figure 9.3). The real output impact reaches a steady state of around \$325 million per annum in 2037, as a steady state of production is reached.

Over the study period, the real output impact in the Northern Territory is estimated to total \$5.1 billion, at an average of \$196 million per annum. Real output is expected to increase over the study period in line with the increase in the level of production. At steady state production in 2037, output in the Territory is estimated to average \$295 million per annum.

Relative to the size of the Northern Territory's economy, the increase in real output from the development of the Industry represents a boost to Gross Territory Product of 0.11 per cent in 2037, once the level of real output reaches a steady state.

Across the Rest of Australia, the real output impact is largely driven by an increase to consumption by the household sector, as a result of the rising real incomes from the development on the Rest of Australia. Over the study period, it is estimated the real output impact on the Rest of Australia will total \$406 million at an average of \$15.6 million per annum.

FIGURE 9.3 BREEZE REAL OUTPUT, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION

SOURCE: ACIL ALLEN CONSULTING

9.3.1 Real Final Demand

Final Demand is the component of real output that accounts for all domestic economic activity. As it does not include exports or imports, the magnitude and timing of the impacts on Final Demand differ from the broader measure of real output.

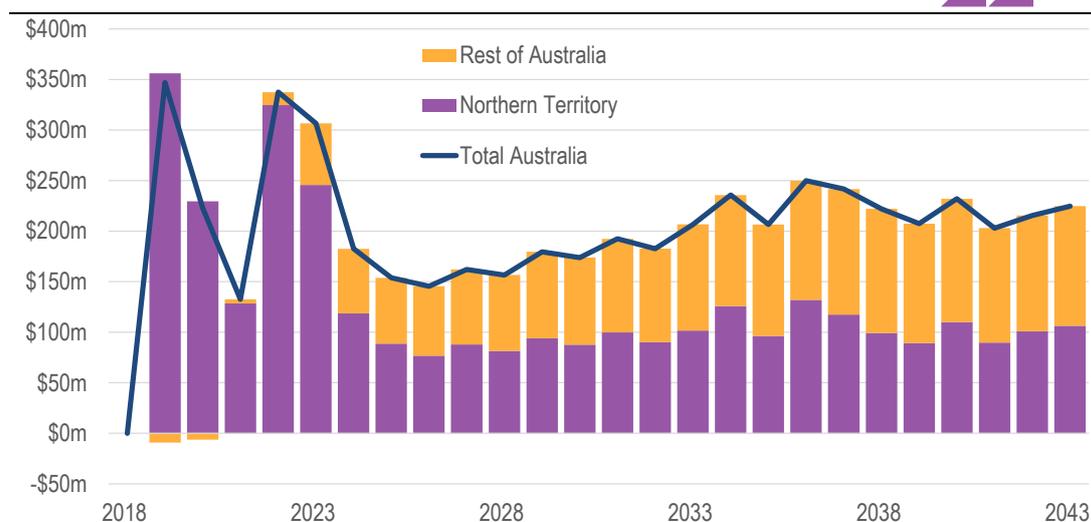
The real Final Demand impact of development under the BREEZE scenario in the Northern Territory is largely accrued through the investment needed to fund the Industry's capital requirements. For the Rest of Australia the impact largely results from the household consumption impacts that are accrued from rising real incomes resulting from the development.

In total, the real Final Demand impact of development under the BREEZE scenario is estimated to total \$5.3 billion at an average of \$205 million per annum over the study period (refer to Figure 9.4).

Real Final Demand in the Territory is expected to peak at \$356 million in 2019, during the Industry's exploration phase, and be maintained at high level during the capital intensive development phase, where real Final Demand is estimated to increase by \$325 million by 2020. Over the study period, the Final Demand impact is estimated to total \$3.3 billion at an average of \$196 million per annum.

Throughout the Rest of Australia, the real Final Demand impact of the Industry does not have a material impact until the Industry becomes profitable in 2023, and when the real income impact begins to impact on household consumption. Over the study period, the Final Demand impact is estimated to total \$2 billion at an average of \$79 million per annum.

FIGURE 9.4 BREEZE REAL FINAL DEMAND, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION



SOURCE: ACIL ALLEN CONSULTING

Real investment

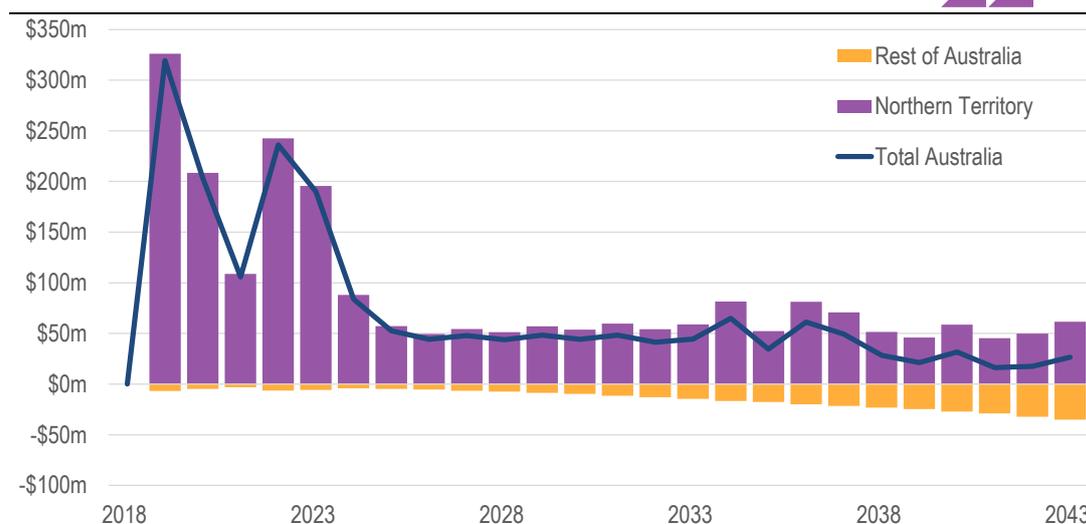
In the Northern Territory, the major component of the Industry's real Final Demand impact is in relation to investment, and is the result of the ongoing capital intensive nature of unconventional shale gas developments.

In total, the real investment impact of the Industry is estimated to total \$1.9 billion at an average of \$73.4 million per annum over the study period (refer to Figure 9.5). The exploration phase of the Industry is when the real investment impact of the Industry peaks (\$326 million in 2019) and again during the development and the duplication of the Amadeus pipeline (\$243 million in 2023).

Following the capital intensive initial production phase of the Industry, the real investment reduces as less capital is required to reach the target production level. Over the study period, real investment in the Territory is estimated to total \$2.3 billion at an average of \$87 million per annum.

Across the Rest of Australia, ACIL Allen estimates that as a result of a reallocation of labour resources to the Northern Territory, the impact on real investment throughout the Rest of Australia falls by of \$359 million at an average of \$13.8 million per annum over the study period.

FIGURE 9.5 BREEZE REAL INVESTMENT, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION



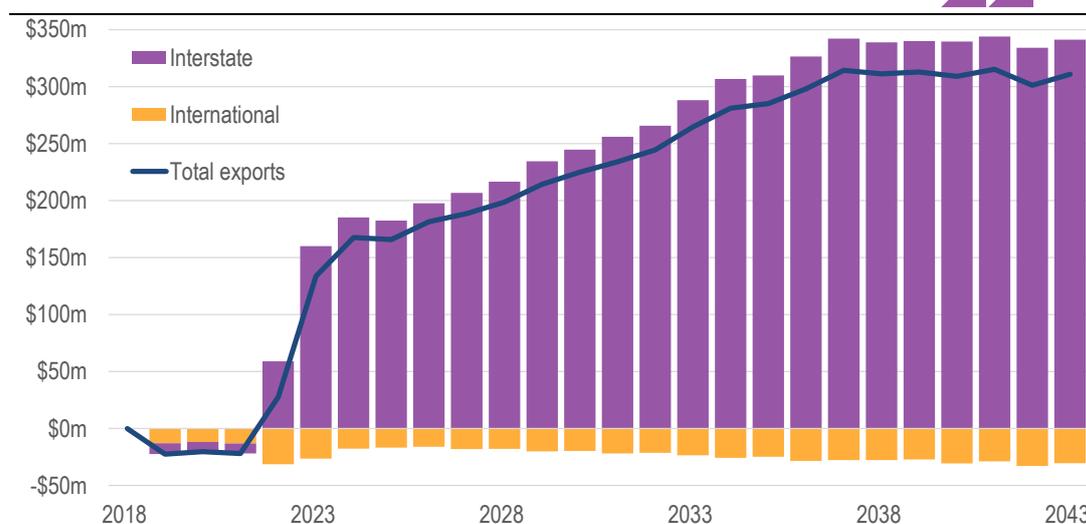
SOURCE: ACIL ALLEN CONSULTING

9.3.2 Real exports

The impact the Industry has on the Northern Territory’s real exports is the other main driver of the impact on the Territory’s real output. While gas is not exported to international markets under the BREEZE development scenario, it is exported from the Territory to the Rest of Australia (specifically the east coast of Australia).

Over the study period, the development is estimated to increase real exports by \$5.2 billion at an average of \$201 million per annum (refer to Figure 9.6). The increase in real exports is driven by the boost to interstate exports (\$5.8 billion over the study period or \$223 million per annum), which offsets the small decrease in international exports resulting from the impact of an expected appreciation in the Australian Dollar (\$573 million over the study period or \$22 million per annum).

FIGURE 9.6 BREEZE NORTHERN TERRITORY REAL EXPORTS, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION



SOURCE: ACIL ALLEN CONSULTING

Once a steady state of real exports is reached in 2037, it is estimated that the exports generated by the Industry under the BREEZE development scenario would account for 1.6 per cent of the Territory’s total exports.

9.4 Real output – industry

Figure 9.7 displays the impact the Industry has on the real output by industry in the Northern Territory. Under the BREEZE development scenario, the largest impact will be realised in the Petroleum industry, given that the Industry would be captured under this industry classification. It is estimated that the Petroleum industry will generate growth over and above the base case of 1.9 per cent per annum on average over the study period.

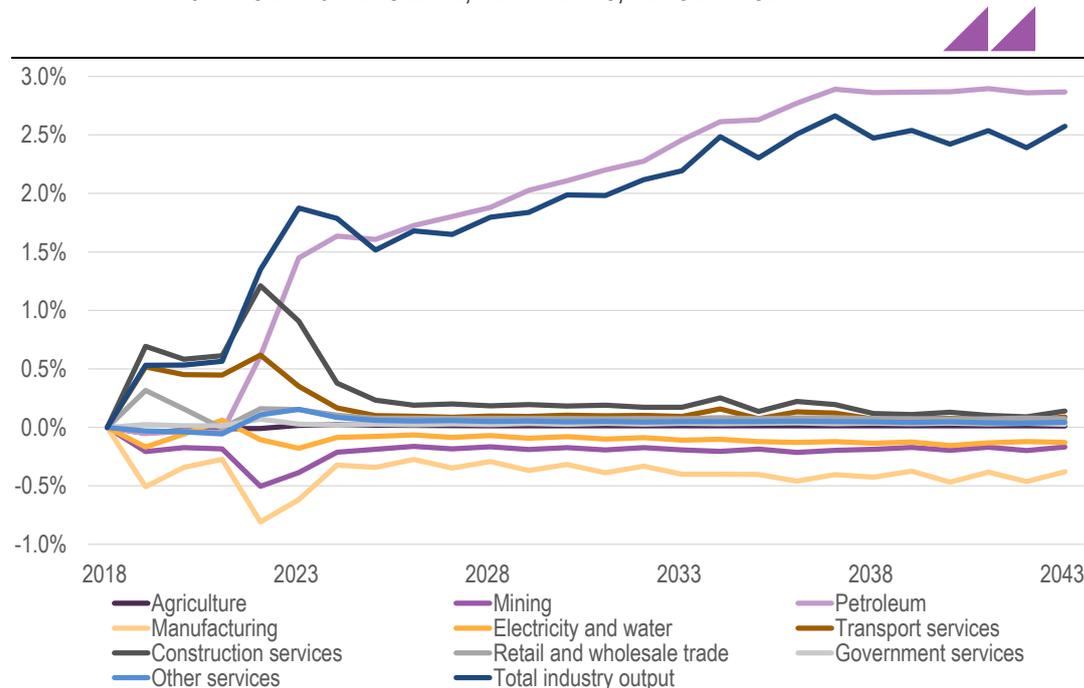
The Construction Services industry is also expected to increase over the study period, averaging growth of 0.3 per cent per annum. The majority of this growth will be realised in the early stages of the Industry’s development, with growth expected to peak at 1.2 per cent in 2022.

The Transport Services industry is also estimated to follow a similar trend, growing on average by 0.2 per cent per annum and peaking at 0.6 per cent in 2022, relative to the base case.

The Manufacturing industry is estimated to contract on average by 0.4 per cent per annum over the study period. This reflects the impact of an appreciation in the Australian Dollar on the global competitiveness of export competing businesses in the Territory. In addition, a reallocation of labour away from the Manufacturing industry to the Petroleum industry results in lower output from that industry. A similar impact occurs in the Mining and Electricity and Water industries, which are estimated to contract on average by 0.2 per cent and 0.1 per cent per annum over the study period.

Across all industries, the development of the Industry in the Territory will have a marginal impact on the growth across most industries. Overall, industry growth is estimated to be 1.9 per cent per annum higher than what would otherwise have occurred if the Industry did not exist.

FIGURE 9.7 BREEZE NORTHERN TERRITORY REAL OUTPUT BY INDUSTRY, PERCENTAGE CHANGE FROM BASELINE, REAL TERMS, PERCENTAGE



SOURCE: ACIL ALLEN CONSULTING

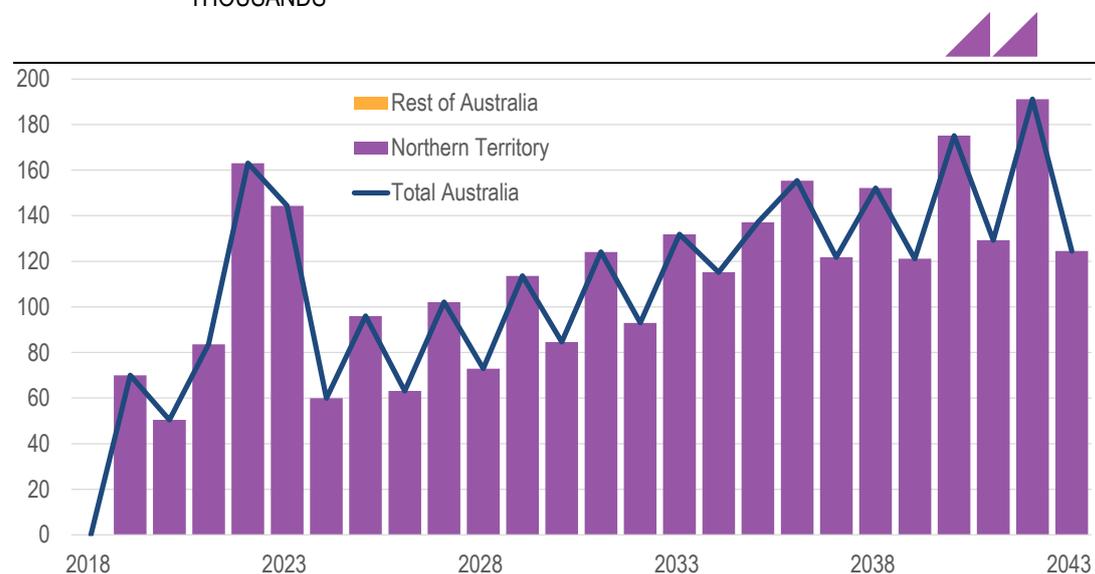
9.5 Labour market

9.5.1 Employment

The development of a new industry in the Territory under the BREEZE development scenario has significant workforce implications. The largest component of the Industry's direct workforce is the staff required to operate the wells and pads. The 'peaking' nature of the FTE requirements presented in Figure 9.8 is a result of the timing of the construction workforce requirements. Labour required for the construction of gas transmission pipelines in the Territory in 2021 and 2022 also contributes to this 'peaking' nature, but on a smaller scale.

Over the study period, it is estimated the development of the Industry will require direct employment of 2,874 FTE jobs at an average of 111 FTE jobs per annum in the Territory. The majority of these FTE jobs are in relation to the construction and operations of the Industry (total of 2,361 FTE jobs at an average of 91 FTE jobs per annum), while a total of 514 FTE jobs (average of 20 FTE jobs per annum) are in relation to the construction of transmission pipes.

FIGURE 9.8 BREEZE DIRECT EMPLOYMENT, DEVIATION FROM BASELINE, REAL TERMS, FTES, THOUSANDS



SOURCE: ACIL ALLEN CONSULTING

However, the total employment impact of the Industry development under the BREEZE scenario is minimal, due to the resulting draw on labour from other industries in the Territory and other parts of Australia.

Over the study period, the Industry is estimated to create 2,145 FTE direct and indirect FTE jobs at an average of 82.5 FTE jobs per annum in the Northern Territory. However, ACIL Allen modelling assumes that these positive impacts will be completely offset by the reallocation of employment from the Rest of Australia to the Territory.

9.5.2 Industry real employment

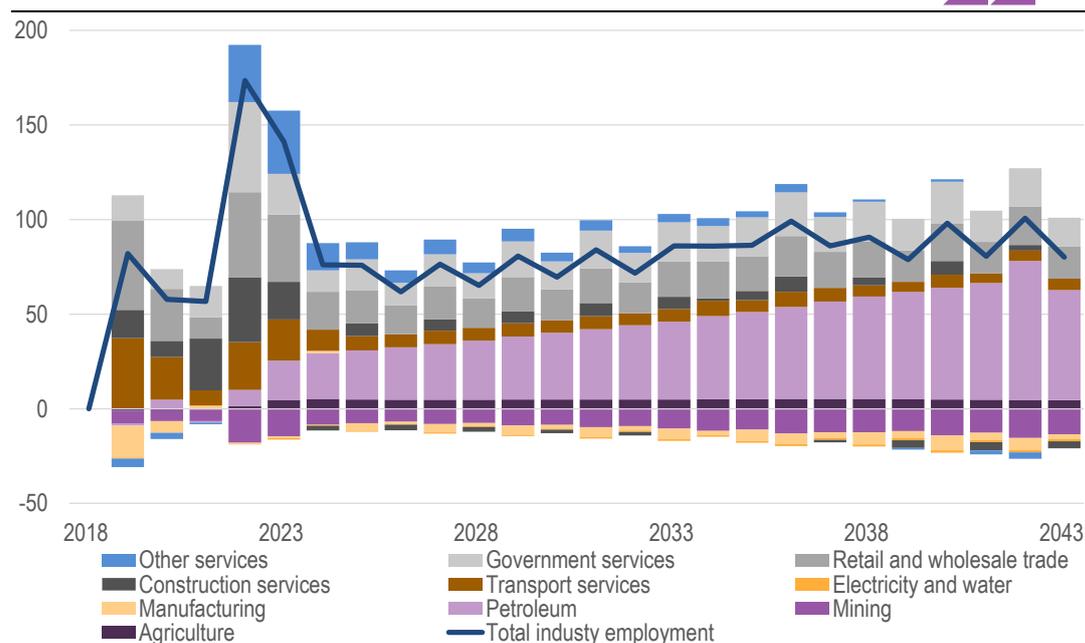
While the development of the Industry under the BREEZE development scenario results in the reallocation of some labour resources from other industries, on average the real employment impact is significantly positive for the Territory (refer to Figure 9.9).

Over the study period, the Petroleum industry is estimated to see the largest real employment impact, with the creation of 910 FTE jobs at an average of 35 FTE jobs per annum. Significant gains are also estimated in the Retail and Wholesale Trade industry, with a total of 526 FTE jobs at an average of 20.3 FTE jobs per annum to be created, as a result of increased household consumption in the Territory.

The Government Service industry (462 FTE jobs at an average of 17.8 FTE jobs per annum), Transport Services industry (253 FTE jobs at an average of 9.7 FTE jobs per annum) and Construction Services industry (141 FTE jobs at an average of 5.4 FTE jobs per annum) are also estimated to see solid employment gains over the study period under the BREEZE development scenario.

The majority of the labour reallocation, as a result of the development of the Industry, is estimated to occur in Mining (loss of 265 FTE jobs at an average of 10.2 FTE jobs per annum), Manufacturing (loss of 100 FTE jobs at an average of 3.9 FTE jobs per annum) and Electricity and Water (loss of 18.5 FTE jobs at an average of 0.7 FTE jobs per annum).

FIGURE 9.9 BREEZE NORTHERN TERRITORY DIRECT AND INDIRECT EMPLOYMENT BY INDUSTRY, DEVIATION FROM BASELINE, REAL TERMS, FTES, THOUSANDS



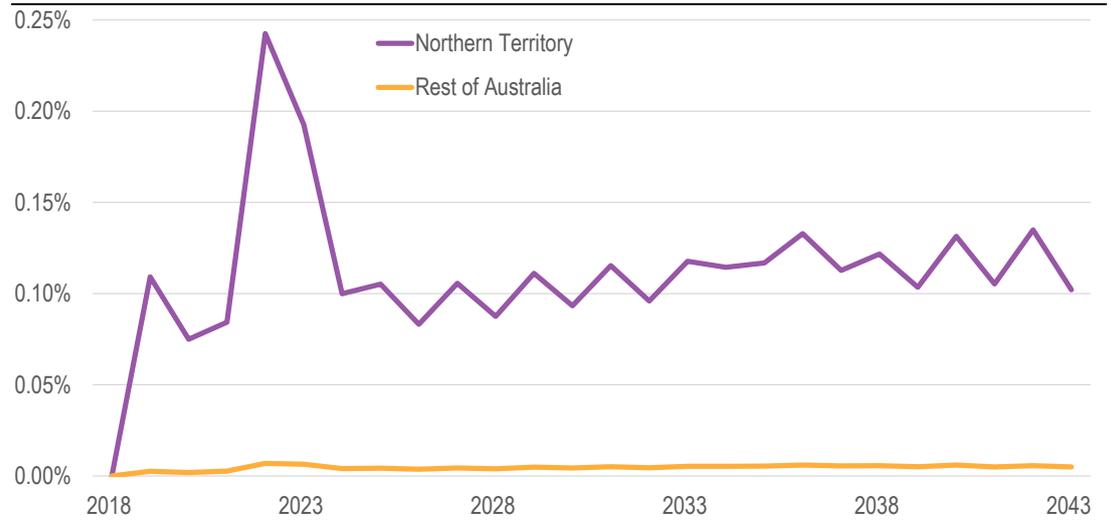
SOURCE: ACIL ALLEN CONSULTING

9.5.3 Real wages

The development of the Industry is estimated to boost real wages in the Northern Territory relative to the Rest of Australia (refer to Figure 9.10).

Over the study period, the increase in real wages is estimated to be on average 0.11 per cent per annum higher than the base case, peaking at 0.24 per cent in 2022 when the demand for labour in the Territory is at its highest. The impact across the Rest of Australia is negligible over the study period, given that there is no job creation under the BREEZE scenario.

FIGURE 9.10 BREEZE REAL WAGE GROWTH, DEVIATION FROM BASELINE, REAL TERMS, PERCENTAGE



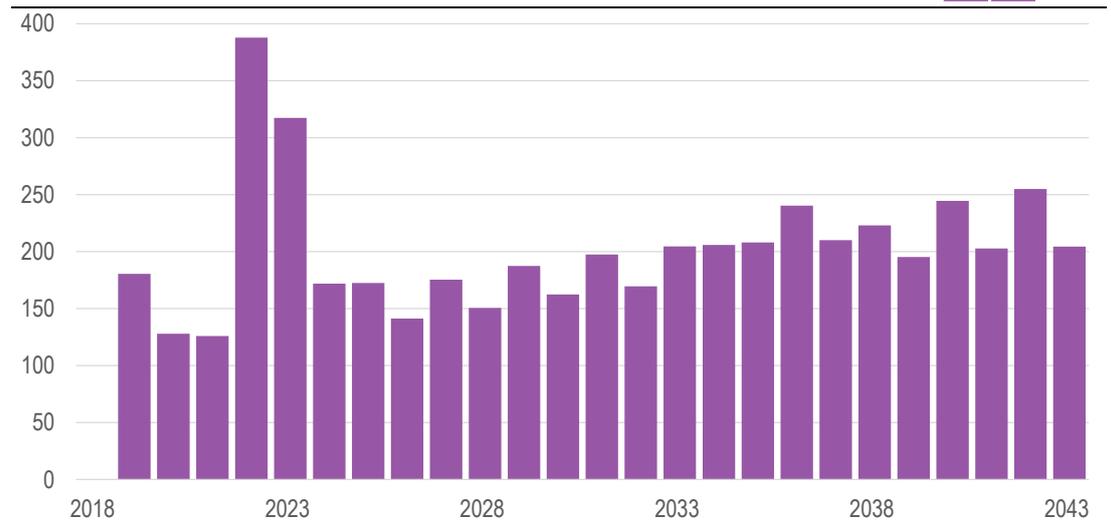
SOURCE: ACIL ALLEN CONSULTING

9.6 Population

The population of the Northern Territory, resulting from the development of the Industry under the BREEZE scenario, is largely driven by interstate migration as workers and their families relocate to the Territory to take up employment opportunities created by the development of the Industry.

Over the study period, it is estimated the population in the Northern Territory will increase by an average of 195 persons per annum. The population impact peaks during the capital intensive construction phase of the development of the Industry at 388 persons in 2022.

FIGURE 9.11 BREEZE NORTHERN TERRITORY REAL POPULATION, DEVIATION FROM BASELINE, REAL TERMS, NUMBER



SOURCE: ACIL ALLEN CONSULTING

9.7 Real taxation

The development of the Industry under the BREEZE scenario will generate significant taxation benefits to the Northern Territory and the Commonwealth Government, primarily in the form of profits based taxes, royalty revenues, payroll tax and a range of other taxes.

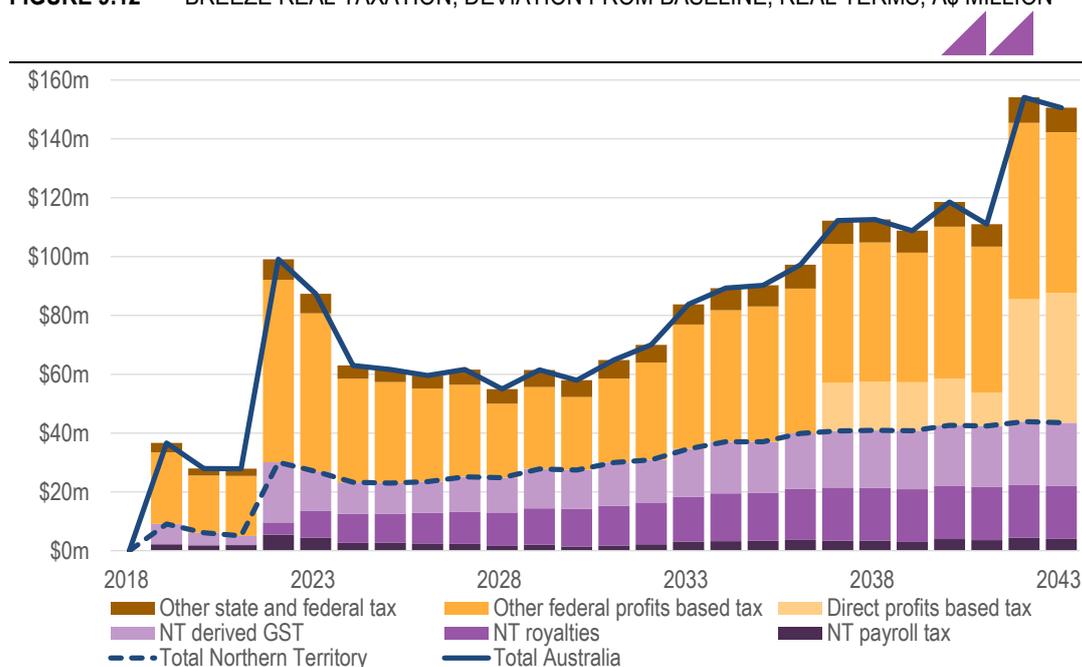
Over the study period, payments to the Commonwealth are projected to be substantial (refer to Figure 9.12). ACIL Allen estimates that the direct profits based taxation payments from the Industry would total \$162 million at an average of \$6.2 million per annum over the study period. There will also be significant indirect taxation payments collected by the Commonwealth, with payments totalling \$989 million at an average of \$38 million per annum.

The development of the Industry is estimated to generate other indirect taxation payments to the Commonwealth (such as personal income, excises, fringe benefits and capital gains tax receipts), totalling \$154 million at an average of \$5.9 million per annum.

Payments made to the Territory Government are expected to be largely accrued through royalty payments, which are estimated to total \$309 million at an average of \$11.9 million per annum over the study period. Direct and indirect payroll taxation payments to the Territory Government due to the development of the Industry are estimated to total \$74.8 million at an average of \$5.9 million per annum over the study period.

Increased commercial activity in the Territory is also estimated to result in GST revenues increasing by \$373 million at an average of \$14.3 million per annum over the study period.

FIGURE 9.12 BREEZE REAL TAXATION, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION



SOURCE: ACIL ALLEN CONSULTING

9.8 Summary

Table 9.1 presents a summary of the economic modelling results presented in the section.

TABLE 9.1 BREEZE DEVELOPMENT SCENARIO, SUMMARY OF ECONOMIC IMPACT RESULTS

	Total	Average	NPV (7 per cent)
Real income			
Northern Territory	\$937.2m	\$36.0m	\$380.1m
Rest of Australia	\$3,339.9m	\$128.5m	\$1,099.0m
Total Australia	\$4,277.2m	\$164.5m	\$1,479.1m
Real output			
Northern Territory	\$5,107.9m	\$196.5m	\$1,742.3m
Rest of Australia	\$406.5m	\$15.6m	\$118.7m
Total Australia	\$5,514.4m	\$212.1m	\$1,861.0m
Real Final Demand			
Northern Territory	\$3,277.7m	\$126.1m	\$1,683.0m
Rest of Australia	\$2,042.2m	\$78.5m	\$684.8m
Total Australia	\$5,319.9m	\$204.6m	\$2,367.8m
Real investment			
Northern Territory	\$2,264.8m	\$87.1m	\$1,265.0m
Rest of Australia	-\$359.3m	-\$13.8m	-\$113.7m
Total Australia	\$1,905.4m	\$73.3m	\$1,151.2m
Northern Territory real exports			
International	-\$572.5m	-\$22.0m	-\$225.9m
Interstate	\$5,791.6m	\$222.8m	\$1,948.0m
Total	\$5,219.1m	\$200.7m	\$1,722.1m
Real employment			
Northern Territory	2,145 FTEs	82 FTEs	
Rest of Australia	-2,145 FTEs	-82 FTEs	
Total Australia	0 FTEs	0 FTEs	
Real employment by industry			
Agriculture	103 FTEs	4 FTEs	
Mining	-265 FTEs	-10 FTEs	
Petroleum	910 FTEs	35 FTEs	
Manufacturing	-100 FTEs	-4 FTEs	
Electricity and water	-19 FTEs	-1 FTEs	
Transport services	253 FTEs	10 FTEs	
Construction services	141 FTEs	5 FTEs	

	Total	Average	NPV (7 per cent)
Retail and wholesale trade	526 FTEs	20 FTEs	
Government services	462 FTEs	18 FTEs	
Other services	133 FTEs	5 FTEs	
Total industry employment	2,145 FTEs	82 FTEs	
Real population			
Northern Territory	5,061 persons	195 persons	
Real taxation			
Northern Territory			
Payroll tax	\$74.8m	\$2.9m	\$31.0m
Royalties	\$309.2m	\$11.9m	\$105.3m
Derived GST	\$372.9m	\$14.3m	\$139.9m
Total Northern Territory	\$757.0m	\$29.1m	\$276.1m
Commonwealth			
Direct profits based tax	\$162.3m	\$6.2m	\$32.8m
Other federal profits based tax	\$988.8m	\$38.0m	\$395.9m
Other state and federal tax	\$154.4m	\$5.9m	\$59.1m
Total Commonwealth	\$1,305.4m	\$50.2m	\$487.8m
Total Australia	\$2,062.4m	\$79.3m	\$764.0m

SOURCE: ACIL ALLEN CONSULTING



10

WIND SCENARIO

This section explores the broader economic impacts of development of an onshore unconventional shale gas industry, as represented in the previous sections as ProjectCo and PipelineCo. The economic impact will be assessed over the period from 2018 to 2043 for the Northern Territory and Rest of Australian economies on the following terms:

- the impact on **real incomes** (a measure of economic welfare or standard of living);
- the impact on **real output** (as measured in terms of Gross Domestic Product, Gross State/Territory Product, National/State Final Demand, Business Investment and Exports),
- the impact on **employment** (as measured on a full time equivalent job basis);
- the impact on **real wages growth**;
- the impact on **population growth**; and
- the impact on **total taxation payments** (those taxes directly paid by the industry, and the indirect taxes paid as a result of the activity generated from the industry).

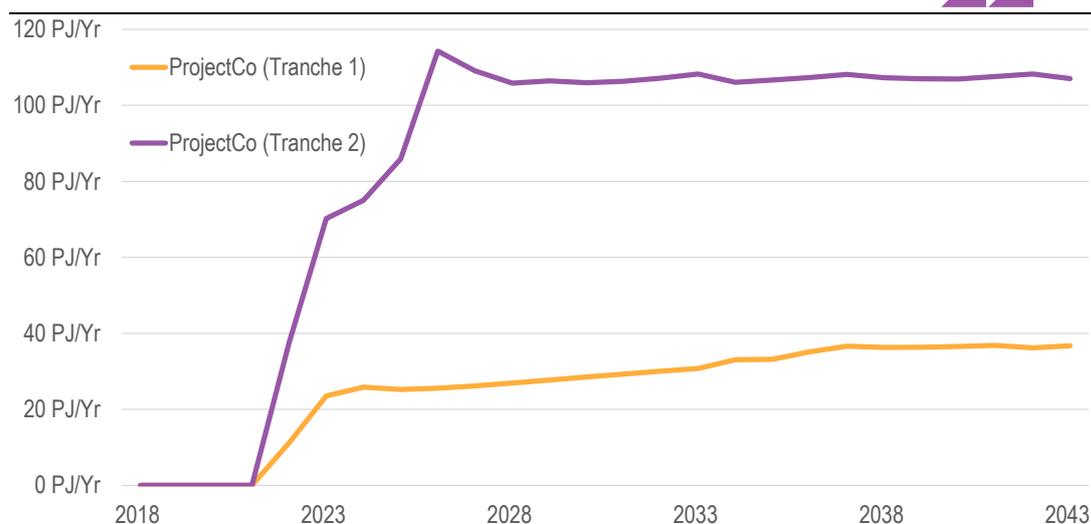
For purposes of the reporting, the economic impact of ProjectCo and PipelineCo will be referred to as the “Onshore Unconventional Gas Industry” or “the Industry”.

The economic impact of the development of the Industry under the WIND development scenario, as detailed in Section 4.3.3, was assessed using ACIL Allen’s *Tasman Global* CGE model. Further details on *Tasman Global* are presented in Appendix E.

10.1 Scenario description

As discussed in Section 4.3.3, under the WIND development scenario, the target production rate increases to 400TJ/day. The majority of gas under this scenario is placed into the East Coast market, requiring additional pipeline infrastructure to be developed as the capacity of the existing NGP is reached. Pipeline-related assumptions are outlined in Section 3.5.1.

The production profile of Industry in the WIND scenario, relative to the BREEZE scenario, is presented in Figure 10.1.

FIGURE 10.1 GAS PRODUCTION, WIND SCENARIO, PJ/ANNUM

SOURCE: ACIL ALLEN CONSULTING

Under the WIND development scenario, the following investment into transmission gas pipelines is also assumed to occur:

- tie into Amadeus pipeline;
- Amadeus duplication;
- National Gas Pipeline duplication; and
- Carpentaria Gas Pipeline duplication.

These assumption are discussed in Section 4.7.

10.2 Real income

The development of the Industry has a significant impact on the real income of Australia. Real income is a measure of the economic welfare (or standard of living) improvement as a result of the developments. The change in real income captures the effect of net foreign income transfers associated with ownership of the capital along with changes in the purchasing power of Australian residents.

The real income impact of the Industry is largely accrued through the profits generated by the Industry once it is operational, which also determines the level of profits based taxation paid by the Industry. Overall, the majority of the real income impact of the development under the WIND scenario is transferred from the Northern Territory to the Rest of Australia, in the form of Commonwealth Government taxes and because the equity ownership of the Industry is assumed to be largely on the east coast of Australia.

Real income impacts are still realised in the Territory, through increased employment and a redistribution of the profits based taxation payments from the Commonwealth back to the Territory. Royalty and payroll taxation payments made to the Northern Territory Government and payments made to pastoralists and native title owners also contribute to the real income impact in the Territory.

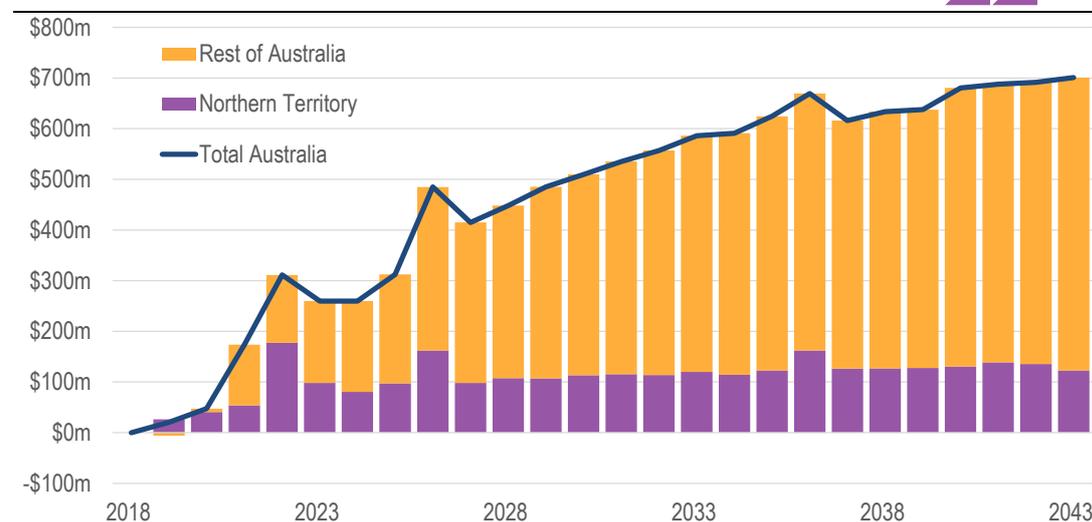
In total, the real income impact of the Industry is estimated to total \$11.9 billion at an average of \$459 million per annum over the study period (refer to Figure 10.2). The real income impact reaches a steady state of around \$690 million per annum in 2040.

Over the study period, the real income impact in the Northern Territory is estimated to total \$2.8 billion, at an average of \$108 million per annum. Real incomes are expected to peak at \$177 million in 2022, which coincides with peak employment and peak wages growth in the Territory. Once the Industry reaches its steady state level of production, the real income impact in the Territory

averages around \$130 million per annum, with further boosts in 2026 and 2036 as a result of investment in to transmission gas pipelines.

The real income impact is largely felt on the east coast of Australia, which is estimated to total \$9.1 billion at an average of \$351 million per annum over the study period. Real incomes are expected to peak in 2043 at \$578 million, when the Industry is at a steady state of production.

FIGURE 10.2 WIND REAL INCOME, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION



SOURCE: ACIL ALLEN CONSULTING

10.3 Real output

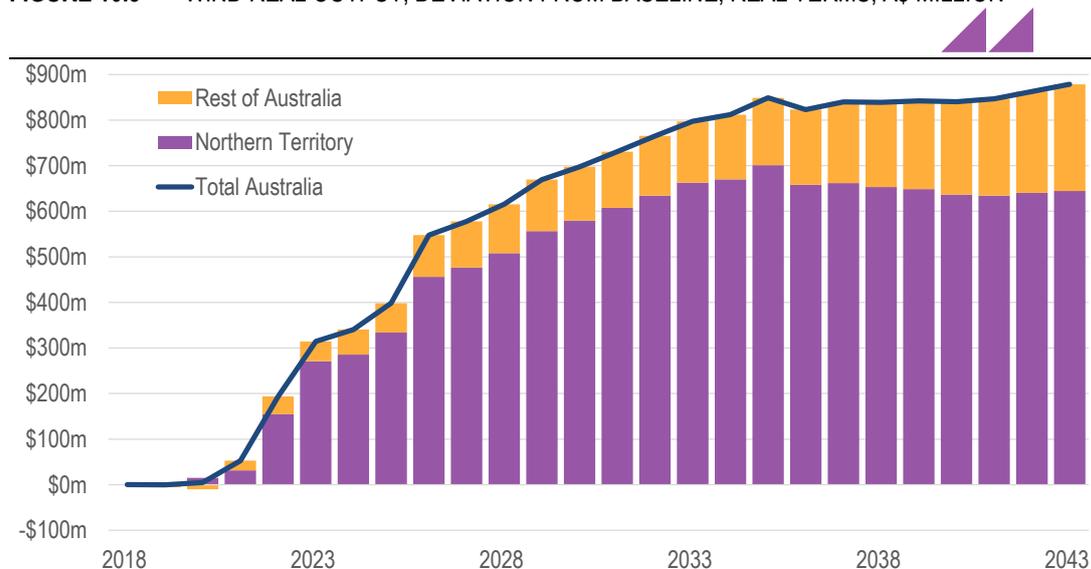
The real output impact is largely accrued through the impact the Industry has on investment in the Northern Territory and the value of the gas exported from the Territory to the Rest of Australia. The real output impact of the Industry is different to the real income impact because, in an output sense, the value of the gas exported is realised in the Territory, whereas in an income sense, the value of the gas exported is realised through profits generated and taxation payments, which largely accrue on the east coast of Australia.

Under the WIND development scenario, real output is estimated to total \$15.1 billion at an average of \$582 million per annum over the study period (refer to Figure 10.3). The real output impact reaches a steady state of around \$846 million per annum in 2036.

Over the study period, the real output impact in the Northern Territory is estimated to total \$12.1 billion, at an average of \$466 million per annum. Real output is expected to increase over the study period in line with the increase in the level of production. At steady state production in 2037, output in the Territory is estimated to average \$646 million per annum.

Relative to the size of the Northern Territory's economy, the increase in real output from the development of the Industry represents a boost to Gross Territory Product of 0.31 per cent in 2037, once the level of real output reaches a steady state.

Across the Rest of Australia, the real output impact is largely driven by an increase to consumption by the household sector, as a result of the rising real incomes from the development on the Rest of Australia. Over the study period, it is estimated the real output impact on the Rest of Australia will total \$406 million at an average of \$15.6 million per annum.

FIGURE 10.3 WIND REAL OUTPUT, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION

SOURCE: ACIL ALLEN CONSULTING

10.3.1 Real Final Demand

Final Demand is the component of real output that accounts for all domestic economic activity. As it does not include exports or imports, the magnitude and timing of the impacts on Final Demand differ from the broader measure of real output.

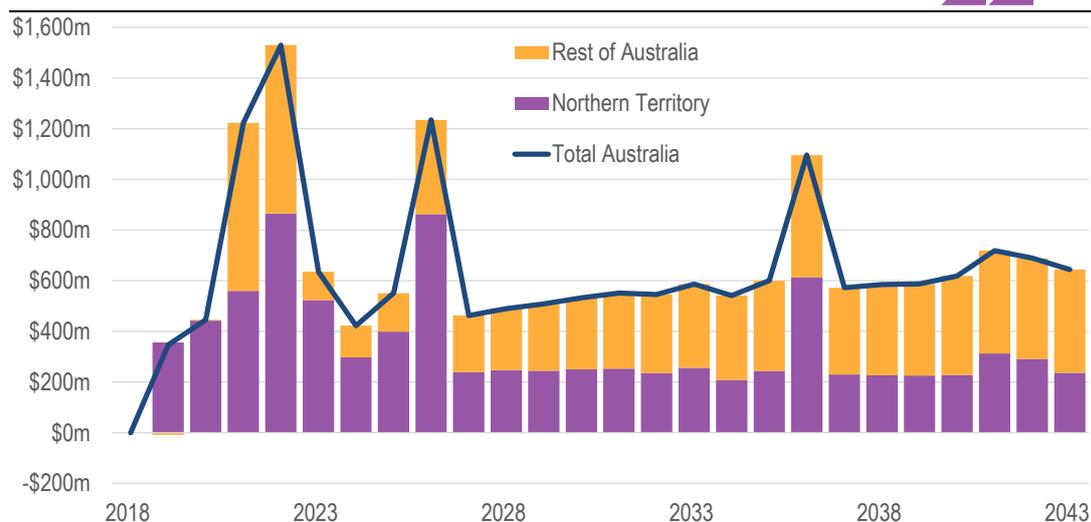
The real Final Demand impact of development under the WIND scenario in the Northern Territory is largely accrued through the investment needed to fund the Industry's capital requirements and the additional investment needed for transmission gas pipelines. For the Rest of Australia the impact largely results from the household consumption impacts that are accrued from rising real incomes resulting from the development, as well as further investment in transmission gas pipelines in Eastern Australia.

In total, the real Final Demand impact of development under the WIND scenario is estimated to total \$16.7 billion at an average of \$643 million per annum over the study period (refer to Figure 10.4).

Real Final Demand in the Territory is expected to peak at \$865 million in 2022, during the Industry's capital intensive development phase and transmission pipeline construction. Over the study period, the Final Demand impact is estimated to total \$8.9 billion at an average of \$340 million per annum.

Throughout the Rest of Australia, the real Final Demand impact of the Industry is more significant than the impact under the BREEZE development scenario, due to the estimated increase in household consumption and also the construction of transmission gas pipelines on the east coast of Australia. Over the study period, the Final Demand impact is estimated to total \$7.9 billion at an average of \$303 million per annum.

FIGURE 10.4 WIND REAL FINAL DEMAND, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION



SOURCE: ACIL ALLEN CONSULTING

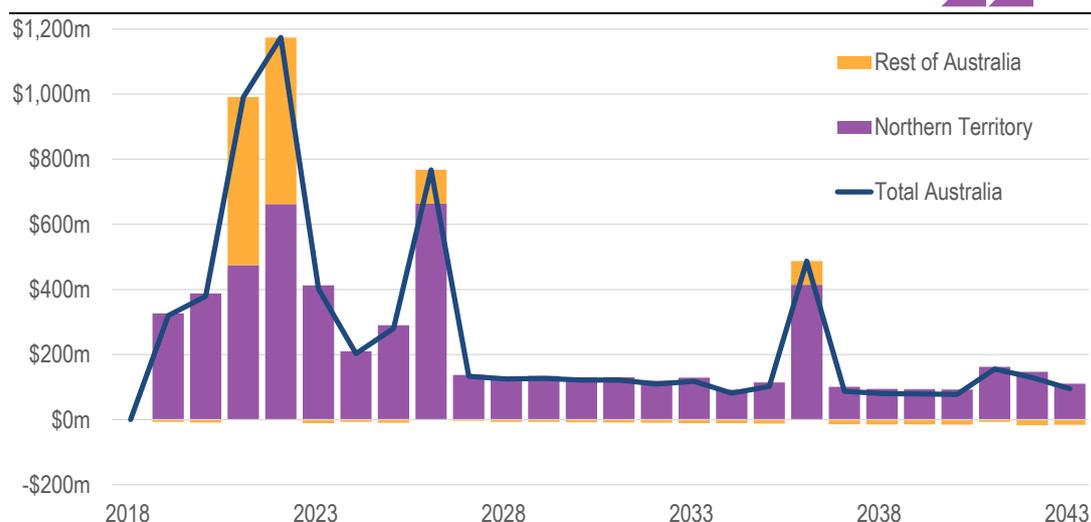
Real investment

In the Northern Territory, the major component of the Industry’s real Final Demand impact is in relation to investment, and is the result of the ongoing capital intensive nature of unconventional shale gas developments.

In total, the real investment impact of the Industry is estimated to total \$6.7 billion at an average of \$259 million per annum over the study period (refer to Figure 10.5). Real investment peaks in 2022 during the development of the Industry and construction of the transmission gas pipelines at \$1.5 billion.

Following the capital intensive initial production phase of the Industry, the real investment reduces as less capital is required to reach the target production level. Over the study period, real investment in the Territory is estimated to total \$5.8 billion at an average of \$222 million per annum.

FIGURE 10.5 WIND REAL INVESTMENT, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION



SOURCE: ACIL ALLEN CONSULTING

Across the Rest of Australia, a small boost to real investment is realised through the construction of gas transmission pipelines. However, ACIL Allen also estimates that as a result of a reallocation of

labour resources to the Northern Territory, real investment falls in most years through the study period across the Rest of Australia. The impact on real investment throughout the Rest of Australia increases by \$983 million at an average of \$37.8 million per annum over the study period.

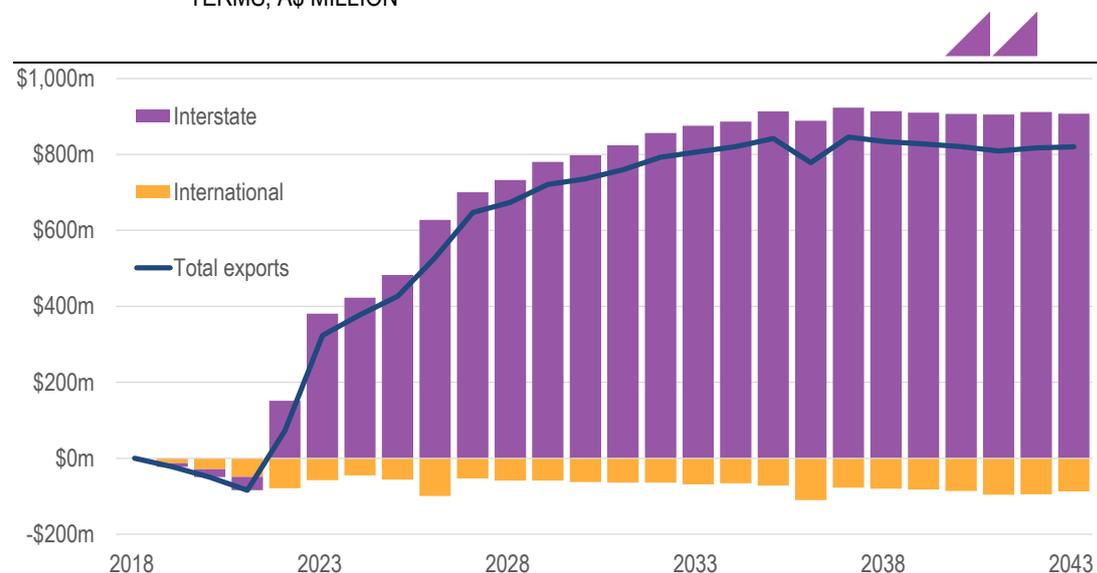
10.3.2 Real exports

The impact the Industry has on the Northern Territory's real exports is the other main driver of the impact on the Territory's real output. While gas is not exported to international markets under the WIND development scenario, it is exported from the Territory to the Rest of Australia (specifically the east coast of Australia).

Over the study period, the development is estimated to increase real exports by \$14.9 billion at an average of \$574 million per annum (refer to Figure 10.6). The increase in real exports is driven by the boost to interstate exports (\$16.6 billion over the study period or \$640 million per annum), which offsets the small decrease in international exports resulting from the impact of an expected appreciation in the Australian Dollar (\$1.7 billion over the study period or \$65.7 million per annum).

Once a steady state of real exports is reached in 2037, it is estimated that the exports generated by the Industry under the WIND development scenario would account for 4.4 per cent of the Territory's total exports.

FIGURE 10.6 WIND NORTHERN TERRITORY REAL EXPORTS, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION



SOURCE: ACIL ALLEN CONSULTING

10.4 Real output – industry

Figure 10.7 displays the impact the Industry has on the real output by industry in the Northern Territory. Under the WIND development scenario, the largest impact will be realised in the Petroleum industry, given that the Industry would be captured under this industry classification. It is estimated that the Petroleum industry will generate growth over and above the base case of 5.7 per cent per annum on average over the study period.

The Construction Services industry is also expected to increase over the study period, averaging growth of 0.9 per cent per annum. The majority of this growth will be realised in the early stages of the Industry's development, with growth expected to peak at 3.3 per cent in 2022.

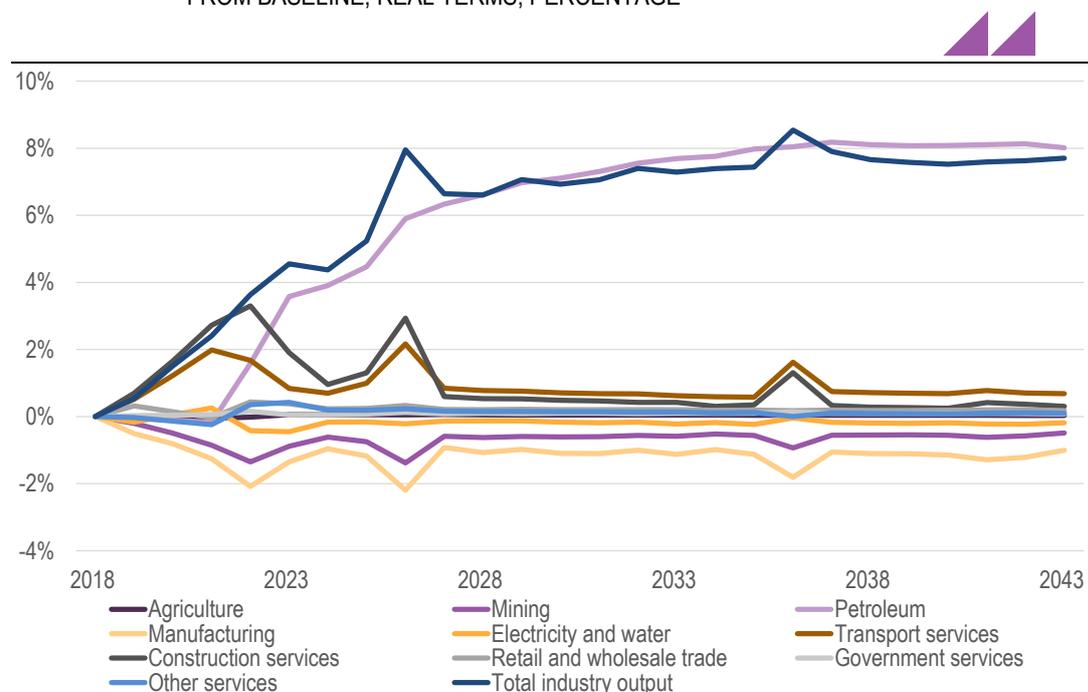
The Transport Services industry is also estimated to follow a similar trend, growing on average by 0.9 per cent per annum and peaking at two per cent in 2021, relative to the base case.

The Manufacturing industry is estimated to contract on average by 1.1 per cent per annum over the study period. This reflects the impact of an appreciation in the Australian Dollar on the global

competitiveness of export competing businesses in the Territory. In addition, a reallocation of labour away from the Manufacturing industry to the Petroleum industry results in lower output from the industry. A similar impact occurs in the Mining and Electricity and Water industries, which are estimated to contract on average by 0.6 per cent and 0.2 per cent per annum over the study period.

Across all industries, the development of the Industry in the Territory will have a marginal impact on the growth across most industries. Overall, industry growth is estimated to be six per cent per annum higher than what would otherwise have occurred, if the development of the Industry did not occur.

FIGURE 10.7 WIND NORTHERN TERRITORY REAL OUTPUT BY INDUSTRY, PERCENTAGE CHANGE FROM BASELINE, REAL TERMS, PERCENTAGE



SOURCE: ACIL ALLEN CONSULTING

10.5 Labour market

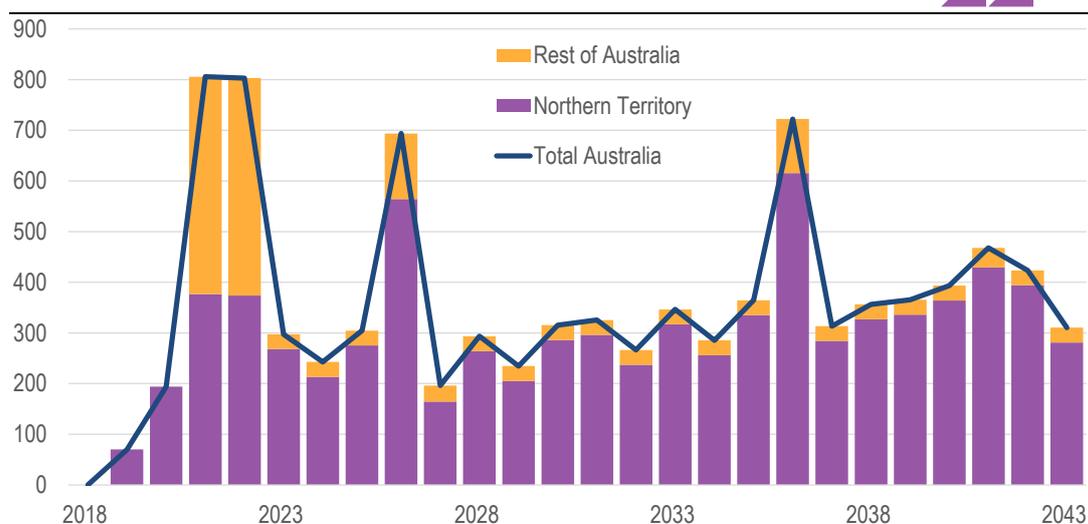
10.5.1 Employment

The development of a new industry in the Territory under the WIND development scenario has significant workforce implications. The largest component of the Industry’s direct workforce is the staff required to operate the wells and pads. Staff required to operate additional transmission gas pipelines also has a significant impact of direct employment in the Rest of Australia.

The ‘peaking’ nature of the FTE requirements presented in Figure 10.8 is a result of the timing of the construction workforce requirements. Labour required for the construction of gas transmission pipelines in the Territory in 2021, 2022, 2026 and 2036 also contributes to this ‘peaking’ nature, but on a smaller scale.

Over the study period, it is estimated the development of the Industry will require direct employment of 7,730 FTE jobs at an average of 297 FTE jobs per annum in the Territory. The majority of these FTE jobs are in relation to the construction and operations of the Industry (total of 5,905 FTE jobs at an average of 227 FTE jobs per annum), while a total of 1,824 FTE jobs (average of 70 FTE jobs per annum) are in relation to the construction and operations of transmission pipes.

Throughout the Rest of Australia, the construction and operations of transmission gas pipelines will require direct employment of 1,663 FTE jobs at an average of 63.9 FTE jobs per annum.

FIGURE 10.8 WIND DIRECT EMPLOYMENT, DEVIATION FROM BASELINE, REAL TERMS, FTES, THOUSANDS

SOURCE: ACIL ALLEN CONSULTING

However, the total employment impact of the Industry development under the WIND scenario is minimal, due to the resulting draw on labour from other industries in the Territory and other parts of Australia.

Over the study period, the Industry is estimated to create 6,559 FTE direct and indirect FTE jobs at an average of 252 FTE jobs per annum in the Northern Territory. However, ACIL Allen estimates that these positive impacts will be completely offset by the reallocation of employment from the Rest of Australia to the Territory.

10.5.2 Industry real employment

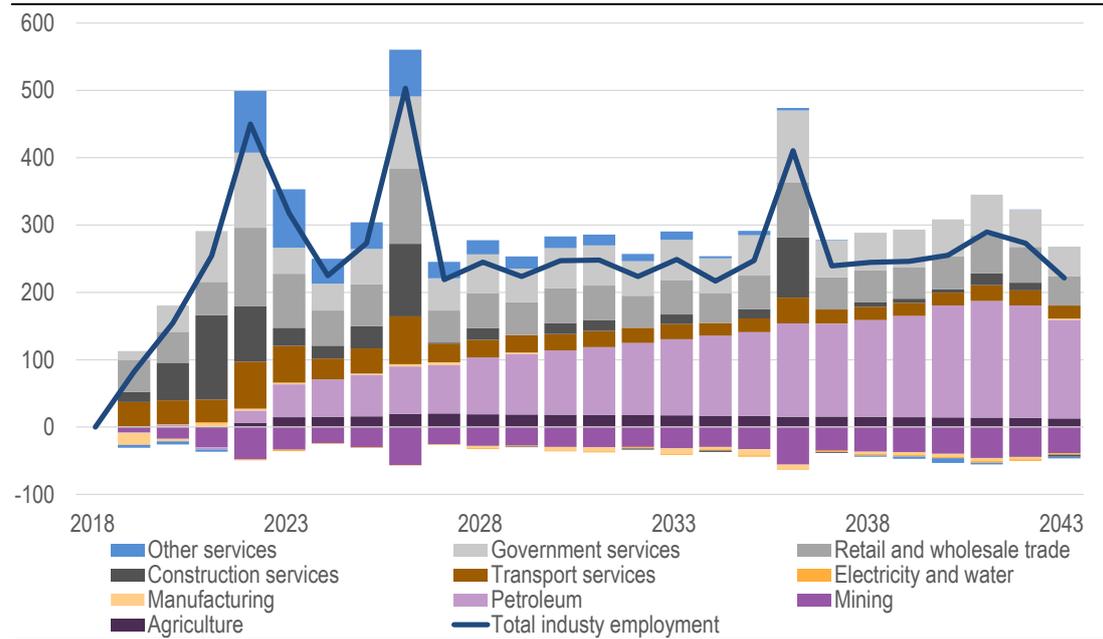
While the development of the Industry under the WIND development scenario results in the reallocation of some labour resources from other industries, on average the real employment impact is significantly positive for the Territory (refer to Figure 10.9).

Over the study period, the Petroleum industry is estimated to see the largest real employment impact, with the creation of 2,384 FTE jobs at an average of 92 FTE jobs per annum. Significant gains are also estimated in the Retail and Wholesale Trade industry, with a total of 1,437 FTE jobs at an average of 55 FTE jobs per annum to be created, as a result of increased household consumption in the Territory.

The Government Service industry (1,461 FTE jobs at an average of 56 FTE jobs per annum), Transport Services industry (765 FTE jobs at an average of 29 FTE jobs per annum) and Construction Services industry (671 FTE jobs at an average of 26 FTE jobs per annum) are also estimated to see solid employment gains over the study period under the WIND development scenario.

The majority of the labour reallocation, as a result of the development of the Industry, is estimated to occur in Mining (loss of 843 FTE jobs at an average of 32 FTE jobs per annum), Manufacturing (loss of 56 FTE jobs at an average of two FTE jobs per annum) and Electricity and Water (loss of 34 FTE jobs at an average of one FTE jobs per annum).

FIGURE 10.9 WIND NORTHERN TERRITORY DIRECT AND INDIRECT EMPLOYMENT BY INDUSTRY, DEVIATION FROM BASELINE, REAL TERMS, FTES, THOUSANDS



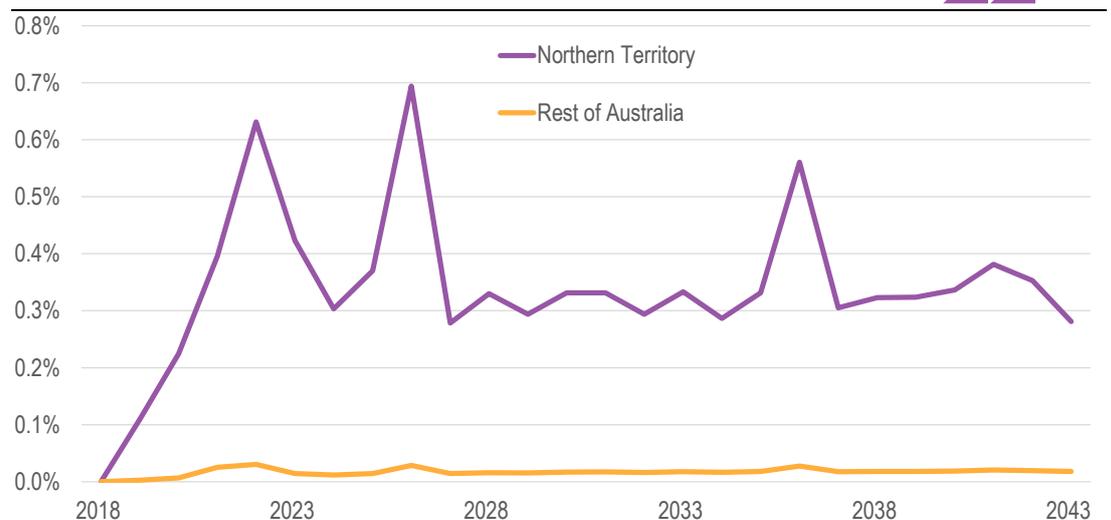
SOURCE: ACIL ALLEN CONSULTING

10.5.3 Real wages

The development of the Industry is estimated to boost real wages in the Northern Territory relative to the Rest of Australia (refer to Figure 10.10).

Over the study period, the increase in real wages is estimated to be on average 0.34 per cent per annum higher than the base case, peaking at 0.69 per cent in 2026 when the demand for labour in the Territory is at its highest. The impact across the Rest of Australia is negligible over the study period, given that there is no net job creation under the WIND scenario.

FIGURE 10.10 WIND REAL WAGE GROWTH, DEVIATION FROM BASELINE, REAL TERMS, PERCENTAGE



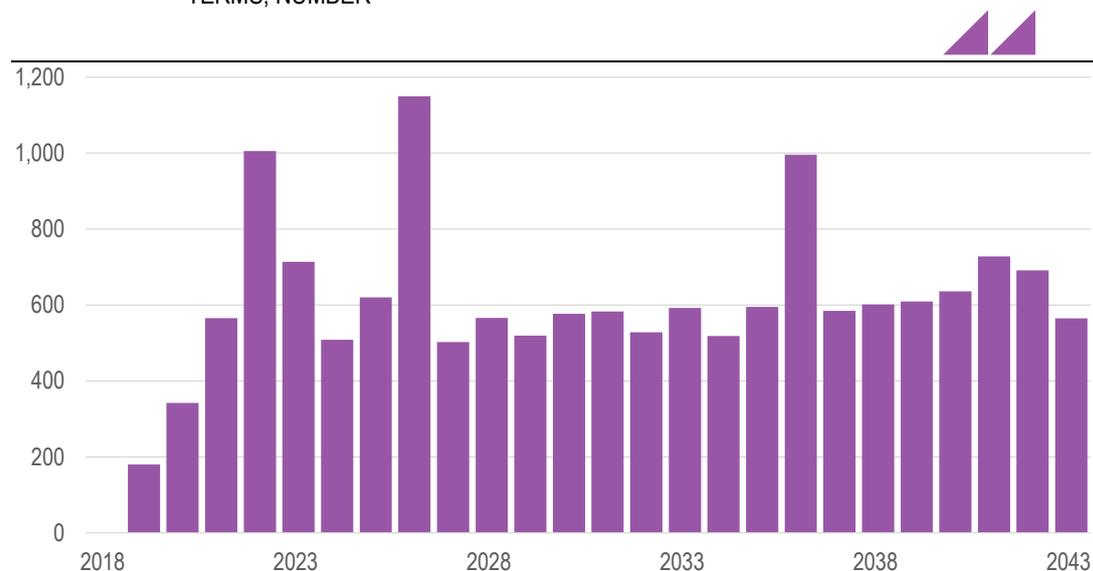
SOURCE: ACIL ALLEN CONSULTING

10.6 Population

The population of the Northern Territory, resulting from the development of the Industry under the WIND scenario, is largely driven by interstate migration as workers and their families relocate to the Territory to take up employment opportunities created by the development of the Industry.

Over the study period, it is estimated the population in the Northern Territory will increase by an average of 595 persons per annum. The population impact peaks during the capital intensive construction phase of the development of the Industry at 1,005 persons in 2022.

FIGURE 10.11 WIND NORTHERN TERRITORY REAL POPULATION, DEVIATION FROM BASELINE, REAL TERMS, NUMBER



SOURCE: ACIL ALLEN CONSULTING

10.7 Real taxation

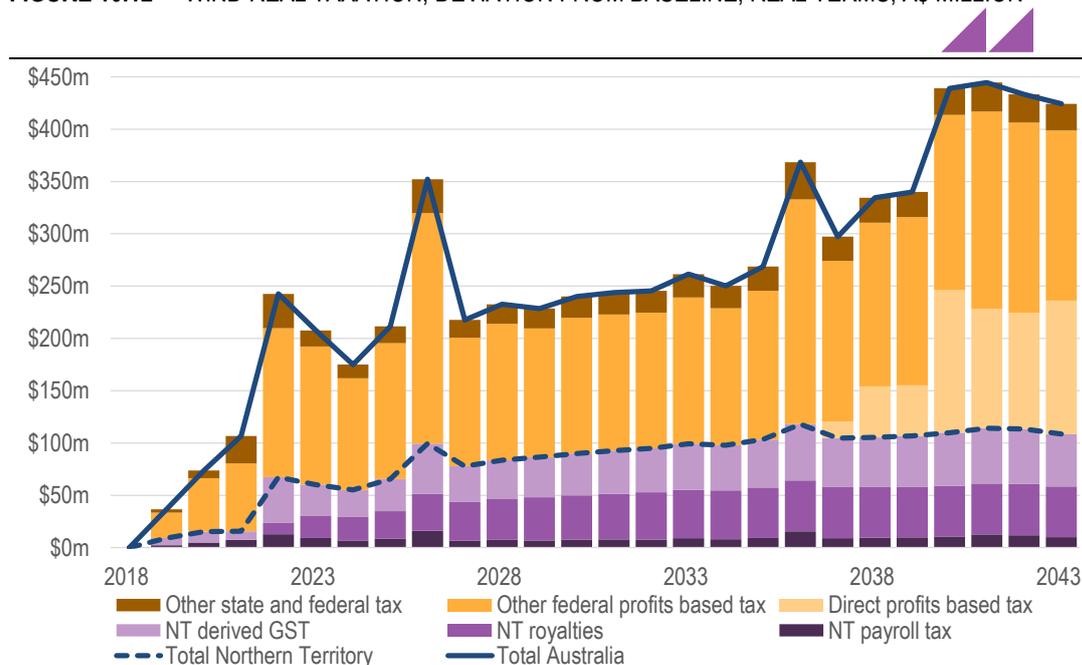
The development of the Industry under the WIND scenario will generate significant taxation benefits to the Northern Territory and the Commonwealth Government, primarily in the form of profits based taxes, royalty revenues, payroll tax and a range of other taxes.

Over the study period, payments to the Commonwealth are projected to be substantial (refer to Figure 10.12). ACIL Allen estimates that the direct profits based taxation payments from the Industry would total \$602 million at an average of \$23.2 million per annum over the study period. There will also be significant indirect taxation payments collected by the Commonwealth, with payments totalling \$3.4 billion at an average of \$132 million per annum.

The development of the Industry is estimated to generate other indirect taxation payments to the Commonwealth (such as personal income, excises, fringe benefits and capital gains tax receipts), totalling \$542 million at an average of \$20.8 million per annum.

Payments made to the Territory Government are expected to be largely accrued through royalty payments, which are estimated to total \$895 million at an average of \$34.4 million per annum over the study period. Direct and indirect payroll taxation payments to the Territory Government due to the development of the Industry are estimated to total \$227 million at an average of \$8.7 million per annum over the study period.

Increased commercial activity in the Territory is also estimated to result in GST revenues increasing by \$973 million at an average of \$37.4 million per annum over the study period.

FIGURE 10.12 WIND REAL TAXATION, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION

SOURCE: ACIL ALLEN CONSULTING

10.8 Summary

Table 10.1 presents a summary of the economic modelling results presented in the section.

TABLE 10.1 WIND DEVELOPMENT SCENARIO, SUMMARY OF ECONOMIC IMPACT RESULTS

	Total	Average	NPV (7 per cent)
Real income			
Northern Territory	\$2,818.1m	\$108.4m	\$1,116.2m
Rest of Australia	\$9,120.0m	\$350.8m	\$3,074.0m
Total Australia	\$11,938.1m	\$459.2m	\$4,190.2m
Real output			
Northern Territory	\$12,126.1m	\$466.4m	\$4,178.0m
Rest of Australia	\$3,011.7m	\$115.8m	\$958.6m
Total Australia	\$15,137.8m	\$582.2m	\$5,136.6m
Real Final Demand			
Northern Territory	\$8,851.0m	\$340.4m	\$4,351.2m
Rest of Australia	\$7,869.6m	\$302.7m	\$3,127.5m
Total Australia	\$16,720.6m	\$643.1m	\$7,478.7m
Real investment			
Northern Territory	\$5,759.1m	\$221.5m	\$3,098.7m
Rest of Australia	\$983.0m	\$37.8m	\$754.0m
Total Australia	\$6,742.0m	\$259.3m	\$3,852.7m
Northern Territory real exports			

	Total	Average	NPV (7 per cent)
International	-\$1,707.8m	-\$65.7m	-\$658.8m
Interstate	\$16,632.2m	\$639.7m	\$5,657.9m
Total	\$14,924.3m	\$574.0m	\$4,999.1m
Real employment			
Northern Territory	6,559 FTEs	252 FTEs	
Rest of Australia	-6,559 FTEs	-252 FTEs	
Total Australia	0 FTEs	0 FTEs	
Real employment by industry			
Agriculture	345 FTEs	13 FTEs	
Mining	-843 FTEs	-32 FTEs	
Petroleum	2,384 FTEs	92 FTEs	
Manufacturing	-56 FTEs	-2 FTEs	
Electricity and water	-34 FTEs	-1 FTEs	
Transport services	765 FTEs	29 FTEs	
Construction services	671 FTEs	26 FTEs	
Retail and wholesale trade	1,437 FTEs	55 FTEs	
Government services	1,461 FTEs	56 FTEs	
Other services	429 FTEs	17 FTEs	
Total industry employment	6,559 FTEs	252 FTEs	
Real population			
Northern Territory	15,480 persons	595 persons	
Real taxation			
Northern Territory			
Payroll tax	\$227.2m	\$8.7m	\$91.8m
Royalties	\$894.6m	\$34.4m	\$307.5m
Derived GST	\$972.7m	\$37.4m	\$362.7m
Total Northern Territory	\$2,094.4m	\$80.6m	\$762.1m
Commonwealth			
Direct profits based tax	\$602.1m	\$23.2m	\$120.5m
Other federal profits based tax	\$3,437.5m	\$132.2m	\$1,332.6m
Other state and federal tax	\$541.7m	\$20.8m	\$215.8m
Total Commonwealth	\$4,581.3m	\$176.2m	\$1,668.8m
Total Australia	\$6,675.7m	\$256.8m	\$2,430.9m

SOURCE: ACIL ALLEN CONSULTING



11

GALE SCENARIO

This section explores the broader economic impacts of development of an onshore unconventional shale gas industry, as represented in the previous sections as ProjectCo and PipelineCo. The economic impact will be assessed over the period from 2018 to 2043 for the Northern Territory and Rest of Australian economies on the following terms:

- the impact on **real incomes** (a measure of economic welfare or standard of living);
- the impact on **real output** (as measured in terms of Gross Domestic Product, Gross State/Territory Product, National/State Final Demand, Business Investment and Exports),
- the impact on **employment** (as measured on a full time equivalent job basis);
- the impact on **real wages growth**;
- the impact on **population growth**; and
- the impact on **total taxation payments** (those taxes directly paid by the industry, and the indirect taxes paid as a result of the activity generated from the industry).

For purposes of the reporting, the economic impact of ProjectCo and PipelineCo will be referred to as the “Onshore Unconventional Gas Industry” or “the Industry”.

The economic impact of the development of the Industry under the GALE development scenario, as detailed in Section 4.3.4, was assessed using ACIL Allen’s *Tasman Global* CGE model. Further details on *Tasman Global* are presented in Appendix E.

11.1 Scenario description

The Darwin LNG plant (DLNG) is currently supplied feed gas from the Bayu-Undan gas project off the coast of the Northern Territory in the Australia Timor-Leste Joint Petroleum Development Area. DLNG has a single production train⁴¹, producing up to 3.7 million tonnes of LNG per annum for sales to Japan⁴². To produce 3.7 million tonnes of LNG, the plant requires approximately 225 PJ/year of feed gas.

As it stands, Bayu-Undan provides 100 per cent of the feed in gas to the plant. The field is set to reach maturity in 2022-23, and will progressively reduce its production. Unless replacement gas is found, DLNG will cease production some time towards the end of the next decade. Acknowledging this, the owners of the Bayu-Undan joint venture have begun independently investigating new sources of gas for the plant, at this stage focussed on a new large scale offshore development off the coast of the Northern Territory.⁴³

⁴¹ ConocoPhillips. 2017. *Our Business Activities – DLNG*. Accessed online at <http://www.conocophillips.com.au/>

⁴² Santos. 2017. *Bayu-Undan/Darwin LNG Joint Venture*. Accessed online at <http://www.santos.com/>

⁴³ Energy News Bulletin. 2017. *Barossa development begins*. Accessed online at <http://www.energynewsbulletin.net/>

Under the GALE scenario, ACIL Allen assumes the development of an onshore unconventional gas industry is able to build to a scale that would allow it to progressively replace the Bayu-Undan gas field as the feed in gas for DLNG, allowing the existing train to continue production beyond 2022-23 at current rates. This necessitates investment to expand the Amadeus Gas Pipeline to allow more gas to flow north to DLNG.

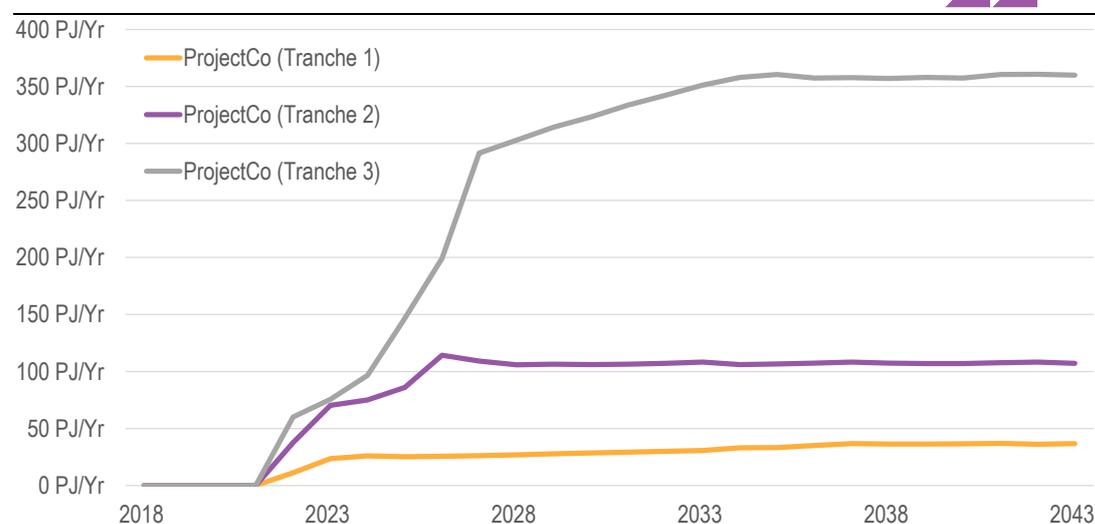
For the purposes of economic modelling, it is assumed that DLNG will continue to produce LNG at its current rate with or without gas from the onshore unconventional gas industry. In the base case, it is assumed one of the new offshore developments discussed above comes to pass and this gas backfills DLNG. This is a critical assumption, as it means there is no incremental value associated with LNG production attributable to onshore unconventional gas industry – the incremental value is any change to the production profile, profitability and local content of gas required to backfill DLNG in an onshore scenario versus an offshore scenario. This is discussed further in Section 6.

It is also assumed that due to increasing scale economies, the cost of production falls below the rate of the WIND scenario, allowing for increased gas sales into the East Coast gas market – potentially including partial backfill of an LNG train at Gladstone – versus the WIND scenario. In any event, the cascading effect of the onshore unconventional gas production results in a reduction in the wholesale price of gas in the East Coast market, with the “ripple” effect of injection of more gas flowing west to east leading to less gas produced in Queensland fields moving south. Similarly to DLNG, there is no incremental value associated with LNG backfill.

As such, this necessitates further investment in the NGP and Carpentaria Gas Pipeline over and above the investment assumed to be required to meet WIND East Coast exports. As a result, the Industry is able to fulfil its full target production of 1000 TJ/day by 2035. Economies of scale in production allowing it to increase its penetration of the East Coast market over the WIND scenario.

The production profile in the GALE scenario is presented in Figure 11.1.

FIGURE 11.1 GAS PRODUCTION, GALE SCENARIO, PJ/ANNUM



SOURCE: ACIL ALLEN CONSULTING

Under the GALE development scenario, the following investment into transmission gas pipelines are also assumed to occur:

- tie into Amadeus pipeline;
- Amadeus duplication;
- National Gas Pipeline duplication;
- Carpentaria Gas Pipeline duplication; and
- construction of DLNG feed pipeline.

These assumption are discussed in Section 4.7.

11.2 Real income

The development of the Industry has a significant impact on the real income of Australia. Real income is a measure of the economic welfare (or standard of living) improvement as a result of the developments. The change in real income captures the effect of net foreign income transfers associated with ownership of the capital along with changes in the purchasing power of Australian residents.

The real income impact of the Industry is largely accrued through the profits generated by the Industry once it is operational, which also determines the level of profits based taxation paid by the Industry. Overall, the majority of the real income impact of the development under the GALE scenario is transferred from the Northern Territory to the Rest of Australia, in the form of Commonwealth Government taxes and given the assumption that the equity ownership of ProjectCo is assumed to be largely on the east coast of Australia.

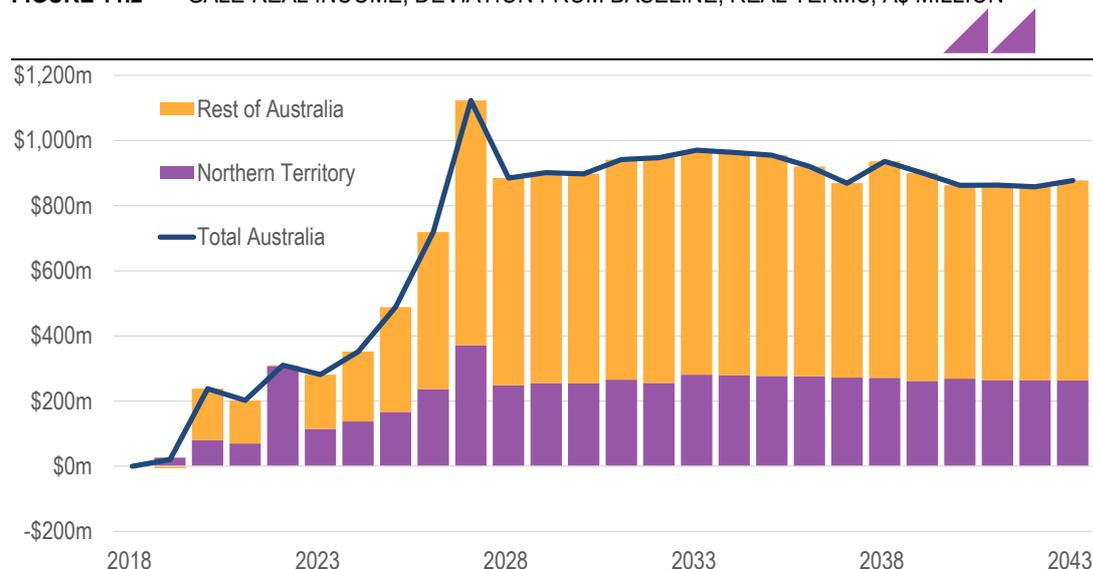
Real income impacts are still realised in the Territory, through increased employment and a redistribution of the profits based taxation payments from the Commonwealth back to the Territory. Royalty and payroll taxation payments made to the Northern Territory Government and payments made to pastoralists and native title owners also contribute to the real income impact in the Territory.

In total, the real income impact of the Industry is estimated to total \$18.3 billion at an average of \$703 million per annum over the study period (refer to Figure 11.2). The real income impact reaches a steady state of around \$909 million per annum in 2028. Importantly, the real income impact under the GALE development scenario does not continue to increase like under the BREEZE and WIND development scenarios, because of the reallocation of feed-in gas to DLNG.

Over the study period, the real income impact in the Northern Territory is estimated to total \$5.8 billion, at an average of \$222 million per annum. Real incomes are expected to peak at \$372 million in 2027, which coincides with peak employment and peak wages growth in the Territory. Once the Industry reaches its steady state level of production in 2037, the real income impact in the Territory averages around \$267 million per annum.

The real income impact is largely felt on the east coast of Australia, which is estimated to total \$12.5 billion at an average of \$481 million per annum over the study period. Real incomes are also expected to peak in 2027 at \$751 million.

FIGURE 11.2 GALE REAL INCOME, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION



SOURCE: ACIL ALLEN CONSULTING

11.3 Real output

The real output impact is largely accrued through the impact the Industry has on investment in the Northern Territory and the value of the gas exported from the Territory to the Rest of Australia. The real output impact of the Industry is different to the real income impact because, in an output sense, the value of the gas exported is realised in the Territory, whereas in an income sense, the value of the gas exported is realised through profits generated and taxation payments, which largely accrue on the east coast of Australia.

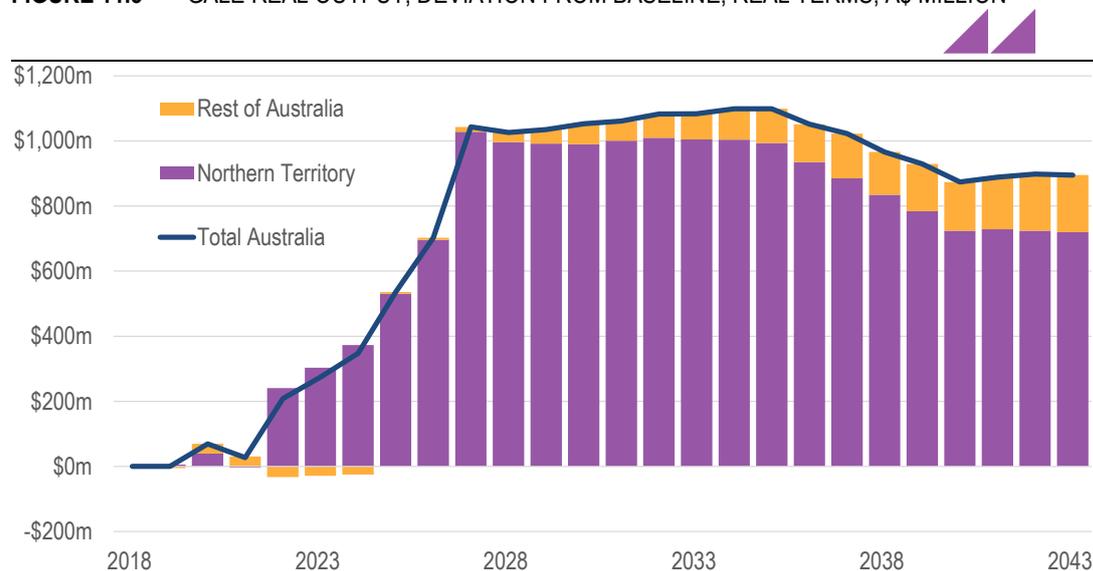
Under the GALE development scenario, real output is estimated to total \$19.3 billion at an average of \$741 million per annum over the study period (refer to Figure 11.3). Between 2027 and 2035 the real output impact average \$1.1 billion per annum, and between 2036 and 2043 the average falls to \$940 million per annum. This is due to a transfer between onshore and offshore gas for feed in stock for DLNG that occurs in 2036, which has no significant net real output impact. The majority of this impact is realised in the Territory.

Over the study period, the real output impact in the Northern Territory is estimated to total \$17.5 billion, at an average of \$674 million per annum. Real output is expected to increase over the study period in line with the increase in the level of production, until 2036 when the transfer between onshore and offshore gas occurs. Between 2027 and 2035 the real output impact average \$1 billion per annum, and between 2036 and 2043 the average falls to \$792 million per annum.

Relative to the size of the Northern Territory's economy, the increase in real output from the development of the Industry represents a boost to Gross Territory Product of 0.66 per cent in 2037. However, the boost to Gross Territory Product peaks at 1.2 per cent in 2027, and at the end of the study period falls to 0.55 per cent.

Across the Rest of Australia, the real output impact is largely driven by an increase to consumption by the household sector, as a result of the rising real incomes from the development on the Rest of Australia. Over the study period, it is estimated the real output impact on the Rest of Australia will total \$1.7 billion at an average of \$66.6 million per annum.

FIGURE 11.3 GALE REAL OUTPUT, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION



SOURCE: ACIL ALLEN CONSULTING

11.3.1 Real Final Demand

Final Demand is the component of real output that accounts for all domestic economic activity. As it does not include exports or imports, the magnitude and timing of the impacts on Final Demand differ from the broader measure of real output.

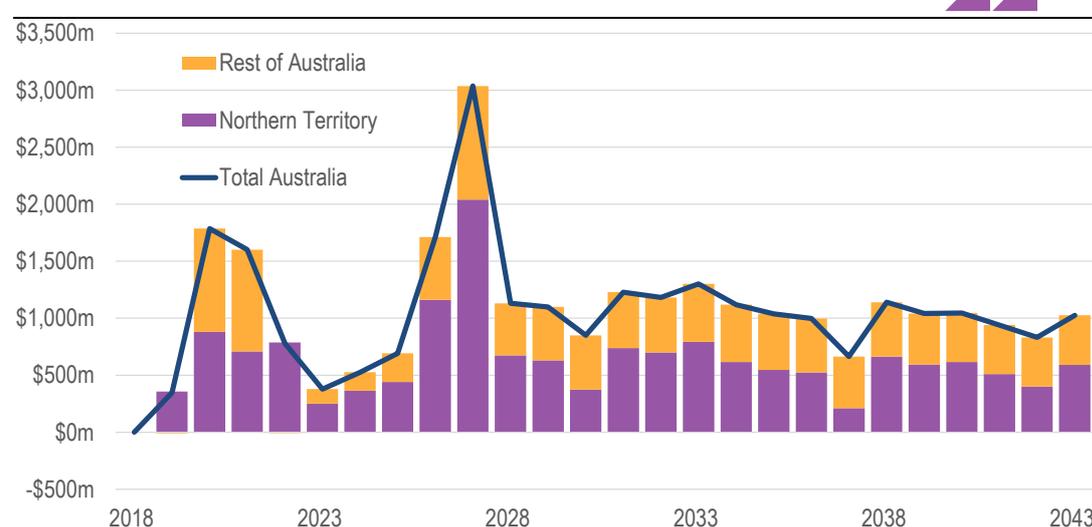
The real Final Demand impact of development under the GALE scenario in the Northern Territory is largely accrued through the investment needed to fund the Industry's capital requirements and investment needed for transmission gas pipelines. For the Rest of Australia the impact largely results from the household consumption impacts that are accrued from rising real incomes resulting from the development, and the additional investment into east coast transmission gas pipelines that is required.

In total, the real Final Demand impact of development under the GALE scenario is estimated to total \$27.5 billion at an average of \$1.1 billion per annum over the study period (refer to Figure 11.4).

Real Final Demand in the Territory is expected to peak at \$2 billion in 2022, during the Industry's capital intensive development phase and transmission pipeline construction. Over the study period, the Final Demand impact is estimated to total \$16.2 billion at an average of \$622 million per annum.

Throughout the Rest of Australia, the real Final Demand impact of the Industry is more significant than the impact under the BREEZE or WIND development scenarios, which is driven by an increase impact to household consumption and also the construction of transmission gas pipelines on the east coast of Australia. Over the study period, the Final Demand impact is estimated to total \$11.3 billion at an average of \$435 million per annum.

FIGURE 11.4 GALE REAL FINAL DEMAND, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION



SOURCE: ACIL ALLEN CONSULTING

Real investment

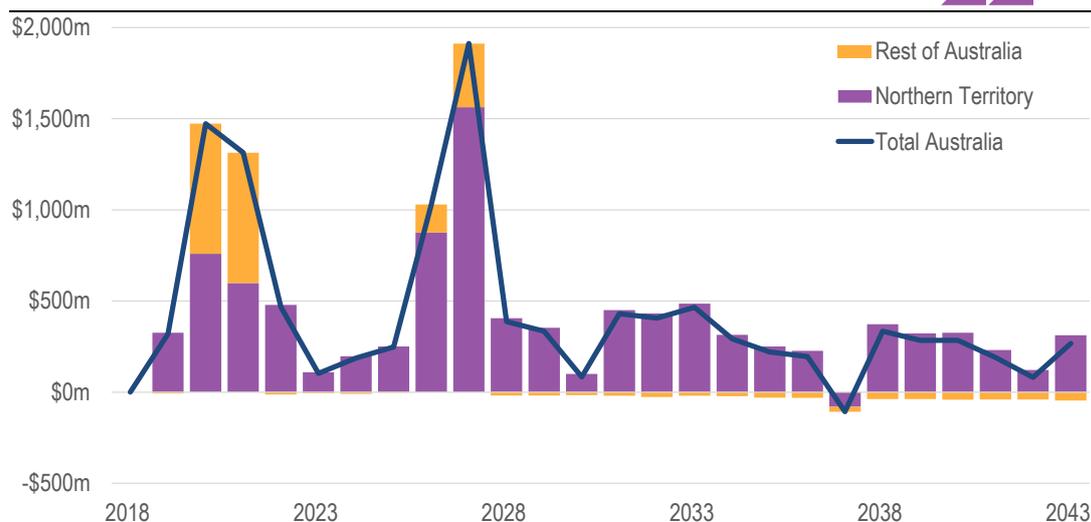
In the Northern Territory, the major component of the Industry's real Final Demand impact is in relation to investment, and is the result of the ongoing capital intensive nature of unconventional shale gas developments.

In total, the real investment impact of the Industry is estimated to total \$11.2 billion at an average of \$376 million per annum over the study period (refer to Figure 11.5). Real investment peaks in 2027 during the development of the Industry and construction of the transmission gas pipelines at \$1.9 billion.

Following the capital intensive initial production phase of the Industry, the real investment reduces as less capital is required to reach the target production level. Over the study period, real investment in the Territory is estimated to total \$9.8 billion at an average of \$376 million per annum.

Across the Rest of Australia, a small boost to real investment is realised through the construction of gas transmission pipelines. However, ACIL Allen also estimates that as a result of a reallocation of labour resources to the Northern Territory, real investment falls in most years through the study period across the Rest of Australia. The impact on real investment throughout the Rest of Australia increases by \$1.4 billion at an average of \$54.6 million per annum over the study period.

FIGURE 11.5 GALE REAL INVESTMENT, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION



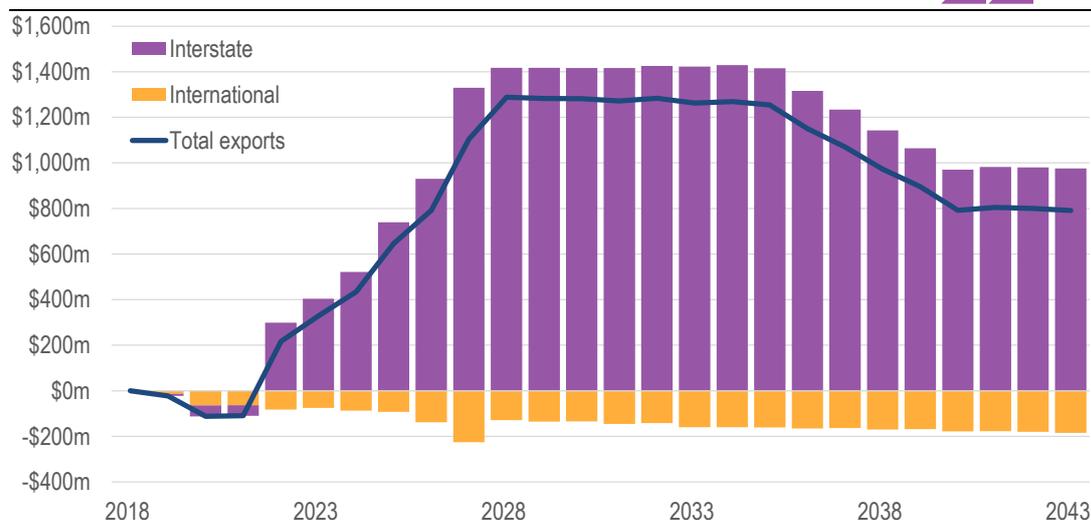
SOURCE: ACIL ALLEN CONSULTING

11.3.2 Real exports

The impact the Industry has on the Northern Territory’s real exports is the other main driver of the impact on the Territory’s real output. The majority of the gas is not exported to international markets under the GALE development scenario, but is exported from the Territory to the Rest of Australia (specifically the east coast of Australia). While some of the onshore stock from the development of the Industry replaces offshore feed-in stock to DLNG for international exports, because onshore gas is replacing offshore gas, the net impact on the value of the Territory’s international exports is zero.

Over the study period, the development is estimated to increase real exports by \$20.7 billion at an average of \$798 million per annum (refer to Figure 11.6). The increase in real exports is driven by the boost to interstate exports (\$24.1 billion over the study period or \$929 million per annum), which offsets the small decrease in international exports resulting from the impact of an expected appreciation in the Australian Dollar (\$3.4 billion over the study period or \$131 million per annum).

FIGURE 11.6 GALE NORTHERN TERRITORY REAL EXPORTS, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION



SOURCE: ACIL ALLEN CONSULTING

Between 2027 and 2035, the value of interstate exports from the Territory average \$1.4 billion per annum, and by 2035 the Industry is estimated will account for 5.6 per cent of the Territory’s exports. As the value of interstate exports falls to an average of \$1.1 billion per annum thereafter, the Industry’s contribution to the Territory’s exports eases slightly to 3.7 per cent of total exports by 2043.

11.4 Real output – industry

Figure 11.7 displays the impact the Industry has on the real output by industry in the Northern Territory. Under the GALE development scenario, the largest impact will be realised in the Petroleum industry, given that the Industry would be captured under this industry classification. It is estimated that the Petroleum industry will generate growth over and above the base case of 10.6 per cent per annum on average over the study period. In 2036 when the offshore feed-in stock for DNLG is replaced by onshore feed-in stock, the growth of the industry is estimated to fall to growth of 8.8 per cent per annum.

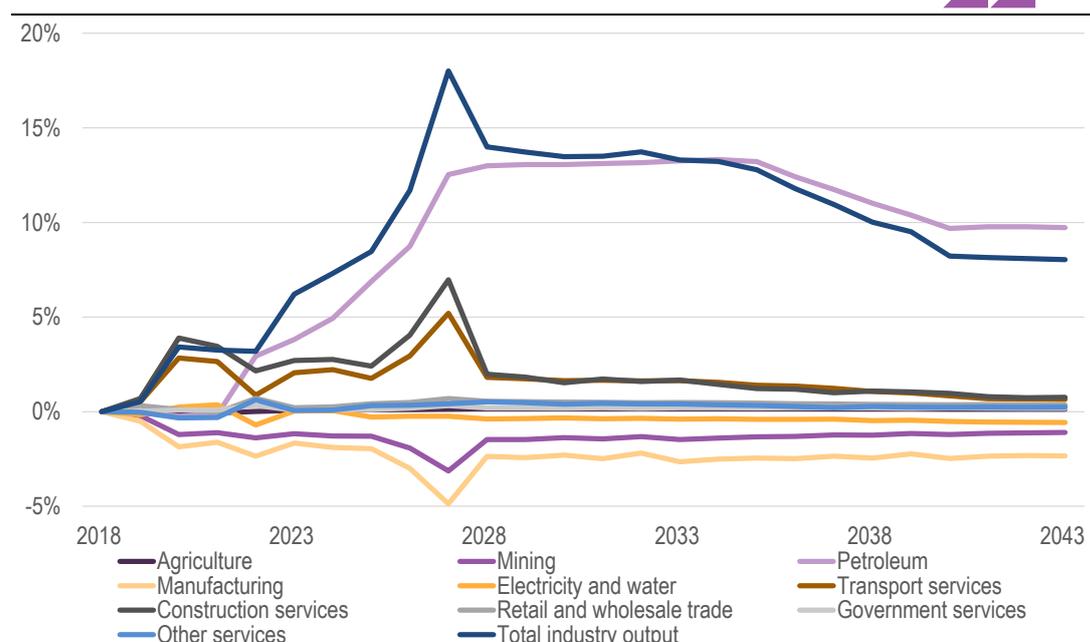
The Construction Services industry is also expected to increase over the study period, averaging growth of 1.9 per cent per annum. The majority of this growth will be realised in the early stages of the Industry’s development, with growth expected to peak at seven per cent in 2027.

The Transport Services industry is also estimated to follow a similar trend, growing on average by 1.6 per cent per annum and peaking at 5.2 per cent in 2027, relative to the base case.

The Manufacturing industry is estimated to contract on average by 2.2 per cent per annum over the study period. This reflects the impact an appreciation in the Australian Dollar has on the global competitiveness of export competing businesses in the Territory. In addition, a reallocation of labour away from the Manufacturing industry to the Petroleum industry results in lower output from the industry. A similar impact occurs in the Mining and Electricity and Water industries, which are estimated to contract on average by 1.3 per cent and 0.3 per cent per annum over the study period.

Across all industries, the development of the Industry in the Territory will have a large impact on the growth across most industries. Overall, industry growth is estimated to be 9.4 per cent per annum higher than what would otherwise have occurred, if the development of the Industry did not occur.

FIGURE 11.7 GALE NORTHERN TERRITORY REAL OUTPUT BY INDUSTRY, PERCENTAGE CHANGE FROM BASELINE, REAL TERMS, PERCENTAGE



SOURCE: ACIL ALLEN CONSULTING

11.5 Labour market

11.5.1 Employment

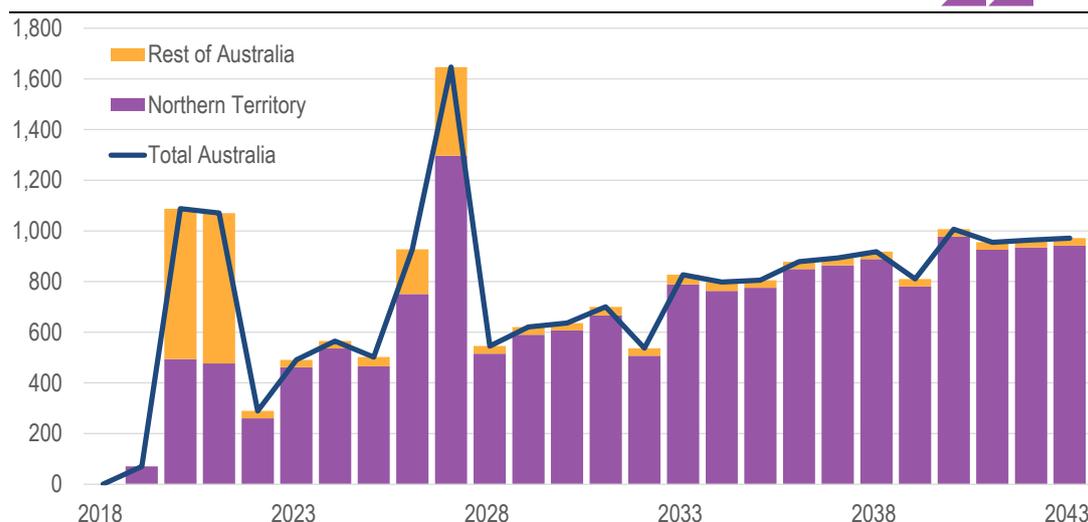
The development of a new industry in the Territory under the GALE development scenario has significant workforce implications. The largest component of the Industry's direct workforce is the staff required to operate the wells and pads. Staff required to operate additional transmission gas pipelines also has a significant impact on direct employment across the Rest of Australia.

The 'peaking' nature of the FTE requirements presented in Figure 11.8 is a result of the timing of the construction workforce requirements. Labour required for the construction of gas transmission pipelines in the Territory in 2021, 2022, 2026 also contributes to this 'peaking' nature, but on a smaller scale.

Over the study period, it is estimated the development of the Industry will require direct employment of 17,187 FTE jobs at an average of 661 FTE jobs per annum in the Territory. The majority of these FTE jobs are in relation to the construction and operations of the Industry (total of 13,300 FTE jobs at an average of 512 FTE jobs per annum), while a total of 3,887 FTE jobs (average of 149 FTE jobs per annum) are in relation to the construction and operations of transmission pipes.

Throughout the Rest of Australia, the construction and operations of transmission gas pipelines will require direct employment of 2,330 FTE jobs at an average of 90 FTE jobs per annum.

FIGURE 11.8 GALE DIRECT EMPLOYMENT, DEVIATION FROM BASELINE, REAL TERMS, FTES, THOUSANDS



SOURCE: ACIL ALLEN CONSULTING

However, the total employment impact of the Industry development under the GALE scenario is minimal, due to the resulting draw on labour from other industries in the Territory and other parts of Australia.

Over the study period, the Industry is estimated to create 13,611 FTE direct and indirect FTE jobs at an average of 524 FTE jobs per annum in the Territory. However, ACIL Allen estimates that these positive impacts will be completely offset by the reallocation of employment from the Rest of Australia to the Territory.

11.5.2 Industry real employment

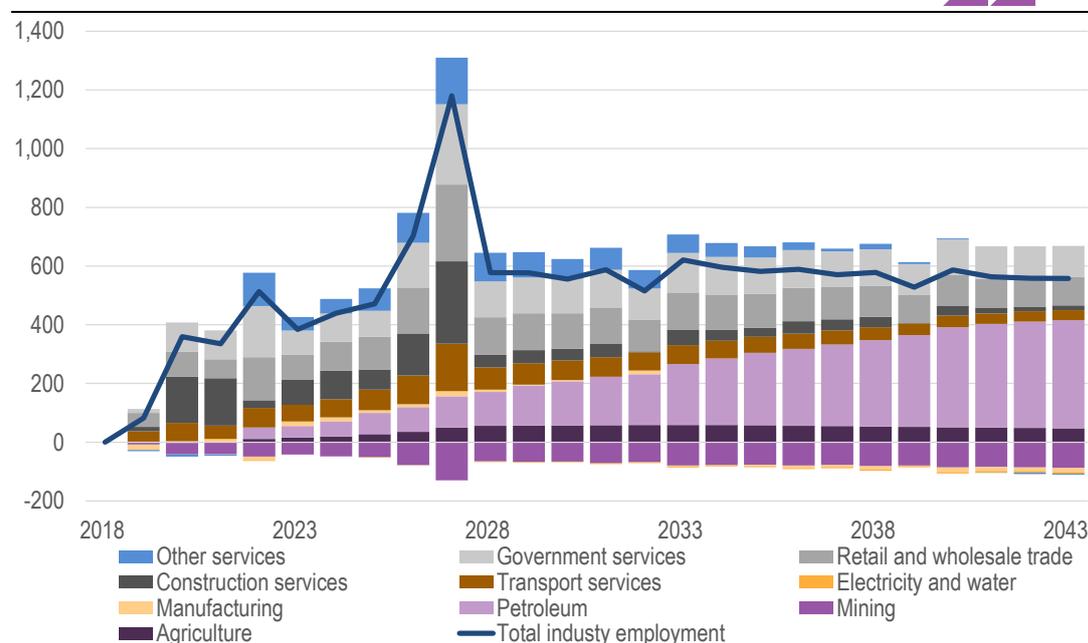
While the development of the Industry under the GALE development scenario results in the reallocation of some labour resources from other industries, on average the real employment impact is significantly positive for the Territory (refer to Figure 11.9).

Over the study period, the Petroleum industry is estimated to see the largest real employment impact, with the creation of 4,384 FTE jobs at an average of 169 FTE jobs per annum. Significant gains are also estimated in the Retail and Wholesale Trade industry, with a total of 2,850 FTE jobs at an average of 110 FTE jobs per annum to be created, as a result of increased household consumption in the Territory.

The Government Service industry (2,985 FTE jobs at an average of 115 FTE jobs per annum), Transport Services industry (1,511 FTE jobs at an average of 58 FTE jobs per annum) and Construction Services industry (1,538 FTE jobs at an average of 59 FTE jobs per annum) are also estimated to see solid employment gains over the study period under the GALE development scenario.

The majority of the labour reallocation, as a result of the development of the Industry, is estimated to occur in Mining (loss of 1,722FTE jobs at an average of 66 FTE jobs per annum), Manufacturing (loss of 18 FTE jobs at an average of one FTE jobs per annum) and Electricity and Water (loss of 62 FTE jobs at an average of two FTE jobs per annum).

FIGURE 11.9 GALE NORTHERN TERRITORY DIRECT AND INDIRECT EMPLOYMENT BY INDUSTRY, DEVIATION FROM BASELINE, REAL TERMS, FTES, THOUSANDS



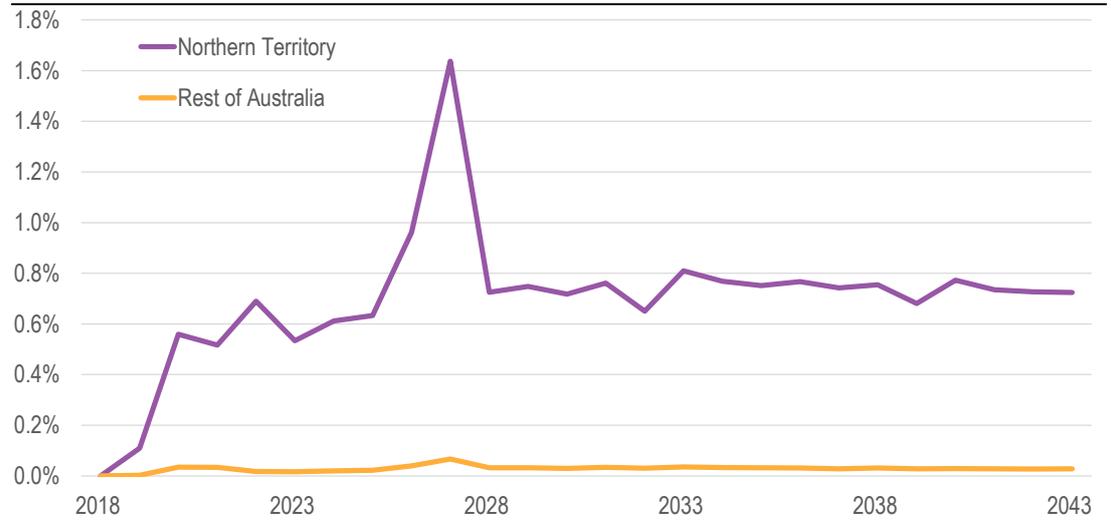
SOURCE: ACIL ALLEN CONSULTING

11.5.3 Real wages

The development of the Industry is estimated to boost real wages in the Northern Territory relative to the Rest of Australia (refer to Figure 11.10).

Over the study period, the increase in real wages is estimated to be on average 0.7 per cent per annum higher than the base case, peaking at 1.6 per cent in 2027 when the demand for labour in the Territory is at its highest. The impact across the Rest of Australia is negligible over the study period, increasing on average by 0.03 per cent per annum over the study period when compared to the base case.

FIGURE 11.10 GALE REAL WAGE GROWTH, DEVIATION FROM BASELINE, REAL TERMS, PERCENTAGE



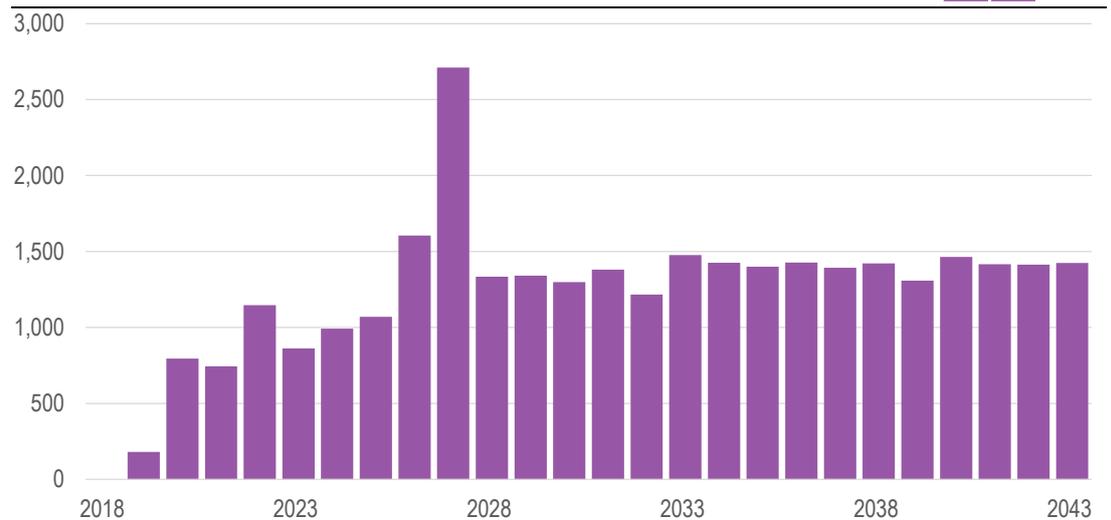
SOURCE: ACIL ALLEN CONSULTING

11.6 Population

The population of the Northern Territory, resulting from the development of the Industry under the GALE scenario, is largely driven by interstate migration as workers and their families relocate to the Territory to take up employment opportunities created by the development of the Industry.

Over the study period, it is estimated the population in the Northern Territory will increase by an average of 1,240 persons per annum. The population impact peaks during the capital intensive construction phase of the development of the Industry at 2,710 persons in 2027.

FIGURE 11.11 GALE NORTHERN TERRITORY REAL POPULATION, DEVIATION FROM BASELINE, REAL TERMS, NUMBER



SOURCE: ACIL ALLEN CONSULTING

11.7 Real taxation

The development of the Industry under the GALE scenario will generate significant taxation benefits to the Northern Territory and the Commonwealth Government, primarily in the form of profits based taxes, royalty revenues, payroll tax and a range of other taxes.

Over the study period, payments to the Commonwealth are projected to be substantial (refer to Figure 11.12). ACIL Allen estimates that the direct profits based taxation payments from the Industry would total \$936 million at an average of \$36 million per annum over the study period.

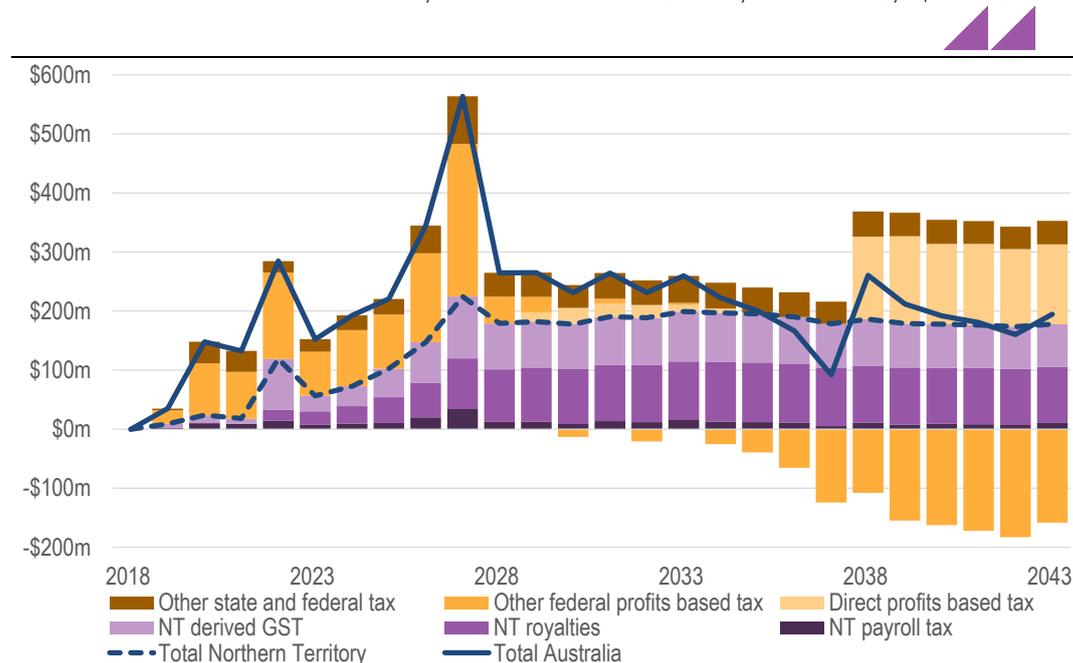
Under the GALE development scenario, when the offshore feed in stock for DNLG is replaced by onshore feed in stock in 2036, indirect profits based taxation payments are reduced because the offshore industry is no longer paying company tax and PRRT. As such, indirect taxation payments collected by the Commonwealth reduce by \$136 million at an average of \$5.3 million per annum over the study period.

The development of the Industry is estimated to generate other indirect taxation payments to the Commonwealth (such as personal income, excises, fringe benefits and capital gains tax receipts), totalling \$950 million at an average of \$36.5 million per annum.

Payments made to the Territory Government are expected to be largely accrued through royalty payments, which are estimated to total \$1.8 billion at an average of \$69 million per annum over the study period. Direct and indirect payroll taxation payments to the Territory Government due to the development of the Industry are estimated to total \$288 million at an average of \$11 million per annum over the study period.

Increased commercial activity in the Territory is also estimated to result in GST revenues increasing by \$1.6 billion at an average of \$63.1 million per annum over the study period.

FIGURE 11.12 GALE REAL TAXATION, DEVIATION FROM BASELINE, REAL TERMS, A\$ MILLION



SOURCE: ACIL ALLEN CONSULTING

11.8 Summary

Table 11.1 presents a summary of the economic modelling results presented in the section.

TABLE 11.1 GALE DEVELOPMENT SCENARIO, SUMMARY OF ECONOMIC IMPACT RESULTS

	Total	Average	NPV (7 per cent)
Real income			
Northern Territory	\$5,777.5m	\$222.2m	\$2,212.9m
Rest of Australia	\$12,508.8m	\$481.1m	\$4,416.6m
Total Australia	\$18,286.3m	\$703.3m	\$6,629.5m
Real output			
Northern Territory	\$17,534.7m	\$674.4m	\$6,298.8m
Rest of Australia	\$1,732.1m	\$66.6m	\$453.6m
Total Australia	\$19,266.9m	\$741.0m	\$6,752.4m
Real Final Demand			
Northern Territory	\$16,173.7m	\$622.1m	\$7,272.4m
Rest of Australia	\$11,320.7m	\$435.4m	\$4,802.4m
Total Australia	\$27,494.4m	\$1,057.5m	\$12,074.8m
Real investment			
Northern Territory	\$9,778.6m	\$376.1m	\$4,768.6m
Rest of Australia	\$1,419.3m	\$54.6m	\$1,233.3m
Total Australia	\$11,198.0m	\$430.7m	\$6,001.9m
Northern Territory real exports			
International	-\$3,395.5m	-\$130.6m	-\$1,261.0m
Interstate	\$24,141.4m	\$928.5m	\$8,590.5m
Total	\$20,745.9m	\$797.9m	\$7,329.6m
Real employment			
Northern Territory	13,611 FTEs	524 FTEs	
Rest of Australia	-13,611 FTEs	-524 FTEs	
Total Australia	0 FTEs	0 FTEs	
Real employment by industry			
Agriculture	1,023 FTEs	39 FTEs	
Mining	-1,722 FTEs	-66 FTEs	
Petroleum	4,384 FTEs	169 FTEs	
Manufacturing	-18 FTEs	-1 FTEs	
Electricity and water	-62 FTEs	-2 FTEs	
Transport services	1,511 FTEs	58 FTEs	
Construction services	1,538 FTEs	59 FTEs	
Retail and wholesale trade	2,850 FTEs	110 FTEs	
Government services	2,985 FTEs	115 FTEs	
Other services	1,124 FTEs	43 FTEs	

	Total	Average	NPV (7 per cent)
Total industry employment	13,611 FTEs	524 FTEs	
Real population			
Northern Territory	32,252 persons	1,240 persons	
Real taxation			
Northern Territory			
Payroll tax	\$288.2m	\$11.1m	\$126.1m
Royalties	\$1,793.8m	\$69.0m	\$606.3m
Derived GST	\$1,640.2m	\$63.1m	\$618.8m
Total Northern Territory	\$3,722.2m	\$143.2m	\$1,351.3m
Commonwealth			
Direct profits based tax	\$935.8m	\$36.0m	\$212.2m
Other federal profits based tax	-\$136.5m	-\$5.3m	\$396.4m
Other state and federal tax	\$950.2m	\$36.5m	\$382.7m
Total Commonwealth	\$1,749.5m	\$67.3m	\$991.3m
Total Australia	\$5,471.6m	\$210.4m	\$2,342.5m
<i>SOURCE: ACIL ALLEN CONSULTING</i>			

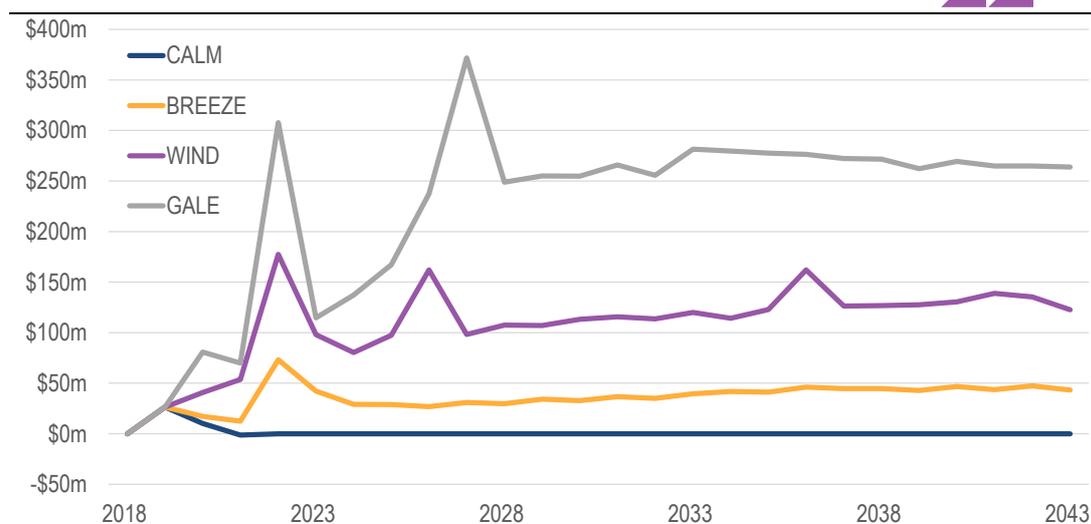


12.1 Economic impact assessment summary

ACIL Allen's economic impact assessment illustrates the potential economic upsides and downsides in the event of small, medium and large scale shale gas industry developments in the Northern Territory, and the flow on effects to the rest of the Australian economy. While the base case and CALM scenarios, where no shale gas industry development occurs, show the Northern Territory economy is set to grow in the years ahead, the development scenario modelling shows the shale gas industry could have an overall net positive impact on the future growth of the Northern Territory economy.

ACIL Allen projects a shale gas industry development could result in a net real income increase of between \$937.2 million (BREEZE), \$2.8 billion (WIND) and \$5.8 billion (GALE) for the Northern Territory over the modelling period, or between \$36 million, \$108.4 million and \$222.2 million per annum. This equates to a net real income per capita increase of \$146, \$439 to \$903 per capita (based on the Northern Territory's 2018 population) over the modelling period. The rest of Australia also sees a lift in real income, of between \$3.4 billion (BREEZE), \$9.1 billion (WIND) and \$12.5 billion (GALE) over the modelling period, on account of the flow on impact of lower gas prices across the economy and the increase in Commonwealth taxes associated with the development (refer to Figure 12.1).

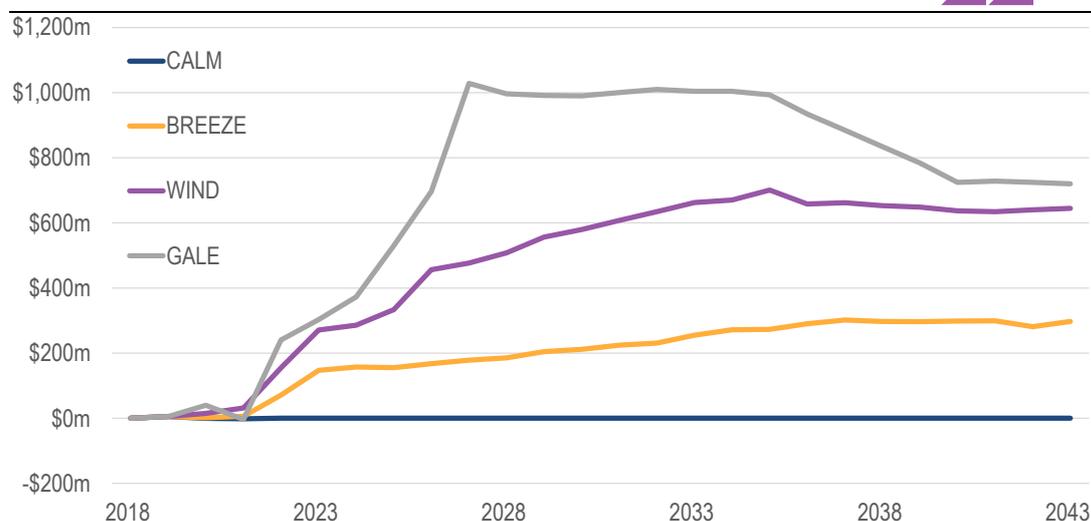
FIGURE 12.1 REAL INCOME, ANNUAL DEVIATION FROM BASE CASE, A\$ MILLION, REAL TERMS



SOURCE: ACIL ALLEN CONSULTING

The net economic benefit to the Northern Territory ranges from \$5.1 billion in the BREEZE scenario (\$196.5m per annum), to \$12.1 billion (\$466.4m per annum) in the WIND scenario, to \$17.5 billion (\$674.4m per annum) in the GALE scenario, in real 2018 dollar terms. In annual average terms, this is the equivalent of an additional 0.8 per cent, 1.9 per cent to 2.9 per cent of the Northern Territory's forecast Gross Territory Product in 2018 (Figure 12.2).

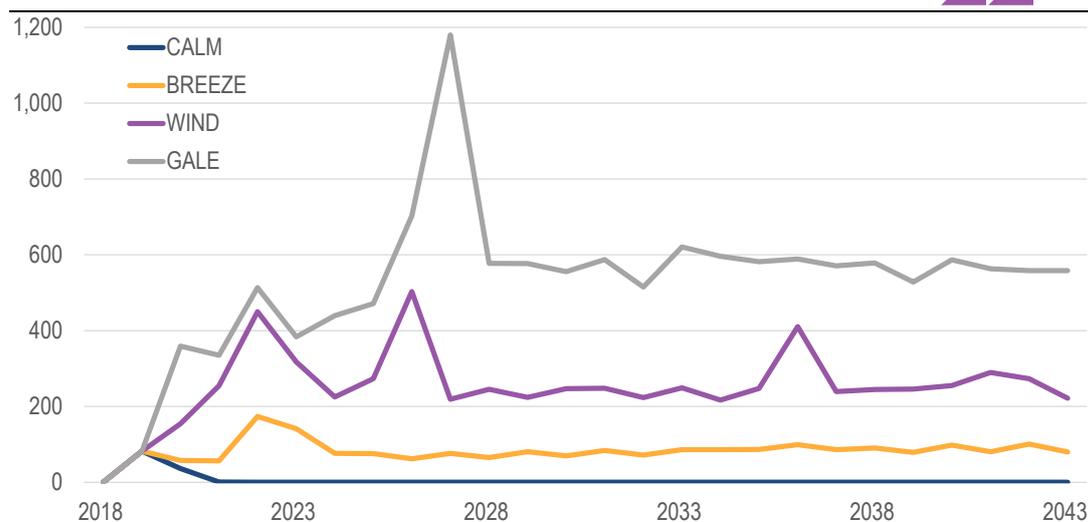
FIGURE 12.2 REAL OUTPUT, ANNUAL DEVIATION FROM BASE CASE, A\$ MILLION, REAL TERMS



SOURCE: ACIL ALLEN CONSULTING

This additional economic activity will generate employment opportunities for Territorians, with an estimated 2,154 FTE job years (BREEZE), to 6,559 FTE job years (WIND) to 13,611 FTE job years (GALE) generated by the various development scenarios over the forecast period – over and above the existing employment growth ACIL Allen has forecast in its base case (Figure 12.3). This equates to between 82 FTEs, 252 FTEs, and 524 FTEs of net employment growth in each year on average. While modest overall, this represents the capital intensive nature of the shale gas industry, and is also a function of ACIL Allen's conservative treatment of employment growth in its modelling activities (see Section 6).

FIGURE 12.3 REAL EMPLOYMENT, FTE JOB YEARS, REAL TERMS, BY SCENARIO

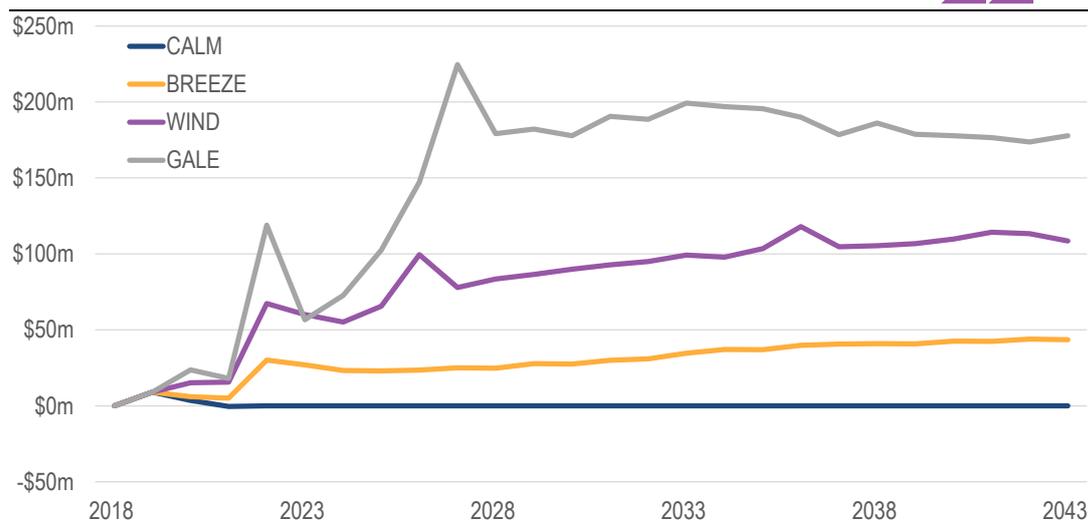


SOURCE: ACIL ALLEN CONSULTING

For Territorians, the primary channel of economic impact that is likely to be felt is the increase to Territory Government revenue. ACIL Allen estimates a successful shale gas industry development could generate between \$757 million (BREEZE), \$2.1 billion (WIND) and \$3.7 billion (GALE) in additional revenue for the Northern Territory Government over the 25 year modelling period, or between \$29.1 million, \$80.6 million, and \$143.2 million per annum (Figure 12.4). In the larger case, this represents a sizeable increase to the Northern Territory’s recurrent revenue base of 2.2 per cent, or more than eight per cent if Commonwealth Government grants are excluded.

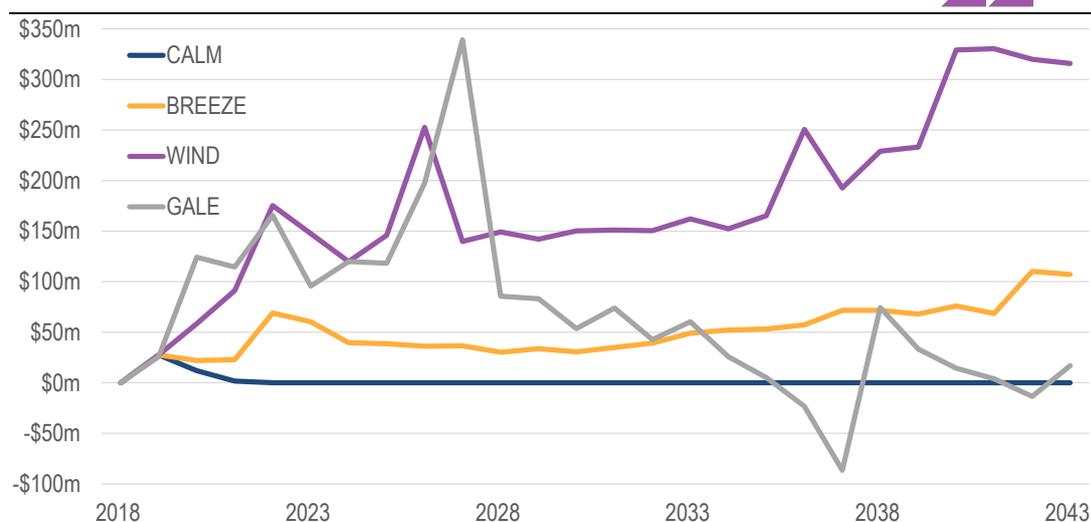
ACIL Allen’s analysis shows a shale gas industry could also deliver windfall growth in Commonwealth revenue, even as the cascading impact of reduced gas prices from the development reduces the income earned by the gas sector outside of the Northern Territory.

FIGURE 12.4 REAL TAXATION, NORTHERN TERRITORY GOVERNMENT, A\$ MILLION, REAL TERMS, BY SCENARIO



SOURCE: ACIL ALLEN CONSULTING

ACIL Allen estimates the Commonwealth Government could expect to raise between \$1.3 billion (BREEZE), \$4.6 billion (WIND), and \$5.5 billion (GALE) in income and profits based taxation over the forecast period, or \$50.2 million, \$176.2 million and \$210.4 million per annum (refer to Figure 12.5).

FIGURE 12.5 REAL TAXATION, COMMONWEALTH GOVERNMENT, A\$ MILLION, REAL TERMS, BY SCENARIO

SOURCE: ACIL ALLEN CONSULTING

As discussed in Section 4, the shale gas industry in the Northern Territory is at such an early stage that the modelling conducted in this engagement is subject to more than usual uncertainty. Below, ACIL Allen has presented the subjective probability matrix prepared to represent the qualitative likelihood of each scale of development occurring (Figure 12.6). This is not an assessment of the commercial prospects of a shale gas industry in the Northern Territory, as ACIL Allen has not been engaged to assess this, and it is too early in the industry's development to make a determination.

FIGURE 12.6 ACIL ALLEN POLICY SCENARIO PROBABILITY MATRIX

INDUSTRY DEVELOPMENT SCENARIO	Production Profile	Production Cost Regime	POLICY SCENARIO PROBABILITY MATRIX		
			PERMANENT MORATORIUM	PARTIAL LIFT	FULL LIFT
BASELINE	Nil Shale Production	N/A	CERTAIN	MODERATE	LOW
SHALE CALM	Exploration occurs Failure to commercialise	N/A	ZERO	VERY HIGH	VERY HIGH
SHALE BREEZE	Scenario 1 Target production: 36PJ per annum	High cost	ZERO	MODERATE	HIGH
SHALE WIND	Scenario 2 Target production: 150PJ per annum	Moderate cost	ZERO	LOW	MODERATE
SHALE GALE	Scenario 3 Target production: 365PJ per annum	Low cost	ZERO	VERY LOW	LOW

SOURCE: ACIL ALLEN CONSULTING

Summary

ACIL Allen's economic impact assessment modelling suggests there will be limited impact on sectors outside of the shale gas industry and its supply chain. This is for a few reasons, some of which centre on the evidence-based assumptions ACIL Allen has made (and which have been endorsed by the Inquiry) related to the treatment of land and water resources. But more significantly is the relatively modest labour requirement of the sector, which means there is limited crowding out activity in the labour market in the Northern Territory. In addition, the shale gas industry is likely to disturb a small

surface area relative to the size of the Northern Territory (as stated in Section 6.2.4, 67.2km² for BREEZE, 231.7km² for WIND, and 475.9km² for GALE, compared to the Northern Territory's total land area of 1,421,000km²).

That is not to say there are no downside risks to a potential shale gas industry development in the Northern Territory. ACIL Allen's economic modelling simply demonstrates that there are quantified net economic benefits available to the Northern Territory economy. There are additional considerations – many of which are outside of the scope of ACIL Allen's work but are being dealt with by others involved in the Inquiry – which must be given due consideration in the process of determining whether the industry should be given a license to operate. ACIL Allen has provided a perspective on these issues in the next Chapter of this report.

12.2 Comparison of ACIL Allen economic impact assessment to APPEA/Deloitte economic impact assessment

As part of its scope of works, ACIL Allen is required to compare the inputs and outputs of its economic impact assessment with the inputs and outputs of the 2015 APPEA/Deloitte study, *Economic impact of shale and tight gas development in the NT*. This is presented in the table below.

Item	APPEA/Deloitte		ACIL Allen		
	“Success”	“Aspirational”	“BREEZE”	“WIND”	“GALE”
Development modelling approach	Deloitte took the price of LNG, subtracted cost of processing and transmission pipeline, and used that to determine its target gas price. From there, it scaled CAPEX & OPEX estimates from a starting position that would allow all gas to be sold assuming a their market price, and had a different breakeven price for three market demand tranches (NT, East Coast and LNG). Deloitte assumed no market constraints.		ACIL Allen began by sizing its developments based on market tolerance, using <i>GasMark</i> . From there, ACIL Allen build its developments from the ground up using data to build a single average type curve, a well scheduling model, development cost assumptions by key components, and pipeline assumptions combining current pipeline capacity and new pipelines. ACIL Allen did not assume gas would be used to facilitate any new LNG development, and instead assumed in its base case that an offshore development would be required to backfill the DLNG facility.		
Economic impact assessment modelling approach	In-house CGE model		In-house CGE model		
Volume of gas (peak PJ/annum)	586 PJ/annum in 2040	910 PJ/annum in 2040	36.9 PJ/annum (2041)	108.3 PJ/annum (2042)	365 PJ/annum in 2043
Incremental LNG?	Yes, 100% incremental LNG. Two additional LNG trains to be built, with capital costs included in the economic impact assessment.	Yes, 100% incremental LNG. Three additional LNG trains to be built, with capital costs included in the economic impact assessment.	No LNG in this scenario.	No LNG in this scenario.	No incremental LNG in this scenario. It is assumed the onshore development displaces an offshore development.
CAPEX per well	\$6.2m - \$9.75m		\$19.1m on average (including learnings)	\$16.3m on average (including learnings)	\$12.7m on average (including learnings)
OPEX per GJ	\$0.53 - \$0.89/GJ		\$1.77/GJ on average (including learnings)	\$1.59/GJ on average (including learnings)	\$1.46/GJ on average (including learnings)
Wellhead cost per GJ (maximum case)	\$1.90 - \$2.67/GJ		\$6.07/GJ on average	\$5.03/GJ on average	\$4.01/GJ on average
GTP impact (deviation from baseline in final year of study)	+\$5.1bn (2040)	+\$7.5bn (2040)	+\$0.30bn (2043)	+\$0.64bn (2043)	+\$0.72bn (2043)
FTE impact (deviation from baseline in final year of study)	+4,195 FTE (2040)	+6,321 FTE (2040)	+80.1 FTE (2043)	+221.5 FTE (2043)	+558.1 FTE (2043)



ECONOMIC
POLICY
CONSIDERATIONS

IV



The Northern Territory Hydraulic Fracturing Inquiry has sought information on options for “leading practice” fiscal and regulatory policy reform that would allow exploitation of shale gas resources in a way that would generate sustainable development from an economic perspective in the Northern Territory of Australia. More specifically, the Inquiry is seeking information on a policy regime that would:

- maximise benefits from the industry
- mitigate and manage costs (including risks of adverse impacts)
- capture net benefits for Territorians in general and those in regions affected by development, without impeding investment
- sustain net benefits over time.

The Inquiry stipulated that this advice should include coverage of measures or instruments to mitigate and manage any adverse effects on other Northern Territory industries, and “boom and bust” economic cycles arising from development of a shale gas industry. This requirement indicates that the Inquiry wants advice on policy instruments that would address potential “Resource Curse” consequences, including “Dutch Disease” effects, of development of a shale gas industry in the Northern Territory.

13.1 The efficiency/equity trade off

Economic assessments of policy regimes or changes typically are undertaken by reference to two widely accepted principles relating to comparison of benefits and costs. An economic efficiency criterion focuses on the aggregate of benefits (positive impacts) and costs (negative impacts). A fairness criterion focuses on the distribution of benefits and costs. Sometimes, these criteria have been teased-out to highlight specific aspects of economic efficiency and fairness.

Criteria along these lines have been proposed in public finance/economics texts over the past 90 years or more.⁴⁴ They can be traced back to Adam Smith’s (1776) pioneering economic work. In Australia, similar criteria have been applied in several reviews of the tax system, over the past 40 years, including the Henry Tax Review in 2010.⁴⁵ Also, they have been applied in reviews of royalty policy undertaken for state and territory governments over the same period, including the *Green Paper on Mining Royalty Policy in the Northern Territory* in 1981.⁴⁶ In addition, economic efficiency and

⁴⁴ See Dalton (1923), Pigou (1929), Musgrave (1959), Musgrave and Musgrave (1973), Atkinson and Stiglitz (1980), Stiglitz (2000), Rosen and Gayer (2008).

⁴⁵ For example, Asprey, others (1975), Commonwealth of Australia, Treasurer (1985), Ralph, others (1998), Commonwealth of Australia, Treasurer (1998), Henry, others (2010), Commonwealth of Australia, the Treasury (2015).

⁴⁶ For example, Northern Territory of Australia (1981), Bradley (1986), Australian and New Zealand Minerals and Energy Council, Royalty Working Party (1991) and Australian Ministerial Council on Mineral and Petroleum Resources (2006).

equity were used as guiding principles in various papers prepared for the previous Commonwealth Governments on climate change policy.

13.1.1 Efficiency principles

The concept of economic efficiency refers to an efficient allocation of resources (human, capital, and natural resources, including land, extractable resources and the environment) at any time and over time. It includes efficient use of resources and efficient distribution of products.

An efficient allocation of resources may be impeded by market failures or policy failures. Market failures – situations in which markets fail to allocate resources efficiently – may arise because of external costs, external benefits, public good characteristics of some goods and services, asymmetric distribution of information, and existence of market power or lack of competition. Policy failure results from government intervention that worsens the allocation of resources because the method of intervention has been poorly designed to correct a perceived market failure or inequity. Policy failure might also result from intervention designed to achieve a political objective regardless of the effects of the policy measure on the efficiency of resource allocation.

Because there are numerous impediments to efficient resource allocation, achievement of the ideal of an efficient allocation of resources or economic efficiency would require multiple, consistent policy adjustments across the economy, not just a policy change to address a particular source of inefficiency. Therefore, the appropriate assessment criterion for formulation of, or a change in policy instruments is usually considered to be an improvement in the efficiency of resource allocation. This means improved capability to provide people with more of what they want (including better health and environmental outcomes) with available resources. Ideally, it involves selection of investments and policy settings that not only produce benefits in excess of costs, but also generate the largest surplus of benefits over costs.

In the case of extraction of exhaustible resources, such as a shale gas, the criterion of improving the efficiency of resource allocation is relevant not only to how and when exploration and extraction take place and how the policy regime affects those activities, but also to how the net *in situ* value of the resource (resource rent) is deployed during and after it is captured. Policy instruments need to be carefully designed to ensure that resource rent is not dissipated or destroyed during exploration and extraction, and is not wasted after it is captured.

The avoidance of unnecessarily large policy administration (compliance, monitoring and enforcement) costs is an aspect of economic efficiency. This sub-criterion has sometimes been referred to as administrative efficiency. It has also been labelled simplicity, because complexity can lead to high administration costs. Often, administrative efficiency or simplicity has been specified as a separate criterion.

13.1.2 Equity principles

Fairness or equity is an important consideration for governments in formulation of policy. The issue relates to treatment of individuals fairly relative to others. It involves highly subjective issues that have to be resolved by value judgements.

Two concepts of equity have been discussed extensively in the economics literature: the ability to pay principle and the benefit principle. These principles pre-date the foundational economic work of Adam Smith (1776), in which they were conflated. Over the past 30 years, a third principle has attained prominence: the concept of intergenerational equity.

The ability to pay principle is that costs of government interventions should be borne differently by people in accordance with differences in economic circumstances, with more being borne by better-off people (vertical equity), and similar burdens for people in similar economic circumstances (horizontal equity). The ability to pay principle has often been a dominant consideration in political discussion of policy issues.

Key issues in considering ability-to-pay in the context of health and environmental risks associated with activities and products are the distribution of the burden of hazards and the distribution of costs and benefits of policy measures designed to address them. A common concern is that low-income

households often bear a disproportionate share of health and other environmental risks, and that policies to address these risks may not be progressive in distributing benefits and costs (Parry, others, 2005; Bento, 2013).

The benefit principle of equity states that entities should contribute to government in accordance with benefits received from governments or from society more generally. It is particularly relevant to consideration of fairness issues in respect of extraction natural resources and use of the environment.

The benefit principle indicates that enterprises that are allowed to extract natural resources owned by a government should be required to pay according to the net *in situ* value of the natural resource. Also, it implies that enterprises should be required to pay compensation if, through their use (or abuse) of the natural environment, they impose non-market costs, such as health and environmental costs (external costs), on others. This implication is consistent and closely associated with the *polluter-pays* principle, which states that those who impose environmental and health costs on others should be required to pay.

Intergenerational equity is an important consideration in formulation and assessment of policy regarding exploitation of natural resources. It is relevant because extraction of mineable resources and damage to the natural environment, particularly elements essential to sustain human life, reduce the stock of natural capital available to future generations, denying them opportunities to benefit from natural resources.

The concept of intergenerational equity has risen to prominence over the past 30 years in the context of concomitant emergence and growth of interest in the concept of sustainable development. The concept of sustainable development incorporates economic efficiency and equity principles discussed above. Like efficient allocation of resources at a particular time and over time, sustainable development is concerned with using natural resources efficiently – extracting them efficiently, and taking into account (risk of) damage (particularly irreparable damage) to the natural environment. Both economic efficiency and sustainable development also involve wisely using the proceeds of exploitation of natural resources. Like intergenerational equity, sustainable development is concerned with ensuring that exploitation of extractable resources and the natural environment in the short to medium term does not leave future generations worse off. Both intra-generational equity and sustainable development concepts recognise that reduction of inequality is conducive to improving and sustaining economic growth.

A recurring theme in the economic literature on policy assessment is that criteria such as those discussed above are meant to apply to policy regimes as a whole (comprising policy instruments at all levels of government), rather than to each policy instrument in isolation. A perceived inequity associated with one policy instrument may be offset by a feature of another policy instrument. An inefficiency associated with one part of the policy mix may be reduced by the settings of another part of the policy regime. It is unrealistic to expect that every policy instrument will perform perfectly with respect to all criteria. It is the performance of the whole policy package that matters, not the performance of individual policy mechanisms.⁴⁷ Nevertheless, it may be useful to assess how each policy instrument performs with respect to the criteria to ascertain how it might contribute to a package of instruments comprising a good policy regime.

The performance of a policy package can be improved by allocating different policy instruments primarily to different policy objectives or sub-objectives, by carefully selecting/designing instruments that are suited to particular targets, and by deploying at least as many instruments as targets. The process of selecting/designing instruments must allow for the effects of each instrument on all targets, not just the primary one to which it has been assigned. The policy packaging process should also include consideration of the attributes of each instrument and how they might complement features of other instruments (Tinbergen, 1952). Such an approach to policy regime design minimises trade-offs or compromises between degrees of achievement of multiple objectives.

⁴⁷ Geoffrey Brennan (1977) discussed these issues specifically with reference to selection/design and assessment of state and local government taxes.

13.2 The “Resource Curse” phenomenon

Substantial natural resource development does not lead automatically to better economic performance and greater well-being of constituents in regions and jurisdictions hosting such activity. Indeed, there is a burgeoning literature on how exploitation of natural resource wealth has too often led to underperformance of the host economy relative to its potential, and relative to economies that are not well endowed with natural resources. This phenomenon has become known as the “Resource Curse”.

The concept originated with Gelb (1988) and Auty and Warhurst (1993).⁴⁸ It attracted considerable interest from economists following pioneering quantitative work by Sachs and Warner (1995) indicating that economic dependence on mineable resources was correlated with slow economic growth after allowing for structural attributes of countries. Helpful surveys of the literature have been provided in work by Humphreys, Sachs and Stiglitz (2007), Arezki and Gylfason (2011), van der Ploeg (2011), Frankel (2012a,b), Shaffer and Ziyadov (2012), and Venables (2016).

Most discussions of the Resource Curse have associated this affliction with developing economies. However, advanced countries with considerable mineable resources wealth are not immune. Indeed, *The Economist* magazine suggested in 1995 that Australia was affected by a “Resource Curse” (Anonymous, 1995). There is considerable circumstantial evidence that Australia has suffered “Resource Curse” symptoms as a result of mismanagement of the mining boom of 2004 to 2011.

A related phenomenon is the “Dutch Disease”, which refers to effects of economic restructuring in response to development of a major mineable resources sector. Pre-existing sectors are disadvantaged because of lower export and import prices associated with nominal exchange rate appreciation, and higher costs of domestic inputs as a result of demand from the mining sector and spending of revenue derived from that sector. The higher cost structure and higher nominal exchange rate together represent a real exchange rate appreciation.

The name “Dutch Disease” was applied by *The Economist* magazine (Anonymous, 1977) following the adverse effects of discovery and exploitation of substantial gas resources in the Netherlands a few decades ago. Pioneering analysis of the phenomenon in an Australian context was undertaken by Cairnes (1859, 1873) in respect of the gold rush, and by Gregory (1976). Subsequent important early contributions to the “Dutch Disease” literature were provided by Corden and Neary (1982), Corden (1984) and Van Wijnbergen (1984). A recent useful discussion of “Dutch Disease” in Australia as a result of the 2004-2011 mining boom was presented by Corden (2012).

Mismanagement of structural adjustment in response to a mining boom or interaction of structural adjustment with external benefits of industrial activity can contribute to a “Resource Curse” problem. Indeed, these occurrences are the potential sources of economic disease, not structural adjustment *per se*. They are typically listed as “Resource Curse” mechanisms.

13.2.1 Regional resource curse issues

Until recently, the rapidly growing “Resource Curse” literature had been focussed almost entirely on effects of major mineable resource developments on national economies. Little consideration was given to the potential for “Resource Curse” issues in state and regional economies. This situation changed because of the shale gas and oil boom in the United States.

Over the last six years, economics literature has been accumulating on investigations into the existence or otherwise of “Resource Curse” effects in “local economies” in the United States.⁴⁹ Important contributions have been made by Resources for the Future (RFF), a highly regarded United States organisation that has been conducting economic research in relation to environmental and

⁴⁸ See also Auty (1990).

⁴⁹ For example, see Freeman (2009), James and Aadland (2011), Brown (2014), Jacobsen and Parker (2014), Hausman and Kellogg (2015), Cust and Poelhekke (2015), Mason, Muehlenbachs and Olmstead (2015), James (2015), Kelsey, Partridge and White (2016), Weinstein, Partridge and Tsvetkova (2017), Feyrer, Mansur and Sacerdote (2017), and Allcott and Keniston (2017). A useful review has been provided by Krupnick and Echarte (2017).

other natural resource issues since 1952. RFF has established research groups focussed on community impacts of shale gas and oil development, and shale public finance.⁵⁰

Investigations of economic impacts of shale gas and oil development in the United States have found strong evidence of local employment gains during the development phase, and increases in incomes through wage/salary increases and private royalty arrangements. However, evidence on long-term growth and development effects is mixed and inconsistent. Several studies provided evidence of negative long-term effects or “Resource Curse” effects. Several other studies found no clear evidence of such effects. Analysis of the mixed and inconsistent results suggests that effects vary across time and locations.

An important insight of the literature relating to the presence or otherwise of regional “Resource Curse” effects is that transmission channels are similar to those for national “Resource Curse” effects. Moreover, policy settings are critical to enabling or avoiding “Resource Curse” problems in sub-national areas, just as they are nationally (Kelsey, Partridge, White, 2016).

13.2.2 Resource curse mechanisms

“Resource Curse” effects typically result from poor policies and institutions, not from resource wealth *per se*. Resource wealth that is properly managed should provide important net economic benefits. Their magnitude is dependent on relevant policy settings, as well as the quantity, quality and location of extractable resources.

There are various “Resource Curse” mechanisms that are relevant in the context of the Northern Territory and Australia. These mechanisms are discussed below.

Loss of growth-inducing external benefits

Economic restructuring in response to development of a major mineable resources sector or a prolonged surge in prices of mined commodities could have “Dutch Disease” and “Resource Curse” effects if trade-exposed sectors that are disadvantaged by real exchange rate appreciation would otherwise be sources of significant growth-inducing external benefits (van Wijnbergen, 1984; Sachs, Warner, 1995). However, this would be a matter of concern only if there are more important growth-inducing benefits associated with disadvantaged sectors than with booming sectors (Frankel, 2012a, b).

The notion that external benefits are more substantial in the case of manufacturing, than for mining and agriculture has been suggested in the economics literature from time to time. It can be traced back to Alfred Marshall (1880-1920), David Ricardo (1817) and Adam Smith (1776).

In the economics literature on “Dutch Disease”, two forms of external benefits (sources of market failure) have been discussed: spillovers of information about demonstration of technology (often called learning-by-doing effects), and linkages between industries. For example, Sweder van Wijnbergen (1984) focussed on technology demonstration effects, and Jeffrey Sachs and Andrew Warner (1995) discussed linkage effects, as well as demonstration effects. Both works have been widely cited.

Technology demonstration effects external to enterprises and internal to industries were originally assumed to characterise manufacturing. However, it has been widely acknowledged that government attempts in Australia and many natural resource-rich developing countries to promote diversification into import competing manufacturing industry by erecting import tariff and quota barriers were dismal failures. More recently, some have assumed that export-orientated manufacturing is characterised by technology demonstration externalities not matched in other sectors, and on that basis they have advocated diversification from mining into such activity. It must be emphasised that these assumptions have not yet been proven empirically.

If external benefits in the form of technology-demonstration and industry-linkage effects are much greater in lagging or declining sectors, one of which is manufacturing, than in expanding sectors – mining and non-tradeable goods – there would be an economically inefficient decline in growth (Venables, 2016). However, it certainly has not been demonstrated that the external benefits

⁵⁰ For example, see Raimi and Newell (2016a,b), Krupnick and Echarte (2017), Krupnick, Echarte and Meuhlenbachs (2017), and Krupnick, Echarte, Zachary and Raimi (2017).

generated by manufacturing are greater than those generated by expanding sectors, which include non-tradeable sectors, as well as mining and processing activities.

Anthony Scott and Peter Pearse (1992) criticised suggestions that governments in natural resource-rich countries, including developed economies like Australia and Canada, should intervene to encourage diversification into so called “high-tech” or “sophisticated” industries to overcome excessive dependence on “old economy” natural resource-based industries. Scott and Pearse pointed out that these arguments have ignored the history of technological advances in the natural resource-based industries.

Jeffrey Frankel (2012a, p. 31) reiterated criticism of the view that external benefits generated by manufacturing would be greater than external benefits from sectors engaged in mining, agricultural, and non-tradeable production:

“.....it must be pointed out that there is no reason why ‘learning by (seeing others) doing’ should be the exclusive preserve of manufacturing tradeables. Nontradeables can enjoy learning by (seeing others) doing. Mineral and agricultural sectors can as well. Some countries have experienced tremendous productivity growth in the oil, mineral and agricultural sectors.”

It is clear that technological progress has inexorably driven down real costs of mining (including oil and gas extraction) and processing of mineable commodities over the long-term. A few examples relevant to gas include technological advances allowing extraction of petroleum from beneath deeper and deeper water, liquefaction of natural gas and transport of that product, extraction of coal seam gas, and extraction of shale gas and oil.

In addition, there has been a rapid rate of development and introduction of new technology applicable to other tradable sectors including agriculture and some service sectors. For example, backward linkages and “learning by seeing others doing” have facilitated development of a substantial mining services sector in Australia that includes provision of technologically sophisticated solutions to Australian and overseas mining activities.

There have also been important linkage and “learning by seeing others doing” effects in non-tradable sectors of the economy, including some service and construction activities. These sectors have expanded as part of the process of economic adjustment in response to a booming mining (including extraction of oil and gas) sector.

Public discussion regarding development of mineable-resource-rich economies has often produced proposals that governments should intervene to encourage diversification away from extraction activities (as observed by Frankel, 2012a,b, and Venables, 2016). Some proponents of diversification have advocated government incentives for enterprises to take advantage of backward and forward linkages with mining activities. Others have advocated incentives to establish enterprises focussed on manufacturing activities unrelated to mining, presumably because of perceived superior growth-inducing effects of those separate activities.

Venables (2016) pointed out that very few resource-rich countries had been successful in diversifying their economies through policies such as allocation of government revenue from mining to support other sectors, and domestic content requirements. A notable, but rare example was development of the Norwegian marine engineering sector.

In summary, a convincing case for government intervention to offset the economic adjustment process triggered by substantial growth in mined commodity prices and/or major new mining developments has not been found.

13.2.3 Neglect of local supply opportunities

Managers of investment and operational phases of mineable resource projects may neglect local supply opportunities. This may occur because managers have preferred suppliers as a result of previous experience in other jurisdictions. It also may occur because managers lack information on capacities of local suppliers, people, and training facilities, including capacities to adapt to the requirements of investment and operational phases of projects. In addition, local suppliers may lack information regarding the requirements of construction project managers and mine managers.

Preferences for previous suppliers and lack of relevant information about locals and projects indicate the existence of information market failure.

A common policy response is specification of local content requirements. Typically they are set on an arbitrary uniform basis for all projects. This regulatory mechanism places responsibility on managers to collect information about local suppliers. It could be expected that this would be pursued just enough to meet local content requirements. That result might mean some economic local supply opportunities are missed or it might raise costs and thereby reduce realised resource rents and the amount captured by government.

An alternative approach is that government could act as an information intermediary. It could communicate with potential purchasers and suppliers about requirements and capabilities, and ensure that relevant information flows in both directions.

Local content requirements address information market failure only indirectly and in an arbitrary way, while the information intermediary option would address the information market failure directly. The former approach would impose costs on purchasers, reducing realised resource rents and potentially returns to government, depending on royalty and tax regimes. The latter approach would be funded by government, logically from resource rent captured by government in an efficient way. The former would cause deadweight losses (inefficiencies). The latter would not. In both cases, benefits should be weighed against costs.

13.3 Managing a “temporary boom”

Economic adjustments to a booming mining sector could have economic “disease” or “curse” elements if the boom is expected to be only a short- to medium-term phenomenon (Corden, 1984; Frankel, 2011, 2012a,b). Commodity-price booms typically fall into this category. Usually, they are much shorter than the post-2004-2011 boom in prices of mined commodities. Also, investment and exploration booms can be brought to an end by the collapse of commodity-price booms or by exploration failures. In addition, mining-related employment typically falls as projects transition from construction to extraction.

A temporary boom could result in a painful adjustment process that has to be reversed when commodity prices inevitably decline. Adjustment costs are then incurred to an unnecessary extent twice. This is economically inefficient, as it wastes resources. Pertinent observations by Jeffrey Frankel (2012a) are re-produced in the following box.

In addition, the macroeconomic instability associated with temporary price booms followed by busts or prolonged price declines is also likely to be detrimental to long-term economic performance (Arezki, 2011; Collier, Venables, 2011; Barnett, Ossowski, 2003; Davis, Ossowski, Daniel, Barnett, 2003).

There is a case for intervention to smooth and moderate real exchange rate changes through fiscal and monetary policy to improve the efficiency of resource allocation in the short-term and over time if losers as well as winners, although gains could be expected to outweigh losses. Gains to consumers from a high nominal exchange rate (cheaper goods and services), and gains to participants in non-trade exposed sectors would be reduced. Meanwhile, participants in all trade-exposed sectors, including the mining sector, would gain from the intervention. Also, benefits from improved economic growth would become widely available.

On the other hand, if it appeared likely that historically high mined-commodity prices and high exploration and investment activity would persist in the long-term, a policy of moderating the high exchange rate caused by a commodity-price and investment mining boom would not be economically sensible. Then, it would be appropriate to facilitate economic adjustments, not moderate them. Therefore, keeping policy options open with a flexible policy approach is important.

BOX 13.1 ECONOMIC WASTE FROM MEDIUM TERM VOLATILITY OF COMMODITY PRICES

“Cyclical shifts of factors of production (labour, capital and land) back and forth across sectors – mineral, agricultural and manufacturing, and services – may incur needless transactions costs. Frictional unemployment of labour, incomplete utilisation of the capital stock, and incomplete occupancy of housing are true deadweight costs (inefficiencies), even if they are temporary. Government policy-makers may not be better than individual economic agents at discerning whether a boom in the price for an export is temporary or permanent. But the government cannot completely ignore the issue of volatility with the logic that the private market can deal with it. When it comes to exchange rate policy or fiscal policy, governments must necessarily make judgements about the likely permanence of shocks.”

SOURCE: FRANKEL (2012A), P. 27.

13.3.1 Neglect of external costs

The wellbeing of some parties in the Northern Territory could be adversely affected as a result of neglect of environmental, health and dis-amenity costs of exploration for, and exploitation of mineable resources (Davis, 2015; Krupnick, Gordon, 2015; Bartik, et al, 2017). These costs should include risks or hazards that might result in damage (Gruenspecht, Lave, 1989; Viscusi, 2007).

Such costs could contribute to a “Resource Curse” (Mason, Muehlenbachs, Olmstead, 2015). However, they have not been discussed further in this report as they are outside the scope set out in terms of reference for the assignment.

13.4 Mineral and petroleum commodities and public finances

Resources in the ground are depletable and ultimately exhaustible assets. In Australia, they are owned by state/territory governments onshore and the federal government offshore on behalf of constituents of relevant jurisdictions. These scarce resources have value in excess of the full costs of exploring for and extracting them. This net value *in situ* is often termed resource rent.

The benefit principle of equity indicates that government should capture as much of the resource rent as possible. That is what a private owner of mineable resources would seek to do. It would price the right to extract resources to capture resource rent. The economic efficiency principle indicates that policy instruments deployed to capture resource rent should be carefully designed to avoid destroying part of it by impeding incentives to realise resource rent through exploration, investment and extraction activities.

Realisation of resource rents and government revenue from capture of a substantial proportion of resource rents are not sustainable, because resource rents are derived by depleting exhaustible natural capital. Government revenue deriving from resource rent is really revenue from sale of assets. It is not sustainable like revenue from taxation linked to ongoing activities.

The unsustainability of realisation of resource rents and government revenue therefrom could be addressed by saving resource rents accruing to Australian entities, rather than consuming them.⁵¹ Subsequently, they could be invested astutely in productivity-enhancing built and human capital. Saving and investing resource rents would be consistent with principles of inter-generational equity and efficient inter-temporal allocation of resources. In other words, it would be conducive to sustainable development from an economic perspective. This insight was originated by Solow (1973). It was subsequently developed by Hartwick (1977) and Solow (1986, 1993). The principle is widely accepted in the economics literature as indicated in a review by Barbier (2016).

⁵¹ Resource rents that accrue to overseas entities would not be available to replace depletable assets. To put this in perspective, about 80 per cent of the Australian mining sector is overseas owned (Connolly, Orsmond, 2011).

13.4.1 Raising revenue

Governments that own mineable resources price the right to extract them via royalty regimes. In the Northern Territory, the Government does so via a 10 per cent ad valorem royalty based on wellhead value for oil and gas, and an 18 per cent accounting profits royalty for other mineable resources.

Resource rent that escapes capture by the Northern Territory royalty regimes becomes subject to Commonwealth Government taxes. The petroleum resource rent tax applies at a rate of 40 per cent to a base that crudely represents resource rent less royalty payments to the Territory. The Commonwealth Government's company income tax regime applies at a rate of 30 per cent to an accounting profits base that excludes royalty and petroleum resource rent tax payments. The Commonwealth Government also collects an additional portion of the resource rent through taxation of providers of capital, skilled labour, and other inputs, who have been able to capture part of the resource rent.

Ad valorem royalty regimes cannot capture a substantial amount of rent without causing substantial economic damage. Such regimes make extraction of marginal resources unprofitable and may have the same effect on resources that are not much better than marginal. If royalty rates are not kept low, they can knock out parts of resources or entire resources. They damage incentives to explore, invest and extract at the margin, thereby destroying some resource rent. However, if royalty rates are kept low to avoid such economic damage, they capture only a small proportion of resource rents realisable from exploitation of superior resources. Resource rent is then allowed to escape to other jurisdictions. There is a substantial literature on this matter, and on effects of alternative regimes, including work by Gaffney (1967), Northern Territory (1982), Willett (1985, 2002), Industry Commission (1991), Smith (1997), Lund (2009), ACIL Allen (2010), Henry, others (2010), and Boadway and Keen (2010, 2015).

An accounting profits regime, such as the Northern Territory royalty regime for mineable resources other than oil and gas, and the Commonwealth Government's company income tax regime, are superior to an ad valorem system. However, these systems still tax the cost of equity capital and they do not treat gains and losses symmetrically. Therefore, they discourage exploration and investment.

13.4.2 Spending revenue

Government misspending of revenue derived from a mining boom ignited by high commodity prices or major discovery may cause a genuine economic "disease" or "curse". This may result from the composition or types of spending undertaken, not just the pro-cyclicality problem discussed above.

It appears that the true "disease" experienced by the Netherlands following major discoveries and substantial exports of natural gas resulted from consumption (not saving and investment) of resulting government revenue. This took the form of high levels of social service or welfare payments that amplified economic adjustment issues, were not sustainable, and proved to be politically difficult to remove (Corden, 1984; Hart, 2010).

Determining how much should be saved and invested is not straight forward. One complication is that mineable resources can be at least partly replenished by exploration and technological advances in exploration and extraction. Additional complications working in the opposite direction are that investments in human and built capital and research are imperfect substitutes for mineable resources, and the marginal productivity of reproducible capital would tend to fall as substitution proceeds. Another issue is that only some of the resource rents remaining in private Australian hands after royalty and tax will be saved and invested in Australia, and resource rents captured by overseas entities would probably be lost to the Australian economy. There is an economic case for saving and investment of all government revenue from resource rents in capital-scarce developed countries like Australia, and particularly in relatively undeveloped locations with considerable potential, such as the Northern Territory.⁵² This approach was recommended by the Productivity Commission (1998) and its predecessor, the Industry Commission (1991).

⁵² In developing countries, where poverty is a major problem, it would be appropriate to allocate some of the revenues derived from resource rents to consumption spending to alleviate poverty. Particularly high rates of return on investment in education, health and infrastructure in such countries could allow release of some revenues to alleviate poverty directly, in addition to alleviating it indirectly through investments (Sachs, 2007; Collier, van der Ploeg, Spence, Venables, 2010).

Selection of specific investments also matters. Investments that have been poorly conceived, directed towards political objectives, and/or do not pass or are not subjected to comparative social benefit-cost analyses should not be made. Government should not provide infrastructure or concessionary funding for infrastructure or other investments to developers of mining or diversification activities that are the main beneficiaries of the expenditure, without a claw-back mechanism to recover the full economic cost (including an appropriate risk-adjusted rate of capital in alternative uses). Investments should not be made by government for the purpose of impeding desirable structural adjustments.

A logical government investment in a jurisdiction that is relatively unexplored, despite favourable geology, would be expansion of funding of very early stage exploration and prompt release of the resulting information provision. There is a strong economic case for government to engage in such activity to correct two market failures: under-provision of basic geological information by the private sector because of its public good character, and asymmetric distribution of exploration information that tends to lead to wasteful pre-emptive exploration by some parties, and tends to shut out other parties and impede competition for tenements. This case has been understood for 50 years (see Gaffney, 1967; Herfindahl, 1969).

This case for government investment in exploration activity can be extended to justify a tapered subsidy scheme (from 100 per cent down to zero) for some subsequent exploration, followed by prompt release of information, because the transition of exploration information from public to private good as exploration becomes more focussed as it proceeds to later stages of assessment is not a clear-cut step. Moreover, there is a case for government investment in infrastructure and personnel to assemble, analyse, package and release information generated by government and private sector exploration activities. The nominated resource-rent capture regime would claw-back much of the value added by this government expenditure on exploration and information dissemination.

Logically, other government investment would take the form of investment in education, health, and infrastructure designed to complement and boost productivity in tradeable and non-tradeable goods and services sectors, reducing costs in those sectors. Investment could be focussed to support productivity improvements in stressed, lagging tradeable goods sectors. It could also be directed towards helping those lagging sectors indirectly by increasing productivity and constraining price rises in expanding non-tradeable sectors providing inputs to, and competing for resources with lagging sectors (Sachs, 2007; Freebairn, 2012).

The timing of government investment is as important as careful selection of specific investments. As discussed above, pro-cyclical government spending could have economic “disease” or “curse” effects. While these would be moderated as productivity-improving effects of targeted government investment come into play, “disease” or “curse” problems could occur in the interim. This suggests it would be economically appropriate to spread government investments over time in a counter-cyclical fashion.

John Freebairn (2012) suggested that revenues derived from resource rents could be invested in tax reform in a manner designed to reduce inefficiencies of the Australian tax regime as a whole. This could be undertaken along lines suggested by the Henry Tax Review (Henry, others, 2009). It should yield large productivity gains.

A common suggestion for investment of government revenue derived from resource rent is to accumulate foreign assets. This is a way of providing a stream of sustainable future revenue, while reducing economic “disease” problems, because it moderates the real exchange rate appreciation resulting from a booming mining sector. However, in the context of apparent under-investment in human capital and infrastructure in the capital-scarce Australian economy, investment solely in foreign assets seems inappropriate. Higher economic returns could be earned by investing domestically. Moreover, Australia’s tax regime interferes with efficient allocation of resources. Therefore, a compromise would appear sensible, including “parking” of a high proportion of revenue derived from resource rents in liquid foreign assets during periods of booming mined-commodity prices, re-investment of some of those funds and new revenue in human capital and infrastructure on a counter-cyclical basis at other times, and investment of government revenue from resource rents in tax reform.⁵³

⁵³ A detailed discussion of saving and investment options has been presented by van der Ploeg (2014).

13.5 Optimal regulation of exploration and production

Resource rent may also be misspent through poorly designed exploration tenement policies. Typical tenement regimes in Australia induce dissipation of ex ante resource rent through misallocation of resources. These regimes fall into two categories: conditional first-come-first-served systems and work programme bidding for highly conditional tenure. The mineral exploration tenement regime in the Northern Territory falls into the former category. The Northern Territory petroleum exploration regime is of the latter type.

Both systems tend to dissipate ex ante resource rent and misallocate resources because of distortion of the timing, amount and composition of exploration activity, through the effective allocation of resource rent by government to subsidise exploration that is marginal because of timing, location and technique. The existence of this policy failure in the Northern Territory context was recognised 36 years ago in the *Green Paper on Mining Royalty Policy for the Northern Territory*.

Policy failure associated with regimes with some common features was discussed in a United States context by Gaffney (1967) and Herfindahl and Kneese (1974). Similar issues with conditional first-come-first-served systems in Australia were noted by Fitzgibbons (1977). Inefficiencies associated with both systems in Australian jurisdictions have been analysed in some depth by ACIL Allen (2012), Henry and others (2010), Willett (2002, 1985), Smith (1997), and the Industry Commission (1991). The analysis has been endorsed by the Productivity Commission (2015).

Work program bidding is a mechanism for allocation of exploration tenements. It involves a formal bidding process for areas released for offers of exploration work. Each tenement is allocated to the bidder offering the exploration programme that is judged to be the best. Typically, more and earlier activity are judged to be better.

The location and timing of release of tenements for allocation by work program bidding is determined by government. Explorers are not able to apply for tenements on an *ad hoc* basis under a work program bidding system, in contrast to a conditional-first-come-first-served system.

Typically, the tenements are highly conditional, being subject to relatively short tenure (5 years), periodic relinquishment requirements (50 per cent after the initial 5 years before renewal), and performance of the work programme that was bid. Capture of resources and retention of ground on a long-term basis depend on performance of the work programme and discovery of resources.

Following release of an area for work program bidding, a potential explorer seeking to capture tenure would offer no more than a work programme of size and timing that would extinguish *ex ante* resource rent. This would involve increasing and bringing forward exploration relative to the exploration programme a rational explorer would choose with secure, prolonged tenure. The earlier that an area is released for work program bidding, the more important will be the effect of bringing forward exploration, which dissipates *ex ante* resource rent through interest on premature outlays, and higher real costs of exploring earlier, rather than later. The closer that release of an area for bidding approaches the ideal time to commence exploration, the greater will be the relative importance of the tendency to increase the amount of the exploration programme offered above what is reasonably expected to be required for discovery. Then, *ex ante* resource rent is dissipated through economically excessive outlays.

Another adverse effect of work program bidding is that it would also tend to dissipate value added by government funding of very early stage exploration. This work would reduce uncertainty and consequent waste of exploration resources experienced by private sector explorers, raising ex ante resource rent from the perspective of those explorers. Subsequent work program bids would be adjusted to reflect the value added.



The literature highlights the range of issues that Governments would need to consider, should the development of a shale gas industry in the Northern Territory proceed. Through the stakeholder consultation process, ACIL Allen gained further insights on the key issues that need to be considered in designing an effective policy and regulatory regime in the Northern Territory, should the development of a shale gas industry proceed. A copy of ACIL Allen's Consultation Guide is presented in Appendix B.

Through the literature review and stakeholder consultation, ACIL Allen has identified six key policy areas considered relevant to the development of a shale gas industry in the Northern Territory. In discussing each of these issues, the de-identified remarks of stakeholders have been included where they provide further context as to the issues and challenges that may arise during a development.

ACIL Allen Consulting has considered the six policy areas as they relate to three key outcomes for the Northern Territory in the event of shale gas industry development.

- Measures to **capture** the benefits
- Measures to **distribute** the benefits
- Measures to **manage** downside risks

As per its scope of works, ACIL Allen Consulting is focussing strictly on the identification of economic policy issues and initiatives that are available to the Northern Territory Government.

14.1 Managing an increase in NT Government revenue

ACIL Allen's modelling suggest the Northern Territory Government would receive between \$18 million (BREEZE scenario), \$34.4 million (WIND scenario) and \$95 million (GALE scenario) in royalty income per annum at full scale production should a shale gas development proceed. This would represent between a 0.3 per cent and 1.4 per cent increase in the revenue base of the Northern Territory Government. In addition, the Territory will raise an estimated \$2.9 million (BREEZE), \$8.7 million (WIND) and \$11.1 million (GALE) in payroll tax, and additional revenue associated with transfer duty, insurance duty and other State taxes which ACIL Allen has not modelled.

Within this policy area, the issues are mostly available to the Northern Territory to capture the benefits and distribute the benefits of a shale development.

In terms of capturing benefits, the Northern Territory Government already levies a 10 per cent ad valorem royalty at the well head (point of production) for all onshore petroleum production. According to NT Treasury, the royalty is calculated using a netback method, which allows operators to deduct upstream costs (principally transport) from the final sales price of gas in order to capture 10 per cent of the well head. This is in line with other Australian States and Territories, which tend to target a 10 per cent return to the community from the sale of mineral and petroleum resources.

The practice of charging the private sector a **royalty** for the sale of a non-renewable resource for extraction is well founded. Broadly, stakeholders were of the view that levying a royalty was a critical way for the Northern Territory to capture the benefits of a shale gas industry development. There was also a view presented to ACIL Allen that the royalty rate could be used as a negotiating tactic for the Government to incentivise non-production elements of the industry to move to the Northern Territory – such as a corporate head office or support function.⁵⁴

It is also important to consider the need for a stable, certain operating environment for potential industry operators. During consultation, industry operators raised the need for a well-defined and stable taxation regime as an important consideration in their decision making as to whether a development would proceed beyond the initial exploration and appraisal phase.⁵⁵

One particular feature of the potential for additional onshore petroleum royalties is how this may interact with Australia's system of **horizontal fiscal equalisation** (colloquially known as "GST distribution"). The Northern Territory is currently a significant beneficiary of the system, mostly on account of its identified additional expenditure needs (see Section 2.4) determined by the Commonwealth Grants Commission.

Each State's onshore petroleum royalty revenue is assessed as part of the Commonwealth Grants Commission's mining revenue assessment; onshore petroleum royalties are considered substantial enough to be assessed as an individual line of revenue. For confidentiality reasons, the Commonwealth Grants Commission does not publish the details of the onshore petroleum royalty assessment, but it does include them in the "other" mineral component. The Northern Territory has an assessed per capita revenue raising capacity in this "onshore oil and gas and other minerals" component of 9.287. This is a similar relativity as the Commission assesses the Western Australian Government in the iron ore royalty assessment (8.831), suggesting a high proportion of the Northern Territory's onshore petroleum royalties could be "equalised away" to other State and Territories in the GST distribution process.

There has also been some discussion that the Commonwealth Government may treat onshore gas revenue as "equal per capita" revenue, which would provide all States with a financial incentive to raise additional revenue from this source as it would not be subject to the GST distribution process. This is an issue worthy of further detailed examination and advice from NT Treasury⁵⁶ and the Commonwealth Grants Commission.

After raising the revenue associated with the shale gas industry, the Northern Territory Government has decisions to make regarding the way it will be treated or spent. This is primarily a distribution issue – with both geographic and intergenerational dimensions. While the pressure to spend any uplift in royalty and other revenue is likely to be strong, there are also options for the NT Government to manage the new revenue streams with an eye to intergenerational equity. There are two ways to do this: a wealth fund or a stabilisation fund.

The literature says there is a strong case for windfall royalty revenue to be treated differently. The Government is selling the right to mine a non-renewable resource, which is a one-off transaction. In this respect, mining royalties are different to taxes on income or consumption, which are perennial tax bases. Revenue raised from royalties should therefore be used to compensate society for the realisation of the value. This can be done by investing in the physical or human capital of the economy – to improve its productivity – or by warehousing the revenue in a special fund.

Traditionally, a **wealth fund** is used to accumulate revenue associated with windfall gains or with the extraction of non-renewable resources such as mineral commodities or petroleum products. The most famous example is the Government Pension Fund of Norway, which has an estimated value of just under US\$1 trillion. The fund was established in 1990 as a warehouse for government revenue earned from oil company profits.⁵⁷ Most major petroleum producing nations have some sort of wealth fund for the purposes of accumulating profits or other revenue (such as royalties).

⁵⁴ ACIL Allen Consulting. 2017. *Stakeholder Consultation, 27-29 June 2017*.

⁵⁵ ACIL Allen Consulting. 2017. *Stakeholder Consultation, 27-29 June 2017*.

⁵⁶ NT Treasury were cognisant of this risk when ACIL Allen met with personnel during its stakeholder consultation

⁵⁷ Sovereign Wealth Fund Institute. 2017. *Norway Government Pension Fund Global – Summary*. Accessed online at <http://www.swfinstitute.org/>

The Western Australian Government developed its own sovereign wealth fund – the *WA Future Fund* – in its 2012-13 budget as a way of warehousing some of the proceeds of the iron ore royalty boom. The WA Future Fund received an initial capital injection of \$1 billion dollars between 2012-13 and 2015-16, and receives ongoing injections equal to one per cent of the State's royalty revenue per annum, and reinvests all of its earnings in additional capital accumulation.

The WA Future Fund is governed by an Act of Parliament, which forbids any future government to access the funds it is receiving and generation until 2031-32 (unless a Bill can pass with the concurrence of an absolute majority, of both houses of the State Parliament), at which time the State Government projects it will have a nominal value of \$4.7 billion.⁵⁸ The Act states the annual interest earnings on the WA Future Fund can be used to finance the economic and social infrastructure needs of the State.

While well-intentioned, the broader settings of the State's finances are not ideal to host a wealth fund, given the State has significant public debt and high operating and cash deficits.⁵⁹ This means the State Government is effectively borrowing money to store in the fund. It is important to consider the state of public finances when making such significant, long-range decisions.

There are also a number of examples of countries which use a **sovereign wealth fund for the purposes of stabilising government finances**. These kinds of funds tend to be more short to medium term in focus than the long term nature of a wealth fund, and are used as a “banking” mechanism for countries with volatile, uncertain revenue bases. These funds tend to have strict rules around when money is to be deposited and can be withdrawn. The objective of smoothing out fluctuations in government revenue is to avoid large deficits or increased spending of short term increases in revenue.

The central government of Chile has operated a stabilisation fund under various guises since 1985, and has drawn on money stored in it during global economic crises in order to avoid large deficits or recessions in their domestic economy.⁶⁰ The rules regarding Chile's current stabilisation fund, the *Economic and Social Stabilization Fund*, are presented in Box 14.1.

BOX 14.1 CHILE COPPER STABILISATION FUND

Chile's Economic and Social Stabilization Fund (the 'ESSF') is often held up as a prime example of best practise stabilisation fund management. The ESSF received an initial seed investment of US\$2.5 billion in 2007, following a decision to consolidate two sovereign wealth funds into one with simplified objective of smoothing out revenue fluctuations associated with Chile's copper industry.

The ESSF receives additional capital on an annual basis when Chile's central government budget is in a surplus position equal to or greater than one per cent of GDP – with the capital injection equal to the surplus less the amount equal to one per cent of Chile's GDP. The ESSF mostly invests in low risk government and corporate bonds, allowing it to earn a return above holding cash but also affording flexibility to allow for a quick sale if the fund needs to be accessed.

Chile's central government has an overall “balanced budget” rule, meaning the ESSF can be called upon if there is a projected central government deficit in a given year to avoid the accumulation of debt to finance the operations of government. The ESSF can also be drawn down to fund any unmet pension or social welfare liabilities at the discretion of Chile's Minister for Finance. The ESSF is consistently one of the highest rated funds by the Sovereign Wealth Fund Institute.

SOURCE: GOVERNMENT OF CHILE, NATIONAL RESOURCE GOVERNANCE INSTITUTE, ACIL ALLEN CONSULTING

The Inquiry is keenly interested in examining the notion of a “royalties for regions” fund, which could quarantine a proportion of royalties associated with the development for spending in the area where

⁵⁸ Parliament of Western Australia. 2012. *Western Australian Future Fund Act 2012*. Accessed online at <http://www.parliament.wa.gov.au/>

⁵⁹ CCIWA. 2012. *Examining the Issues of Sovereign Wealth Funds*. Accessed online at <http://www.cciwa.com/>

⁶⁰ International Monetary Fund. 2007. *Assessing Chile's Reserve Management*. Accessed online at <http://www.imf.org/>

resources are extracted. Such a policy was implemented in Western Australia just as its iron ore and gas boom gathered pace in 2008-09, as a result of the negotiations associated with the formation of a new government in a hung parliament. An overview of the structure of the program is in Box 14.2.

BOX 14.2 WESTERN AUSTRALIA'S ROYALTIES FOR REGIONS FUND

The Royalties for Regions Fund Program is administered by the *Royalties for Regions Fund Act 2009*. The Act directs 25 per cent of annual resources royalties raised by the Western Australian Government to a special purpose account that can only be spent in areas outside of the Perth Metropolitan Area. The Act specifies the Fund is to be “over and above” the usual expenditure of government in regional areas, and it can be expended for three purposes:

1. To provide infrastructure and services in regional Western Australia
2. To develop and broaden the economic base of regional Western Australia
3. To maximise job creation and improve career opportunities in regional Western Australia

The remainder of the Program is established by administrative provisions within the Department of Primary Industries and Regional Development (formerly the Department of Regional Development). These provisions set out the strategic framework guiding spending, including the project approvals process which sees Fund applicants skip the usual WA Treasury review process.

There is a \$1 billion limit placed on the end of financial year balance of the Fund, meaning in times where royalty revenue is booming, the Fund must expend close to \$1 billion per annum. Prior to 2014-15, the Fund received an appropriation equal to 25 per cent of royalty revenue without a cap on the appropriation. This was changed in the 2014-15 State Budget – independent \$1 billion appropriation and expenditure caps were put in place – to maintain the integrity of the program and ensure it did not become an undue drag on the State's finances.

SOURCE: ACIL ALLEN CONSULTING

The policy has been in place in Western Australia since 2008-09, quarantining 25 per cent of total royalty revenue (up to an annual amount of \$1 billion) for spending on regional development projects, town beautification and social programs. There are a series of changes the Western Australian Government has made to the program in recent years (both past and current Governments) to improve the transparency, decision-making and accountability associated with it, and to shift its focus to job-creating projects rather than the provision of amenity enhancements.

Numerous reviews have also called into question the governance arrangements of the Program, noting it was not subject to the usual scrutiny of government expenditure review.⁶¹ This was particularly true in the early years of the Program, when money was distributed to regional local government authorities with very loose accountability and little guidance on how it should be spent. The Program is now subject to a Special Inquiry.⁶²

While these are important considerations, based on the development scenarios modelled by ACIL Allen Consulting it is unlikely that the revenue streams associated with the development of a shale gas industry would be of a requisite scale to warrant development of a specialist fund for the purposes of fiscal stabilisation or intergenerational equity. However, it is worth considering the benefits and costs of such an idea given it is an issue front of mind for many of the stakeholders ACIL Allen consulted.⁶³

⁶¹ WA Office of the Auditor General. 2014. *Royalties for Regions: Are the benefits being realised?* Accessed online at <http://www.audit.wa.gov.au/>

⁶² WA Government. 2017. *Media Statement: Commission of Inquiry to Investigate financial mismanagement, 15 May 2017*. Accessed online at <http://www.mediastatements.wa.gov.au/>

⁶³ ACIL Allen Consulting. 2017. *Stakeholder Consultation, 27-29 June 2017*.

14.2 Managing an increased demand for labour

The development of the shale gas industry in the Northern Territory has the potential for substantial labour benefits in the form of job creation, skills development and workforce diversification. An increase in the demand for labour from the development of the industry can be measured by the direct labour that is hired to work on the construction and operation phases of the development, as well as the indirect employment impact from the jobs that are generated by the spending in the economy as a result of the development.

It is estimated the employment impact of a development will average 82 FTE (BREEZE), 252 FTE (WIND) and 524 FTE (GALE), with much of this employment likely to occur in regional areas where the activities of an industry would occur.

Given the remote locations of the development sites, it is expected that there will be a need for some of the workforce to be employed on a fly-in, fly-out employment roster as the availability of sufficient skilled labour in these areas is unlikely to be able to be sourced locally. However, depending on the location of the development sites, there could be opportunities for nearby regional job seekers to be employed on a drive-in, drive-out basis. The use of regional employment will depend on the skills sets of local job seekers and the availability of training to gain the skills required of the developments. There was a preference in consultation from local communities to maximise the use of local job seekers in order to assist in keeping the benefits of the development of the industry on country.⁶⁴

The more remote locations of the development areas means there is often limited employment and career opportunities. With high levels of unemployment in many regional areas of the Territory, the labour opportunities presented by the development of the shale gas industry are potentially important to improving economic and social outcomes in regional and remote areas.⁶⁵

The types of skills required to develop shale gas deposits differ between the construction and operation phases. In construction the skills set generally favour engineers, drillers, logistics personnel and labourers while engineers, geoscientists and technicians comprise the bulk of the workforce once a project is operational. This range of skill set requirements provides opportunities for job seekers in the Northern Territory, particularly for those job seekers with low skills and those wishing to develop their skills set. It also provides opportunities for trainees and apprentices.

Given the skills set and experience of the Northern Territory workforce, it has been assumed that some specialist skills may need to be sourced from elsewhere in Australia or overseas. However the majority of the workforce is expected to be sourced from within the Territory. During consultation, it was advised that local job seekers would be trained to meet the requirements of the developments. Over time, it is expected that the local employment content of the developments will increase as the skills and experience of the local workforce employed on the developments grow.⁶⁶

There are opportunities for government to maximise the workforce benefits of shale gas development and ensure that benefits are able to be accessed by all job seekers in the Northern Territory. There is **a role for government in co-ordinating the requirements of the shale gas industry with employment and training providers**. This includes identifying the timing of developments and the skills sets required for the construction and operation phases of the developments. There is further opportunity to work with employment agencies and training providers to ensure that they match their services to the needs of the shale gas industry. This will assist in maximising local employment benefits and promoting the distribution of labour benefits to job seekers throughout the Territory.

According to potential suppliers to a shale gas industry, there is an important role for “localised” on the job training opportunities. MS Contracting, one of the major suppliers of supplies and services to the shale gas industry during its brief exploration activities in the Northern Territory, made a submission to the Inquiry and reinforced this submission during stakeholder consultation that referenced the positive outcomes of their localised training program for Indigenous persons in the regions they operate in.⁶⁷

⁶⁴ ACIL Allen Consulting. 2017. *Stakeholder Consultation, 27-29 June 2017*.

⁶⁵ ACIL Allen notes this is an issue to be covered by the Inquiry's Social Impact consultancy.

⁶⁶ ACIL Allen Consulting. 2017. *Stakeholder Consultation, 27-29 June 2017*.

⁶⁷ ACIL Allen Consulting. 2017. *Stakeholder Consultation, 17 October 2017*.

The Northern Territory captures the employment benefits of projects through local labour content policies such as the Indigenous participation in construction projects policy which requires contractors to develop an Indigenous Development Plan aimed at maximising the employment of Indigenous labour and businesses on construction projects. There are benefits in setting local employment targets and Indigenous employment targets as long as they do not result in a misallocation of resources. These types of targets assist in ensuring employment benefits are targeted at local job seekers.

Other programs aimed at maximising local employment and skills development through matching information flows include the NT Apprenticeships and Traineeships Database which is co-ordinated by the Northern Territory Government. The database contains details of all approved apprenticeship / traineeship qualifications in the Northern Territory and provides information on all apprenticeship/traineeship qualifications. Programs aimed at facilitating the flow of information will be important tools in ensuring positive outcomes for the workforce in the Northern Territory.

14.3 Maximising local expenditure and opportunities

Local content policy is founded on the principle of full, fair and reasonable opportunity for local businesses to secure work on large public and private sector projects. An important enabling aspect of local content policy is providing the platform for suppliers and project owners to connect, and to understand the demand for and supply of goods and services which may be required in a project.

The development of shale gas in the Northern Territory offers opportunities for local businesses through the expected high local spend.

The location of the development sites in remote areas provides a range of supply opportunities for regional businesses that provide goods and services. Opportunities are varied but examples of the types of local businesses that could be involved in the construction stage include earthmoving and civil engineering companies; trades such as electricians, plumbers and gas fitters; caterers; suppliers of fresh food and household consumables; and training providers.

In operation, there will be ongoing opportunities for local businesses to enter into long term agreements to provide goods and services to the developments. These will include those businesses that provide cleaning, maintenance, catering, grading, electrical, plumbing and other goods and services.

As discussed earlier in this report, there can be a mismatch between the expectations of developers and the capabilities and services of local suppliers which results in local businesses missing out on opportunities. **There is a role for government to ensure that there is an information flow from developers regarding available opportunities.** There is also a role to work with local businesses to ensure they properly communicate their capabilities and availability to service developments.

The Northern Territory already has a number of key initiatives in place to capture the benefits from spending by developments. These include the Building Northern Territory Industry Participation Policy, a Government procurement program requiring local content, and a partnership with the Industry Capability Network Northern Territory (ICN NT), to ensure to the Government's commitment to local participation is met.

There is benefit in setting local content targets for developers and contractors in order to maximise the capture of direct and indirect spending in the Northern Territory as long as they do not result in a misallocation of resources. There is further benefit in working with developers to promote the services of local businesses, particularly those in regional and remote areas. This would assist in distributing the benefits of the developments to businesses located throughout the Territory. **Addressing information asymmetries**, by identifying the timing of developments, and the goods and services required for the construction and operation phases of the developments is an important role for government. This would further assist local industry to access full, fair and reasonable opportunities to capture business opportunities from a new project.

There are opportunities for government to work with local businesses, particularly those in regional areas, to identify business opportunities and to match the services of regional businesses to those opportunities. The remote location of the developments offer important business opportunities for Aboriginal communities such as in the area of cleaning, catering, maintenance services, fire services

and other parks and ranger services, the hire of heavy equipment such as graders, and the provision of general labour.

BOX 14.3 BUILDING NORTHERN TERRITORY INDUSTRY PARTICIPATION POLICY

Under the Building Northern Territory Industry Participation Policy, an Industry Participation Plan will be a requirement for all Northern Territory Government assisted private sector projects that have an expected value in excess of \$5 million. It will also be a requirement for all Northern Territory Government tendered projects that have an expected value in excess of \$5 million and for Territory Public Private Partnerships (Territory Partnerships) which will provide opportunities for all sectors in the economy to contribute to the efficient delivery of infrastructure and services.

Industry Participation Plans are intended to:

- assist project proponents and developers to maximise opportunities to utilise local suppliers, services and labour;
- improve the capacity of businesses to compete globally; and
- assist decision making in relation to Government purchasing and investment where value will be the primary consideration.

SOURCE: NT GOVERNMENT, ACIL ALLEN CONSULTING

Many regional and remote areas in the Northern Territory are experienced with working with resources companies in the exploration, construction and operation phases of developments. By way of example, the Central Land Council **makes agreements with resources companies on behalf of traditional Aboriginal landowners** that define the outcomes for companies and Aboriginal people before activity commences. These agreements ensure that the benefits of developments flow to Aboriginal people through a commitment to employment, training, sacred site protection, environmental protection and opportunities for Aboriginal people.⁶⁸

These types of agreements, along with a transparent and timely flow of information regarding the timing of developments and their purchase requirements will be essential to maximise the opportunities for businesses in the Northern Territory.

14.4 Industry co-existence

The issue of industry co-existence – the ability for a shale gas industry to “fit in” with the existing industry structures of the Northern Territory – was raised by most stakeholders consulted by ACIL Allen. This issue has a multitude of applications to the work of the Inquiry. The economic dimension is the extent to which a shale gas industry **may impede or distort the allocation of the factors of production**⁶⁹, particularly natural resources like land and water.

ACIL Allen’s development scenarios anticipate a potential shale gas industry could disturb between 67.7 square kilometres (km²) in the BREEZE scenario, 231.7km² (WIND), and 475.9km² in the GALE scenario.⁷⁰ This represents some 0.03 per cent of total land in the Northern Territory in the GALE scenario. ACIL Allen has accounted for the opportunity cost of this land by assuming it is made unavailable for cattle pastures. This is the primary channel of negative economic impact on the agriculture industry in the event of a shale gas development (see Section 6.2.4).

Under ACIL Allen’s adopted assumptions regarding water use, the development may use between 4.2 GL (BREEZE), 11.2 GL (WIND), and 28.2 GL (GALE) of water, respectively. In annual average terms, over the 25 year project life ACIL Allen has modelled, this represents between a 0.17 GL,

⁶⁸ Central Land Council, Making agreements on Aboriginal land: Mining and development, <http://www.clc.org.au/articles/cat/mining/>, accessed September 2017.

⁶⁹ Classical economic theory divides the factors of production – the means of producing goods and services – into four categories: land, labour, capital and enterprise. In this instance, the capital and enterprise are to be provided by the private sector and so this has not been discussed. Labour resources are discussed in Section 14.2.

⁷⁰ These values are adopted as conservative assumptions – ie ACIL Allen has overestimated the area of disturbance so as to ensure it cannot be underestimated. It is noted producers expected approximately 100km² of land disturbance over the life of their “full scale” developments (400TJ/day), the majority of which is associated with transmission pipelines rather than the number of pads.

0.45 GL and 1.13 GL draw on water supplies. This is significantly less than the Australian Bureau of Statistics estimates is used by the agriculture industry in the Northern Territory (47 GL in 2015-16).⁷¹

Through the Inquiry, ACIL Allen has received information that suggests there are a range of options available to a shale gas development to source water – both potable and non-potable – in a manner which minimises tensions with existing users. For example, the Department of Primary Industry and Resources has identified underground aquifers with a sustainable groundwater yield of 100GL per annum or more across the four prospective shale gas basins.⁷² All things being equal, this would suggest **water is unlikely to be a constraint on the development of a shale gas industry** within the current industry structure of the Northern Territory, and the prospect of a reduction in water availability for non-shale gas industry users in the aggregate is limited. In an economic sense, this means there is unlikely to be an opportunity cost borne by society flowing from the use of water by a shale gas development.

Given the above, **it is unlikely that a shale gas industry will impede on the existing allocation of natural factors of production in the Northern Territory**, in an economic sense. However, it is important for the Northern Territory Government to remain fully aware of the activities of potential shale gas operators to monitor the draw on the Territory's natural resources. This would primarily occur through regulation.

There are regulatory measures in place to manage potential land use tensions between industry and Traditional Owners, through a formalised negotiation process involving the various Aboriginal Land Councils established to govern native title in the Northern Territory. Pastoralists also have access to a process to ensure engagement with potential industry proponents, albeit it is not a formalised regulatory instrument. This issue was raised by representatives of the pastoralist industry during ACIL Allen's stakeholder consultation, noting they had advocated for a legislated right of negotiation, access and veto similar to that available to Traditional Owners. Meanwhile, the **Northern Territory Government controls the allocation of permits** for the purposes of exploration or production of petroleum products through its petroleum title system.

The somewhat complex approach to land access is driven in part by the fact that all mineral and petroleum resources are owned by the Crown, and reflects the view that minerals and petroleum are "a gift of nature" and that benefits should accrue to the community as a whole rather than to those who happen to own the surface rights to the land.⁷³

In the United States, petroleum resources are owned by the person or entity which owns the land. This can be the State, but it can also be a home owner whose land sits atop a prospective shale. This has its own benefits – access to land can be a relatively simple process, with direct engagement between a prospective shale gas producer and the private land holder allowing a project to progress rapidly.⁷⁴ However, it also has costs – the State does not always realise the value of the resource, but bears some of the cost in terms of infrastructure and regulatory oversight.

ACIL Allen has commented on appropriate regulatory design in Section 14.6.

Water has been a consistent theme throughout the Inquiry. There are many dimensions, most of which are covered by elements outside of the scope of ACIL Allen's engagement. The economic dimension to water use is the opportunity cost attached to the use of water for shale gas, primarily for the purposes of creating "frack fluid" to conduct a fracture stimulation down well.

While technology is rapidly advancing, ACIL Allen has assumed there is no water recycling in its industry development scenarios. Industry operators have assumed a recycling factor of between 30 and 50 per cent of water used for fracture stimulation,⁷⁵ while industry has proposed the use of lined water "ponds" to store used fracking fluid as a means of disposing of it through evaporation.⁷⁶

⁷¹ Australian Bureau of Statistics. 2017. *ABS Cat. 4618.0: Water Use on Australian Farms*. Accessed online at <http://www.abs.gov.au/>

⁷² Department of Primary Industry and Resources NT. 2017. *Submission to Scientific Inquiry into Hydraulic Fracturing in the Northern Territory: #226*. Accessed online at <http://www.frackinginquiry.nt.gov.au/>

⁷³ Productivity Commission. 1991. *Mining and petroleum in Australia: Volume 3*. Accessed online at <http://www.pc.gov.au/>

⁷⁴ Resources for the Future. 2013. *US Shale Gas Development: What led to the boom? Issue brief 13-04*. Accessed online at <http://www.rff.org/>

⁷⁵ Santos. 2017. *Submission to Scientific Inquiry into Hydraulic Fracturing: #168*. Accessed online at <http://www.frackinginquiry.nt.gov.au/>

⁷⁶ Origin Energy. 2017. *Submission to Scientific Inquiry into Hydraulic Fracturing: #153*. Accessed online at <http://www.frackinginquiry.nt.gov.au/>

As it stands, the **Northern Territory Government does not put a price on the use of groundwater** for mining or petroleum producers. This is in contrast to other Australian jurisdictions, which charge industrial users accessing groundwater resources for industrial purposes. For example, the New South Wales Government licenses access to its surface and groundwater resources, and applies a series of tariffs based on the entitlements allocated and actual water drawn from the allocation.⁷⁷

Implementing a water licensing and charging regime would allow the Northern Territory Government to adequately deal with any opportunity cost which may arise as a result of the use of groundwater resources by the shale gas industry. However, this would need to be balanced against the potential costs that would be incurred by industry, and whether the costs impact on the prospects of the shale gas industry's development in the Northern Territory.

Throughout its stakeholder consultation, representatives from industry, government and non-government organisations provided ACIL Allen with a **range of potential co-existence issues** that were not able to be included in the economic modelling activities in our scope of works. These are presented in the table below (Table 14.1), with the channel of impact discussed in a second column.

TABLE 14.1 INDUSTRY CO-EXISTENCE ISSUES IDENTIFIED DURING STAKEHOLDER CONSULTATION

Issue	Discussion
Increased use of major arterial roads through central Northern Territory	<p>Stakeholders from the private sector and government raised the concerns about the potential use of major arterial roads in the Northern Territory flowing from the development of a shale gas industry. They were concerned that this may lead to an increased incidence of traffic accidents, increased congestion, and reduced usability for tourists travelling through central Australia.</p> <p>This may have an impact across the Northern Territory economy, although it is impossible to determine the scale without conducting substantive work to understand the current state of major arterial roads and their use. It could be ameliorated by requesting a shale gas development includes plans to upgrade the road network should traffic volumes grow large, or commitments to manage traffic flows in such a way that it does not impede other road users.</p>
Reduced land use available for cattle farming	<p>ACIL Allen has addressed this in its economic modelling.</p> <p>The transmission mechanism is a reduction in the capital of the Northern Territory's cattle industry, which reduces the ability for it to earn income by an amount equal to the share of cattle pastures disturbed by the shale gas industry.</p>
Reduced water draw available for agricultural and other uses	<p>ACIL Allen has addressed this in the above discussion of natural resource management. There is no price on ground water, and there are no foreseen constraints on the ability for the industry nor current users to draw.</p>
Reputational impact of shale gas on the tourism industry	<p>Stakeholders were concerned that the Northern Territory's "clean and green" reputation could be tarnished by the connotations of a shale gas industry development occurring in the Northern Territory.</p> <p>This may reduce tourism visitor spend, although it would be difficult to measure the impact, likely very small.</p>

⁷⁷ NSW Government Independent Pricing and Regulatory Tribunal. 2017. *Setting fees and charges*. Accessed online at <http://www.water.nsw.gov.au/>

Issue	Discussion
The Aboriginal Carbon Fund Savannah Burning Program	<p>Aboriginal rangers in the Northern Territory conduct annual programs of savannah burning, where portions of the Territory's landscape are burned in a controlled manner to reduce fire risk. One component of this program is carbon credit farming, which occurs when burning takes place during periods of the year where the volume of greenhouse gases (methane and carbon monoxide) which escapes into the atmosphere is reduced – leading to reduced environmental impact. A stakeholder was concerned that a shale gas industry may result in a reduced availability of land for burning, which would impact on the rangers who conduct the savannah burning.</p> <p>This may have an impact on the employment of those involved in the savannah burning program. However as discussed, the total area of disturbance of the shale gas industry in the Northern Territory is likely to be very small.</p>

SOURCE: ACIL ALLEN CONSULTING

14.5 Addressing potential infrastructure constraints

The development of shale gas in the Northern Territory will place additional pressure on existing and planned infrastructure in the Northern Territory including economic infrastructure, social services, social infrastructure, and civic infrastructure. It is expected that the focus will be an increase demand for road, rail and port infrastructure to transport goods and personnel to and from the development sites, in the form of constraints. There could also be additional pressure placed on social infrastructure such as health, education and civic services, particularly in regional areas where infrastructure often has limited capacity to cater for an increase in demand.

Development of infrastructure by the shale gas industry has social and economic benefits for the Northern Territory and particularly for regional areas where much of the infrastructure development is likely to occur. Well planned economic infrastructure is a key enabler for economic and social growth. The development of infrastructure in the Northern Territory is guided by the Northern Territory Infrastructure Strategy that sets out the vision and objectives for infrastructure development along with policy drivers and a framework for the development of infrastructure projects.⁷⁸ The Strategy is supported by the Northern Territory 10 Year Infrastructure Plan which details planned projects for the first two years (2017–18 and 2018–19) with proposed infrastructure projects identified in the medium (2019–20 to 2021–22) and longer (2022–23 to 2026–27) term.⁷⁹ It is important that the government is made aware of developments in the shale gas industry in order to ensure the infrastructure planning and policy framework in the Territory reflects that development.

Supporting infrastructure is a critical component of any resource venture. Given the remote locations of some resource projects, infrastructure is often provided as part of an integrated self-contained development. However, there are often significant benefits from improvements in infrastructure to other users. The development of the shale gas industry could result in upgrades to infrastructure such as roads, thereby creating efficiencies for other road users. The construction of roads in regional and remote areas can assist in providing better access to communities in these areas providing social benefits such as improved safety outcomes, and economic benefits from a more efficient logistics network, and allowing tourists and other visitors to access these areas. The development of infrastructure also allows better access to developments providing greater opportunities for all residents of the Northern Territory to share in the wealth generated by them.

Consultation found that there were perceived issues with some infrastructure that would support the development of the shale gas industry. Examples include the capacity of the Stuart Highway given the current and potential activity of the resources sector along this Highway.⁸⁰ The Northern Territory 10 Year Infrastructure Plan has identified the upgrade of the Highway as a strategic priority to assist freight and economic development. The plan also identifies multiple required road upgrades in the Territory that primarily involve the sealing of regional roads.

⁷⁸ Northern Territory Government (2017), Infrastructure Strategy, Darwin

⁷⁹ Northern Territory Government (2017), 10 Year Infrastructure Plan 2017 to 2026, Darwin

⁸⁰ ACIL Allen Consulting, 2017. Stakeholder Consultation, 27-29 June 2017.

An often overlooked feature of the public sector's role in the provision of infrastructure is process surrounding **project selection, prioritisation and long term planning**. Infrastructure investments are often made without due regard given to the basic economic principle of opportunity cost, in that Governments have a limited ability to fund projects. In recent times, both the Australian Government and a number of State Governments have developed independent infrastructure advisory bodies, to assist in the selection, prioritisation and planning for major infrastructure in their respective jurisdictions. The Northern Territory is likely not of the requisite scale to require such a body, but it can learn – and indeed appears to have learned, given its 10 Year Infrastructure Plan – from the principles used to underpin these bodies (Box 14.4).

The Government has a key role in the development of infrastructure in the Northern Territory however with limited resources, **there is a need for private investment**. The Northern Territory 10 Year Infrastructure Plan identifies the private sector as potentially contributing funds to the development of a number of infrastructure projects relevant to the development of shale gas including roads, railways, marine/barge landings, airports, and water supply.

BOX 14.4 THE FUNCTIONS OF INFRASTRUCTURE NSW

Infrastructure NSW (INSW) is established by the *Infrastructure NSW Act 2011*, which among other things sets out the general and specific functions of the body. These include:

- prepare and submit to the Premier a 20-year State infrastructure strategy;
- prepare and submit to the Premier 5-year infrastructure plans and other plans requested by the Premier;
- prepare and submit to the Premier sectoral State infrastructure strategy statements;
- prepare project implementation plans for major infrastructure projects;
- review and evaluate proposed major infrastructure projects by government agencies or the private sector and other proposed infrastructure projects (including recommendations for the role of Infrastructure NSW in the delivery of those projects);
- oversee and monitor the delivery of major infrastructure projects and other infrastructure projects identified in plans adopted by the Premier;
- carry out or be responsible for the delivery of a specified major infrastructure project in accordance with an order of the Premier;
- assess the risks involved in planning, funding, delivering and maintaining infrastructure, and the management of those risks;
- provide advice to the Premier on economic or regulatory impediments to the efficient delivery of specific infrastructure projects or infrastructure projects in specific sectors;
- provide advice to the Premier on appropriate funding models for infrastructure;
- co-ordinate the infrastructure funding submissions of the State and its agencies to the Commonwealth Government and to other bodies;
- carry out reviews of completed infrastructure projects at the request of the Premier; and
- provide advice on any matter relating to infrastructure that the Premier requests.

One of the critical features of INSW is any project that receives approval must have undertaken a rigorous, transparent cost-benefit analysis.

SOURCE: INFRASTRUCTURE NEW SOUTH WALES

There are also opportunities to **leverage Australian Government infrastructure funding** to assist in funding any new infrastructure that may be required.

- **The Northern Australia Infrastructure Facility (NAIF)** is a concessional loan facility established by the Australian Government to encourage and complement private sector investment in infrastructure in northern Australia. The Australian Government has made \$5 billion available to approve loans between 1 July 2016 and 30 June 2021, with terms determined on a case by case basis.

- **The Building Better Regions Fund (BBRF)** is a grant-based program available to provide infrastructure or community investments in areas outside of Adelaide, Brisbane, Canberra, Melbourne, Perth and Sydney. The application for funding can be made by a Local Government Authority or not for profit organisation, but can be supported by State/Territory Governments and private sector organisations. There is just under \$500 million in funding available in the program.
- **The National Water Infrastructure Fund** is available to assist public and private sector entities improve water infrastructure across Australia. Projects can build new or augment existing water infrastructure, including dams, pipelines or aquifer related projects. Projects must be sponsored by a State Government, who must be involved in the project.

These are in addition to regular programs such as national partnerships for roads and rail, local roads investments, and discretionary infrastructure investment funds made available by the Australian Government from time to time.

14.6 Approaches to industry regulation

The Productivity Commission's 2009 review into upstream petroleum regulation in Australia found the system was overly complex, contained numerous overlapping areas of compliance and statutes, and was likely harming the international competitiveness of Australia's energy sector.⁸¹ In 2017, little appears to have change, particularly when it comes to onshore regulation (the Commonwealth Government has implemented some of the Productivity Commission's recommendations regarding consolidation of offshore petroleum regulations).

Petroleum extraction is subject to significant regulatory impost relative to other sectors, in line with the heightened safety risks and potential environmental impacts should something go wrong. During stakeholder consultation, potential industry proponents did not express a strong dissatisfaction with the current regulatory regime for petroleum extraction in the Northern Territory.⁸²

The Fraser Institute's Global Petroleum Survey (2015) found **the Northern Territory was rated as the third most development-favourable jurisdiction in Australia** from a regulatory perspective, and the 34th most favourable of 126 jurisdictions surveyed by the Institute.⁸³ Comment on specific regulatory matters is not within ACIL Allen's scope of works, but at face value it appears the Northern Territory's existing petroleum regime serves the needs of industry well ensuring Territorians are protected.

The most substantive issue regarding industry regulation was a **perception that the Northern Territory Government may not be fully equipped to regulate a shale gas industry**. This was an issue raised by stakeholders from the private sector, government and non-government organisations.⁸⁴ Regulatory enforcement is a critical part of the way the Northern Territory Government can help provide the public with certainty industry is meeting its social license to operate. The significant land mass of the Northern Territory, and the remote location of prospective developments, make physical regulation of the industry difficult.

The functions of petroleum regulation are vested in the Department of Primary Industry and Resources' "Energy Services" group.⁸⁵ In its 2017-18 Budget, the Northern Territory Government has reduced the appropriation granted to the group from \$3.9 million to \$3.4 million, on account of the cessation of a one-off research funding grant. There are additional regulations which apply to the petroleum sector, such as occupational health and safety and environmental protection. Broadly speaking, the Northern Territory Government spends \$37.2 million on mining and petroleum industry information services and regulation.

While the direct expenditure on petroleum-specific regulation in the Northern Territory is an increase on recent years (the Energy Services group, formerly a part of the Department of Mines and Energy, received an appropriation of \$2.6 million in 2014-15 and 2015-16), **the level of funding is low**

⁸¹ Productivity Commission. 2009. *Review of the regulatory burden on the upstream petroleum (oil and gas) sector, April 2009*. Accessed online at <http://www.pc.gov.au/>

⁸² ACIL Allen Consulting. 2017. *Stakeholder Consultation: 27-29 June 2017*.

⁸³ Fraser Institute. 2016. *Fraser Institute Global Petroleum Survey, 2015*. Accessed online at <http://www.fraserinstitute.org/>

⁸⁴ ACIL Allen Consulting. 2017. *Stakeholder Consultation: 27-29 June 2017*.

⁸⁵ NT Treasury. *NT Budget 2017-18, Agency Statements*. Accessed online at <http://www.budget.nt.gov.au/>

compared to the cost of services of mining and petroleum regulators in other States
(Table 14.2).

The level of expenditure on services is not prima facie a measure of the level of service delivery. However the stark difference between the Northern Territory and other State and Territories suggests stakeholder concerns require this issue to be examined further. In any event, the capacity of regulators to enforce the regulation of a shale gas industry is a significant consideration for the Northern Territory Government. Given the Northern Territory's current financial challenges, there may be a need for the Northern Territory Government to examine innovative approaches to industry regulation.

Best practice principles suggest **industry should "pay its way" when it comes to industry regulation**. This is because appropriate regulations, and regulatory enforcement, is critical to industry earning a social license to operate; operators themselves are also the major beneficiary of a regulatory regime which enables the safe development of an industry. The Northern Territory Government levies a fees and charges regime for onshore petroleum exploration and production licenses, but these are relatively small in the scheme of the life of a development (for example, ACIL Allen estimates ProjectCo will spend just \$3.6 million in licensing fees in the GALE scenario – 0.003 per cent of forecast revenue). There may be scope to increase these fees and charges in order to fund any uplift in expenditure required to more adequately resource government regulators.

TABLE 14.2 COST OF ADMINISTERING AND REGULATING THE MINERAL AND PETROLEUM SECTORS, BY STATE, 2016-17, \$M

State	Mining and/or petroleum information and regulation expenditure	Department/s applying regulation
Queensland	Mining and petroleum \$258.5m	Department of Natural Resources and Mines Department of Energy and Water Supplies
South Australia	Mining and petroleum. Also includes some electricity regulatory services related to consumer safety \$132.8m	Department of Premier and Cabinet
Western Australia	Mining and petroleum \$154.6m	Department of Mines, Industry Regulation and Safety

SOURCE: ACIL ALLEN CONSULTING, BASED ON ANALYSIS OF STATE BUDGET PAPERS



APPENDICES
PART ONE:
ENGAGEMENT
INFORMATION



A.1 Background to the Inquiry

On 14 September 2016 the Chief Minister of the Northern Territory, the Hon Michael Gunner MLA, announced a moratorium on hydraulic fracturing of onshore unconventional reservoirs in the Northern Territory. At the same time, the Chief Minister announced that a *Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs in the Northern Territory* (the **Inquiry**) would be established and released draft Terms of Reference, which were open for public comment for four weeks.

On 3 December 2016 the Northern Territory Government announced the final Terms of Reference for the Inquiry and the composition of the panel that will be undertaking the Inquiry (the **Panel**).

The Inquiry was established under section 4 of the *Inquiries Act 1945* (NT) and is comprised of a judicial chair, the Hon Justice Rachel Pepper, and ten highly regarded scientists with expertise in areas ranging from hydrogeology to social science.

The Inquiry's final Terms of Reference can be read in full on the Inquiry's website (www.frackinginquiry.nt.gov.au).

On 20 February 2017 the Inquiry released a *Background and Issues Paper*, also available on the Inquiry's website, which was followed by hearings and community meetings held in March 2017 in various town centres and remote communities across the Northern Territory. The Issues Paper includes a timeline for the Inquiry, which indicates that an interim report will be released in mid-2017, a draft final report will be released during the last quarter of the year, and a final report will be released in December 2017.

The Hydraulic Fracturing Taskforce (the **Taskforce**) has been established in the Department of the Chief Minister to support the Inquiry.

A.2 Terms of Reference for the Inquiry and the economic impact theme

The Panel has divided the work of the Inquiry into the following themes: water, land, air, social impacts, economic conditions, cultural conditions, human health, land access, and the regulatory framework. This request relates to the economic theme only, however, there are overlaps with the social impact and regulatory framework themes. A sub-group of Inquiry Panel members has been allocated responsibility for each theme.

The Terms of Reference for the Inquiry require the Panel to do the following in respect of each theme:

1. determine and assess the impacts and risks associated with hydraulic fracturing of unconventional reservoirs and the associated activities;
2. determine whether additional work or research is required to make that determination;

3. advise the level of impact or risk that is acceptable in the Northern Territory context;
4. describe methods, standards or strategies that can be used to reduce the impact and risk to acceptable levels; and
5. identify what government can do, including implementing any policy or regulatory changes, to ensure that the impacts and risks are reduced to the required levels.

The *Background and Issues Paper* includes a non-exhaustive list of the potential risks and benefits associated with the economic theme at page 22.

In accordance with the definitions in the Terms of Reference, a reference to an “unconventional reservoir” in this document is a reference to a reservoir where the rock formation is *shale*. There is currently no gas being produced from unconventional, or shale, reservoirs in the Northern Territory. The Amadeus Basin is currently producing gas from conventional reservoirs.

With regard to the third Term of Reference stated above, the level of impact or risk that is acceptable will ultimately be a matter for the decision maker under the relevant legislation (typically the Minister), however, at this stage the meaning of acceptability or acceptable levels of risk is a matter for the Panel, taking into account principles of ecological sustainable development, including the precautionary principle and intergenerational equity.

The Terms of Reference make it clear that the Panel must not only look at the impacts of hydraulic fracturing and the associated activities on economic conditions in the Northern Territory – the Panel must also consider the economic impacts of the onshore unconventional gas industry *as a whole* on the Northern Territory. This is made clear in the following extract from the Terms of Reference, which has been amended to include the relevant language only:

“When the inquiry makes a determination... about whether or not there has been an impact or risk on ... economic conditions, the inquiry will ... consider the impacts and risks of the development of the onshore unconventional gas industry, including exploration activities such as seismic surveys and aerial surveys, land access and costs and benefits of the industry.”

A.3 Steering Committee

A Steering Committee has been established to oversee the work. The Steering Committee is comprised of the Hon Justice Rachel Pepper, Dr Vaughan Beck and the Executive Director of the Hydraulic Fracturing Taskforce. The point of contact for all matters will be the Executive Director of the Hydraulic Fracturing Taskforce.

A.4 Probity Advisor

The Territory has appointed a Probity Advisor to oversee the Territory’s processes in relation to the stages of this process. The Probity Advisor’s role is to ensure that fairness and impartiality are observed throughout, and that the evaluation criteria stated in any related documentation are consistently applied to all submissions.

A.5 Scope of Work

The supplier must consider the following scenarios:

- **Scenario 1** or the baseline scenario, where the moratorium on hydraulic fracturing of unconventional shale gas reservoirs remains in place;
- **Scenario 2**, which involves the development of the onshore unconventional shale gas industry in the Northern Territory; and
- **Scenario 3**, which involves the development of unconventional shale gas reservoirs in the Beetaloo Sub-Basin only.

A.6 Benefits

The supplier must describe, in both quantitative and qualitative terms, the actual and potential direct and indirect economic benefits associated with each of Scenarios 1, 2 and 3 on the Northern Territory economy under the current regulatory regime.⁸⁶

The supplier must describe, in quantitative and qualitative terms, the actual and potential direct and indirect economic benefits associated with Scenario 2 on the national economy under current regulatory, fiscal and economic settings.

For each of Scenarios 1, 2 and 3 the supplier must estimate the following:

- Gross State Product (**GSP**);
- State Final Demand (**SFD**);
- employment;
- business investment and output;
- CPI;
- population;
- wages; and
- the quantum of royalties that might be received by the Northern Territory Government under the *Petroleum Act 1984* (NT) (to avoid doubt this will include any royalties received in connection with both unconventional and conventional reservoirs).

The supplier must provide the Steering Committee with:

- in accordance with Part C, any assumptions made and an explanation of the methodology used to develop such assumptions, both of which must be approved by the Steering Committee prior to undertaking any economic modelling. The supplier must explain how reasonable and reliable the assumptions are, as well as how any potential bias has been managed, and
- a description of the similarities or differences between the assumptions made under item 7(a) above and the assumptions made in the report entitled *Economic Impact of Shale and Tight Gas Development in the NT* dated 14 July 2017 by Deloitte Access Economics.

The supplier must describe the options available to the Northern Territory Government, whether through policy or regulatory reforms or otherwise, to maximise and sustain the benefits captured by Territorians and others.⁸⁷ In this regard the supplier must:

- conduct a literature review to advise on leading practice methods for the sustainable development of onshore unconventional shale gas projects from an economic perspective, and
- provide case studies and examples from comparable jurisdictions, including domestic and overseas jurisdictions, where such options have been successful and unsuccessful and what lessons can be learned from these experiences in the Northern Territory context.

The supplier must describe the options available to the Northern Territory Government, including regulatory or policy reforms, for how revenue from the development of onshore unconventional shale industry can be retained both jointly and separately in the regions affected by the development and the Northern Territory, in each case, without impeding investment. Consideration must be given to:

- local procurement requirements, local training programs and other mechanisms to improve local capacity as well as any 'Royalty for Regions' or similar type programs, and
- case studies and examples from comparable jurisdictions, including domestic and overseas jurisdictions, where such options have been successful and unsuccessful and the lessons that can be learned for the Northern Territory context.

⁸⁶ Indirect benefits might include the opening up of supply chains for local businesses, innovation spin offs, opportunities to develop or support supply and maintenance industries and any other flow-on opportunities the supplier identifies.

⁸⁷ It is noted that onshore unconventional gas industry, local communities, local governments, Aboriginal stakeholders (including Aboriginal land councils and prescribed bodies corporate under the *Native Title Act 1993* (Cth)) have a significant role to play in the maximisation of economic benefits, however, the scope of the work is limited to actions that government can take.

A.7 Risks

The supplier must describe, in qualitative terms, any actual and potential adverse impacts and risks associated with Scenario 1, Scenario 2, and Scenario 3 on the Northern Territory economy under the current regulatory regime.

The supplier must consider the impacts of development on other industries in the Northern Territory, including, but without limitation, the tourism, agricultural, horticultural and pastoral, industries.

The supplier must describe the options available to the Northern Territory Government, including policy or regulatory reforms, to mitigate and manage any actual and potential impacts and risks identified above. For example, the supplier must advise what the Northern Territory Government can do to mitigate any “boom and bust” economic cycle associated with the development of any unconventional shale gas industry.

The supplier must:

- conduct a literature review to advise on leading practice methods that could be used to manage and mitigate any risks identified, and
- provide case studies and examples from comparable jurisdictions, including domestic and overseas jurisdictions, where such options have been successful and unsuccessful, and what lessons can be learned from these experiences in the Northern Territory context.

A.8 Assumptions

No production licences have been granted under the Petroleum Act for the purpose of producing unconventional shale gas in the Northern Territory. Further exploration work, including the drilling of appraisal wells, is required to fully understand the scope of the Northern Territory’s shale gas reservoirs and whether or not they are commercially recoverable.

The most prospective area for shale gas development, should the moratorium be lifted by the Government, is the Beetaloo Sub-Basin (see Attachment A). Origin Energy announced a significant discovery of unconventional shale gas in the Beetaloo Sub-Basin in February 2017, which significantly increased prior estimates of the resource.

In developing any assumptions required to undertake Part A and B, the supplier must consult with relevant stakeholders, including, but without limitation, the Departments of Treasury and Finance; Primary Industry and Resources; Trade, Business and Innovation; Chief Minister; NT Farmers; the Northern Territory Cattleman’s Association; petroleum operators and titleholders in the Beetaloo Sub-Basin, Aboriginal Land Councils, and the Australian Petroleum Production and Exploration Association.

The supplier must notify the Steering Committee prior to any consultation and members of the Steering Committee may attend the consultation.

A.9 Timelines and Reporting

The work must be in the form of a written report. The report must be written in plain English. All technical terms (including economic metrics such as Gross State Product, State Final Demand, and employment multipliers) must be explained.

At the end of each calendar month following the award of the tender the supplier must provide the Steering Committee with a written progress report and a verbal presentation within five working days of receipt of the report.

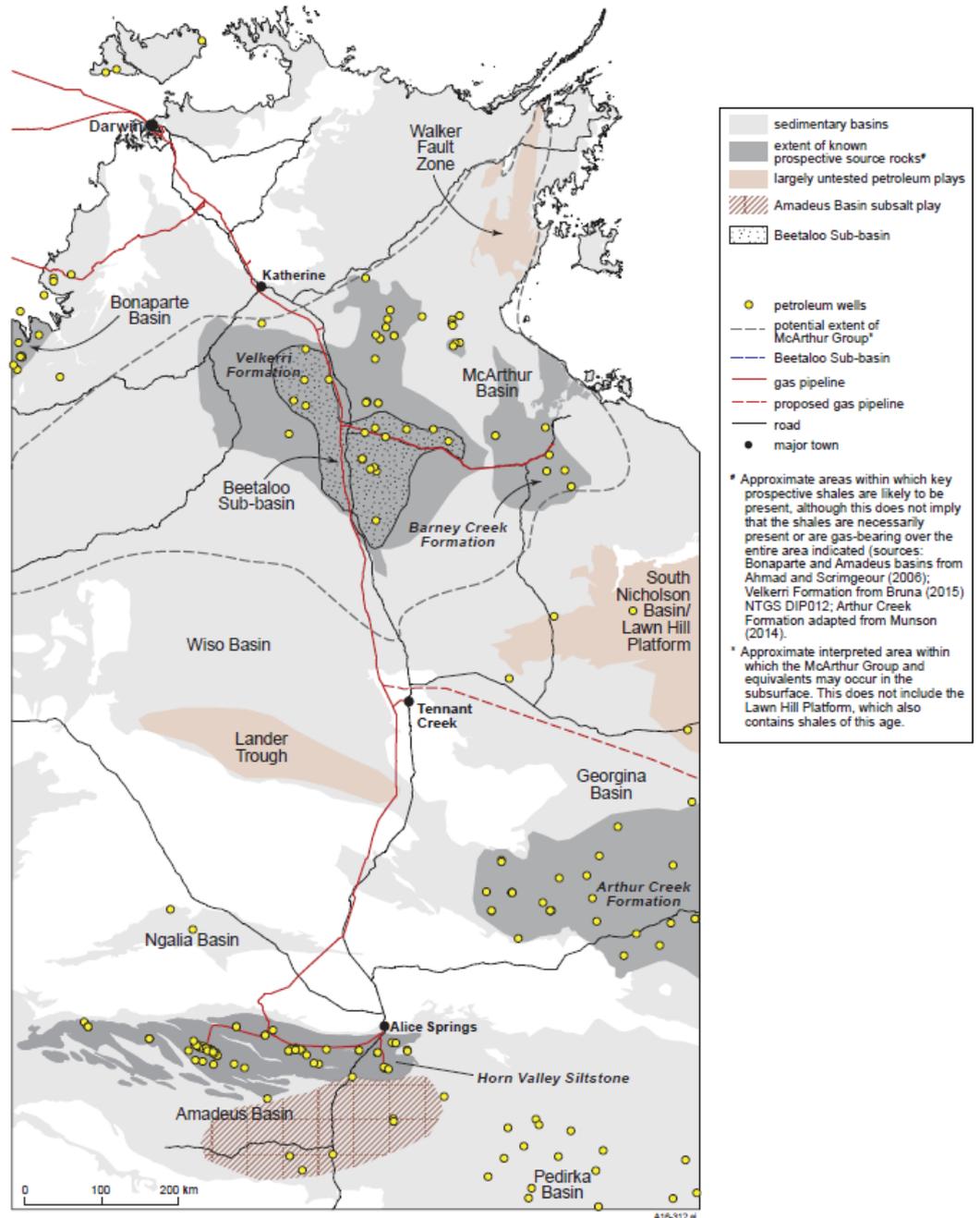
The supplier must provide the Steering Committee with a draft final report and a verbal presentation to the Steering Committee on or prior to 18 August 2017.

A final report must be provided to the Steering Committee by 1 September 2017 and the supplier must present the final report to the Panel on a date to be determined.

The Inquiry will publish the final report on the Inquiry’s website on a date to be determined.

The supplier must keep all correspondence, reports and presentations to the Steering Committee confidential, except that the supplier may make the final report publicly available after it has been published on the Inquiry's website.

Northern Territory petroleum potential



Dec 2016

Northern Territory Geological Survey
Department of Primary Industry and Resources





The below Consultation Guide was issued to all stakeholders consulted during ACIL Allen's initial round of stakeholder consultation in the Northern Territory in June 2017. It was used to guide conversations, and assist stakeholders to provide the most relevant information for ACIL Allen's scope of works.

Background

On 3 December 2016 the Northern Territory Government announced an independent Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (the 'Inquiry'). The Inquiry is investigating the environmental, social and economic risks and impacts of hydraulic fracturing ('fracking') of onshore unconventional gas reservoirs and associated activities in the Northern Territory.

This was the result of an election commitment made by the current Northern Territory Government while in opposition. On 14 September 2016, the Northern Territory Government announced a moratorium on hydraulic fracturing of onshore unconventional reservoirs, including the use of hydraulic fracturing for exploration, testing, and extraction. The moratorium will remain in place during the Inquiry. The Northern Territory Government's terms of reference guide the conduct of the Inquiry. These are included in Box 14.5.

BOX 14.5 TERMS OF REFERENCE: SCIENTIFIC INQUIRY INTO HYDRAULIC FRACTURING IN THE NORTHERN TERRITORY

The terms of the Inquiry are to:

4. assess the scientific evidence to determine the nature and extent of the environmental impacts and risks, including the cumulative impacts and risks, associated with hydraulic fracturing of unconventional reservoirs and the Associated Activities in the Northern Territory;
5. advise on the nature of any knowledge gaps and additional work or research that is required to make the determination in Item 1, including a program for how such work or research should be prioritised and implemented, that includes (but is not limited to):
 - a) baseline surface water and groundwater studies,
 - b) baseline fugitive emissions data,
 - c) geological and fault line mapping, and
 - d) focus areas for baseline health impact assessment,

6. for every environmental risk and impact that is identified in Item 1, advise the level of environmental impact and risk that would be considered acceptable in the Northern Territory context;
7. for every environmental risk and impact that is identified in Item 1,
 - a) describe methods, standards or strategies that can be used to reduce the impact or risk; and
 - b) advise whether such methods, standards or strategies can effectively and efficiently reduce the impact or risk to the levels described in Item 3;
8. identify any scientific, technical, policy or regulatory requirements or resources that are in addition to the reforms being implemented through the existing environmental reform process that are necessary to reduce environmental risks and impacts associated with the hydraulic fracturing of unconventional reservoirs to acceptable levels; and
9. identify priority areas for no go zones.

SOURCE: HYDRAULIC FRACTURING TASKFORCE

Role of ACIL Allen

ACIL Allen Consulting has been appointed by the Inquiry to assess the actual and potential direct and indirect economic benefits, risks and impacts of fracking on the Northern Territory under the current regulatory regime.

To facilitate this, ACIL Allen's scope of works gives regard to three distinct scenarios:

6. Scenario 1, or the baseline scenario, where the moratorium on hydraulic fracturing of unconventional shale gas reservoirs remains in place (the 'base case')
7. Scenario 2, which involves the development of the onshore unconventional shale gas industry in the Northern Territory (the 'unconstrained case')
8. Scenario 3, which involves the development of unconventional shale gas reservoirs in the Beetaloo Sub-Basin only.

In order to do this, ACIL Allen will complete two main tasks:

- **Conduct economic impact assessment modelling, using ACIL Allen's suite of in-house economic models**, including models of the national gas and electricity markets. To complete this task, ACIL Allen will develop credible, evidenced-based scenarios for the development of shale gas projects in the Northern Territory under a set of assumptions which are agreed by the Inquiry. The outcome of this task will be quantitative economic impact assessment results under each of the three scenarios listed above.
- **Research, analyse, articulate and discuss the potential impacts on the Northern Territory economy's other industries**, including but not limited to tourism, agriculture, horticulture and pastoral. This will centre on findings of stakeholder consultation and a review of relevant international literature and case studies. The outcome of this task will be a chapter or chapters in the final report of this engagement that outlines the economic risks and provides suggestions on policy initiatives the Inquiry may recommend to the Northern Territory Government in the Inquiry report.

ACIL Allen is undertaking consultation with key stakeholders in order to inform these two main tasks.

Stakeholder consultation process

The Inquiry has identified your organisation as an interested stakeholder that may be able to assist ACIL Allen in delivering on our scope of works.

This consultation guide provides some basic background information on the Inquiry, and the issues that ACIL Allen is seeking input from participating stakeholders. In order to guide the meeting, ACIL Allen has developed a series of questions that the project team will be asking stakeholders at their scheduled meeting.

Following the initial contact, ACIL Allen may issue additional questions via email to request data or evidence to assist in completing the above tasks.

Please note: all stakeholder consultation will be recorded (via written notes) as evidence for the Inquiry. A member of ACIL Allen's project team will take notes during consultation, and these notes will be delivered to the Inquiry to assist in the formulation of project assumptions and other elements of the engagement as required. ACIL Allen has in place a confidentiality agreement as it relates to the Inquiry and any commercial-in-confidence material provided will be treated as such.

The Northern Territory economy

The Northern Territory economy is a regional economy, which generated \$23 billion in Gross State Product (GSP) in 2015-16, accounting for 1.4 per cent of Australia's Gross Domestic Product (A\$1.6 trillion). Northern Territory is an emerging economic centre, with average annual rates of growth in the economy exceeding five per cent per annum over the past five years (around double the rates of growth recorded in the national economy over the same period).

Economic growth in the Northern Territory is fairly volatile due to its small size and narrow economic base. As a result, major investments can have a disproportionately large impact on overall growth. The development of the Ichthys LNG Project is already having a substantial impact on the Northern Territory economy, which most recently recorded economic growth of 15.8 per cent in 2012-13 as investment activity accelerated. However, economic growth in the Northern Territory been more measured since, with the economy growing by 2.7 per cent in 2015-16.

The largest industries in the Northern Territory are construction (17.7 per cent of GSP), mining (12.9 per cent) and public administration and safety (10.3 per cent).

The working age population in the Northern Territory is 187,000, with 134,500 person employed as at June 2016. Employment growth in the Northern Territory has been strong for a number of years, with the jobs market only recently contracting in line with a downturn in the resources sector.

Jobs growth in the Northern Territory is heavily influenced by major resource projects, with employment growth at its strongest during the construction of key projects in the Territory, with the falling levels of employment coming as the construction phase is completed.

The estimated residential population in the Northern Territory (as at June 2015) was just under 245,000, with 58 per cent of the population concentrated around the greater Darwin area. Since 2010, the estimated residential population of the Northern Territory has increased by 6 per cent, with greater Darwin growing by 11 per cent and all areas outside of greater Darwin remaining relatively unchanged (less than a 1 per cent increase).

The Northern Territory's 2017-18 Budget, released on in May 2017, projects five consecutive net operating deficits for the Territory Government, with net debt rising from \$2.4 billion to \$5.5 billion between 2016-17 and 2020-21. The Northern Territory non-financial public sector raised \$1.9 billion in revenue from its own sources in 2016-17, and recorded total operating expenditure of \$6.5 billion. The Government relies on Commonwealth Government grants to fund a large proportion of its operations.

Fracking

For the purposes of this engagement, ACIL Allen has relied upon background materials produced by the Inquiry and published on its website (www.frackinginquiry.nt.gov.au/information). A brief introduction to fracking, adapted from this information, is included below.

What is fracking?

There are two broad types of gas reserves: conventional and unconventional. Conventional gas reserves accumulate in confined areas with well-connected pore spaces in a sedimentary basin. This allows for effective drainage of reserves with well-placed vertical wells. By contrast, unconventional gas reserves accumulate in a larger area amongst more tightly bound and less porous sedimentary basins, which are typically lower in the ground. A visual representation of conventional and

unconventional gas accumulations and some of the extraction techniques is provided in Figure 3.1 (overleaf).

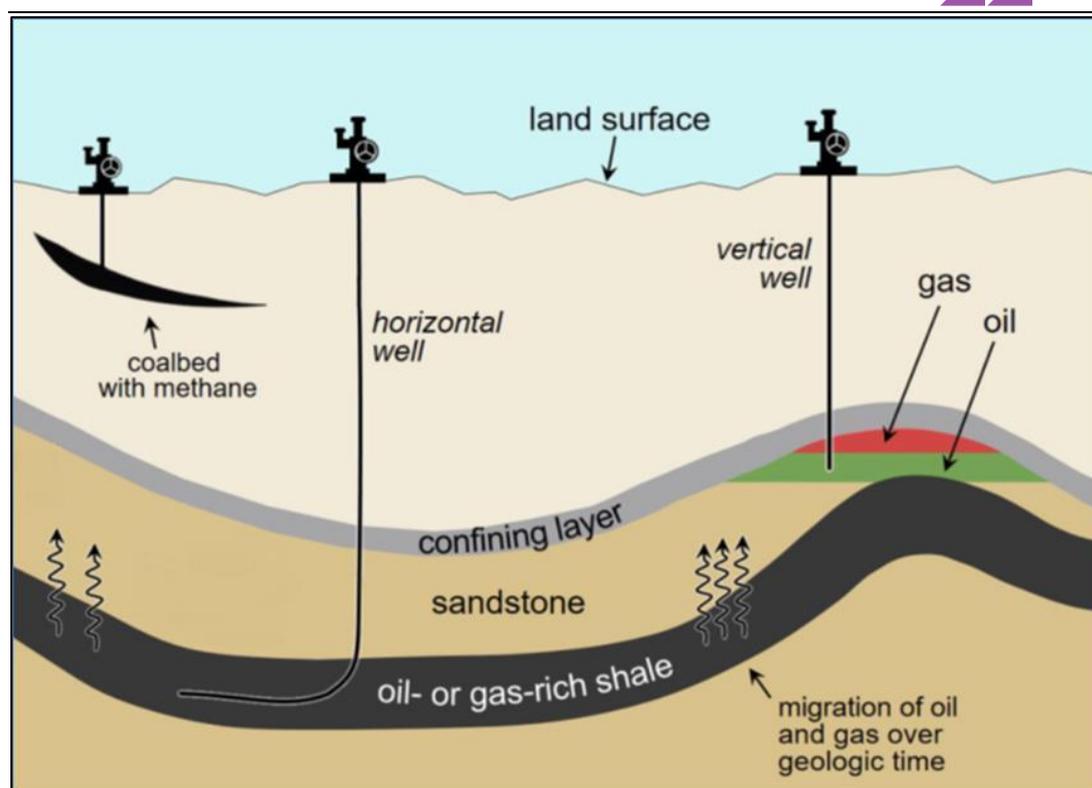
Artificial stimulation is typically required to make the gas in unconventional reservoirs flow through a well. One commonly used technique to achieve this is called hydraulic fracturing, commonly known as 'fracking'. Fracking basically involves pumping a mixture of water, sand and chemical additives ('fracking fluid') into the production well, under pressure, so that the rocks containing the gas resources crack. This allows the gas contained in the tight reservoir to flow more freely.

Shale gas versus coal seam gas (CSG)

Fracking is used to extract both coal seam gas (CSG) and shale gas. The two types of resources differ significantly.

- CSG is typically extracted from wells that are much closer to the land surface (300m – 1,000m) than shale wells (1,500m – 4,000m)
- CSG is typically much closer to the surface, and therefore closer to potable water sources such as aquifers. Shale gas is not typically located near aquifers
- CSG is most often extracted using vertical wells, while shale gas is extracted using a combination of vertical and horizontal drilling techniques
- CSG wells are typically low productivity and require a larger number of wells, where shale gas wells produce more energy per well. However, shale wells use more water per well, and operate across a larger underground footprint.
- The land surface area of CSG wells and shale gas wells is largely the same.

FIGURE 14.1 DIFFERENT TYPES OF PETROLEUM ACCUMULATIONS AND DEVELOPMENT



SOURCE: THE INQUIRY, VIA U.S. ENVIRONMENTAL PROTECTION AGENCY.

The fracking process

Shale gas is mainly methane (often with associated liquid hydrocarbons) that is trapped within clay-rich sedimentary rock at depths greater than 1,500 metres. The low permeability of the rock means that gas, either absorbed or in a free state, in the pores of the rock, is unable to flow easily.

To extract shale gas, wells are drilled anywhere from 1,500 – 4,000 metres deep through various layers of rock to access the shale. The wells are lined with various steel casings, which are cemented using fit-for-purpose cement designed to protect groundwater from contamination.

To maximise shale gas recovery a technique called horizontal drilling is used. This technique typically involves the well changing from a vertical to a horizontal direction deep underground.

Before gas can be extracted from the shale gas reservoir, hydraulic fracturing must occur. Hydraulic fracturing is a technique used to enhance the production of the gas. Hydraulic fracturing refers to the injection of fluid (comprising approximately 99.5% water and proppant (sand) and approximately 0.5% chemical additives) at high pressure into targeted sections of the layers of gas-bearing rocks. This creates localised networks of fractures that unlock gas and allow it to flow into the well and up to the surface. An average of 20 to 30 megalitres (ML) of water is used per fracked horizontal well over the life of the well.

After fracturing, the hydraulic pressure is released and most of the ‘frack fluid’ is pumped back out of the well. Typically gas production from the well builds up over a period of days or weeks as the frack fluid is recovered (a process known as ‘well clean-up’). Much of the sand remains in the well, propping open the cracks so that gas flow is maintained (hence ‘proppant’).

Basically similar processes can be used to enhance gas production rates in vertical or horizontal wells in other tight reservoirs (both unconventional and conventional).

- * *Is there any additional information relevant to an economic impact assessment that ACIL Allen Consulting should consider regarding the process of drilling, fracking, and related activities required to produce shale gas?*

The investment and operating expenditure profile of a shale gas project differs significantly from a more conventional gas project, which the Northern Territory has had recent experience with in the form of the INPEX’s Ichthys LNG project. A typical fracking project has a smaller upfront capital component than a conventional gas project, but may have larger ongoing capital costs associated with management and maintenance of a given level of production through development of additional wells.

- * *To your knowledge, is this assumption regarding the capital and operating expenditure profile of a fracking operation versus a conventional gas project correct?*
- * *Do you have any information or evidence you can provide ACIL Allen regarding the capital and operating expenditure profile of a hypothetical or actual fracking operation in Australia?*

Fracking in the Northern Territory

ACIL Allen is required to develop realistic, evidence-based scenarios for shale gas developments in the Northern Territory over a defined period of time. There are two development scenarios: the moratorium on activities is lifted in the Beetaloo Basin only, and the moratorium on activities is lifted across the entirety of the Northern Territory. In order to develop these scenarios, we require information on shale gas reserves and resources in the Northern Territory.

We understand from information provided to us by the Inquiry and from our initial research that the Beetaloo Basin hosts a highly prospective and large scale (one company has raised the spectre of 6.6 trillion cubic feet of resource in its license area alone) contingent gas resource. By way of contrast, the Pluto LNG project was approved on the basis of a 4.4 trillion cubic feet contingent resource. One of the scenarios ACIL Allen is required to model is the development of the Beetaloo Basin.

- * *Do you have any information regarding the Beetaloo Basin and its prospectivity that you can share with us to assist us in developing our modelling assumptions?*

ACIL Allen is also required to develop an estimate of the economic impact of the removal of a moratorium on activities across the whole land area of the Northern Territory. The information on the impact of this is largely unknown, as we understand there has been limited shale gas exploration activity outside of the Beetaloo Basin

- * *Do you consider there is potential for the discovery and development of shale gas reserves outside of the Beetaloo Basin in the Northern Territory? Why or why not?*
- * *Is there any information about the prospectivity of shale gas outside of the Beetaloo Basin that you are able to share with ACIL Allen Consulting?*
- * *If the moratorium was lifted across the Northern Territory, are there any areas that should remain “off limits”? If so, which areas and why? If not, why not?*

There are significant land holdings in the Northern Territory which are subject to long term pastoral leases, are held under native title, or both.

- * *How would you expect a lift of the moratorium to interact with land ownership in the Northern Territory? Is it reasonable to assume as a starting point that persons or groups which hold land under pastoral lease or native title will not allow development on their land holdings, a view ACIL Allen has formed in a preliminary review of submissions made to the Inquiry?*

Any potential shale gas produced from wells in the Northern Territory will require additional processing and transport to reach its end destination – be that consumption in the Northern Territory, consumption in other States, or export. This requires infrastructure over and above the development of fracking wells by project proponents.

- * *What current infrastructure does the Northern Territory have in place to support the processing and transport of shale gas produced?*
- * *What infrastructure do you believe would be required to support the processing and transport of shale gas produced in the Northern Territory?*

ACIL Allen’s understanding is that shale gas operations require specialist skills from a labour perspective. It is considered unlikely that those skills exist in the Northern Territory today.

- * *Does the Northern Territory labour market have enough capacity to absorb a potential increase in labour demand from the development of a shale gas industry? Why or why not?*

There are many options for the ultimate use of shale gas produced in the Northern Territory. ACIL Allen’s scope of works requires it to consider benefits, impacts and risks to the Northern Territory economy, however this will also involve consideration and analysis of the potential end use of production outside of the Northern Territory.

- * *What are the options for consumption of shale gas produced in the Northern Territory? Where do you think shale gas produced in the Northern Territory would ultimately be consumed? Why?*

Potential economic benefits of fracking to the Northern Territory economy

There are a range of potential economic benefits of shale gas production to the Northern Territory. ACIL Allen’s economic model assumes there are flow on benefits to industries that supply an industry which growth disproportionately to others, via the supply of services or a reduction the cost base for those industries.

ACIL Allen wishes to hear from you what you consider to be the five most significant channels of **economic benefits** to the Northern Territory, and why.

- * *In your view, what are the key benefits that you believe could arise in the Northern Territory economy resulting from shale gas production in the case of a lift in the moratorium on activities in the Beetaloo basin only?*

- * *In your view, what are the key benefits that you believe could arise in the Northern Territory economy resulting from shale gas production in the case of a lift in the moratorium on activities across the Northern Territory?*

Potential economic risks of fracking to the Northern Territory economy

There are a range of potential economic risks/costs of shale gas production to the Northern Territory. ACIL Allen's economic model assumes a degree of "crowding out" occurs when a one industry grows disproportionately to others.

ACIL Allen wishes to hear from you what you consider to be the five most significant channels of **economic risks** (costs) to the Northern Territory, and why.

- * *In your view, what are the risks (costs) that you believe could arise in the Northern Territory economy resulting from shale gas production in the case of a lift in the moratorium on activities in the Beetaloo Basin only?*
- * *In your view, what are the risks (costs) that you believe could arise in the Northern Territory economy resulting from shale gas production in the case of a lift in the moratorium on activities across the Northern Territory?*

Potential economic policy implications of fracking in the Northern Territory

Development of fracking in the Northern Territory is likely to entail some policy challenges for the Northern Territory government. The Inquiry has requested ACIL Allen examine these, using international case studies, best practice, stakeholder views, and our firm's internal expertise in policy development, to provide some initial guidance on the policy issues and challenges that are likely to arise in the case that the moratorium on activities is lifted.

ACIL Allen is required to consider this within the context of the current regulatory regime – that is, we must discuss policy challenges within the constraints of current policies and regulations, and make suggestions to address these.

The Inquiry is cognisant of the potential for "boom-bust" cycles given the Northern Territory's recent experience with the Ichthys LNG Project, and extensive literature associated with resources industry development.

These policy issues and challenges are wide-ranging, and include:

- Human capital (labour supply, education and training, apprenticeships)
- Infrastructure (specific to fracking like pipelines, but also supporting infrastructure like roads)
- Government finances (royalties, expenditure demands)
- Local content ("Buy Local" policy)
- Land access regimes and environmental approvals

- * *Do you have any insights on the potential policy issues which may arise in the Northern Territory in the case that the moratorium on activities is lifted?*
- * *Which policy issue(s) do you believe have the potential to create the most risk to the Northern Territory economy? Why?*

Other issues

- * *Are there any other issues you wish to raise with us related to our scope of works?*
- * *Are there any other costs, benefits or risks associated with each scenario that you would you like to raise?*

About ACIL Allen

ACIL Allen Consulting is the largest independent economics and public policy consulting firm in Australia, with a specialisation in economics, policy and strategy advice. With over 60 consultants across five offices, we have an established reputation for providing sound and independent advice on economic, public policy and organisational issues for all levels of government and business. We have experience in conducting projects that involve policy, program and funding evaluations, analysis of data, development of policy options, extensive stakeholder consultations, and the preparation of clear and concise reports.

Further Enquiries

If you have any questions in relation to the Inquiry, the role of ACIL Allen, and the consultation process that is being undertaken, please contact:

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In this Appendix we set out the results of the modelling of the market effects of different Northern Territory shale gas development scenarios using ACIL Allen's GasMark® model of the eastern Australian and Northern Territory gas market. First, we summarise the gas production capacity and ex-field pricing assumptions under the three Northern Territory shale gas development scenarios (BREEZE: 100 TJ/d target market; WIND: 400 TJ/d target market; GALE: 1,000 TJ/d target market), and explain how the 'optimal' ex-field pricing assumptions were determined. We then present key modelling results for each of the three shale gas development scenarios in turn. For each scenario we present the modelling results for:

- modelled production performance of the Northern Territory, including total market penetration over time relative to the assumed level of shale gas production capacity and levels of gas exports from NT to eastern Australia
- levels of gas consumption in the eastern Australian and NT domestic markets, and incremental effects on domestic consumption compared to the Reference Case (no Northern Territory shale gas)
- levels of LNG production in the Northern Territory and Queensland, and incremental LNG production compared to the Reference Case
- wholesale delivered gas prices in Queensland, New South Wales, Victoria and South Australia, and the incremental effects on gas prices compared to the Reference Case.

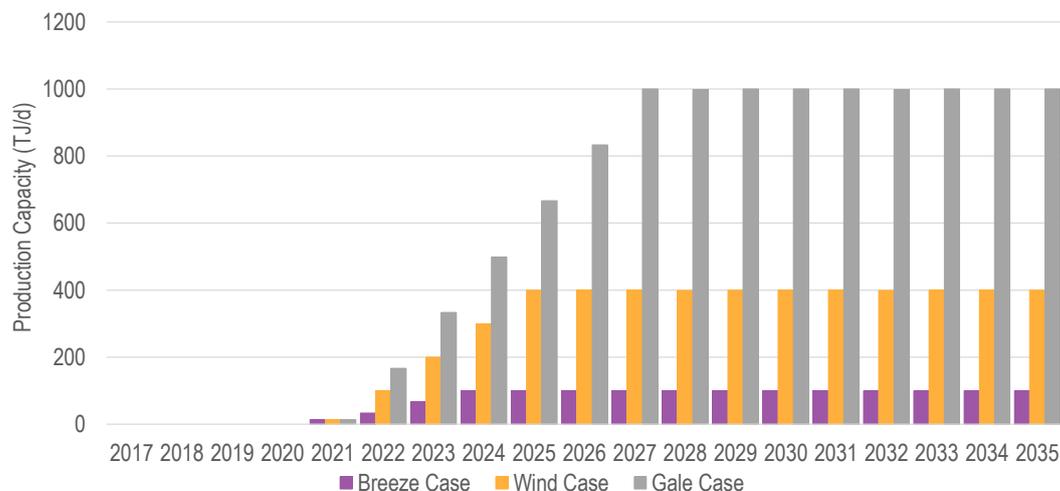
C.1 Northern Territory shale gas production and pricing assumptions

The three Northern Territory shale gas development scenarios each adopt different assumptions about the levels of shale gas production capacity that are offered into the market. The production capacity ramp-up profiles for the three cases are summarised in Figure C.1.

However, the fact that production capacity is made available or 'offered to the market' does not guarantee that all of that capacity will be taken up. If the price at which the shale gas can be offered to the market is too high, then some or all of the production capacity will remain idle. Gas users will either obtain supply from another, more competitively-priced supply source, or if this is not possible, will forego consumption because they cannot afford to buy gas at the price offered. All else being equal, it would be reasonable to expect that as the shale gas prices required to justify commercial production from the Northern Territory increase, the quantity of gas actually taken up in the market will decrease.

For the purposes of this analysis, 'optimal' ex-field pricing assumptions for each scenario were determined by using the *GasMark* model to test the volumes of gas sold across a range of ex-field pricing assumptions. Generally speaking, the volumes of gas sold fall as prices rise. Multiplying the volumes of gas sold by the price at which the gas is offered into the market allows calculation of annual gas sales revenue. The 'optimal' price path for each scenario is then the price path that

FIGURE C.1 AVAILABLE SHALE GAS PRODUCTION CAPACITY FOR THE THREE NORTHERN TERRITORY SHALE GAS DEVELOPMENT SCENARIOS



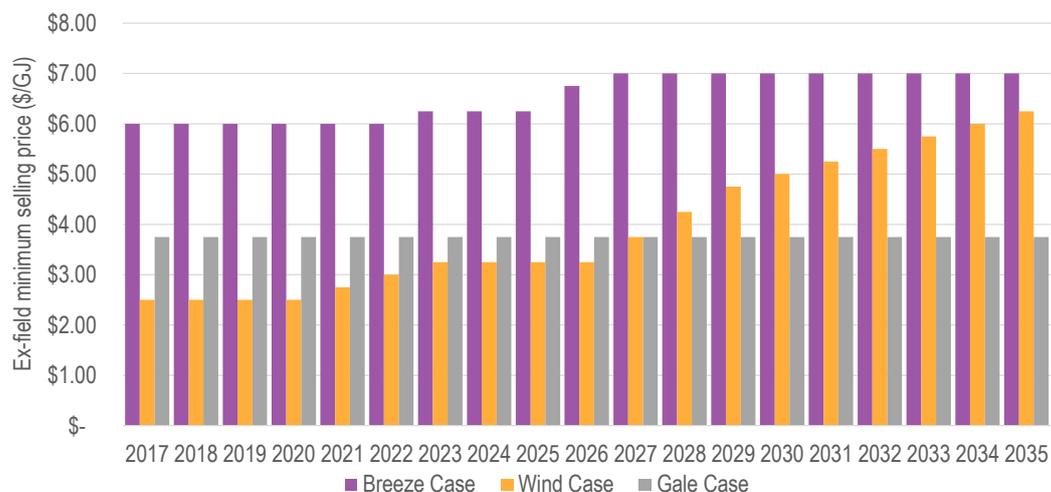
SOURCE: ACIL ALLEN GASMARK MODELLING

maximises the net present value (NPV) of modelled revenues over time. We have used a discount rate of 15 per cent (pre-tax) to calculate the NPV of revenues.

The 'optimal' prices effectively represent the maximum (capital inclusive) average cost of shale gas production that will need to be achieved if the Northern Territory producers are to earn a commercial rate of return on the targeted volumes of gas sales. If the producers are able to produce gas at a cost lower than the 'optimal' prices, they will be able to achieve rates of return above the minimum commercial threshold.

In these circumstances, producers would have no incentive to offer gas for sale at lower prices reflecting their long-run marginal costs of production because the modelling shows that they would not achieve a large enough increase in sales volumes to offset the reduction in revenue per unit of gas sold. The 'optimised ex-plant gas price assumptions for the three scenarios are shown in Figure C.2.

FIGURE C.2 'OPTIMAL' EX-PLANT PRICE ASSUMPTIONS FOR THE THREE NORTHERN TERRITORY SHALE GAS DEVELOPMENT SCENARIOS



SOURCE: ACIL ALLEN GASMARK MODELLING

C.2 Modelling results: BREEZE Case

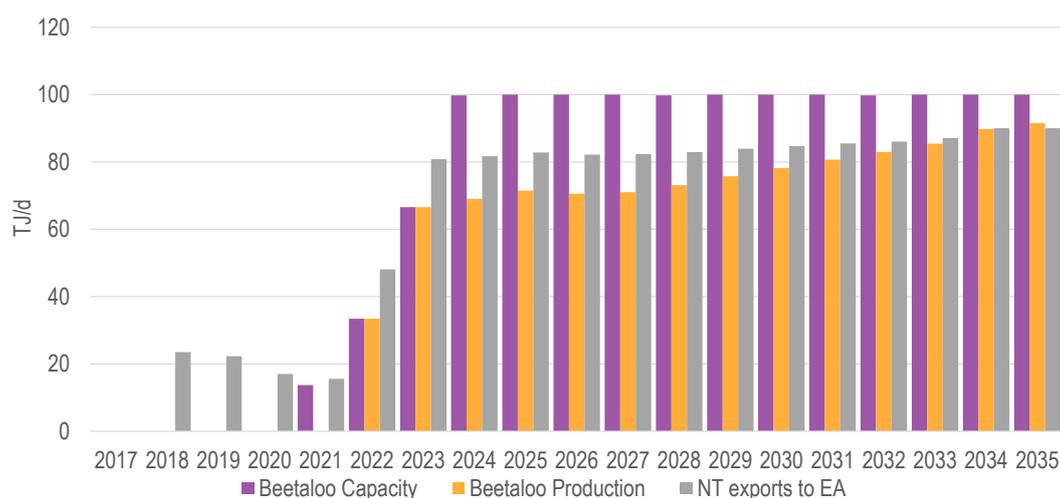
C.2.1 Northern Territory Shale Gas production performance: BREEZE Case

Figure C.3 shows the Northern Territory Shale Gas production performance under the BREEZE Case (100 TJ/d nominal production capacity). Capacity is assumed to ramp up from 2021, reaching the full 100 TJ/d nominal capacity by 2024. Actual levels of shale gas production taken up in the market increase from around 35 TJ/d in 2022 to a maximum of 92 TJ/d by the end of the modelling period.

Under the optimal pricing assumptions, the full 100 TJ/d of production capacity is not utilised during the modelling period to 2035. Higher rates of production could be achieved by discounting ex-field selling prices, but this would result in a reduction in the overall NPV of sales revenues.

Initially the total gas exports to eastern Australia (via the Jemena Northern Gas Pipeline, 'NGP') are significantly higher than the amount of Northern Territory shale gas being produced. This reflects the contribution to EA exports from Blacktip gas under the existing arrangements with PowerWater. However, the proportion of Northern Territory shale gas in exports increases over time, and by 2034 the volume of Northern Territory shale gas production reaches 90 TJ/d, equal to the assumed capacity of the NGP. Once the NGP capacity is reached, incremental production of Northern Territory shale gas is supplied into the NT market.

FIGURE C.3 NORTHERN TERRITORY SHALE GAS PRODUCTION PERFORMANCE: BREEZE CASE (100 TJ/D NOMINAL PRODUCTION CAPACITY)

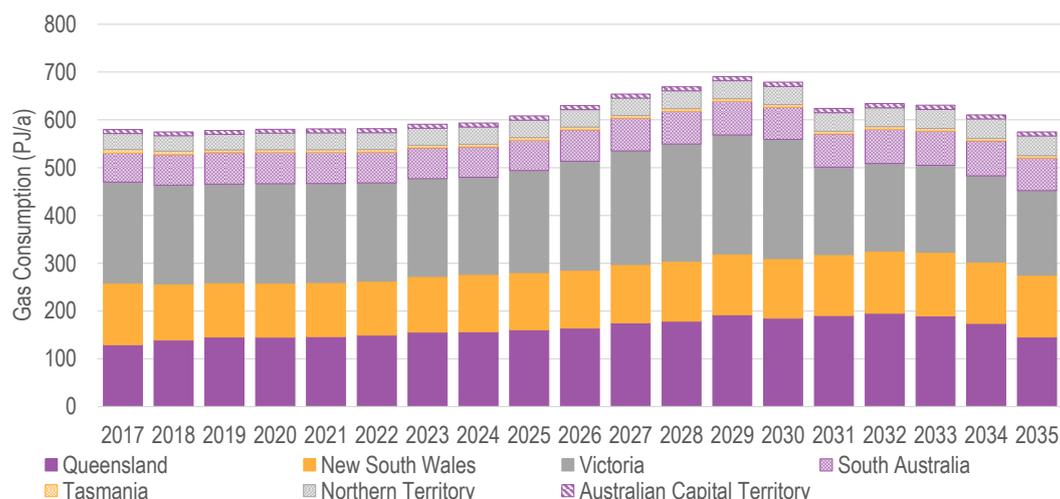


SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

C.2.2 Consumption volume effects: BREEZE Case

Figure C.4 shows the modelled levels of domestic gas consumption, by State/Territory, under the BREEZE Case assumptions. Domestic consumption recovers from current levels to reach almost 700 PJ/a by 2029, but then falls to less than 600 PJ/a by the end of the modelling period as a result of constrained gas supply, with new sources of supply unable to fully replace current production as reserves are depleted.

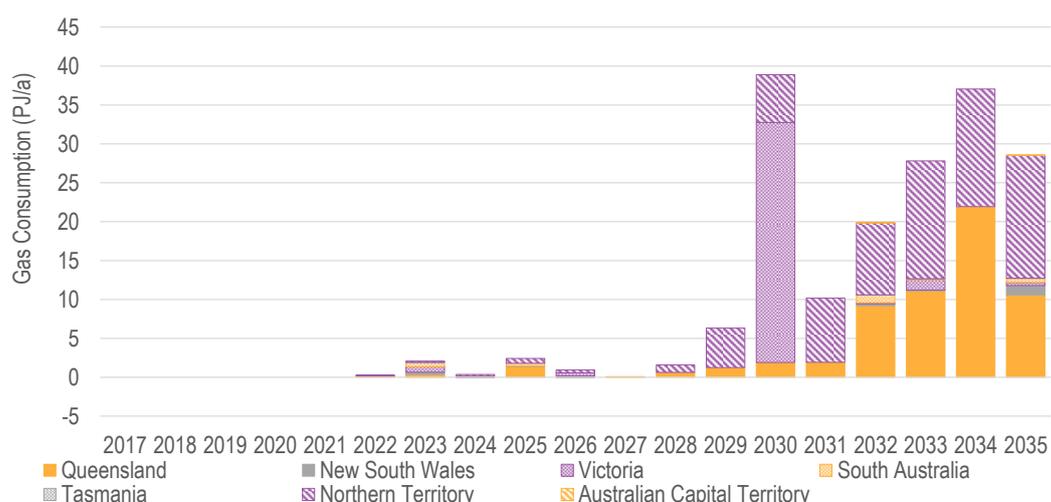
FIGURE C.4 BREEZE CASE: GAS CONSUMPTION



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.5 shows the incremental levels of gas consumption in eastern Australia and the Northern Territory under the BREEZE Case assumptions, when compared to the Reference Case (without Northern Territory shale gas production). As shown, there is little incremental effect on consumption until 2029. Prior to that time, the NT gas exports to eastern Australia (Figure C.3 refers) are effectively substituting for high-cost local supply sources. However, from 2029 on total consumption levels increase relative to the Reference Case as the increased levels of overall gas supply reduce the amount of ‘demand destruction’ as the supply position from non-shale sources in both the Northern Territory and eastern Australia tightens. In most years, the largest consumption effects are felt in the Northern Territory and Queensland, but there is one year (2029) in which Victorian consumption is also given significant (indirect) support as a result of the introduction of NT shale gas into the eastern Australian market.

FIGURE C.5 BREEZE CASE: GAS CONSUMPTION DIFFERENTIAL FROM REFERENCE CASE

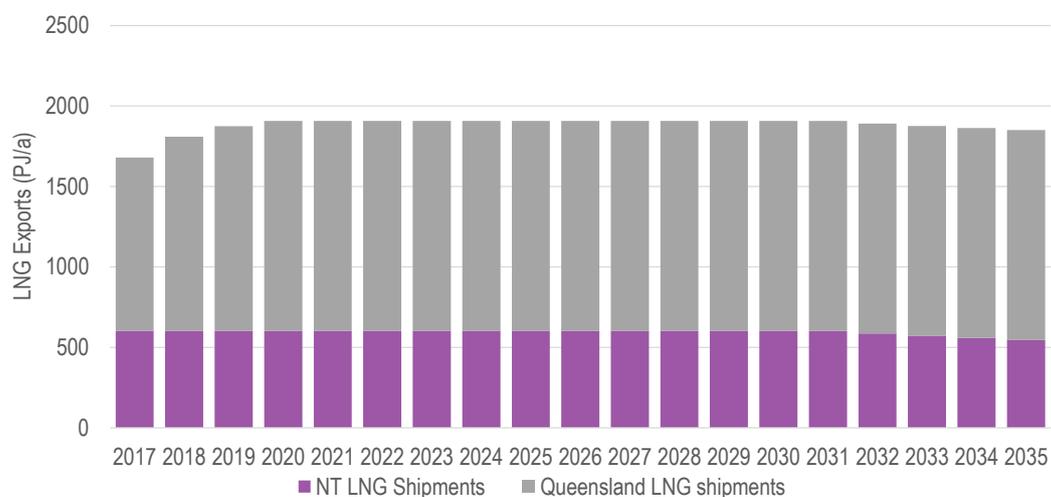


SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.6 shows the total levels of LNG exports from eastern Australia (NT shipments: Darwin LNG and INPEX Ichthys LNG; Queensland shipments: Gladstone LNG, Australia Pacific LNG, Queensland Curtis LNG) under the BREEZE Case assumptions. Compared to the Reference Case (no Northern

Territory shale gas production) there is no change in LNG shipments from NT or Queensland under the BREEZE Case.

FIGURE C.6 LNG SHIPMENTS: BREEZE CASE (100 TJ/D NOMINAL PRODUCTION CAPACITY)



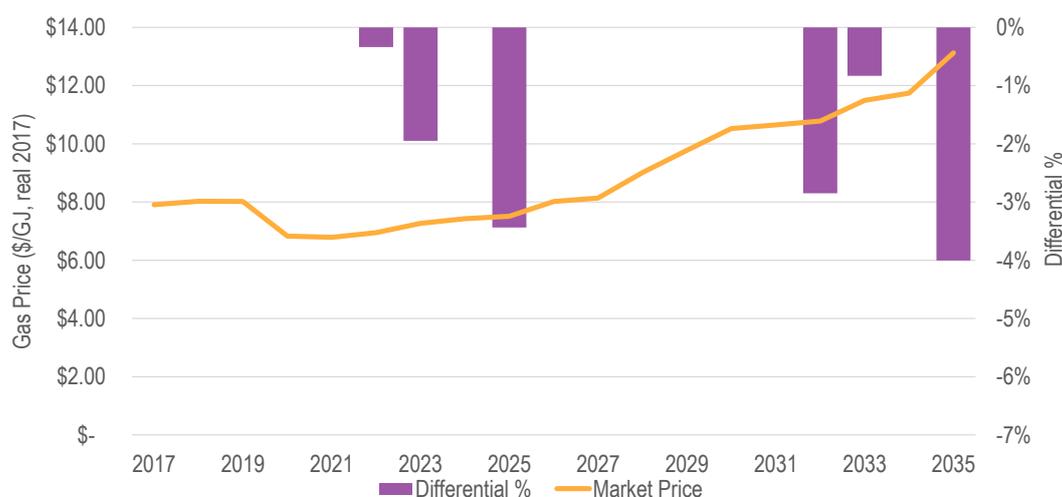
SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

C.2.3 Eastern Australia price effects: BREEZE Case

The increase in gas supply to eastern Australian as a result of imports of Northern Territory shale gas under the BREEZE Case assumptions results in modest, intermittent downward pressure on wholesale delivered gas prices.

Figure C.7 shows the market price at Brisbane, and the per cent price differentials from the Reference Case, under the BREEZE Case assumptions. The price effects tend to occur toward the end of the modelling period although in Queensland there are also some significant effects (up to 4 per cent reduction in price) over the period 2022 to 2025.

FIGURE C.7 BREEZE CASE: DELIVERED WHOLESALE GAS PRICES AT BRISBANE

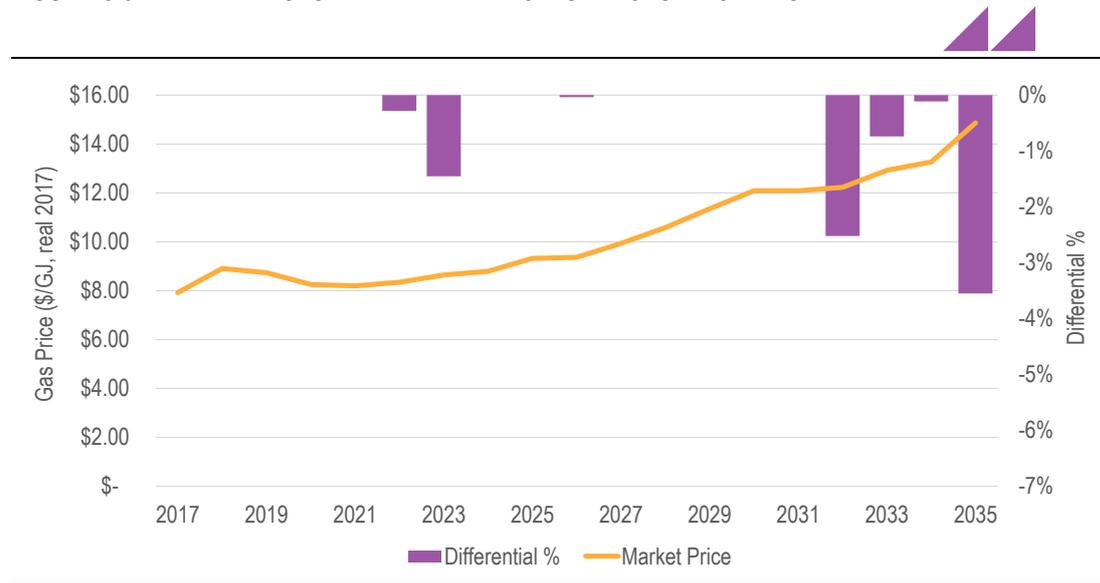


SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.8 shows the corresponding price effects in New South Wales (Sydney). Total price levels are higher in Sydney than in Brisbane (because of the added transport costs). When compared to the

Reference Case results, the early differential price impacts (2022 to 2025) are less apparent than in Queensland, but the patterns of price movement toward the end of the modelling period (2032 on) are generally similar. Levels of downward movement in gas price are somewhat lower (in percentage terms) in Sydney than in Brisbane, reflecting the increased distance from the incremental source of supply.

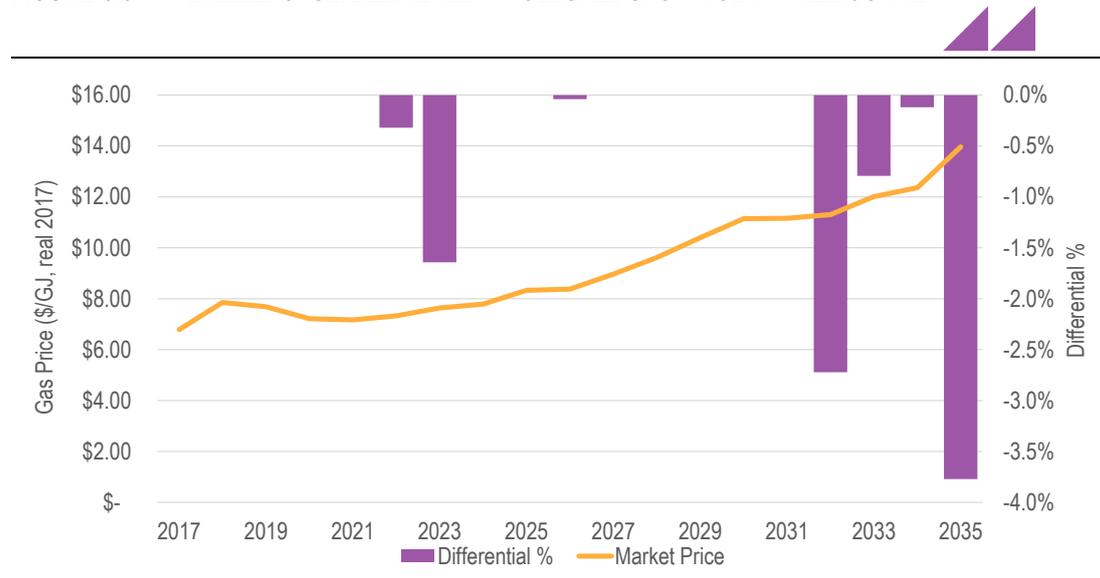
FIGURE C.8 BREEZE CASE: DELIVERED WHOLESALE GAS PRICE AT SYDNEY



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

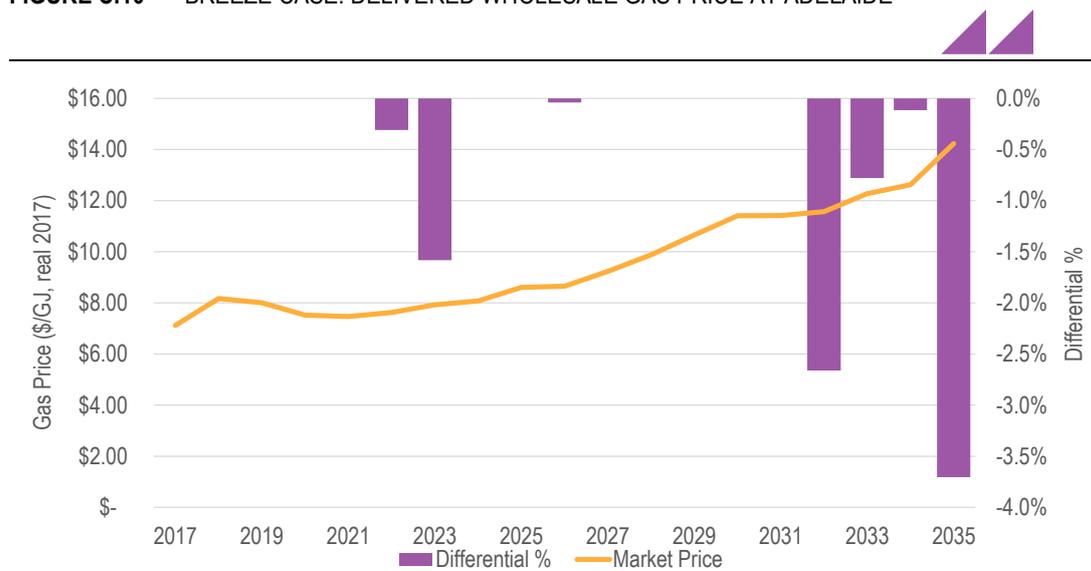
Figure C.9 shows the corresponding results for wholesale gas prices at Melbourne. Total price levels are lower than for Sydney, because of Melbourne’s proximity to the major production sources in Bass Strait. In terms of differential price effects compared to the Reference Case, the results for Melbourne are very similar to Sydney.

FIGURE C.9 BREEZE CASE: DELIVERED WHOLESALE GAS PRICE AT MELBOURNE



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.10 shows the corresponding results for wholesale gas prices at Adelaide. Total price levels are slightly higher than for Melbourne, but show a similar pattern of movement. In terms of differential price effects compared to the Reference Case, the results for Adelaide are very similar to both Melbourne and Sydney.

FIGURE C.10 BREEZE CASE: DELIVERED WHOLESALE GAS PRICE AT ADELAIDE

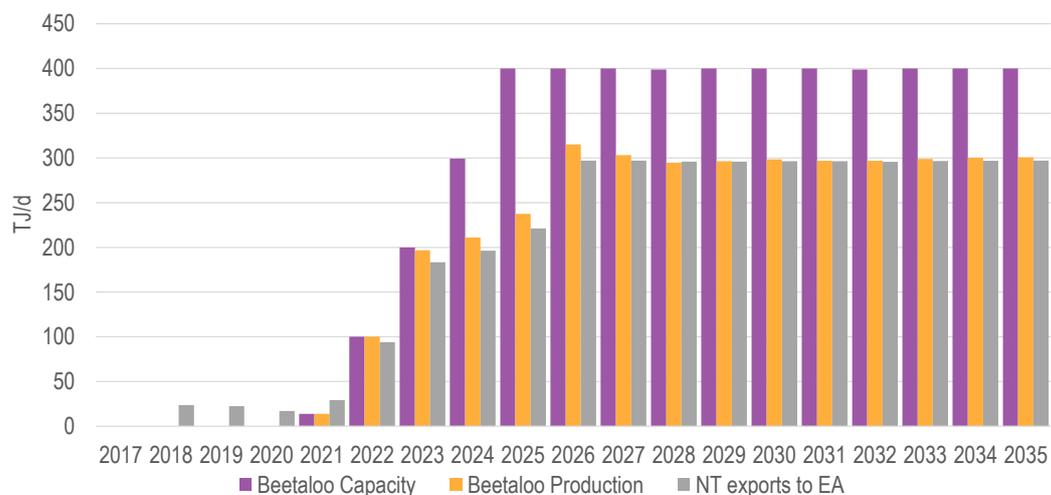
SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

C.3 Modelling results: WIND Case

C.3.1 Northern Territory Shale Gas production performance: WIND Case

Figure C.11 shows the Northern Territory Shale Gas production performance under the WIND Case (400 TJ/d nominal production capacity). Capacity is assumed to ramp up from 2021, reaching the full 400 TJ/d nominal capacity by 2025. Actual levels of shale gas production taken up in the market increase from 100 TJ/d in 2022 to a maximum of 315 TJ/d by 2026, then fall slightly to plateau at around 300 TJ/d through to the end of the modelling period. Under the optimal pricing assumptions, the full 400 TJ/d of production capacity is not utilised during the modelling period to 2035. Higher rates of production could be achieved by discounting ex-field selling prices, but again this would result in a reduction in the overall NPV of sales revenues. Initially the total gas exports to eastern Australia (via the Jemena Northern Gas Pipeline, 'NGP') are significantly below the amount of Northern Territory shale gas being produced, which indicates that some of the Northern Territory gas production is taken up in the Northern Territory. By 2028, the quantities of Northern Territory shale gas closely match the total volume of exports to eastern Australia.

FIGURE C.11 NORTHERN TERRITORY SHALE GAS PRODUCTION PERFORMANCE: WIND CASE (100 TJ/D NOMINAL PRODUCTION CAPACITY)

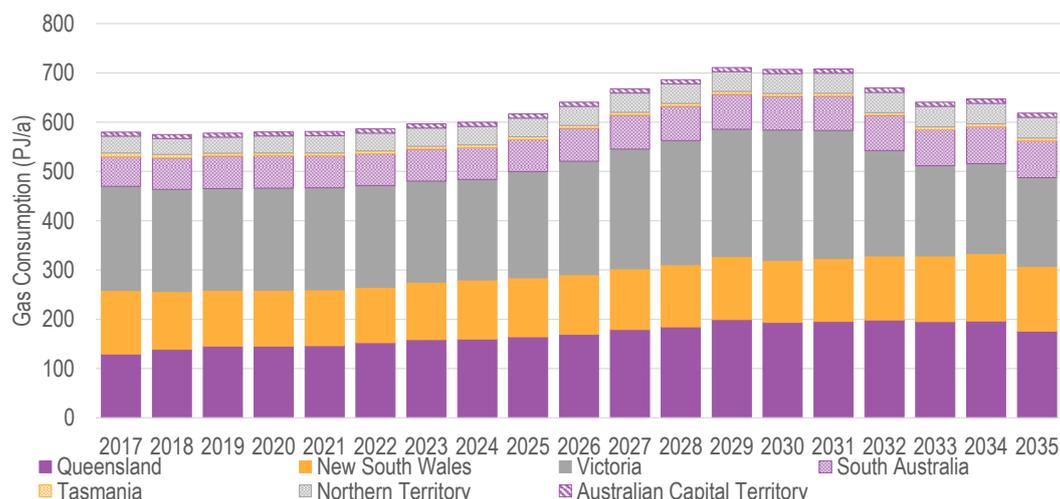


SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

C.3.2 Consumption volume effects: WIND Case

Figure C.12 shows the modelled levels of domestic gas consumption, by State/Territory, under the WIND Case assumptions. Domestic consumption recovers from current levels to peak at a little over 700 PJ/a by 2029, but then falls to around 615 PJ/a by the end of the modelling period as a result of constrained gas supply, with new sources of supply unable to fully replace current production as reserves are depleted.

FIGURE C.12 WIND CASE: GAS CONSUMPTION

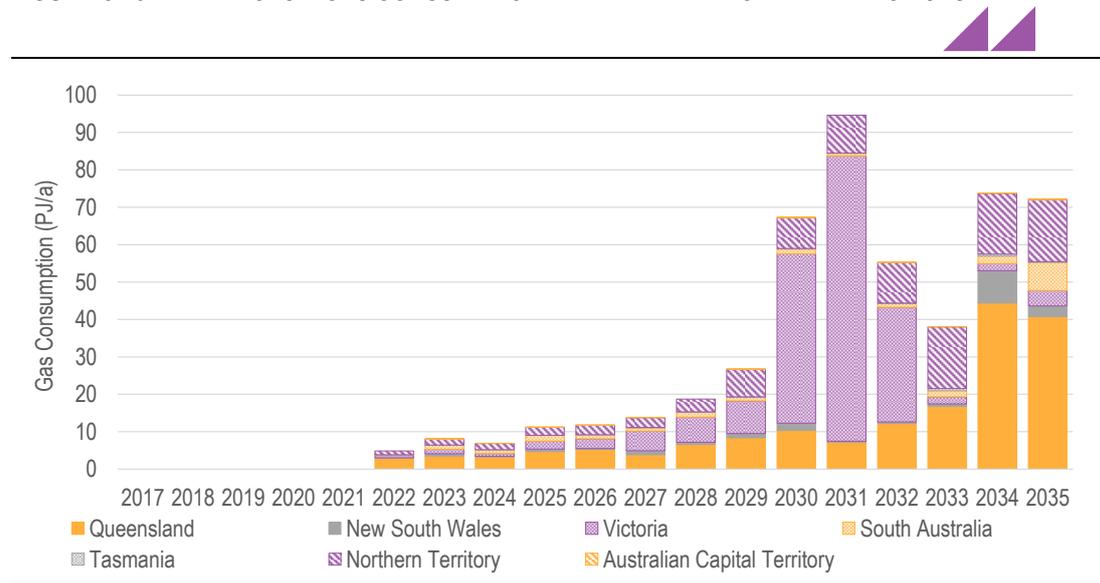


SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.13 shows the incremental levels of gas consumption in eastern Australia and the Northern Territory under the WIND Case assumptions, compared to the Reference Case. The levels of incremental consumption rise slowly over the period 2022 to 2029. During this period, the NT gas exports to eastern Australia (Figure C.11 refers) are largely substituting for high-cost local supply sources. However, from 2030 on total consumption levels increase sharply relative to the Reference Case as the increased levels of overall gas supply reduce the amount of ‘demand destruction’ as the

supply position from non-shale sources in both the Northern Territory and eastern Australia tightens. The largest consumption effects are felt in the Queensland, Victoria and the Northern Territory. Victorian consumption is impacted not as a result of physical supply from the Northern Territory but because NT supply reduces the levels of gas exported from Victoria to interstate markets – particularly New South Wales.

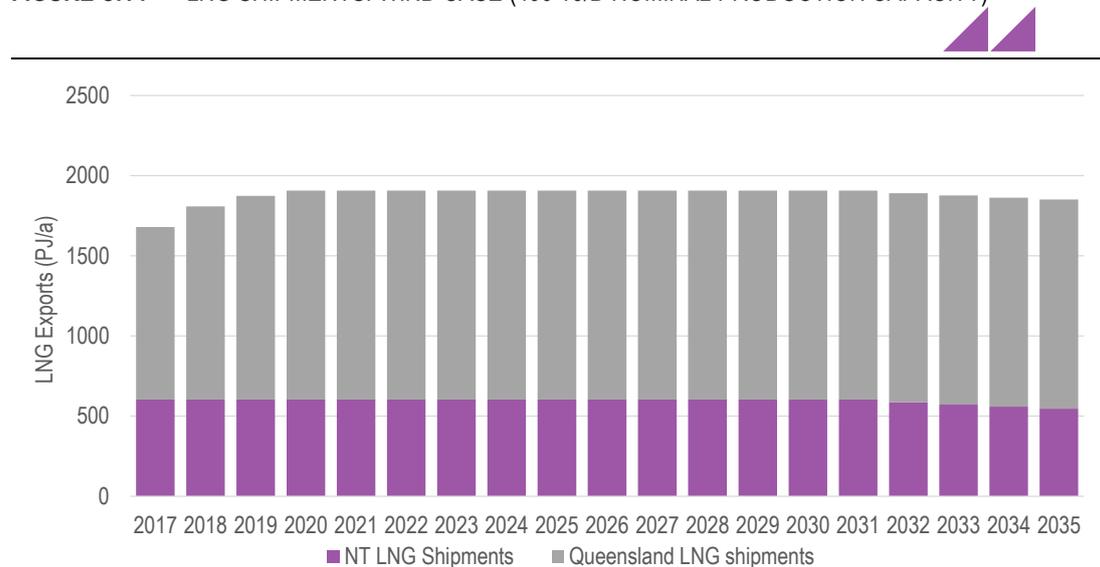
FIGURE C.13 WIND CASE: GAS CONSUMPTION DIFFERENTIAL FROM REFERENCE CASE



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.14 shows the total levels of LNG exports from eastern Australia (NT shipments: Darwin LNG and INPEX Ichthys LNG; Queensland shipments: Gladstone LNG, Australia Pacific LNG, Queensland Curtis LNG) under the WIND Case assumptions. Compared to the Reference Case (no Northern Territory shale gas production) there is no change in LNG shipments from NT or Queensland under the WIND Case.

FIGURE C.14 LNG SHIPMENTS: WIND CASE (400 TJ/D NOMINAL PRODUCTION CAPACITY)



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

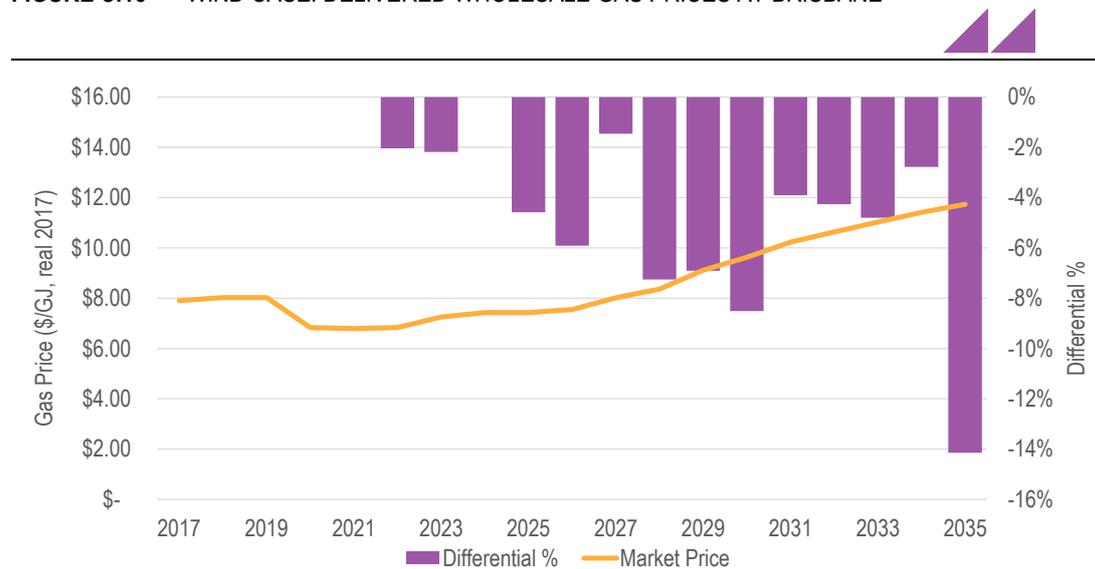
C.3.3 Eastern Australia price effects: WIND Case

The increase in gas supply to eastern Australian as a result of imports of Northern Territory shale gas under the WIND Case assumptions results in significant and sustained downward pressure on

wholesale delivered gas prices. The level of price reductions tends to increase over time as more NT gas is taken up in the eastern Australian domestic market.

Figure C.15 shows the market price at Brisbane, and the per cent price differentials from the Reference Case, under the WIND Case assumptions. The price effects tend to increase across the modelling period, averaging 5 per cent over the period 2022 to 2035, and reaching 14 per cent by the end of the modelling period. The price effects come about principally as a result of the additional supply volumes which reduce the number of periods through the year when supply becomes very tight and prices are bid up to high levels.

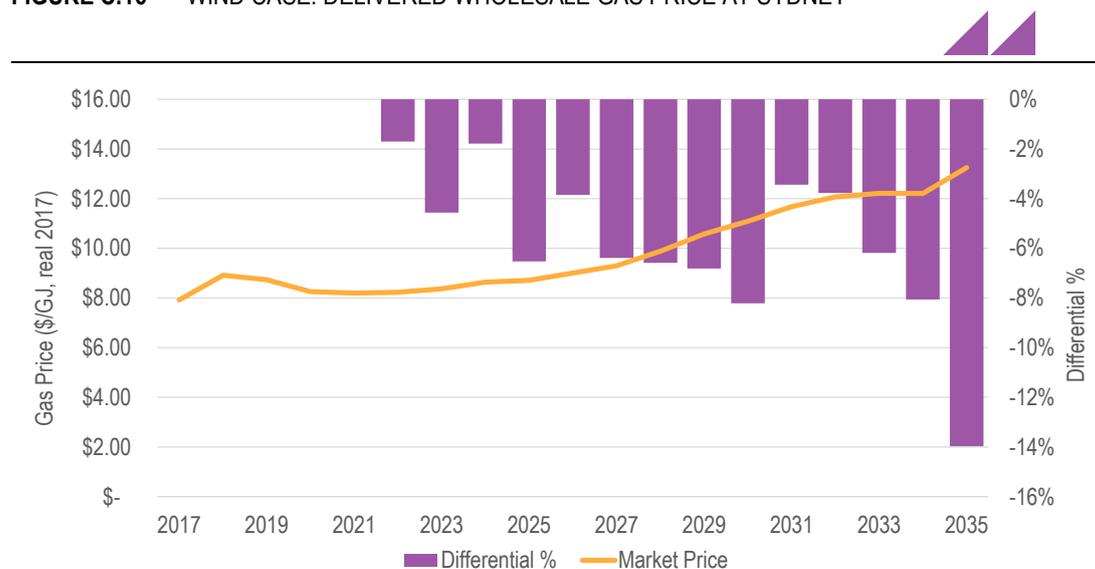
FIGURE C.15 WIND CASE: DELIVERED WHOLESALE GAS PRICES AT BRISBANE



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.16 shows the corresponding price effects in New South Wales (Sydney). Total price levels are higher in Sydney than in Brisbane (because of the added transport costs). When compared to the Reference Case results, the patterns of price movement are generally similar to those observed in Queensland. The price effects tend to increase across the modelling period, averaging 6 per cent over the period 2022 to 2035, and reaching 14 per cent by the end of the modelling period.

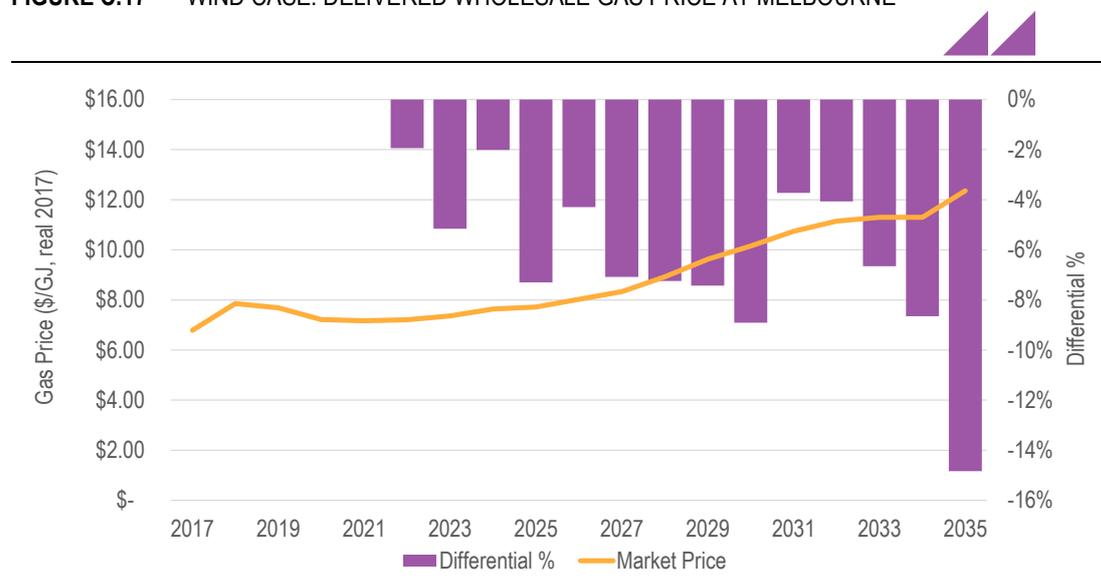
FIGURE C.16 WIND CASE: DELIVERED WHOLESALE GAS PRICE AT SYDNEY



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.17 shows the corresponding results for wholesale gas prices at Melbourne. Total price levels are lower than for Sydney, because of Melbourne's proximity to the major production sources in Bass Strait. In terms of differential price effects compared to the Reference Case, the results for Melbourne are very similar to Sydney.

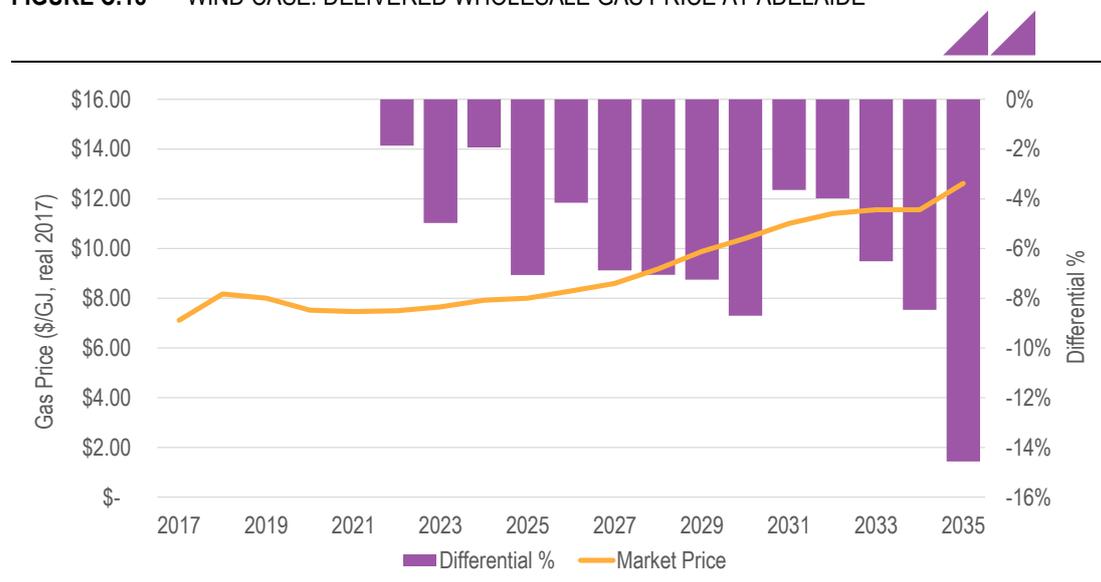
FIGURE C.17 WIND CASE: DELIVERED WHOLESALE GAS PRICE AT MELBOURNE



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.18 shows the corresponding results for wholesale gas prices at Adelaide. Total price levels are slightly higher than for Melbourne, but show a similar pattern of movement. In terms of differential price effects compared to the Reference Case, the results for Adelaide are very similar to both Melbourne and Sydney.

FIGURE C.18 WIND CASE: DELIVERED WHOLESALE GAS PRICE AT ADELAIDE



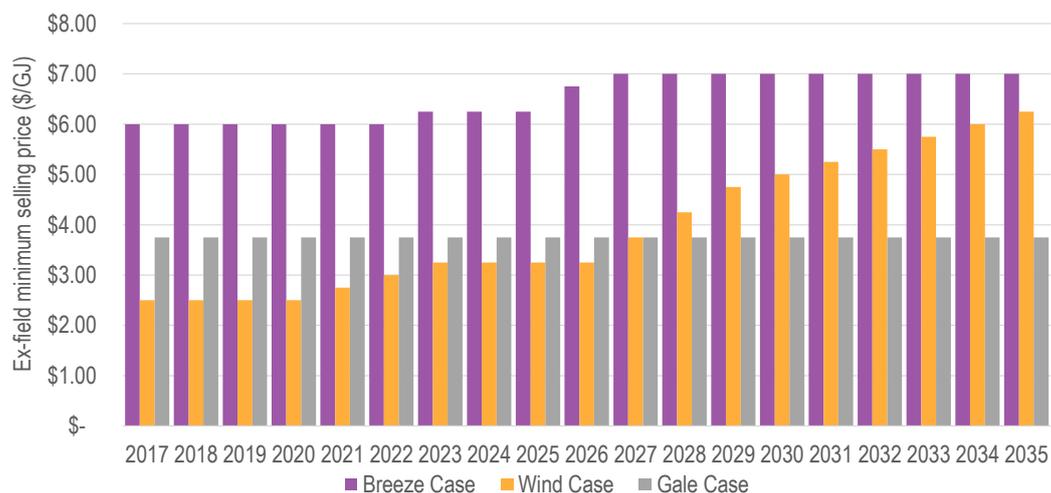
SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

C.4 Modelling results: GALE Case

C.4.1 Northern Territory Shale Gas production performance: GALE Case

Figure C.19 shows the Northern Territory Shale Gas production performance under the GALE Case (1,000 TJ/d nominal production capacity). Capacity is assumed to ramp up from 2021, reaching the full 1,000 TJ/d nominal capacity by 2027. Pipeline capacity augmentation allows delivery of gas to Darwin LNG as well as expanded supply to eastern Australia. Actual levels of shale gas production taken up in the market increase from 400 TJ/d in 2025 to 800 TJ/d by 2027, then continues to climb steadily. Under the optimal pricing assumptions, the full 1,000 TJ/d of production capacity is not utilised until 2034. Higher rates of production could be achieved earlier by discounting ex-field selling prices, but as for the previous cases this would result in a reduction in the overall NPV of sales revenues. From 2025 on, total gas exports to eastern Australia (via the Jemena Northern Gas Pipeline, 'NGP') are significantly below the amount of Northern Territory shale gas being produced, which indicates that a substantial amount of the Northern Territory gas production is taken up in the Northern Territory. By the end of the modelling period, the quantities of Northern Territory shale gas being produced exceed the total volume of exports to eastern Australia by some 315 TJ/d.

FIGURE C.19 NORTHERN TERRITORY SHALE GAS PRODUCTION PERFORMANCE: GALE CASE (1000 TJ/D NOMINAL PRODUCTION CAPACITY)

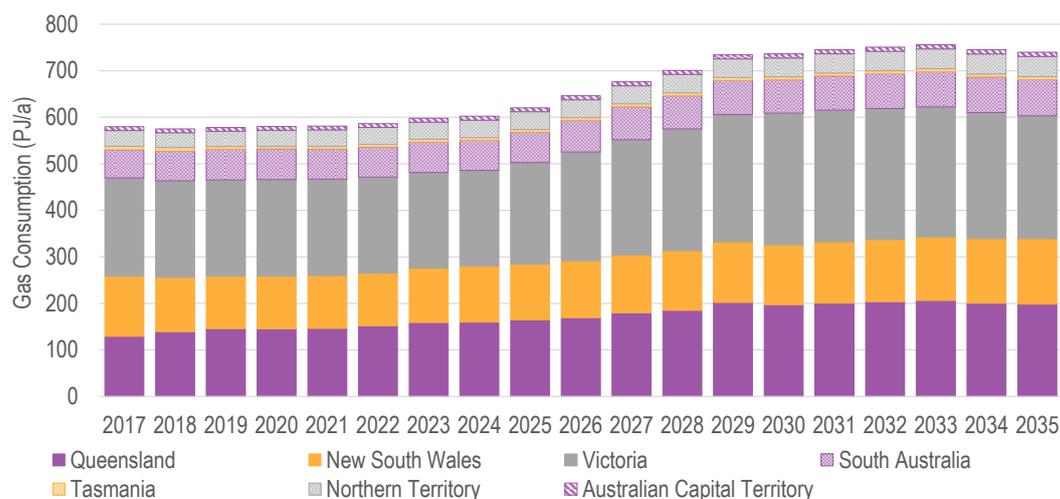


SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

C.4.2 Consumption volume effects: GALE Case

Figure C.20 shows the modelled levels of domestic gas consumption, by State/Territory, under the GALE Case assumptions. Domestic consumption recovers from current levels to peak at a little over 750 PJ/a in 2033, but then falls to 740 PJ/a by the end of the modelling period as gas supply constraints start to be felt, with new sources of supply unable to fully replace current production as reserves are depleted.

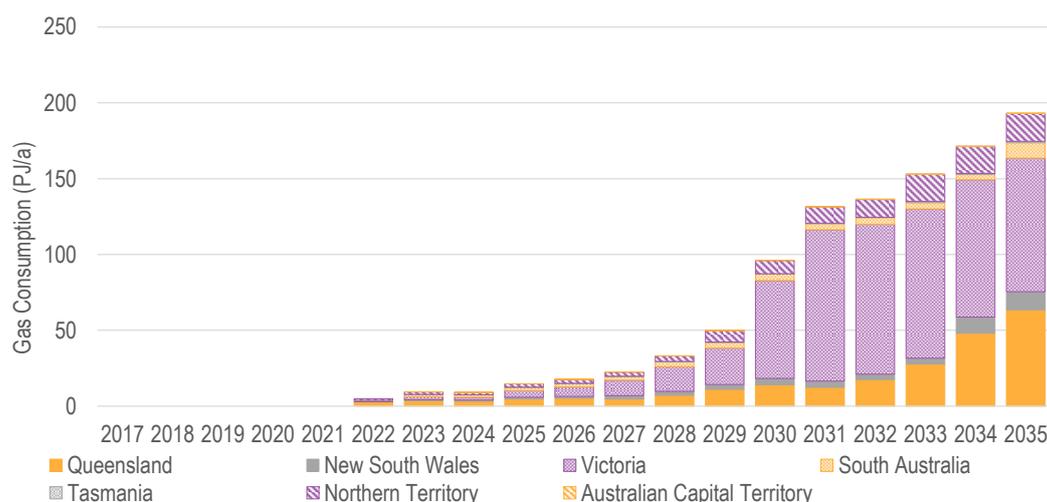
FIGURE C.20 GALE CASE: GAS CONSUMPTION



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.21 shows the incremental levels of gas consumption in eastern Australia and the Northern Territory under the GALE Case assumptions, compared to the Reference Case. The levels of incremental consumption rise slowly over the period 2022 to 2029, reaching a total incremental consumption level of about 50 PJ/a. However, from 2030 on total consumption levels increase sharply relative to the Reference Case as the increased levels of overall gas supply reduce the amount of ‘demand destruction’ as the supply position from non-shale sources in both the Northern Territory and eastern Australia tightens. By the end of the modelling period in 2035, the total incremental supply stands at almost 200 PJ/a. The largest consumption effects are felt in the Victorian, Queensland, and Northern Territory markets. Victorian consumption is impacted not as a result of physical supply from the Northern Territory but because NT supply reduces the levels of gas exported from Victoria to interstate markets – particularly New South Wales.

FIGURE C.21 GALE CASE: GAS CONSUMPTION DIFFERENTIAL FROM REFERENCE CASE

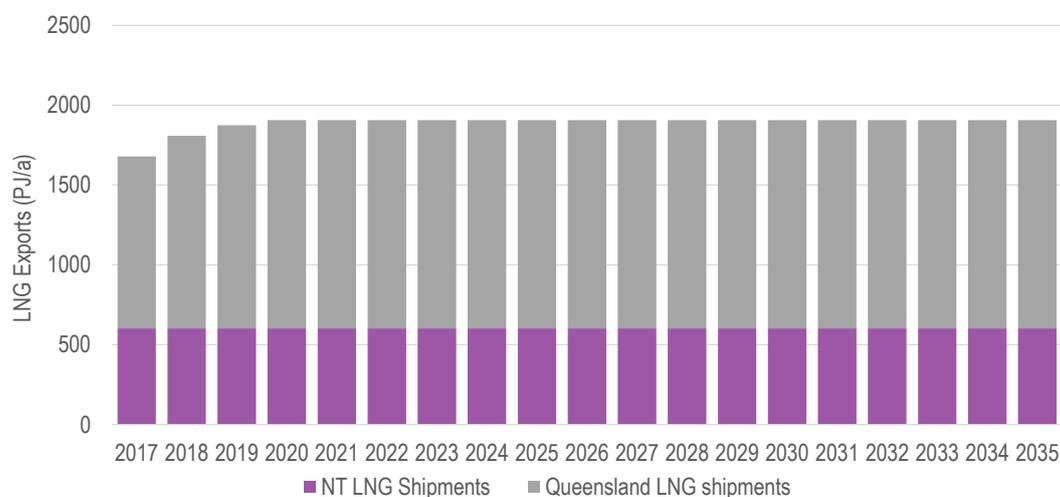


SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.22 shows the total levels of LNG exports from eastern Australia (NT shipments: Darwin LNG and INPEX Ichthys LNG; Queensland shipments: Gladstone LNG, Australia Pacific LNG, Queensland Curtis LNG) under the GALE Case assumptions. Compared to the Reference Case (no Northern

Territory shale gas production) there is no change in LNG shipments from NT or Queensland under the WIND Case.

FIGURE C.22 LNG SHIPMENTS: GALE CASE (100 TJ/D NOMINAL PRODUCTION CAPACITY)



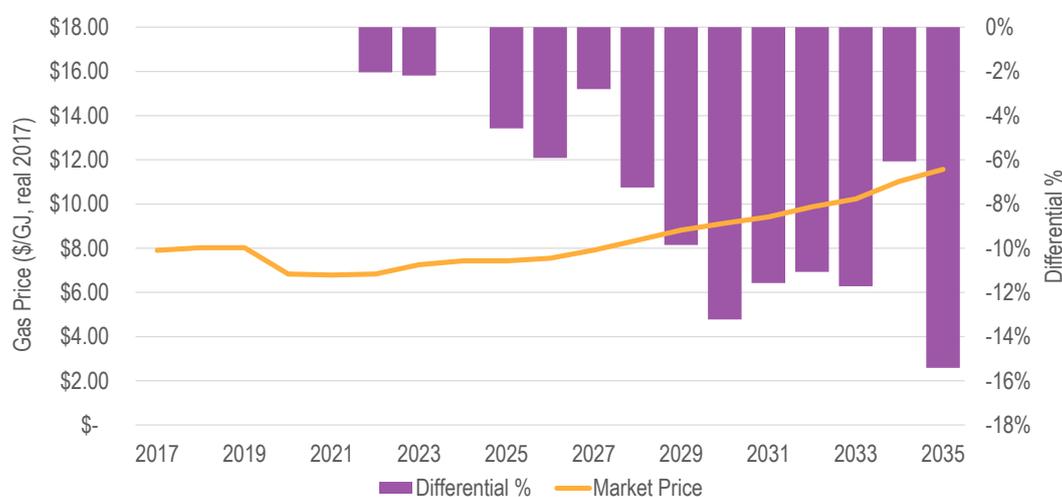
SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

C.4.3 Eastern Australia price effects: GALE Case

The increase in gas supply to eastern Australian as a result of imports of Northern Territory shale gas under the GALE Case assumptions results in significant and sustained downward pressure on wholesale delivered gas prices. The level of price reductions tends to increase over time as more NT gas is taken up in the eastern Australian domestic market.

Figure C.23 shows the market price at Brisbane, and the per cent price differentials from the Reference Case, under the GALE Case assumptions. The price effects tend to increase across the modelling period, averaging 7 per cent over the period 2022 to 2035, and reaching 15 per cent by the end of the modelling period. The price effects come about principally as a result of the additional supply volumes which reduce the number of periods through the year when supply becomes very tight and prices are bid up to high levels.

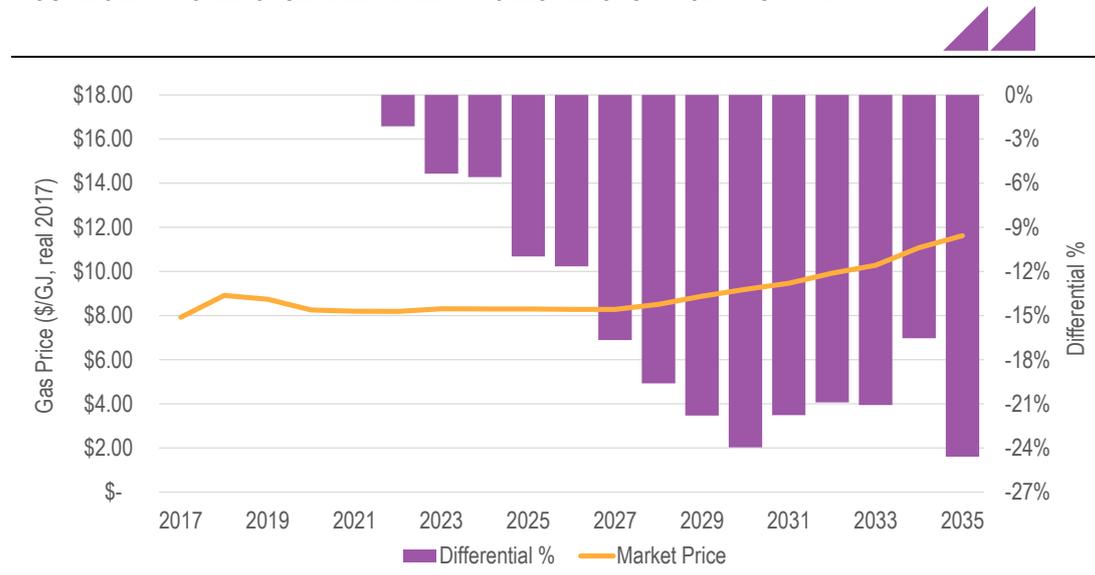
FIGURE C.23 GALE CASE: DELIVERED WHOLESAL GAS PRICES AT BRISBANE



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.24 shows the corresponding price effects in New South Wales (Sydney). Total price levels are higher in Sydney than in Brisbane (because of the added transport costs). When compared to the Reference Case results, the patterns of price movement are generally similar to those observed in Queensland, but are considerably stronger. The price effects tend to increase across the modelling period, averaging 16 per cent over the period 2022 to 2035, and reaching 25 per cent by the end of the modelling period.

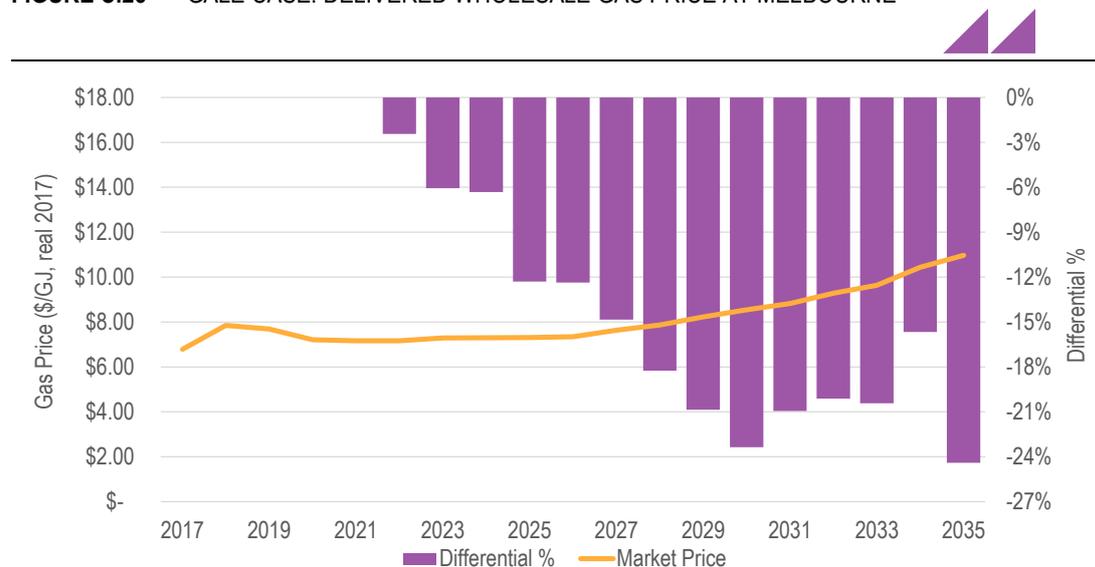
FIGURE C.24 GALE CASE: DELIVERED WHOLESALE GAS PRICE AT SYDNEY



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.25 shows the corresponding results for wholesale gas prices at Melbourne. Total price levels are lower than for Sydney, because of Melbourne’s proximity to the major production sources in Bass Strait. In terms of differential price effects compared to the Reference Case, the results for Melbourne are very similar to Sydney.

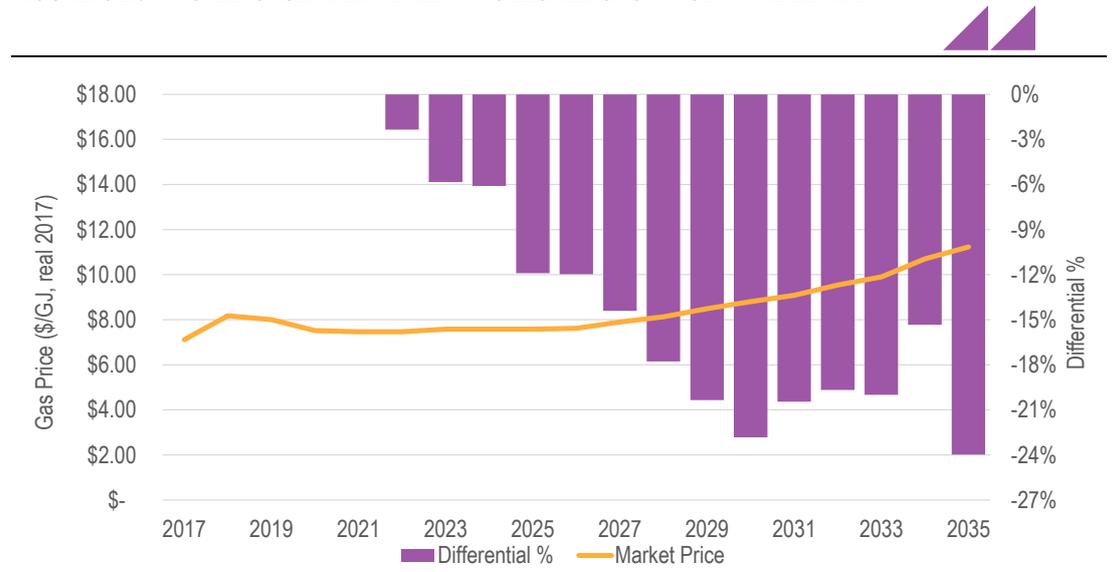
FIGURE C.25 GALE CASE: DELIVERED WHOLESALE GAS PRICE AT MELBOURNE



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING

Figure C.26 shows the corresponding results for wholesale gas prices at Adelaide. Total price levels are slightly higher than for Melbourne, but show a similar pattern of movement. In terms of differential price effects compared to the Reference Case, the results for Adelaide are very similar to both Melbourne and Sydney.

FIGURE C.26 GALE CASE: DELIVERED WHOLESALE GAS PRICE AT ADELAIDE



SOURCE: ACIL ALLEN CONSULTING, GASMARK MODELLING



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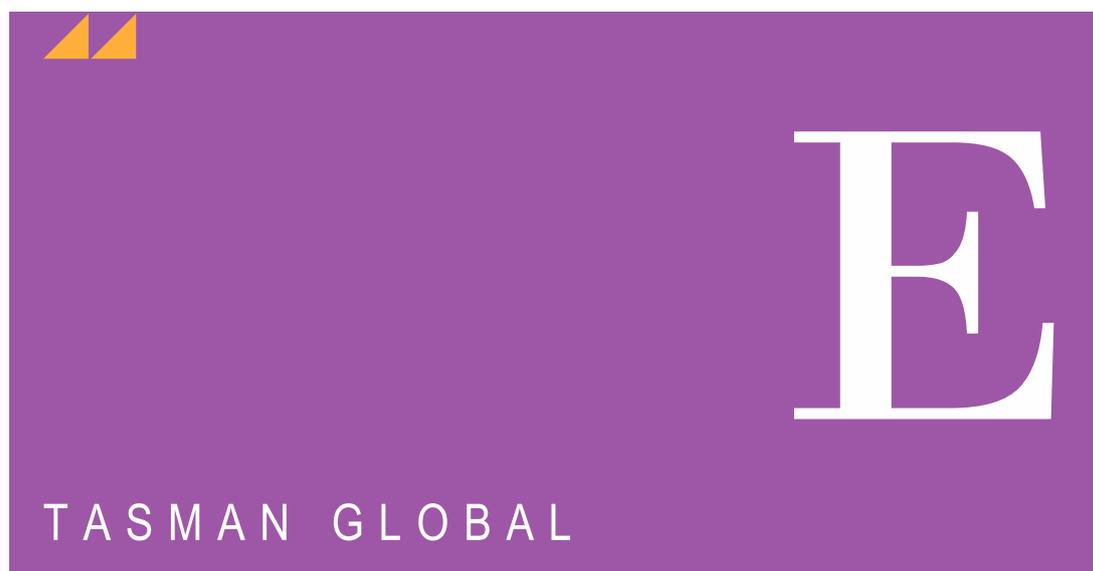
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APPENDICES
PART TWO:
ABOUT ACIL
ALLEN'S MODELS



ACIL Allen's CGE model *Tasman Global* is a powerful tool for undertaking economic impact analysis at the regional, state, national and global level.

There are various types of economic models and modelling techniques. Many of these are based on partial equilibrium analysis that usually considers a single market. However, in economic analysis, linkages between markets and how these linkages develop and change over time can be critical. *Tasman Global* has been developed to meet this need.

Tasman Global is a large-scale CGE model which is designed to account for all sectors within an economy and all economies across the world. ACIL Allen uses this modelling platform to undertake industry, project, scenario and policy analyses. The model is able to analyse issues at the industry, global, national, state and regional levels and to determine the impacts of various economic changes on production, consumption and trade at the macroeconomic and industry levels.

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.

The Database

A key advantage of *Tasman Global* is the level of detail in the database underpinning the model. The database we will use for this project is derived from the Global Trade Analysis Project (GTAP) database (version 8.1). 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.

The GTAP model was constructed at the Centre for Global Trade Analysis at Purdue University in the United States. It is the most up-to-date, detailed database of its type in the world.

Tasman Global builds on the GTAP model's equation structure and database by adding the following important features:

- dynamics (including detailed population and labour market dynamics)
- 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

- a detailed emissions accounting abatement framework
- explicit representation of the states and territories of Australia
- the capacity to explicitly represent multiple regions within states and territories of Australia

Nominally the *Tasman Global* database divides the world economy into 141 regions (133 international regions plus the 8 states and territories of Australia) although in reality the regions are frequently disaggregated further. ACIL Allen regularly models Australian projects or policies at the regional level.

The *Tasman Global* database also contains a wealth of sectoral detail currently identifying up to 70 industries (Table 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.

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.

Factors of Production

Capital, land, labour and natural resources are the four primary factors of production. The capital stock in each region (country or group of countries) accumulates through investment (less depreciation) in each period. Land is used only in agriculture industries and is fixed in each region. *Tasman Global* explicitly models natural resource inputs as a sector specific factor of production in resource based sectors (coal mining, oil and gas extraction, other mining, forestry and fishing).

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 the 112 international regions and for the 8 states and territories of Australia 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 the 120 regions in *Tasman Global*, 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 workforce 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.

SECTORS IN THE *TASMAN GLOBAL* DATABASE

Sector	Sector
1 Paddy rice	36 Paper products, publishing
2 Wheat	37 Diesel (incl. nonconventional diesel)
3 Cereal grains nec	38 Other petroleum, coal products
4 Vegetables, fruit, nuts	39 Chemical, rubber, plastic products
5 Oil seeds	40 Iron ore
6 Sugar cane, sugar beef	41 Bauxite
7 Plant- based fibres	42 Mineral products nec
8 Crops nec	43 Ferrous metals
9 Bovine cattle, sheep, goats, horses	44 Alumina
10 Animal products nec	45 Primary aluminium
11 Raw milk	46 Metals nec
12 Wool, silk worm cocoons	47 Metal products
13 Forestry	48 Motor vehicle and parts
14 Fishing	49 Transport equipment nec
15 Brown coal	50 Electronic equipment
16 Black coal	51 Machinery and equipment nec
17 Oil	52 Manufactures nec
18 Liquefied natural gas (LNG)	53 Electricity generation
19 Other natural gas	54 Electricity transmission and distribution
20 Minerals nec	55 Gas manufacture, distribution
21 Bovine meat products	56 Water
22 Meat products nec	57 Construction
23 Vegetables oils and fats	58 Trade
24 Dairy products	59 Road transport
25 Processed rice	60 Rail and pipeline transport
26 Sugar	61 Water transport
27 Food products nec	62 Air transport
28 Wine	63 Transport nec
29 Beer	64 Communication
30 Spirits and RTDs	65 Financial services nec
31 Other beverages and tobacco products	66 Insurance
32 Textiles	67 Business services nec
33 Wearing apparel	68 Recreational and other services
34 Leather products	69 Public Administration, Defence, Education, Health
35 Wood products	70 Dwellings

Note: nec = not elsewhere classified.

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
- limited labour mobility between states and regions within each state.

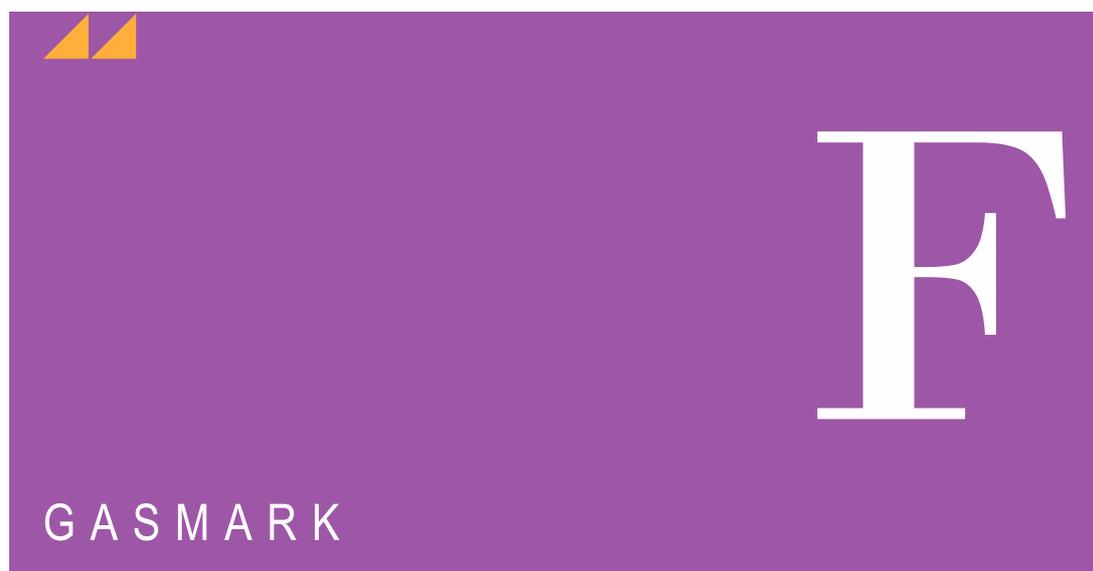
Tasman Global recognises 97 different occupations within Australia – although the exact number of occupations depends on the aggregation. The firms who hire labour are provided with some limited scope to change between these 97 labour types as the relative real wage between them changes. Similarly, the 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.

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:

- labour makes itself available to the workforce based on movements in the real wage and the unemployment rate;
- labour chooses between occupations in a state based on relative real wages within the state; and
- 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).



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 Global Australia (GMG Australia)* 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.

The model can be specified to run at daily, monthly, quarterly or annual resolution over periods up to 30 years.

F.1 Settlement

At its core, GMG Australia 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 theory⁸⁸, 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.

The figure below seeks to explain diagrammatically a simplified example of the optimisation process. The two charts at the top of the figure below show simple linear demand and supply functions for a particular market. The charts in the middle of the figure below 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

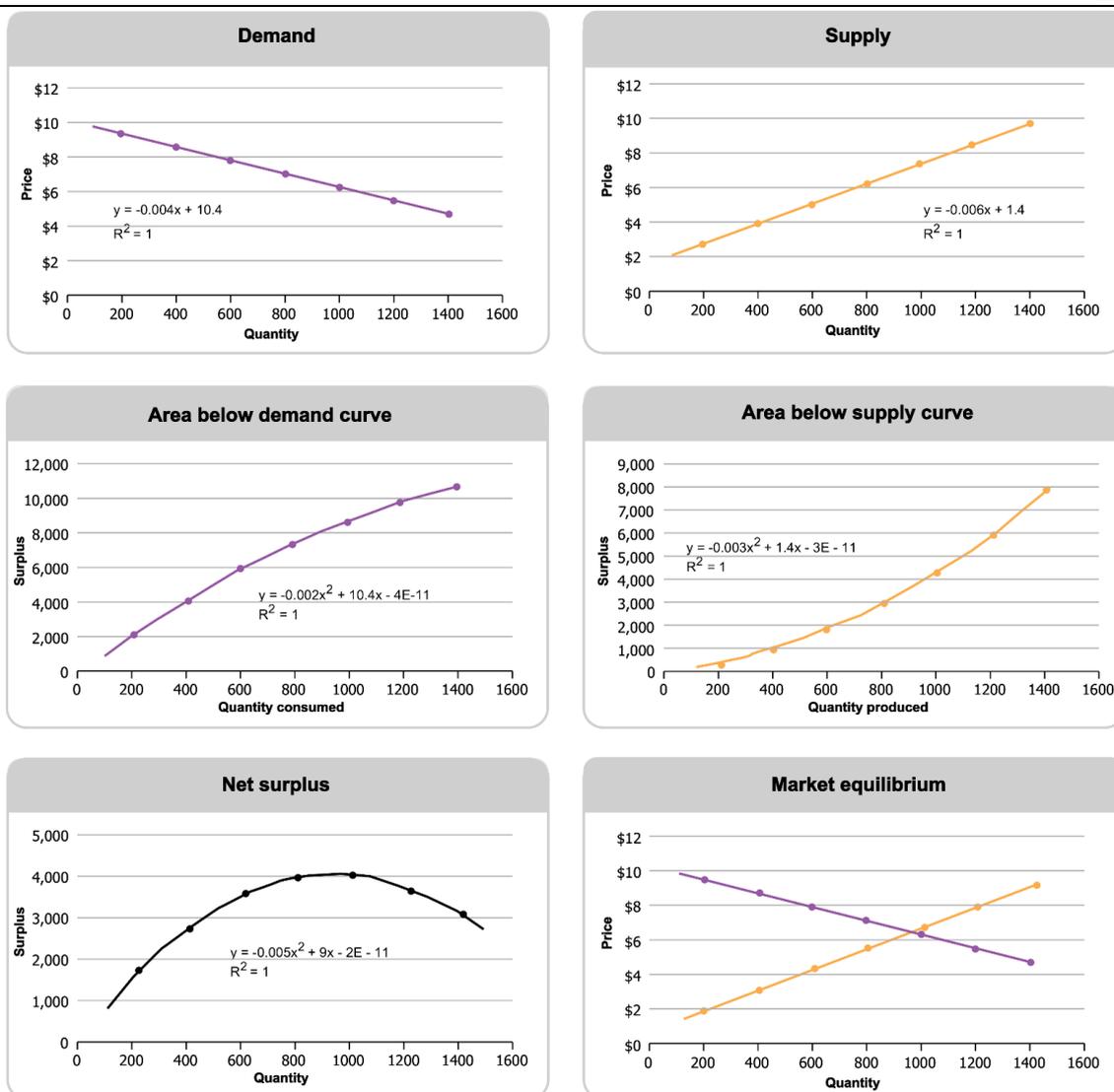
⁸⁸ The theoretical framework for the market solution used in GMG is attributed to Nobel Prize winning economist Paul Samuelson.

evident at a quantity of 900 units. This is equivalent to the equilibrium quantity when demand and supply curves are overlaid as shown in the bottom right figure.

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), GMG Australia 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.

SIMPLIFIED EXAMPLE OF MARKET EQUILIBRIUM AND SETTLEMENT PROCESS



SOURCE: ACIL ALLEN CONSULTING

F.2 Data inputs

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 GMG Australia 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.

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