

9th March 2020

Australia Oil & Gas Industry Outlook Report



Executive Summary

The Australian upstream oil and gas industry experienced an unprecedented wave of investment and activity through the early 2010s. Success took the form of multiple greenfield LNG project sanctions, with most starting production over the past few years. Such a scale of investment yielded substantial indirect and induced economic benefits to the regions surrounding these projects in the form of, for example, increased local employment, industrial activity to service construction and engineering tenders, and infrastructure build-out, alongside the inevitable trickle-down effect of this investment.

Conversely, due to the profile of these projects having high upfront development costs and lengthy payback periods, it follows that full benefits from this wave of investment have not yet translated into direct government revenues. The economics of large-scale LNG projects that typify Australian oil and gas show that the lion's share of direct economic benefit in the form of royalty and corporate income tax is expected to be accrued in the latter half of the 2020s. Any attempt to increase headline rates to address perceptions of current under-receipt of tax revenues is likely to be counterproductive in terms of stabilising long-term investment and returns and facilitating further expansion and investment by the industry.

While success can be readily characterised, it was by no means guaranteed. Strengths such as the prevalence of material hydrocarbon deposits, strategic access to high demand-growth markets in Asia and leadership in innovative developments were counterbalanced by other, limiting factors such as the high-cost environment and increasing challenge of developing more marginal and technically challenging resources. The analysis presented in this report shows that the overarching reason for Australian success was that oil and gas majors with strong balance sheets and development capability were able to make a long-term commitment to the country, predicated on certainty and stability of the long-term regulatory and fiscal environment. The relatively few regulatory and fiscal changes made in Australia from the period 2000–2010 formed the foundation for this perception of stability and thus directly contributed to the wave of investment.

Neither is continued success guaranteed. Against the backdrop of a challenging macroeconomic environment driving lower commodity pricing in the second half of the decade, Australian fiscal and regulatory volatility has increased. The net result of these changes is that there has been no major LNG project sanction since Ichthys in 2012. In addition to this, upstream competition for capital is becoming fiercer and new sources of LNG are appearing at a rapid rate across the globe, from entirely new provinces such as the US Gulf Coast and East Africa to established players in the Middle East.

New and existing threats should be viewed under a wider, global energy context however. Under even the most aggressive of Energy Transition scenarios such as the IEA Sustainable Development Scenario, gas / LNG demand is expected to remain robust into the 2030s and 2040s. Australia will need to reverse its growing perception of instability and volatility to retain its seat at the top table of LNG exporters and claim its share of the gas demand growth going forward.

In response to this changing environment, we have already seen other upstream regulators and governments stake their claim for a continued or even enhanced share of industry investment. Most notable are the examples of the UK and Norway sacrificing short-term fiscal revenue for long-term attractiveness and sustainability of their upstream sectors through changes to abandonment / decommissioning credits and exploration costs respectively. Going even further would include the Qatari government who actively partakes in LNG project funding and development through QP and Qatargas, sharing downside development and operational risks with operators. These incentives may not be recommended, or even viable for Australia but their existence shows how eager and proactive governments are becoming to ensure their upstream industry remains robust and able to deliver economic benefit to the country for the coming decades.

We believe that a successful future for Australian oil and gas will consist of developing the currently uneconomic or stranded discovered gas resources that abound through Australia's hydrocarbon regions. Using this gas is vital to extending the economic life and utility of existing gas and LNG infrastructure and thus maximise value from these assets. To unlock this potential, Australia would need to see a step change in cooperation, mainly agreeing commercial structures across different ownership interests and priorities. This change is most likely to occur if the Australian oil and gas ecosystem can rebuild its confidence in the investment environment. One clear way to advancing this objective would be to minimise future interference in fiscal and legislative systems.



Contents

1. Breaking down the success of Australia’s upstream oil & gas industry	4
1.1. Key macroeconomic and industry-specific enablers	4
1.2. Attracting international investment	6
2. How a healthy oil and gas industry benefits Australia	9
2.1. Jobs and regional wealth creation	9
2.2. Fiscal revenues	9
3. New challenges on the horizon	12
3.1. Upstream investment challenges	12
3.2. Mounting international LNG competition	12
3.3. Upcoming decommissioning liabilities.....	14
4. Maintaining Australia’s upstream attractiveness	16
4.1. Enhancing project cost competitiveness	16
4.2. Maintaining fiscal competitiveness and stability.....	18
5. How other jurisdictions attempt to stimulate investment	20
5.1. The United Kingdom: Keeping headline tax rates flat and adding options for late-life deals.....	20
5.2. Norway: Accelerating tax relief to stimulate exploration	20
5.3. Nigeria: Raising royalties to the detriment of cost and fiscal competitiveness	21
6. Conclusion and a potential vision for the future	22

Figures

Figure 1. Industry spend in Australian upstream oil and gas sector.....	5
Figure 2. Average LNG shipping costs from key LNG producing regions to China.....	5
Figure 3. Australian state and federal legislative changes, inquiries / reviews (1999 – 2010).....	6
Figure 4. Oil and/or gas field lifecycle and key operator activities.....	6
Figure 5. Hydrocarbon resource deposits and key population centres in Australia.....	8
Figure 6. Global total primary energy demand (TPED).....	11
Figure 7. Government take from North West Shelf LNG project.....	11
Figure 8. Global upstream CAPEX spend.....	13
Figure 9. Global liquefaction capacity growth by FID year (left) and global LNG year-on-year supply growth (right).....	13
Figure 10. Global LNG supply-demand balance.....	14
Figure 11. Total abandonment costs faced by Australia’s upstream sector.....	15
Figure 12. Key issues surrounding Australia’s upcoming decommissioning exercise.....	15
Figure 13. Upstream development cost comparison for key oil and gas producing countries.....	16
Figure 14. Cost stack (DES to Asia) for select LNG projects.....	17
Figure 15. Fiscal Attractiveness vs. Prospectivity ratings for key oil and gas producing countries / regions.....	18
Figure 16. Australian state and federal legislative changes, inquiries / reviews (1999 – 2019).....	19
Figure 17. Breakdown of project (i.e., pre-government) undiscounted cash flow from Norway’s 2005–2017 exploration activity.....	21

Tables

Table 1. Fiscal measures and instruments applied in Australia.....	10
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1. Breaking down the success of Australia's upstream oil & gas industry

A successful upstream oil and gas regime is one most appropriately defined as consistently attracting substantial levels of investment. Oil and gas is a global and capital-intensive business and companies typically have significant optionality in their upstream portfolios as to where and when they invest.

Australia's success can be demonstrated by the fact that its oil and gas industry has enjoyed a globally significant investment boom over the last decade, headlined by a US\$200 billion (A\$305 billion¹) wave of liquefied natural gas (LNG) mega-projects which set the country on course to become the world's top LNG exporter. Through this sustained investment, Australia's gas production has grown by over 140% in the decade 2010–2020 and liquids production has returned to over half a million barrels a day – a level not seen for nearly a decade.

By end-2020, a total of US\$310 billion (A\$473 billion) will have been invested in the industry since 2010, and further large upstream investments are on the horizon (e.g., LNG backfill opportunities at Darwin and North West Shelf LNG, expansion of Pluto LNG and the associated upstream development at Scarborough).

Australia's success has been the result of a unique combination of factors spanning geological potential and prospectivity to strategically advantageous positioning and a stable, investable fiscal environment. We explore each of the identified key factors in this section.

1.1. Key macroeconomic and industry-specific enablers

There are a wide array of factors driving Australia's recent upstream industry success, and a unique combination of three stand out:

1. Proven hydrocarbon resource base:

Australia has a substantial hydrocarbon resource base. According to Wood Mackenzie's database, as of October 2019, over 18 billion barrels of crude oil, natural gas, and natural gas liquids (NGLs) had been produced from the nine major basins across Australia, with over 40 billion barrels remaining (refer to Figure 5). In terms of commercially exploitable reserves, the country had about 2.6 billion barrels of crude oil and NGL reserves, accounting for 0.3% of liquids reserves globally. Natural gas reserves are estimated at 156 trillion cubic feet (tcf), accounting for 1.7% of global gas reserves. In addition, Australia has up to 68 tcf of 'technical reserves' of gas – i.e. gas which is technically recoverable but not currently considered for development due to a range of reasons including market and pricing.

Perceived prospectivity obviously ranks highly when oil and gas companies consider global investment destinations. Australia has consistently delivered exploration success and ranks in the top 20 countries in Wood Mackenzie's upstream coverage for reserves discovered during both previous decades (2000–2019). In fact, discovery of many of Australia's largest oil and gas assets – over 1 billion barrels of oil equivalent (boe) – preceded this period. This repeated success built confidence across the oil and gas industry that Australia is an attractive province in terms of exploration and development activity.

2. LNG market opportunity:

Growing global demand for energy, led mainly by China and India over the past decade, has driven a strong increase in gas demand and particularly LNG due to its suitability for long-distance transportation. Australia is advantaged geographically and has been able to position itself technically and commercially to meet this demand, emerging as a global leader in LNG. Projects sanctioned between 2007 and 2013 have delivered over 60 mtpa of additional LNG capacity since 2015, adding to legacy production from the North West Shelf and Darwin. Australia's ability to attract the oil and gas majors and key Asian LNG buyers to develop its gas deposits as LNG was critical to this. The majors Chevron, Shell, Total and ExxonMobil had the technical capability, balance sheet strength and strategic goal and drive to bring Australia's technically challenging gas

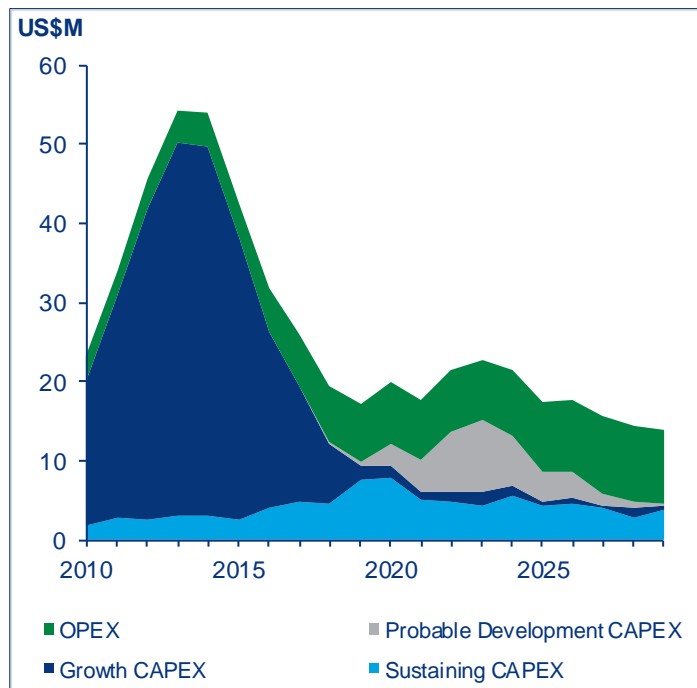


Figure 1. Industry spend in Australian upstream oil and gas sector.

“Australia's success has been the result of a unique combination of factors spanning geological potential and prospectivity to strategically advantageous positioning and a stable, investable fiscal environment.”

¹ Applied current exchange rate is USD1: AUD1.53.



fields to commercial success. The Asian buyers brought the market.

This has given rise to a gas export business that is uniquely diversified. Australia now has three clusters of LNG plants (i.e., Gladstone, Darwin, and the Carnarvon basin), supply comes from both conventional and unconventional sources, and it leads the way in terms of technologically advanced projects (e.g., Prelude FLNG, Gorgon Carbon Dioxide Injection Project which employs carbon capture and storage, and the world’s first CSG–LNG projects). We expect Australia to maintain its position as the world’s largest LNG exporter this year, when it is expected to ship approximately 84 million tonnes of gas.

Supplementing Australia’s technological and strategic leadership of LNG projects is its advantaged geographical locale. Being close to high growth and high demand Asian markets such as Japan, Korea, and China enables lower transport costs and therefore confers a unique benefit to the Australian LNG producers. This geographical advantage is shown in Figure 2 below, showing the alternative routes of supply of LNG into the Pacific basin.

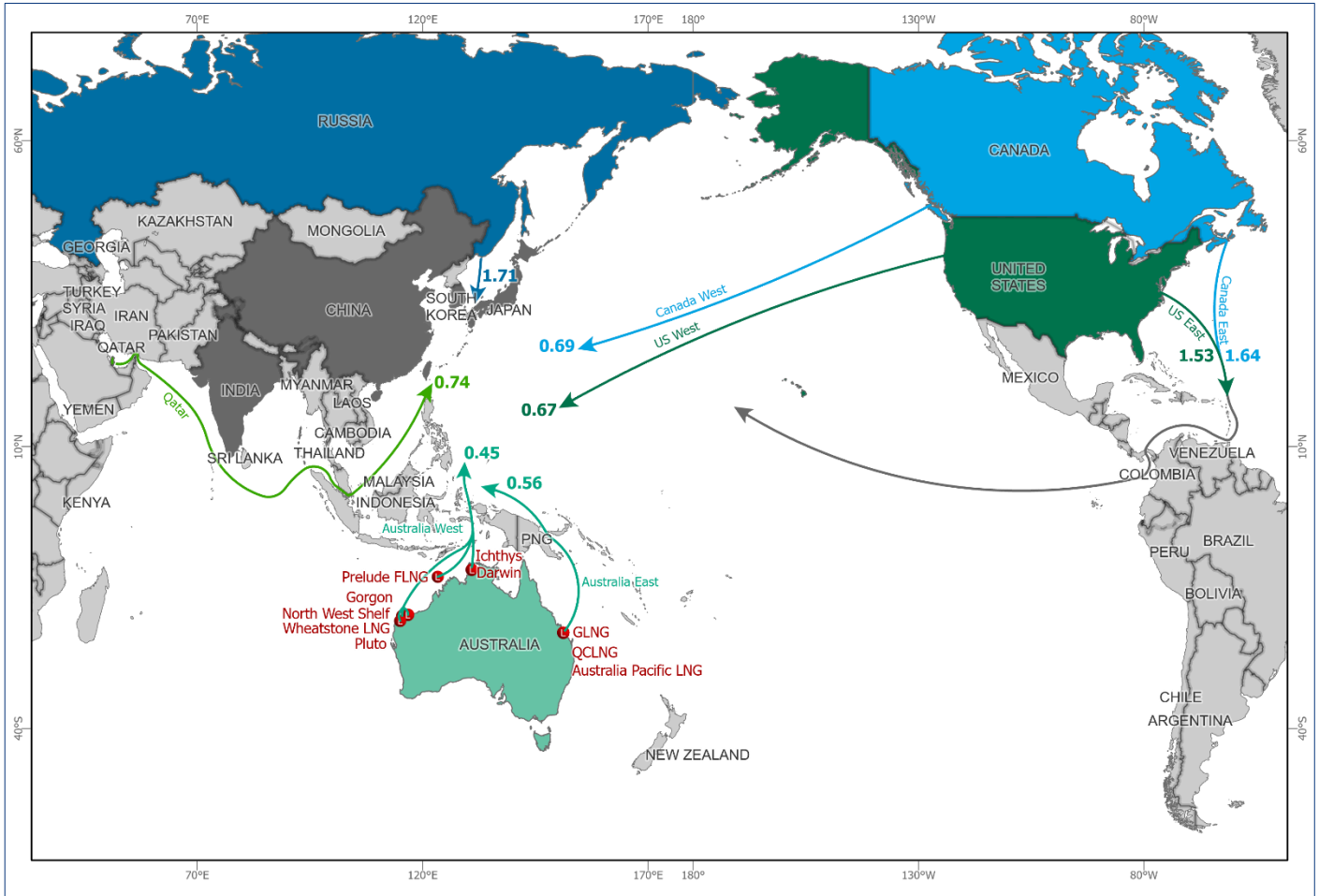


Figure 2. Average LNG shipping costs from key LNG producing regions to China.

3. Regulatory stability:

Oil and gas investment decisions, particularly of the mega-project scale developed in Australia, are often considered over multiple years, and in some cases decades. Australia’s LNG success has been supported by a comparatively stable policy and regulatory environment which underpinned the significant long-term investments during the period of 1999–2010. The stability of Australia’s taxation arrangements was a key contributing factor in attracting this wave of investment.

In addition, Australia offers the rare combination of being an OECD, developed economy with the ability to attract skilled labour and technology, alongside the significant prospectivity outlined in the first point of this section. The dual attraction of stability and material resource is often a compelling factor for investment.

In summary, Australia’s oil and gas success is evidenced by the track record of consistent capital investment and strong gas production growth over the past decade. The key for these successes is the unique combination of factors Australia has to offer – proven evidence of substantial hydrocarbon, particularly natural gas, resources; an established global leadership position in LNG development and production; and the stabilising effect of a tax system which has remained relatively constant in the face of drastic global macroeconomic changes.

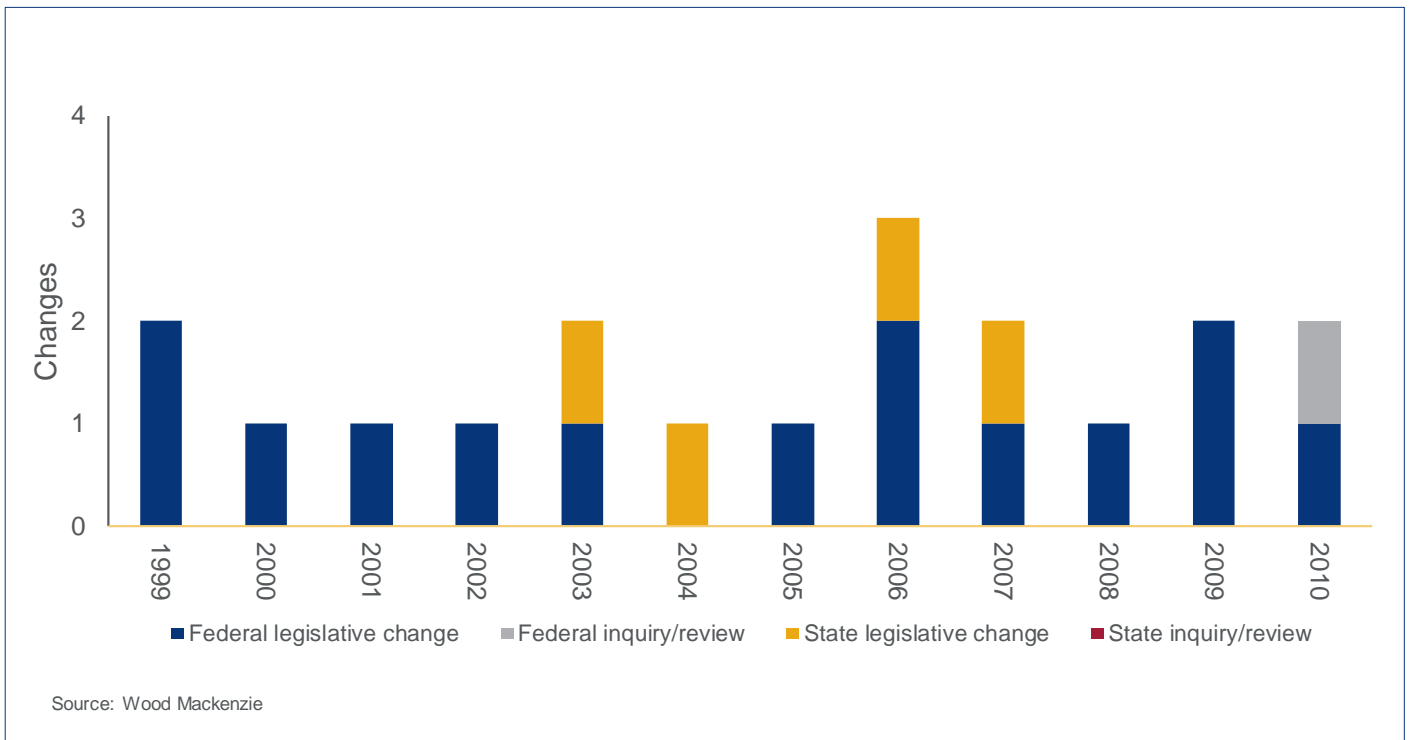


Figure 3. Australian state and federal legislative changes, inquiries / reviews (1999 – 2010).

1.2. Attracting international investment

Oil and gas companies must continually develop new resource opportunities to secure future cashflows and generate long-term shareholder value. One of the key measures that investors look to is RP (i.e., reserves-to-production) ratio, which is seen as a measure of the long-term health of an oil and gas company. Oil and gas companies can replace volumes through exploration, appraisal and project sanction, or through acquisitions.

Replacing production volumes is a capital-intensive, multi-year process with inherent risks throughout, and companies must take decisions on where to invest with significant care and diligence. To attract upstream investment, countries such as Australia must position themselves as more stable, prospective or lower risk than other countries competing for this capital.

Figure 4 below illustrates the key activities of resource capture and commercialisation.



Figure 4. Oil and/or gas field lifecycle and key operator activities.



Uncertainty over costs, timelines and a range of other factors introduce risk throughout the project development process. While not an exhaustive list, typical risks may include:

- Regulatory and legal risks (e.g., property title disputes, increased taxes and royalties, compliance with governmental and intergovernmental body regulations)
- Market risks (e.g., commodity price variations, competition for licenses and assets)
- Subsurface risks (e.g., reservoir characteristics and properties, reserves and resources up- and down-grades)
- Schedule and cost risks (e.g., time and budget overruns, inaccuracies in cost estimation)
- Operational / performance risks (e.g., inability of partners or contracted service companies to finance or execute the project, inability to develop or implement technologies to access fields)
- Governance risk (i.e., board and management performance)



To attract upstream investment, countries such as Australia must position themselves as more stable, prospective or lower risk than other countries competing for this capital.

Many of these risks are outside of a company's control. This leads companies to place even greater value on the factors that they can control. One such factor is selecting a stable fiscal or regulatory environment in which to invest. Fiscal stability allows upstream operators to better forecast future cashflow and derive an economic value for their asset(s) with greater certainty, which in turn facilitates access to funding and offers a more tolerable risk profile when gaining investment board approval.

Australia's success as an international investment destination has benefitted from such a calling card, and helped it overcome its competitive disadvantage of a significantly higher-cost operational environment. This lack of cost competitiveness in Australian upstream oil and gas is largely due to:

1. High industry wages:

Based on the Hays Oil and Gas Global Salary Guide Review of 2013, Australia's oil and gas professionals earned some of the highest salaries in the world – an average of US\$163,700 (A\$170,248²) per annum, just behind Norway in first place. Wages have generally continued to rise since then, with the wage price index for the resources and mining sector increasing at an annual average of 1.6% from 2013 to 2018.

The high wage environment is largely down to the higher living costs in Australia, which is multiplied by unmet demand for skilled industry labour and the strength of labour policy and unions. Compounding this is the strong competition from the mining industry in Australia. In 2016, National Energy Resources Australia (NERA) reported that nearly every second worker in the Australian oil and gas industry is employed in highly skilled positions (e.g., geophysicists, engineers, accountants), of which almost half are employed in production and a third in corporate services.

These structural factors make it challenging for the Australian oil and gas sector to be cost-competitive against other investment destinations. As testament to this, the 2019 World Economic Forum Global Competitiveness Report identified labour market productivity (i.e., the strength of the relationship between salary and worker productivity) as an area of weakness for Australia. In this measure, Australia ranked 39th out of the 141 countries surveyed.

2. Geographical remoteness of its resources:

As shown in Figure 5, a large majority of remaining hydrocarbon reserves (i.e., North Carnarvon, Browse, Bonaparte) are situated far from the key population centres along the east coast. All other things being equal, Australian upstream operators would face higher costs in the upstream and midstream as compared to an oil and gas hub like Houston, where oil and gas projects have easy local access to demand and skilled labour.

² Applied 2013 exchange rate is USD1: AUD1.04.

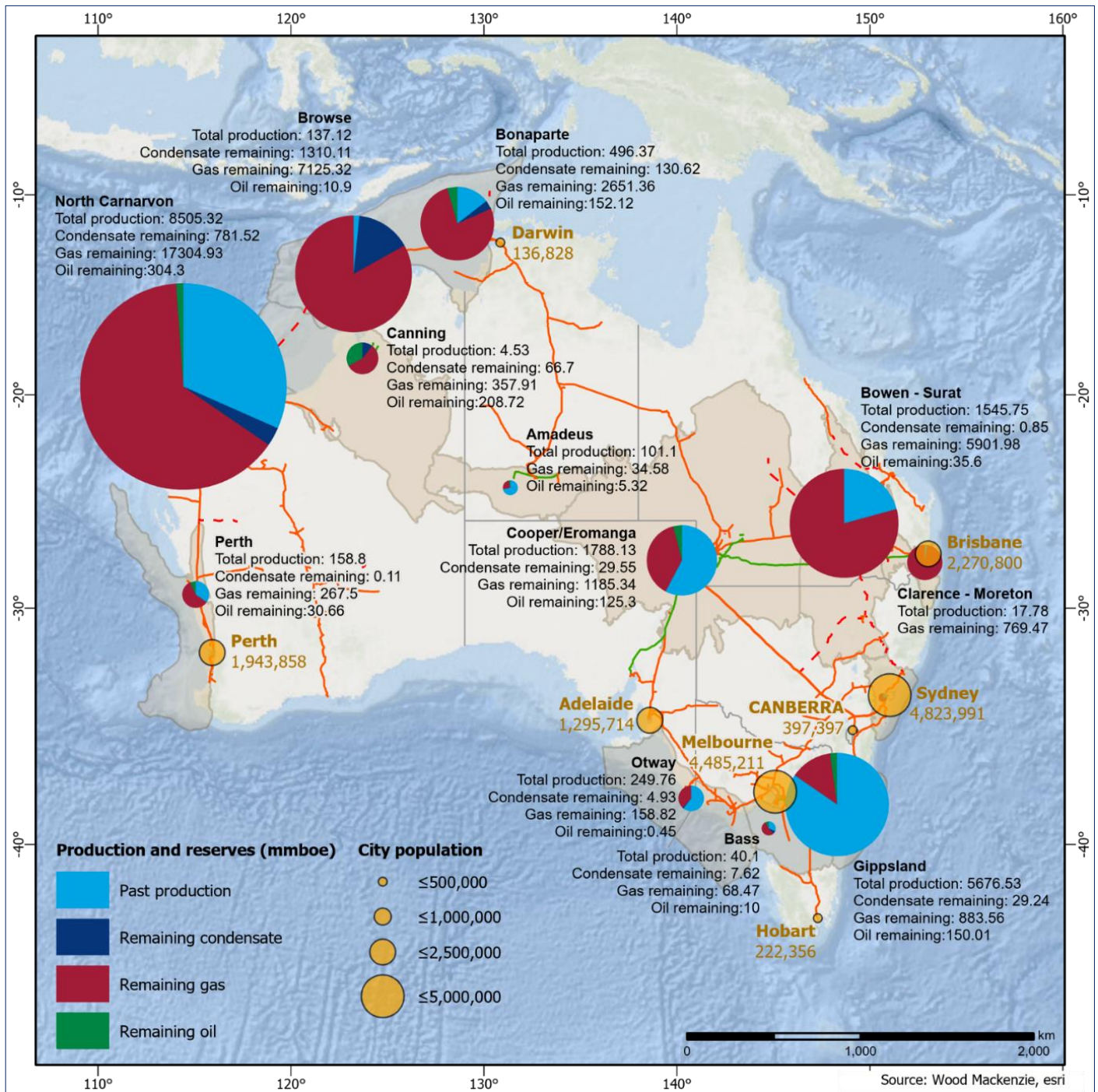


Figure 5. Hydrocarbon resource deposits and key population centres in Australia³.

³ Reserve volumes include both commercial and technical reserves. Population data is taken from the Australian Bureau of Statistics (2019).



2. How a healthy oil and gas industry benefits Australia

With rising populations (albeit at moderating intensities), global total primary energy demand (TPED) is set to rise from 101.6 billion boe in 2020 to 118.8 billion boe in 2040. We expect the energy consumption mix to change only gradually; with coal, gas, and oil accounting for 78% of TPED in 2040, compared to 83% in 2020. Gas will maintain its share at approximately 25% for the next two decades, even as the role of renewables increases.

This backdrop provides impetus for continued development of the Australian upstream oil and gas industry, particularly its LNG sector. In this section we examine how this bedrock industry underpins wealth and employment in Australia.

2.1. Jobs and regional wealth creation

The oil and gas industry spurs economic activity across the energy value chain (e.g., through direct and indirect employment) and across regional Australia (e.g., through the development of regional oil and gas hubs outside of the major commercial centres).

During the period from 2006 to 2016 as the industry enjoyed an investment boom, the direct oil and gas workforce more than doubled, with jobs being created not just in exploration and production but also in corporate and project development⁴. This industrial activity also supports an extensive supply chain of businesses and numerous jobs in manufacturing, construction, technology, transportation, accounting, and other services (e.g., transport). NERA estimated that each oil and gas worker sustained 5.4 other jobs across the supply chain – a multiplier significantly higher than the average of 0.8 across all industries due to the capital-intensive nature of oil and gas projects – and a further 4.6 jobs in the broader Australian economy through consumer spending. APPEA estimates that in total, the sector supports some 80,000 jobs through direct and indirect employment. In addition, in 2016-17 the industry provided a US\$20 billion (A\$27 billion⁵) boost to the economy through the purchase of goods and services from local businesses.

Oil and gas activity also spurred the development of regional technology and areas of substantial economic development. In Western Australia, for example, the development of remote offshore gas resources and mega-scale LNG facilities has driven technological advances in exploration and infrastructure, establishing the region as an important global centre for offshore LNG research and innovation. In terms of wealth creation, Chevron estimated that the economic impact of its operations in the Gorgon, Wheatstone, and North West Shelf LNG projects has comprised:

- 2,603 direct and indirect full-time equivalent (FTE) jobs per annum, 90% of which are in Western Australia
- A US\$450 billion (A\$687 billion) boost to Australia's GDP from 2016 through to 2050, roughly equal to three times the size of the Western Australian economy in 2016-17
- US\$12.4 billion (A\$18.9 billion) in annual export value, comparable to the total combined export value of goods from South Australia, the Northern Territory, and Tasmania

On the east coast, the development of the CSG-LNG industry led to more than US\$39 billion (A\$60 billion) being invested in LNG export facilities at Gladstone, contributing significantly to the state's prosperity. These projects continue to be an important driver of economic growth. In 2011, Queensland became home to the Gas Industry Social and Environmental Research Alliance (GISERA), a ground-breaking research alliance to support sustainable CSG industry development. By mid-2018, direct employment in the Queensland oil and gas industry had grown to 6,500, well above the levels that existed pre-CSG-LNG development. Increased local employment induces follow-on effects that benefit the wider local economy, most notably increased personal and corporate income tax contributions, PAYG contributions, increased spending in local communities with the associated increase in GST, etc.

2.2. Fiscal revenues

Governments also derive direct economic benefit (i.e., revenues) from the development of oil and gas resources through a variety of

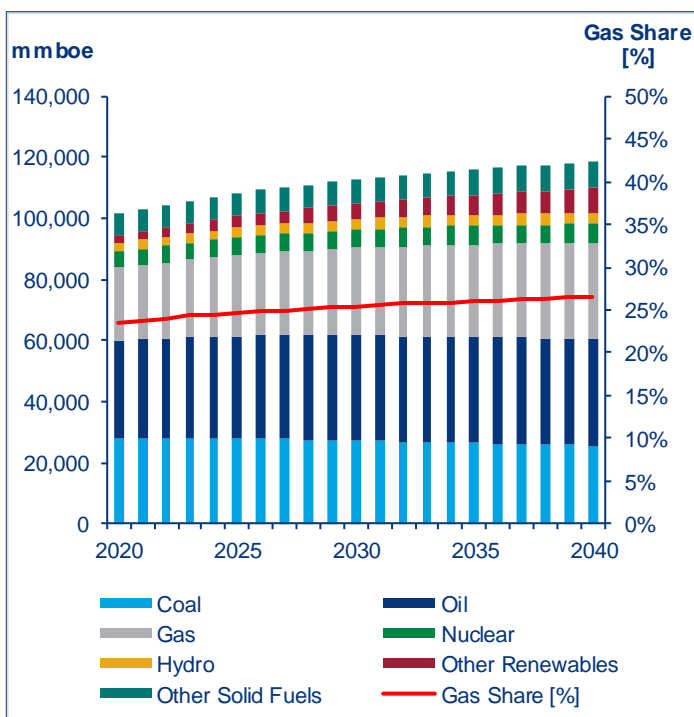


Figure 6. Global total primary energy demand (TPED).

⁴ Based on data from the Australian Bureau of Statistics and National Energy Resources Australia (NERA).

⁵ Applied 2016 exchange rate is USD1: AUD1.35.



tax and non-tax measures. Table 1 explains the fiscal measures and instruments applied in Australia.

Table 1. Fiscal measures and instruments applied in Australia.

Measure	Description	Application in Australian Upstream Fiscal Regime
Royalties	<ul style="list-style-type: none"> Levied on production / revenue Up front and stable cashflow stream to government 	<ul style="list-style-type: none"> Applied only to fields under state jurisdiction and the North West Shelf project Applied on gross oil and gas revenue, less excise duty payments and transportation costs Royalty rates are usually between 10% and 12.5%, and vary by state
Resource rent tax	<ul style="list-style-type: none"> Levied on revenue once the company has earned a hurdle rate of return 	<ul style="list-style-type: none"> Applied on gross revenue of hydrocarbons at market price, less allowable deductions Petroleum Resource Rent Tax (PRRT) rate is 40% – removed from onshore assets in 2019 (no significant change as most of these projects would never pay appreciable PRRT)
Income tax	<ul style="list-style-type: none"> Levied on revenue of all companies (i.e., not just the oil and gas sector) 	<ul style="list-style-type: none"> Applied on gross oil and gas revenue, less allowable deductions including PRRT Federal income tax rate is 30%
Excise duty	<ul style="list-style-type: none"> Levied on production / revenue at the moment of production 	<ul style="list-style-type: none"> Applied only to fields under state jurisdiction and the North West Shelf project, between 0-55%
Bonuses, rentals, and fees	<ul style="list-style-type: none"> Bonuses are one-off payments that serve to provide some up-front revenue for the government, and encourage companies to explore and develop contract areas more rapidly Annual rental payments serve to encourage companies to explore and develop contract areas, or to relinquish their rights 	<ul style="list-style-type: none"> Signature bonus: Cash bids for offshore fields Area rentals: For areas under federal jurisdiction, annual rental charges are payable relating to exploration acreage (A\$10,000 per title), retention license (A\$20,000 per block), and production license (A\$20,000 per block)
Indirect taxes	<ul style="list-style-type: none"> Examples include customs duties and value-added tax (VAT) 	<ul style="list-style-type: none"> VAT: 10% Goods and Services Tax (GST) paid on expenditure Import duties: Levied at the rate of either 0% or 5% (for certain types of goods)

The Australian fiscal system levies a wide range of taxes and fees on upstream companies. Many of the taxes are on profits, rather than revenue or production. Profits-based taxation is viewed by business groups as an appropriate and reasonable method of taxation, particularly in an industry such as oil and gas with substantial production / sales volumes and commensurate capital costs. However, due to these profit-based mechanisms, some taxes only become payable at a later stage of the project lifecycle once payback is achieved. High capital costs compounded with cost overruns have caused deferment of this payback period of many larger projects.

Using North West Shelf LNG as a proxy for the wider set of Australian LNG investments, a view of current and historic tax paid to date has the potential to mis-represent the overall economic benefit to the Australian federal government.

As an example, the North West Shelf LNG project (refer to Figure 7) only began to generate significant government revenue after its 17-year payback period. We estimate that cumulative government take as of 2019 amounted to approximately US\$41 billion⁶, 99% of which was contributed post-1997. Thus, using North West Shelf LNG as a proxy for the wider set of Australian LNG investments, a view of current and historic tax paid to date has the potential to mis-represent the overall economic benefit to the Australian federal government.

⁶ Based on Wood Mackenzie's base case long-term Brent price assumption of US\$65/bbl real.

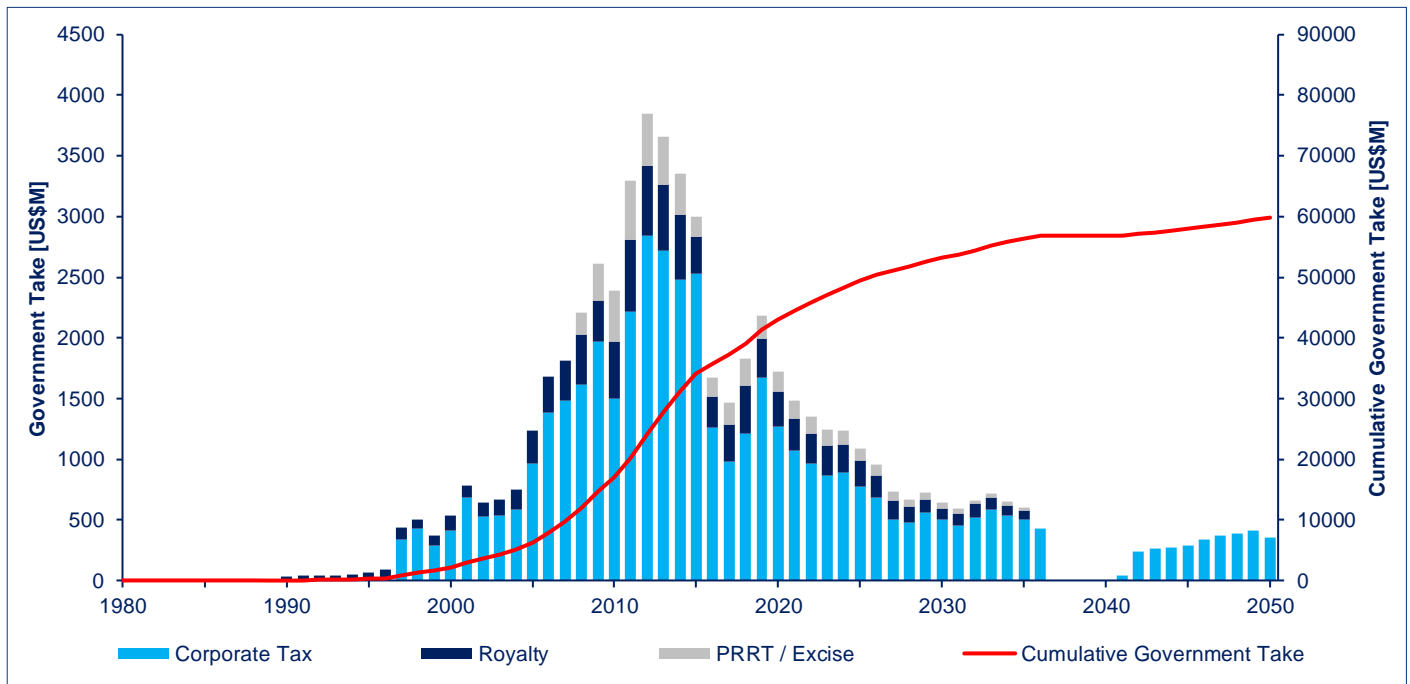


Figure 7. Government take from North West Shelf LNG project.

In short, we expect that the bulk of the government revenue from oil and gas taxation is likely to occur only in the coming years because of two factors:

- **Large stock of deductible expenditures from the recent wave of new projects:** The total project costs of Gorgon LNG and Wheatstone LNG, for example, were estimated at US\$54 billion (A\$82 billion) and US\$34 billion (A\$52 billion) respectively.
- **Low oil and gas prices which reduce project profitability:** Using Gorgon LNG as an example, at our base case long-term Brent price assumption of US\$65/bbl real, the payback period is 19.5 years. At US\$50/bbl real, however, the payback period is pushed to 21.4 years; and at US\$30/bbl real, it is pushed further to 32.5 years.

In view of this, it is important that the Australian government continue to support the upstream oil and gas sector by providing a stable regulatory environment for investors. Existing projects will attain breakeven and reach the tax-paying part of their lifecycles in due time. It is also important to note that whilst the bulk of payments will be made once costs are recovered, it is not to say that payments to governments do not occur before costs are received.



3. New challenges on the horizon

While many of Australia's key success-enabling factors are still relevant today, we foresee challenges on the horizon that could threaten Australia's ability to maintain its excellent track record in attracting international oil and gas investment. Changing market and investment conditions raise some red flags for future investment dollars globally and Australia must maintain its relative attractiveness and competitiveness in the global context to respond to these challenges.

3.1. Upstream investment challenges

Global upstream development spend has contracted significantly in recent years, with structural indications that it may indeed never return to previous levels. We expect global upstream investment of US\$350 billion (A\$534 billion) in 2020, representing just 5% year-on-year growth and a 40% drop from the peak of 2014.

This is partly because companies have had to keep a sharp focus on reducing their costs to maintain margins in a weaker oil and gas price environment. Delivering free cash flow and maintaining dividend payments are increasingly prioritised over new investment projects, and caution is exercised over all discretionary spend. Capital discipline has become the order of the day, and only the most economically robust projects or those where stable returns are expected are being progressed.

This is potentially bad news for Australia's upstream industry on two counts. Firstly, there is simply less capital available for deployment – the overall pot is smaller. Secondly, as capital allocation becomes more competitive, higher-cost jurisdictions are less attractive for deploying what capital is made available.

Oil and gas companies will also see increasing pressure to make tangible, strategic commitments towards decarbonisation and the initial outcome of this will be a prioritisation of traditional assets so that only the lowest-cost, highest-returns projects in their portfolios are selected for sanction. In addition to this, increasing Environmental Social Governance (ESG) disclosure requirements will add another layer of complexity and administrative burden to the upstream investment process.

In these circumstances the outlook for Australia is more nuanced, since natural gas is expected to play a key role as the world transitions to cleaner sources of energy. In many parts of the world, particularly in North and Southeast Asia, gas is expected to continue to displace coal in power generation and global gas demand will rise. Even for those countries which have a significant proportion of power derived from renewable sources (e.g., Germany, UK, Spain), gas is still relied upon to provide flexibility in the generation system and maintain capacity for periods of increased demand. Given Australia's leading position as an LNG supplier, and the role of gas as a cleaner fuel, it is possible that the Australian oil and gas industry may not be subject to the full impact of environmental changes versus other resource types and host nations.

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Capital discipline has become the order of the day, and only the most economically robust projects or those where stable returns are expected are being progressed.

This points to the importance of clear climate change policies, including carbon abatement techniques, which may assist in underpinning its credentials as a cleaner source of fuel in key markets (e.g., Europe and Japan). Remaining cost-competitive is key for future Australian LNG projects to reach project sanction. Australia's challenge for the near term will be to enhance not to reduce its attractiveness as an investment destination to maintain its leading LNG export position.

3.2. Mounting international LNG competition

Australia has dominated the LNG investment landscape over the past decade, primarily off the back of project decisions taken between 2009 and 2013. Since then, no new LNG projects have reached investment sanction. Indeed, a flood of cheaper, more flexible projects have moved to development elsewhere, particularly in the US between 2013–2015 (e.g., Freeport, Cameron, Corpus Christi, Sabine Pass Train 5, Elba Island) and subsequently in Russia, Mozambique, Nigeria, Canada and Mauritania / Senegal.

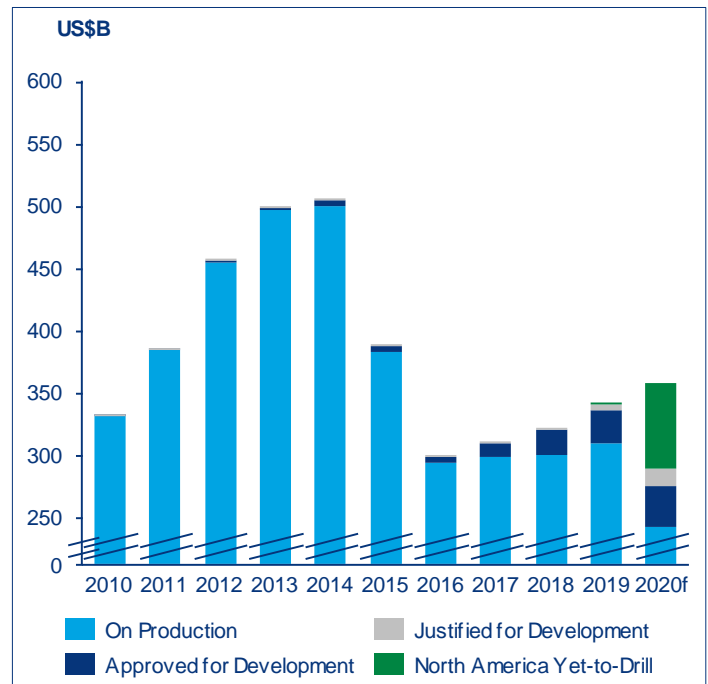


Figure 8. Global upstream CAPEX spend.



The global LNG market remains on a growth trajectory. Over the next 20 years, we expect LNG demand to grow from 374 mmtpa to 740 mmtpa by 2040. The Asia-Pacific region will account for more than 70% of this growth, with its key markets facing declining indigenous production and rising power and industrial sector demand as its economies continue to develop. The opportunity for Australia to help meet this demand growth is clear, given its existing export infrastructure and its geographical proximity to markets.

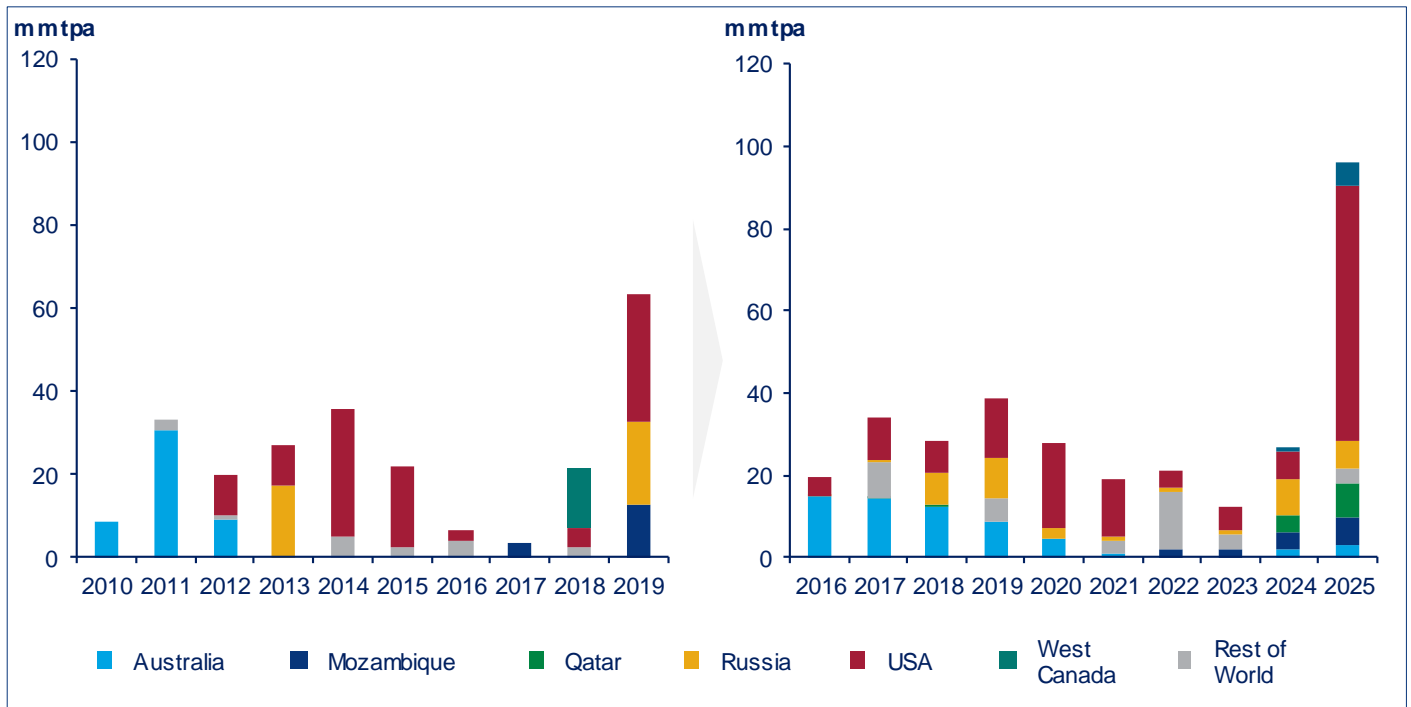


Figure 9. Global liquefaction capacity growth by FID year (left) and global LNG year-on-year supply growth⁷ (right).

However, as LNG FIDs continue apace outside of Australia there is a danger that the current wave of opportunity is missed, and future Australian LNG may end up priced out of the market. 2019 was a record year for LNG supply investment decisions with multiple liquefaction projects. Projects in North America, East Africa, Qatar, Russia, Papua New Guinea are vying for FID over the next 36 months alongside Australia. In Australia, this reflects over US\$50 billion (A\$76 billion) worth of potential investment in expansion and backfill projects at Pluto, Browse, Scarborough, Barossa (Darwin LNG), and Crux (Prelude FLNG).

Wood Mackenzie’s current view, based on the expected progress for the current pipeline of global pre-FID projects, is for Australia’s market share of global LNG supply to shrink from 20% to 10% by 2040, as competing supply sources take a larger share of Asian demand growth. To maintain its LNG supply leadership position in the world, Australia needs to ensure its involvement in this next wave of investment.

⁷ Year-on-year supply growth includes both new projects coming onstream and ramp-up / ramp-down of existing projects.

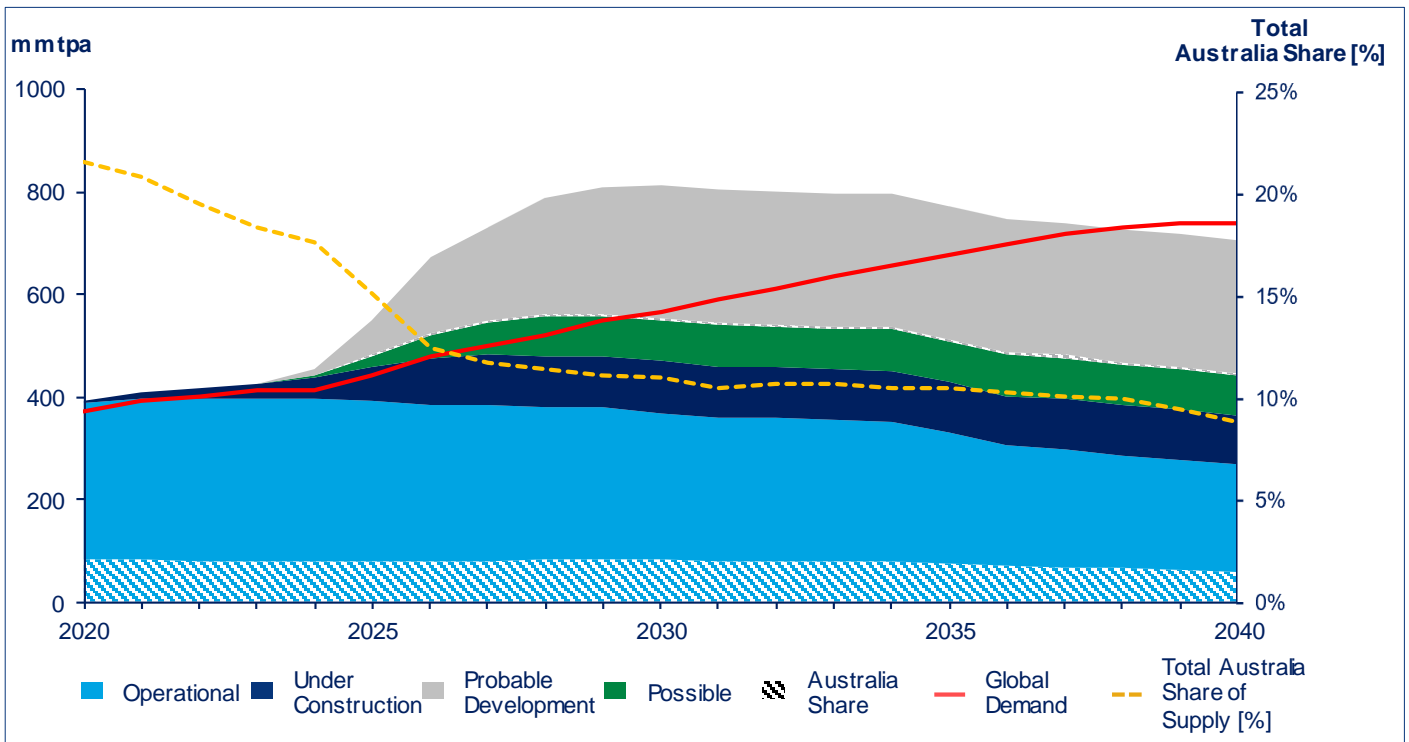


Figure 10. Global LNG supply-demand balance⁸.

3.3. Upcoming decommissioning liabilities

Upstream operators will need to decommission over 65 offshore platforms – many aged – and cease production at seven floating facilities by 2026. The current cost of decommissioning (i.e., total abandonment expenses, or AbEx) is estimated at more than US\$39 billion (A\$60 billion) over the next 30 years.

Unlike in the Gulf of Mexico and the North Sea, decommissioning is still in its infancy in Australia, and all involved (i.e., regulators, operators, and the service sector) need to be prepared for the coming wave as assets approach the end of their producing lives. To date, unclear regulations, a widening competency gap and stringent environmental considerations have kept effective decommissioning to a minimum. And with many company finances depleted after the fall in prices, there is a reluctance from operators to proactively pursue decommissioning of already abandoned fields while regulations remain vague.

To continue to stimulate upstream investment and M&A, Australia will need to provide greater certainty and potential offsets of the large costs associated with decommissioning. Figure 12 provides a view of the key issues that surround this large-scale decommissioning exercise.

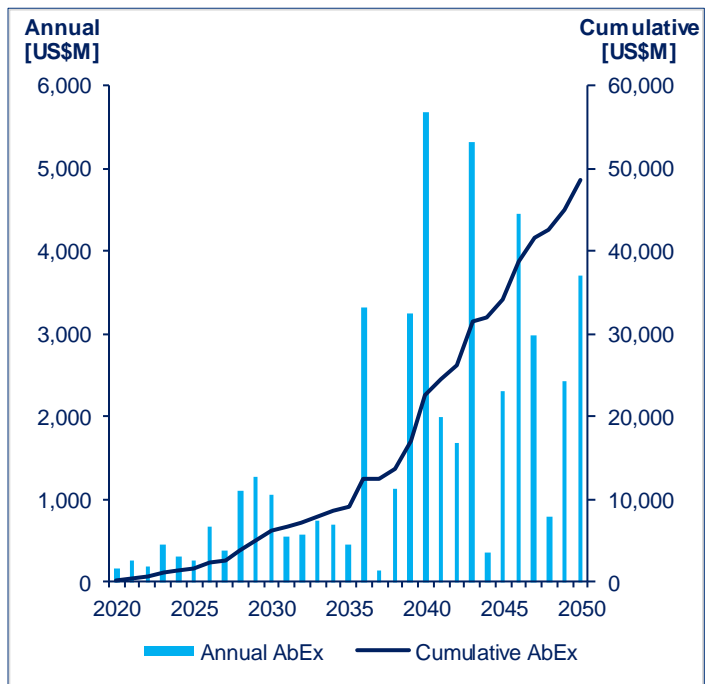


Figure 11. Total abandonment costs faced by Australia's upstream sector.

⁸ Supply projects have been classified based on their development status as of Q4 2019: 'Probable' supply projects have not yet taken FID but are expected to do so within the next 12 months. 'Possible' supply projects have only been named and defined (i.e., in terms of participation, structure, and underlying gas resources), but are not expected to take FID within the next 12 months.

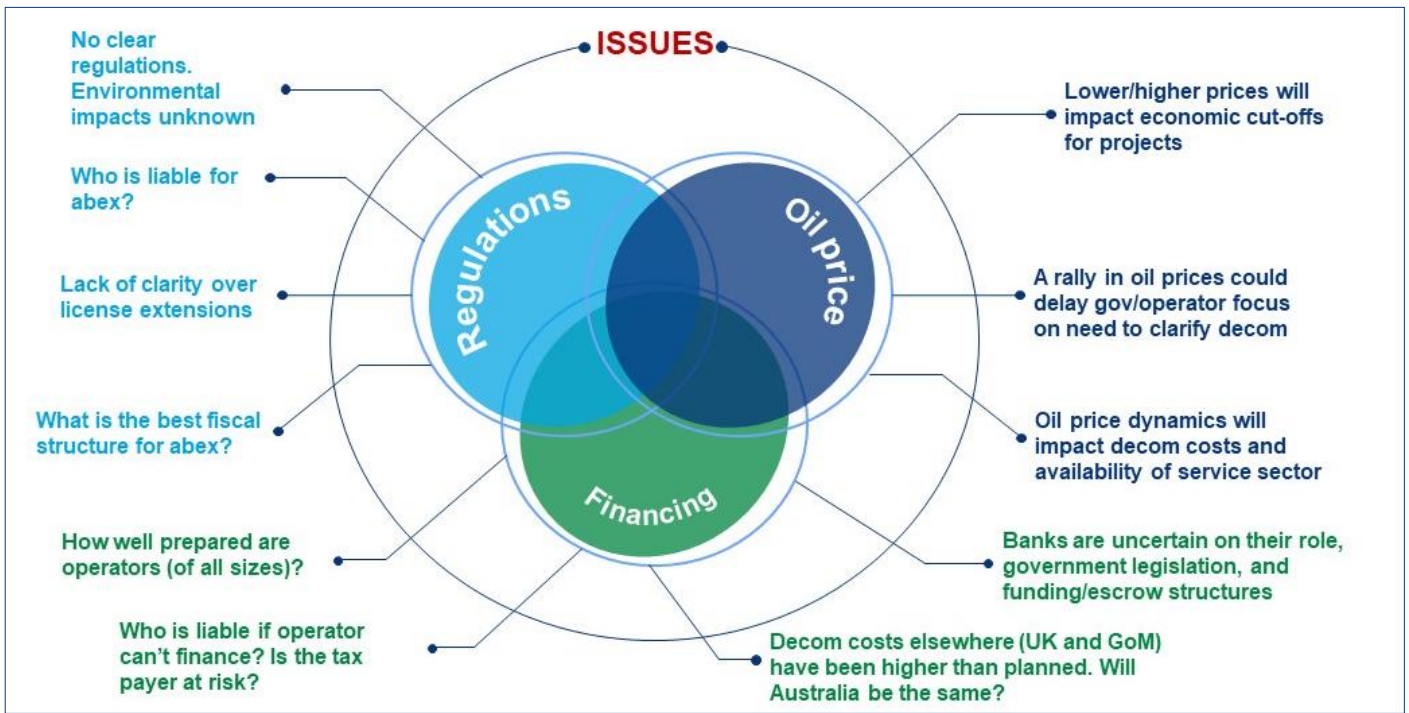


Figure 12. Key issues surrounding Australia's upcoming decommissioning exercise.



4. Maintaining Australia’s upstream attractiveness

Given the new threats caused by global macroeconomic and energy trends (i.e., those outlined in Section 3), we see two key internal areas of focus for the Australian upstream industry to remain globally competitive.

4.1. Enhancing project cost competitiveness

The Australian oil and gas industry is regarded as a high-cost business environment when compared to many other international jurisdictions. This perception was largely born from some well-publicised cost overruns at the large-scale LNG developments during the last decade. While cost overruns are not unusual in major capital projects across the industry, the scale and breadth of the cost containment issues in Australia during this period mean that negative perceptions of Australia’s cost environment are still prevalent. Australia must thus attempt to demonstrate that budgets can be better controlled to continue to attract investment.

In terms of exploration and production, the Commonwealth Scientific and Industrial Research Organisation (CSIRO) estimated in 2017 that the average cost of drilling an onshore exploration well in Australia is more than two and a half times that in the US. In terms of offshore developments, it was estimated that development costs per unit of North West Shelf reserves had increased by more than 11-fold from 2004 to 2013. On both a CAPEX and OPEX per boe basis, Australia falls in the bottom half of comparable oil and gas producing countries.

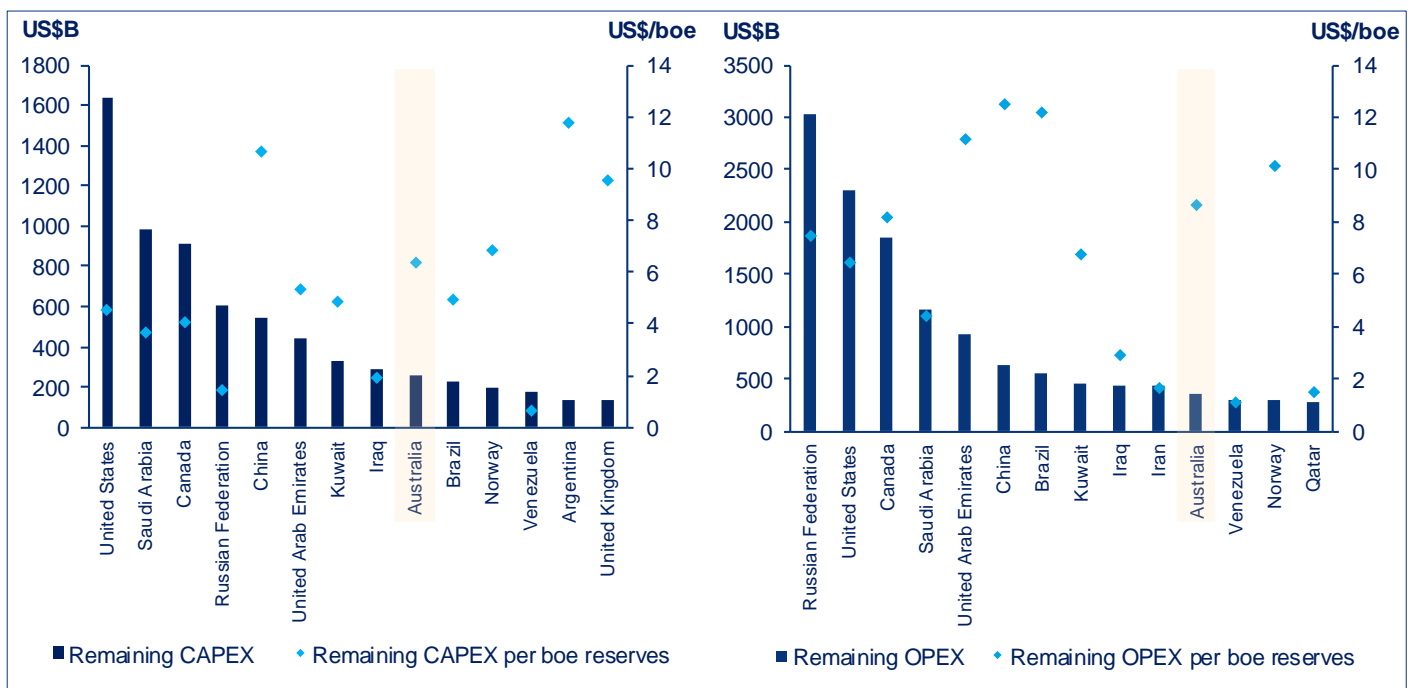


Figure 13. Upstream development cost comparison for key oil and gas producing countries.

High costs and cheaper competition threaten Australia’s ability to compete for the next wave of oil and gas investment, particularly in the key LNG market segment. Higher above-ground costs and logistical challenges mean that Australia could struggle to economically develop its unconventional resources. Not only may this impact on the economics of future LNG developments, regulatory instability may also threaten the ongoing competitiveness of existing projects on the international market, for example as increased royalties in Queensland push up the cost of supply into the LNG projects at Gladstone. Currently, as shown in Figure 14, Australia sits relatively high up along the global LNG cost curve in relation to other major LNG producing nations. Qatar has a clear cost advantage over other global LNG projects due to its low cost base for natural gas production. Integrated projects deriving feedgas from large conventional resources (e.g., Arctic LNG-2, Tortue) enjoy a similar cost advantage.

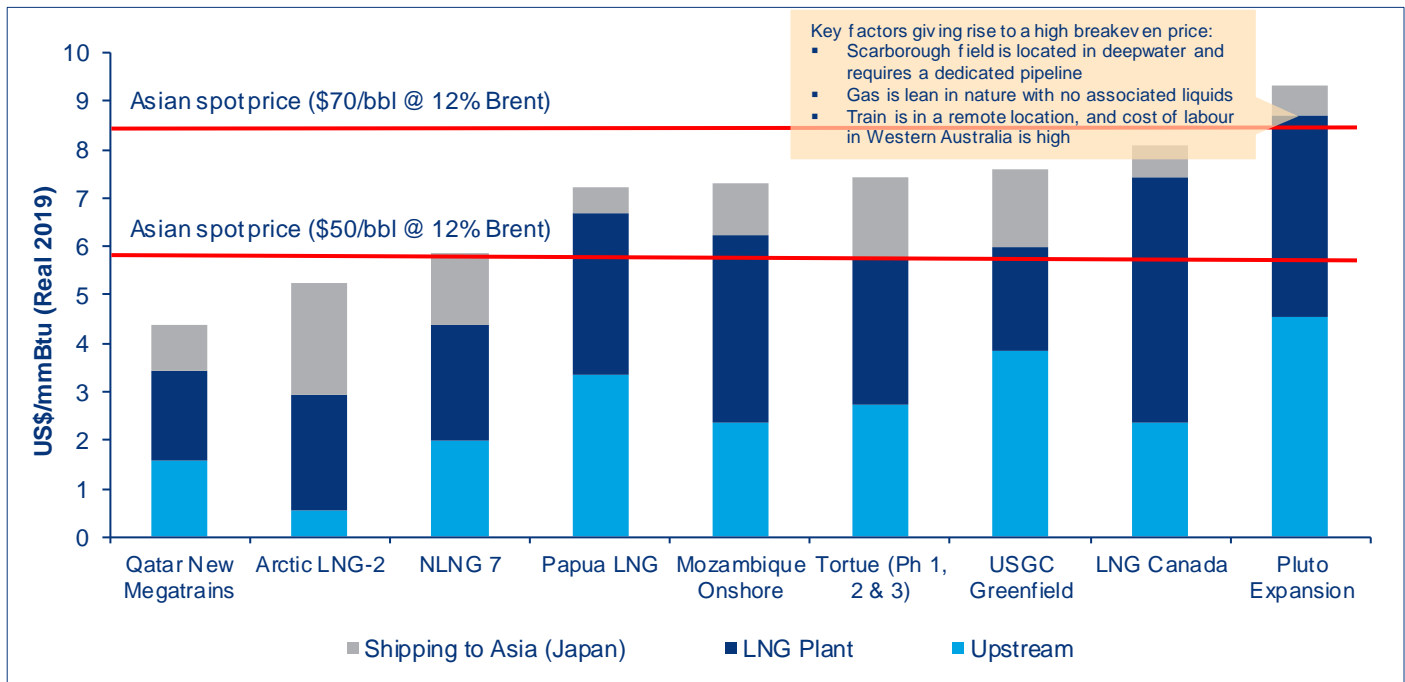


Figure 14. Cost stack⁹ (DES to Asia) for select LNG projects.

For other projects that fall within the competitive range of US\$7-8/mmBtu (with delivery to Asia), cost reduction initiatives have played a significant role. In the US LNG sector, there has been continued downward pressure on LNG plant EPC costs (i.e., towards US\$700/tonne and below). Similarly, Rovuma LNG has pushed towards lower EPC costs to maintain its cost competitiveness against the US. Russian LNG projects have targeted even further cost savings owing to localisation of equipment, efficient development concepts (e.g., Arctic LNG-2), proximity to market (e.g., Sakhalin-2 expansion), and a cheap conventional upstream base.

LNG Canada was able to achieve FID in late 2018 FID largely due to successful cost reduction initiatives:

- **Competitive tender for EPC services:** LNG Canada sought to drive down EPC costs through a competitive tender, which received four bids (e.g., KBR / Technip, Fluor / JGC). The result of this was to bring construction costs down to under US\$1,000/tonne
- **Pipeline tariff negotiation:** LNG Canada brought down their pipeline tariff fee by negotiating for a 40-year rate-of-return basis, instead of 20-year.

We estimate that the cost reduction initiatives led to a US\$0.95/mmBtu improvement in project breakeven economics. Both the provincial and federal governments also supported the development with several fiscal incentives such as provincial sales tax relief on construction costs, elimination of LNG income tax. We calculate that these incentives likely benefit LNG Canada breakeven costs by US\$0.23/mmBtu, showing that this was an important lever, but FID was dependent on cost reduction and control.

Specific to Australia, aside from cost reduction initiatives, another lever to enhance project cost competitiveness lies in increasing its use of existing infrastructure and stranded assets. Brownfield or backfill projects should benefit from lower downstream costs due to the existing foundation infrastructure which now exists around Australia's coast.

At the same time, the increasing complexity of extraction and remoteness of resources could feasibly drive up the cost of upstream gas. As the example of cost escalation in the last wave of Australian LNG shows, the external environment is variable, difficult to forecast, and ultimately shifts value perceptions back and forth between upstream and downstream over any projected period. Australia's high-cost labour, often geographical remoteness of its infrastructure, and extreme weather-related events will continue to impact the risk profile of future and existing downstream, and underutilised LNG capacity (i.e., both currently and threatened in the future) would increase downstream unit costs.

⁹ All supply costs are at long-run marginal cost (LRMC) or hub price. Applied discount rates are 15% for upstream component and 10% for LNG plant component; 12% for integrated projects. LNG shipping costs are based on long-term charter rates and currently available routes.



As in 1998, most of Australia’s upstream gas resources would not be developed without the infrastructure and market opportunity that LNG provides. The value-creating activities downstream (i.e., liquefaction, marketing and shipping of LNG) similarly require the development of upstream feed gas. This symbiotic relationship remains strong and presents little evidence for change on a circumstantial basis. Similarly, forecasting the profitability and allocation of value of future Australian LNG projects remains as problematic as accurately calculating the bargaining power splits between upstream and downstream over a period.

4.2. Maintaining fiscal competitiveness and stability

Governments of oil and gas producing nations strive to ensure that their fiscal competitiveness (i.e., determined by factors such as the level of government take, bonuses payable, and carried state equity) matches closely with their perceived resource prospectivity. Australia’s combination of perceived resource potential and fiscal attractiveness worked in tandem with a prolonged period of stability to help it overcome its disadvantages in terms of cost competitiveness and remote resource locations as an investment destination.

A lever to enhance Australia’s project cost competitiveness lies in increasing its use of existing infrastructure and stranded assets. Brownfield or backfill projects should benefit from lower downstream costs due to the existing foundation infrastructure which now exists around Australia’s coast.

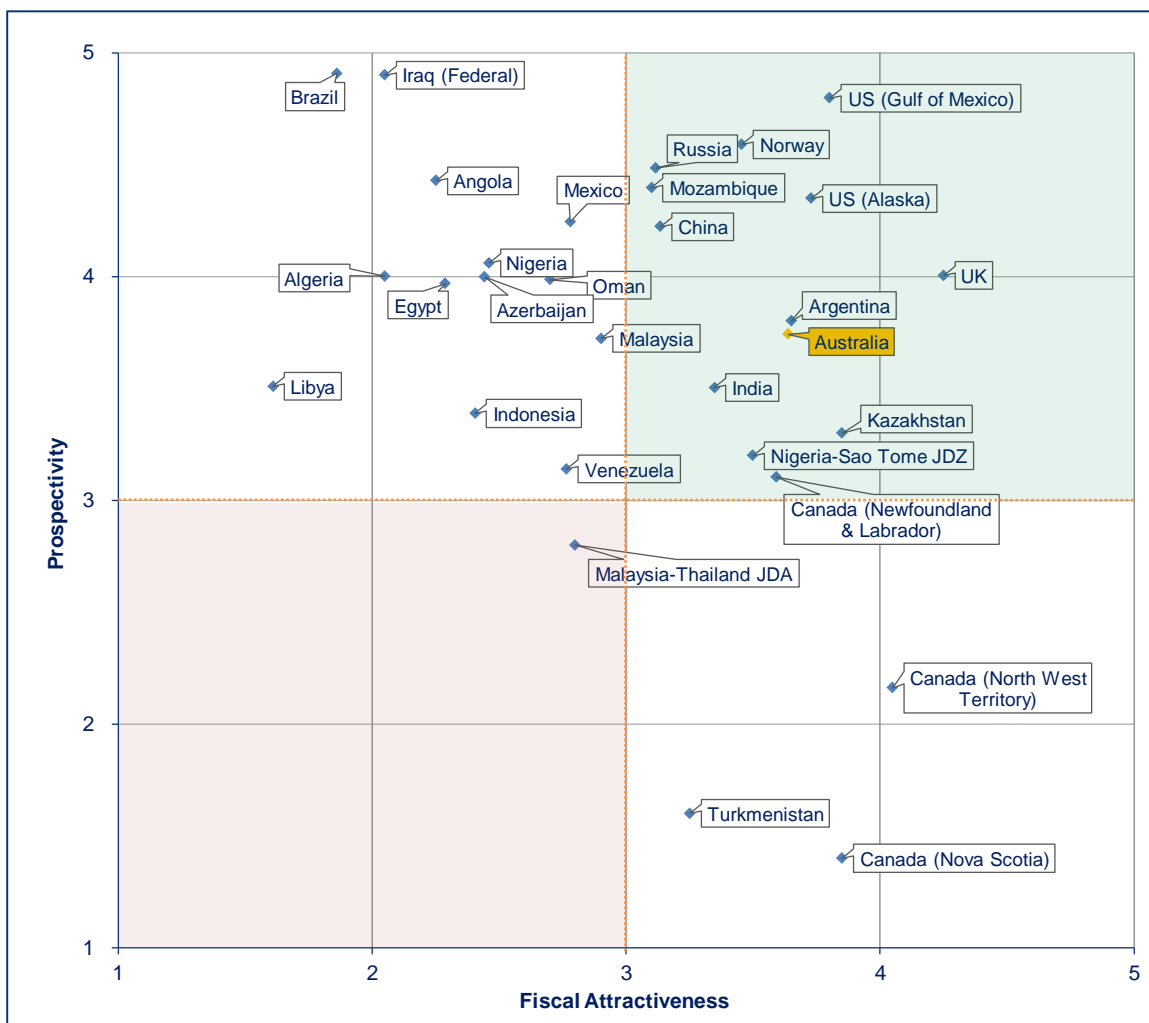


Figure 15. Fiscal Attractiveness vs. Prospectivity ratings¹⁰ for key oil and gas producing countries / regions.

¹⁰ Taken from Wood Mackenzie’s Upstream Competitiveness Index, published in July 2019.

The Fiscal Attractiveness rating shows how harsh or benign the fiscal terms for new licences currently are. It looks at the government’s share of future cash flows from a range of hypothetical developments under various prices. This is supplemented with considerations of bonuses payable and the level of carried state equity.

The Prospectivity rating compares countries and locations (water depth) based on recent exploration history (i.e., reserves discovered, success rates, etc.) and yet-to-find resource estimates. The hypothesis is that those countries with the highest prospectivity rating are most likely to attract the most investment, but the attractiveness of the fiscal terms may influence that decision.



Australia’s current position remains conducive to attracting upstream investment. A shift towards less internationally competitive fiscal terms could move it alongside less fiscally attractive countries such as Iraq, Brazil, and Angola in the competition for capital without the giant scale resources and economies of scale offered by these world class hydrocarbon provinces. Any move from Australia’s current positioning towards a more onerous fiscal regime has the potential to adversely impact future interest and developments.

Alongside fiscal attractiveness, we have identified fiscal stability as being a key enabling factor for Australia’s success, particularly in the decade preceding Australia’s LNG investment boom. Since then, the number of regulatory changes has increased significantly. Australia had an average of 1.6 state and federal reviews or legislative changes per year, which increased to 4.6 per year from 2010–2019 as clearly demonstrated in Figure 16 below.

This increased variability has been accompanied by an absence of new LNG project sanctions since 2013.

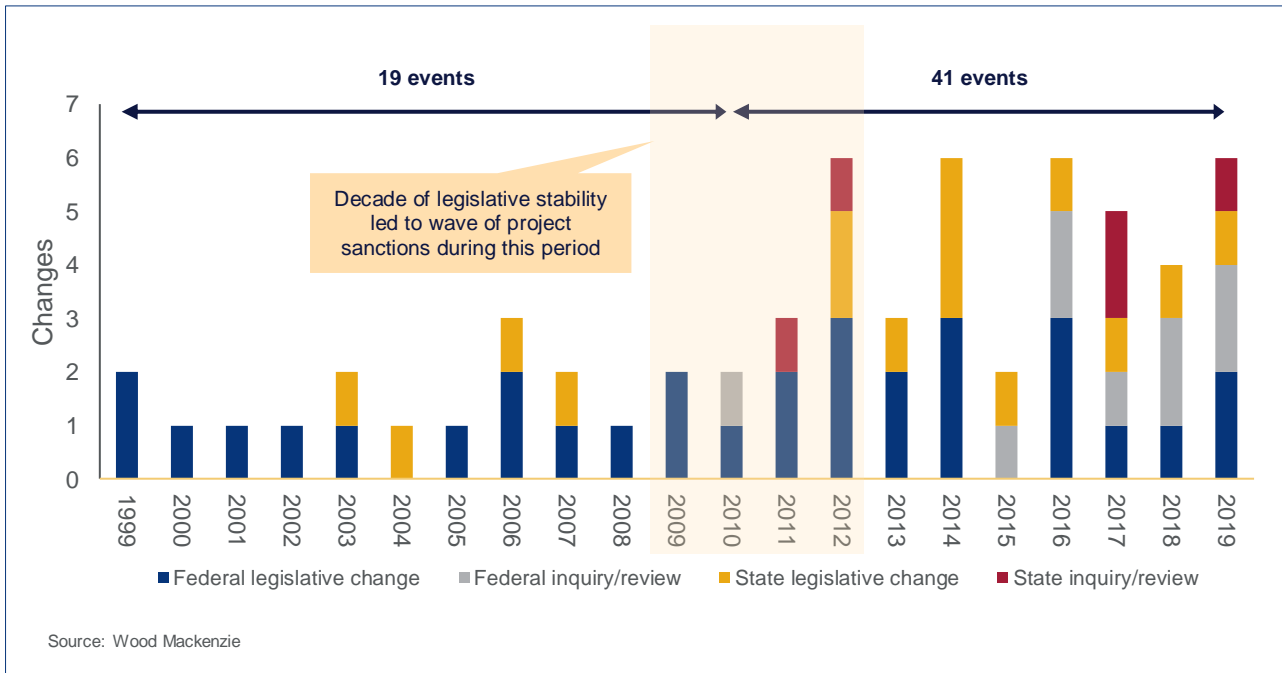


Figure 16. Australian state and federal legislative changes, inquiries / reviews (1999 – 2019).

This increased variability has been accompanied by an absence of new LNG project sanctions since 2013.

An example of the recent fiscal volatility in Australia is the frequent review of the PRRT structure and terms. For instance, in 2019, a review was launched into the validity of existing gas transfer pricing mechanisms, and a 25% increase in the Queensland gas royalty rate was announced. These measures could end up impacting the economic feasibility of Australia’s future large-scale oil and gas projects and in addition, they were not envisaged or accounted for by the incumbent operators as they took their project decisions in the early part of the last decade.

Clearly other factors in place since 2014 were also important reasons behind there being fewer Australian project sanctions, most notably the emergence of new investment destinations such as North America and

East Africa. Nevertheless, uncertainty over increased regulatory change is likely to have dampened the appetite for investment. The next section will present examples of other jurisdictions that have managed regulatory and fiscal change to stimulate upstream activity, or maximise government cashflows, with mixed results.

Maintaining current levels of taxation and reducing the volume of fiscal and regulatory change would likely strengthen Australia’s case as an attractive upstream jurisdiction and allow the country to meet the oncoming challenges brought on by the next decade of LNG competition. Furthermore, the LNG sector is at a pivotal stage as a review of the Residual Pricing Method¹¹ (RPM) is currently underway, and fiscal changes need to be mindful not to disrupt this development.

¹¹ In the late 1990s the Australian government, following extensive consultation with industry and other stakeholders, introduced the Residual Pricing Method (RPM) to help address the issue of how to estimate gas feedstock value within integrated LNG projects and derive assessable PRRT receipts. The aim of the RPM was to establish an efficient and equitable mechanism to help a taxpayer calculate a ‘fair and reasonable’ gas transfer price reflective of an arm’s length transaction where observable gas transfer prices do not exist, be it Advance Pricing Arrangements (APA) or Comparable Uncontrolled Prices (CUP).



5. How other jurisdictions attempt to stimulate investment

Australia is not alone in facing the challenges of lower industry spend, high-cost environment and increasing regulatory and environmental pressures. In this section, we present three case studies of countries that have recently changed their fiscal terms or incentives. While fiscal changes are just one of many factors that influence investment, they remain a powerful tool that governments can use to encourage – or inadvertently discourage – oil and gas exploration and development.

5.1. The United Kingdom: Keeping headline tax rates flat and adding options for late-life deals

In the UK Budget on 29 October 2019, it was announced that there would be no headline change to oil and gas tax rates. This came despite speculation that tax rates could be increased owing to rising oil prices and the need to raise government income to fund public spending. Petroleum tax rates were changed several times previously in response to commodity price volatility. The UK Government decided to favour stability over potential short-term windfalls.

In addition, two measures were introduced to support operators in their asset divestment and decommissioning liabilities:

- **Transferrable Tax History (TTH):** TTH provides an additional option to facilitate late-life M&A transactions by helping the buyer realise the full value of decommissioning tax relief, acting as a form of optional insurance that can be used to offset the decommissioning losses.
- **Petroleum Revenue Tax (PRT) refunds:** Both buyers and sellers can now access PRT relief when making deals, which could be particularly useful for Majors that are looking to divest and currently own a large proportion of mature fields that paid PRT in the past.

These changes expand the range of options available to companies to address the issue of large decommissioning costs when making deals. Previously, there was already the possibility to claim tax refund for ring fence corporation tax and the supplementary charge. By providing certainty and potential offsets of the large costs associated with decommissioning, the UK aims to stimulate upstream investment and M&A.

5.2. Norway: Accelerating tax relief to stimulate exploration

The Norwegian government levies a 78% tax rate on net income from petroleum activities, comprising a corporate income tax of 23% and special tax of 55%. Companies can consolidate their upstream activities for tax purposes, meaning that companies generating taxable income from producing fields may reduce their tax payable by deducting E&A costs and depreciation associated with new projects. To equalise the economics of investment opportunities for new entrants, the government introduced an exploration cost refund. Previously, non-taxpayers had to bear the full cost of exploration and can only recover it from future income. With the new policy, 78% of non-taxpayers' E&A costs could be refunded. In effect, this is accelerated tax relief which equalises the net cost of exploration for new entrants and existing producers and intends to make the profitability of a project the same on a pre-government and post-government basis.

Since the policy was introduced, the number of companies holding licenses has more than doubled from 25 to 55. The number of active companies has remained relatively stable since, showing that the increased interest in exploration was not entirely due to the oil price rise. Exploration activity between 2005 and 2017 yielded more than 10 billion new barrels across 204 new fields. Many new small and medium-sized companies have entered the country and established a prominent role in exploration and development.

On a full cycle basis, we estimate that this exploration has added Nkr1.9 trillion (A\$310 billion¹²) of value to Norway's upstream sector.

¹² Applied current exchange rate is Nkr1: AUD0.16.

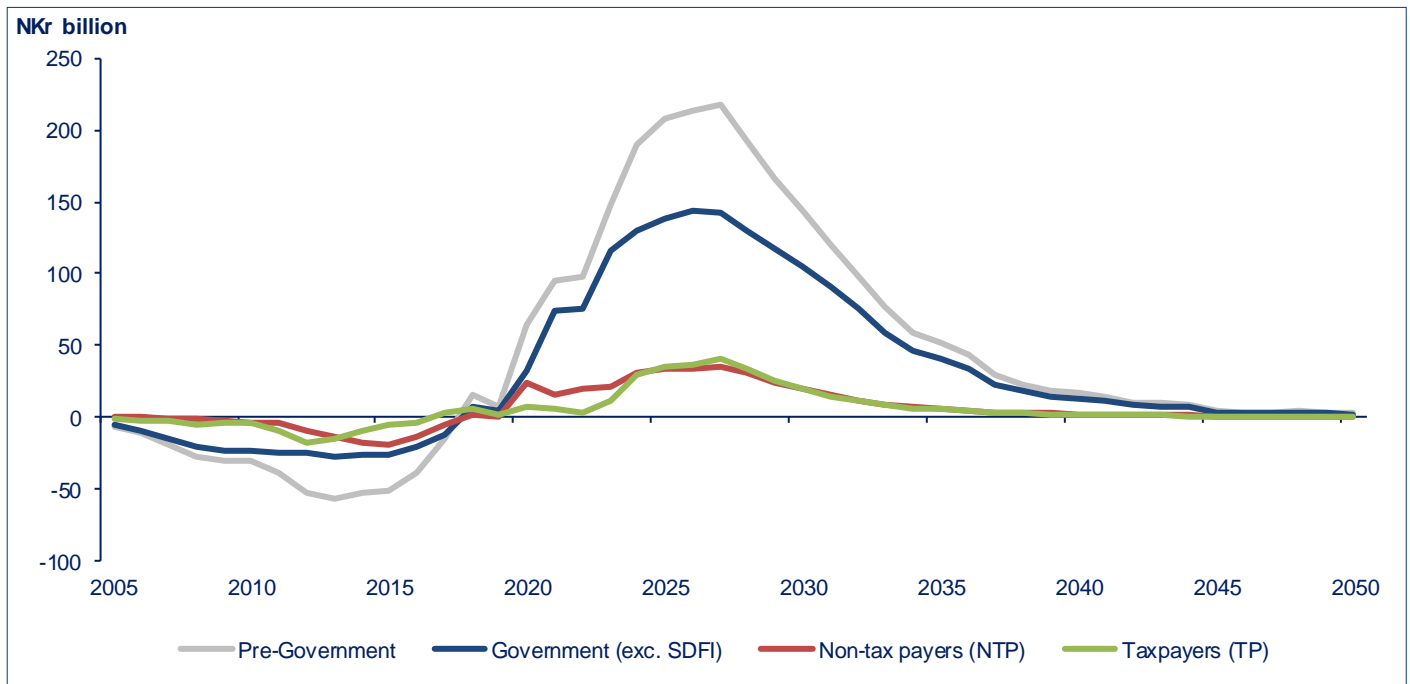


Figure 17. Breakdown of project (i.e., pre-government) undiscounted cash flow from Norway's 2005–2017 exploration activity.

Norway is a good example of how investment activity can be spurred by a balanced approach to risk and reward in fiscal design. In this case, the government assumed a sizeable share of exploration risk to balance out its high tax rates applicable to production profits and both industry and taxpayer benefitted.

5.3. Nigeria: Raising royalties to the detriment of cost and fiscal competitiveness

In October 2019, Nigeria's National Assembly voted through amendments to royalty arrangements within its Deep Offshore and Inland Basin PSC regime:

- Removal of the current water depth-based royalty, replacing it with a uniform 10% royalty for all deepwater PSCs
- Introduction of a price-based royalty which will add 0% to 10% depending on oil price
- Possible royalty increments for deepwater fields from the current 0–8% to 14%
- Review of terms every eight years

Based on our estimates, this change would result in a loss of value of US\$2.7 billion (A\$4.1 billion) over the remaining life of the deepwater assets – a value reduction of 18%. From a fiscal competitiveness standpoint, the amendments make Nigeria slightly less attractive as state share increases from 68% to 71%.

The bigger story is around cost competitiveness. Nigeria already suffers from high costs in the deepwater, attributable to a lack of cost focus by deepwater operators during periods of high oil prices, and local content requirements that inflated project costs. This has made it difficult for Nigeria to deliver the low breakevens that deepwater investors require (i.e., typically around US\$50-55/bbl, given price fluctuations and long-term forecasts of declining oil demand). Now, the royalty amendments move Nigeria further up the breakeven curve, considerably increasing the risk of deepwater projects being left stranded.

The key observation is the impact that a seemingly small fiscal change can have on investment decisions. On the surface, the change is relatively modest – a guaranteed 10% royalty plus a small price-based royalty. Deepwater fields, which contribute a third of Nigeria's liquids production, would continue producing, and most new projects could technically still breakeven at a long-term oil price of US\$65/bbl and a discount rate of 15%. However, when investors evaluate Nigeria against other destinations, the royalty change could very well tip the balance by pushing Nigeria down the attractiveness ranking and possibly out of the money. Moreover, royalty is only one piece of the fiscal framework: deepwater investors would know that when their contracts expire, they are likely to face more fiscal changes in return for a renewal.



6. Conclusion and a potential vision for the future

This analysis of Australia's oil and gas industry shows that success has largely been achieved due to companies being able to commit significant investment to the country over a long period. The confidence to make these investments was engendered by a stable tax and fiscal system from 2000–2009, strategically advantaged location, and repeated evidence of the prospectivity for large-scale discoveries. Following this period, we have seen that increased fiscal and regulatory volatility from 2010 onwards preceded a period of relative lack of activity. It follows that more instability would make Australia a harder place in which to justify continued oil and gas investment.

Despite significant changes across the wider global industry and within Australia, the Australian upstream landscape retains a mix of participants from world-class majors with significant funding and development capacity; to innovative, agile mid- and large- cap independent producers; to smaller niche players each with a diversified and unique skill and capability set. This diverse mix should contribute to a positive future for Australian oil and gas.

For now, Australia remains at the forefront of the global energy business but faces both new and renewed challenges to this position – the ongoing prevalence of a high cost development and operating environment, increased new sources of LNG competition, and a sharp reduction in the overall upstream spend the industry is committing each year. We believe that Australia's best chance of continuing to attract investment – and by extension, success – is to continue the same tact that has made it successful to date.



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