

## Oil & Gas and Capital Productivity Practices



# Extending the LNG boom: Improving Australian LNG productivity and competitiveness

May 2013



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Michael Ellis  
Christiaan Heyning  
Olivier Legrand



# Preface

Australia has been very successful in attracting investments into its resources sector, which has spread wealth throughout the country. Within resources, the LNG sector has seen the largest absolute growth, attracting investment over A\$200 billion in the last decade (more than the mining industry). The ‘mining boom’ has in fact been an ‘LNG and mining boom’.

With such a track record, it is natural the country has begun a debate about how to continue this success. Much has been said about factors that influence the attractiveness of Australia for additional LNG investments. However, the debate has so far been inconclusive. One of the reasons may be the lack of a comprehensive fact base on the LNG industry’s economic contribution, relative competitive position and competitive improvement options.

This report aims to inform the debate and move it forward by providing a fact base of Australia’s current competitive position in LNG and the economic benefits at stake. Further, it lays out the full scope of measures for improving Australia’s LNG capital productivity and competitiveness. These measures could be implemented by industry, project operators or these parties in wider partnerships within the community. It demonstrates that no single party can close the productivity gap alone. Working together or sharing the burden will be needed to make full improvement possible.

This report draws on and enlarges the findings of *Beyond the Boom: Australia’s Productivity Imperative* (McKinsey Global Institute 2012) which advances a

*...model for income growth accounting to explore the current dynamics of the Australian economy [and homes in on] individual sectors of the economy to analyse their key growth drivers and better understand what business and policy makers might do to maximise productivity and income growth.*

McKinsey partners Michael Ellis (Sydney), Christiaan Heyning (Perth) and Olivier Legrand (Perth), led this project, supported by McKinsey’s Australian Oil & Gas and Capital Productivity Practices, and a team from Australia, London and Amsterdam comprising Ani Chakraborty, Marte Guldemond, Meili Han, Daniel Ho, Alice Hudson, Rowan Mawa, Clare O’Neil, Wombi Rose and Kathryn Zealand.

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Industry and government offered guidance and suggestions. Our thanks go particularly to APPEA and the Department of Resources, Energy and Tourism.

This report contributes to McKinsey’s mission to support the communities we operate in by addressing important, yet challenging issues. As with all McKinsey’s published research, this work is independent and has not been commissioned or sponsored in any way by any business, government, or other institution.

Michael Ellis, Christiaan Heyning, and Olivier Legrand  
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# Executive summary

Productivity is critical to increase Australia's GDP. Australian GDP could be A\$90 billion p.a. higher if its productivity could be lifted.<sup>1</sup> To achieve this lift, the resources sector is key for two reasons. First, the sector is a major contributor to the economy as a whole, providing 35 percent of all income growth since 2005. But the sector has also contributed to the decline in productivity. In *Beyond the Boom* we summarised the consequence of this dichotomy:

*Thanks to the resources boom, Australia has had strong growth but has also been able to avoid confronting some deteriorating fundamental trends, a luxury that it cannot afford indefinitely.*

Within resources, much of this dynamic of income growth alongside productivity decline plays out in the LNG sector. The sector is now at a point where 'getting productivity right' is likely to secure tremendous additional investments with corresponding wealth creation for the nation. Conversely, failing to do so will mean losing this opportunity for at least a decade and possibly longer.

Why is this? It is straightforward. The world, and especially Asia, will need more natural gas in the coming two decades. Australia has plenty of unproduced reserves, it is geographically close to Asia, and has a long history of reliably delivering LNG to Asian customers.

As this report shows, the Australian economy has benefited and will continue to benefit significantly from LNG investments committed in the past. There are many projects on the drawing board, representing an investment exceeding A\$180 billion. Realising these would benefit the entire nation; as GDP would increase by 1.5 percent, about 150,000 jobs would be created, and tax revenues created equivalent to nearly half the total federal debt. The benefits of improving productivity would also flow to other sectors. So the stakes are high.

However, the cost of building new LNG projects has increased tremendously in the past decade and is now about 20–30 percent higher than that of the competition in North America and East Africa. This has been driven by a number of factors, including some of which are beyond our control—for example, the exchange rate. New LNG competitors have emerged that were not present when the last round of LNG investments in Australia were sanctioned—in particular in North America and East Africa.

The higher costs jeopardise the chance of potential projects being built in Australia, and the economic benefit that this would bring. As global capacity is expected to rise higher than global demand, Australia needs to reduce costs of LNG projects by 20–30 percent to remain competitive.

Part of Australia's higher costs is driven by compressible factors, where Australia could move towards the same levels as competing countries. A large share however is driven by incompressible factors, like reservoir characteristics, which cannot be influenced. Therefore Australia not only needs to resolve the cost difference with competing countries where it can, but also needs to surpass these countries in certain cost areas to overcome its relative disadvantage on these incompressible factors.

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<sup>1</sup> *Beyond the Boom: Australia's Productivity Imperative*, McKinsey Global Institute, 2012.

Therefore, Australia needs to urgently reduce the cost of new LNG projects by this 20–30 percent to increase the chances of successfully attracting the next wave of LNG investment. If this does not happen, others will offer a cost advantage that companies may find hard to ignore. Also, it is not certain that LNG demand will remain strong because factors as diverse as Chinese gas demand (due to the potential for local shale gas production), or the Japanese power mix, could impact it significantly. Hence Australia might have a window of opportunity now that could close in the future. Hence the urgency of improving the cost of building LNG projects in Australia before it is too late.

The good news is that it can be done. Measures exist that can bridge the cost gap, and even surpass it. All of these have worked somewhere, either in the oil and gas industry internationally and in Australia, or in another sector. But the size of the cost gap is large enough to suggest that closing it will require significant effort of *all* parties involved: individual project owners, the LNG industry as a whole, and the different layers of government. No single actor can close it single-handedly. Although there are examples of cooperation within Australia, *all* parties will need to work together more closely than before. Such cooperation is common in other regions such as the UK and Norway, and is also the emerging pattern in a major rising competitive region: East Africa.

For example, Industry could decide to deepen cooperation on joint qualification of vendors, which would reduce the time needed when tendering work. Another example could be enhanced cooperation between industry and government to improve infrastructure in relevant remote areas. While such cooperation has been happening in some areas in Australia, the scale must now be increased.

Change is difficult and there is also a need for speed. Urgency is required to ensure that Australia does not miss out on investment and on peak demand growth. Some of the measures described in this report can be implemented relatively quickly; others will require time and effort. So it is important to start now.

Australia faces a choice. With effort and a willingness to tackle the productivity gap, it can continue to create significant wealth from LNG. If the window of opportunity closes, much economic gain will be lost.



Chapter 1 of this report shows how the benefits of the LNG sector reach deep and wide in Australia. Chapter 2 illuminates where and by how much Australian projects are more expensive than those of the competition. Chapter 3 outlines what options and measures are available to improve the cost position. Chapter 4 states that both individual and cooperative action is required to close the gap. Chapter 5 spells out some next steps to consider.

# 1. Australia's LNG productivity challenge

The Australian economy is at a crossroad. As we stated in *Beyond the Boom: Australia's Productivity Imperative*, McKinsey Global Institute, 2012:

*The boom... belies some weaker fundamental trends in the economy that could put Australia's future prosperity at risk unless they are addressed. Notably, growth in labour productivity has fallen to 0.3 percent per annum in the last six years, down from an average of 3.1 percent from 1993 to 1999. This slowdown has taken place at a time of significant wage inflation, with average private-sector weekly earnings growing at 4.4 percent per annum over the same period... Moreover, capital productivity is now a drag on income growth. Improving productivity performance is imperative if Australia hopes to prepare for a future that may not offer the tonic of record investment and export prices.*

We further calculated in our paper that, if Australia can return its productivity levels to the long term average, income growth would amount to 3.7 percent by 2017. Failure to do this will result in income faltering and the prosperity of the entire economy being challenged for the first time in many years.

All industries will play a part, but Australia's LNG will be a bellwether sector. Substantial productivity improvement in LNG will make a tangible improvement to the economy, which everyone will notice and benefit from. If LNG productivity cannot be improved, it is difficult to see how the desirable increases in national income can be achieved.

The economic benefits of the development of LNG projects are huge. However, to be internationally competitive, and therefore ensure successful development, it will require a significant improvement in overall capital productivity. The opportunities and challenges are commensurate with each other.

For definitions used in this report, see Box 1, and for metrics, see Box 2.

## **BOX 1: PRODUCTIVITY DEFINITION**

- This report focuses on capital productivity which we define as the amount of output generated per unit of capital stock
- Because labour costs are capitalised in these projects, labour productivity (the amount of output generated per hour worked) is included as a subset of capital productivity
- Note: Analyses contained in this report exclude the effects of any changes proposed in the May 2013 Federal Budget

## BOX 2: METRICS

### ■ Metrics and prices

- LNG capacity, production and demand are measured in mtpa (million tonnes per annum)
- LNG or natural gas prices are priced in US\$/mmbtu (million British Thermal Units)
- Natural gas reserves are measured in cf (cubic feet) or cm (cubic metres)

### ■ Conversions

- 1 cubic metre = 35.3 cubic feet
- 1 million tonne of LNG = 1.35 billion cubic metres = 49,241,379 mmbtu

### ■ Currency

- Australian dollar (A\$, AUD) is generally used throughout the report
- US dollar (US\$, USD) is used for landed cost calculations to allow global comparisons, as is conventional in the industry. An exchange rate of USD 1.0285 per AUD is applied in the landed cost calculations
- Norwegian Krone (NOK) appears in a boxed insert

## 1.1 THE SIZE OF THE PRIZE

Australia benefits a lot from LNG projects. For example, Exhibit 1 shows that 63 percent of revenues from gas sales remain in Australia for a conventional gas project. Exhibit 2 shows that for Coal Seam Gas (CSG) or unconventional gas to LNG projects, 69 percent of revenues remain in Australia. This is to the advantage of all the beneficiaries of the revenue flows, and indeed of the beneficiaries of the tax system, including workers, communities, local suppliers and investors.

The impact on the Australian economy of these LNG revenues is substantial. Existing and committed projects in Australia<sup>2</sup> are expected to contribute A\$520 billion to the economy over 2015 to 2025. Exhibit 3 puts this in perspective—these projects will add 2.6 percent to Australian GDP, or A\$5,500 per household per year, support 180,000 jobs and increase the tax take by A\$11 billion or A\$1,100 per household (average nominal annual contribution 2015 to 2025).<sup>3</sup>

Additionally, if all projects currently on the drawing board are realised,<sup>4</sup> this would create a further capex investment of more than A\$180 billion. This would contribute an additional A\$320 billion to the economy, which is 1.5 percent of GDP, or A\$3,300 per household, create 150,000 new jobs, and increase the annual tax take by A\$5 billion, or A\$400 per household over the period 2015 to 2025. To put this in context, the median annual household income in Australia is A\$64,000.

In an environment where budgets will come under increasing pressure, the potential for sizeable tax revenues make actions now more compelling. Exhibit 4 shows the scale of the potential revenues from the LNG sector relative to some federal budget items.<sup>5</sup>

2 Onstream: Northwest Shelf, Darwin, Pluto; Under development: GLNG, QCLNG, Gorgon T1-3, Ichthys, Wheatstone T1-2, APLNG, Prelude.

3 Tax income is nominal and includes production taxes (upstream royalties, carbon tax, PRRT and company tax) and construction taxes of direct suppliers (payroll tax, GST and import duties). Calculation based on ABS population forecast (population of 24.5m for 2015–25, 26.8m for 2025–2035, average household size of 2.6).

4 Planned: Arrow, Browse, Gorgon T4, GDF Bonaparte; Speculative: Darwin LNG T2, Greater Sunrise, Wheatstone T3, Fisherman's Landing, PTT FLNG, Pilbara.

5 These numbers do not account for any government expenditure incurred in encouraging LNG projects to go ahead. Includes both direct and indirect tax effects, based on FY2012 figures.

Growing the LNG industry is also important for another reason—it would make the economy more resilient by further diversifying the country’s export earnings. For example, while iron ore and metcoal prices are driven by the steel market, LNG prices are mostly linked to crude oil, which is subject to different dynamics. Further, gas is a natural competitor to thermal coal, with some economies switching to gas for power generation to lower CO<sub>2</sub> emissions. Exhibit 5 shows the importance of the LNG market to Australia’s trade in commodities by 2025, relative to other large Australian exports.

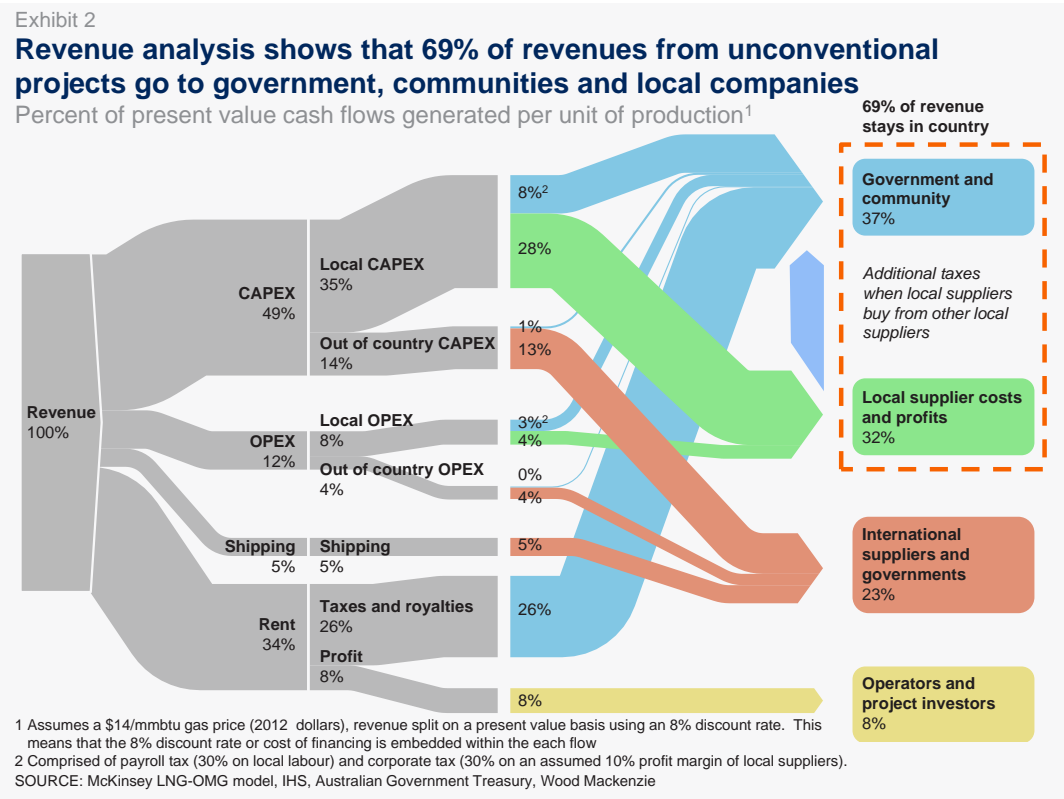
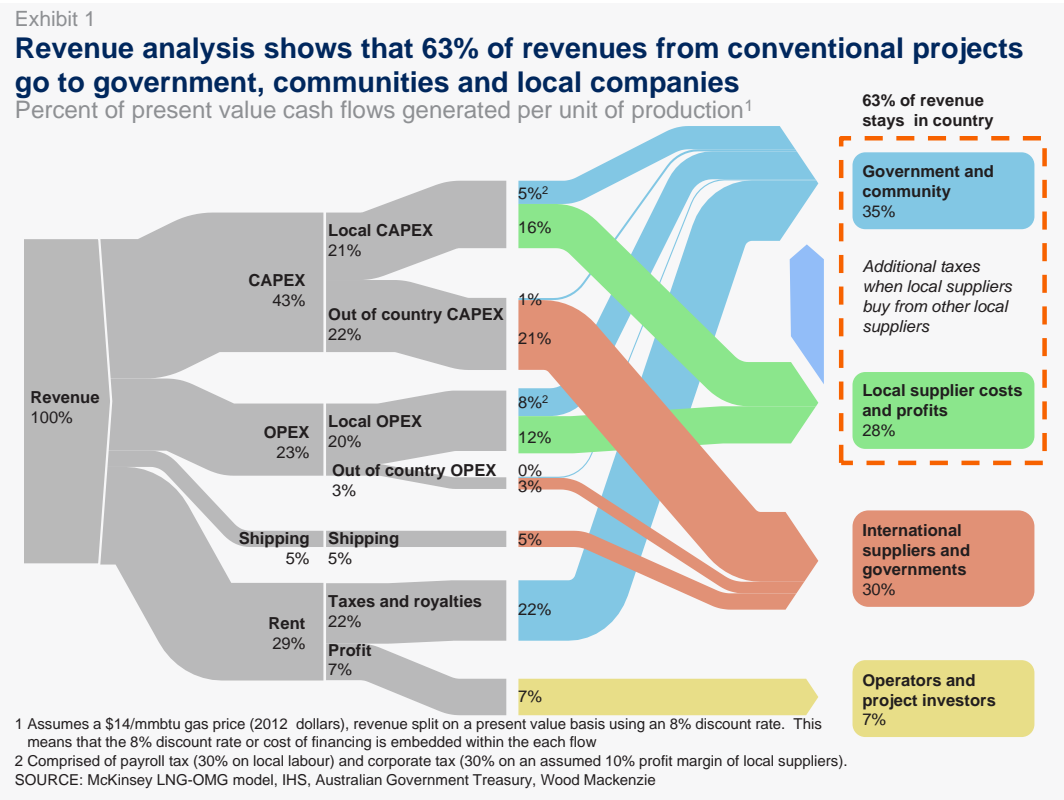


Exhibit 3

## Impact of LNG projects on the Australian economy

Contribution 2015-2025

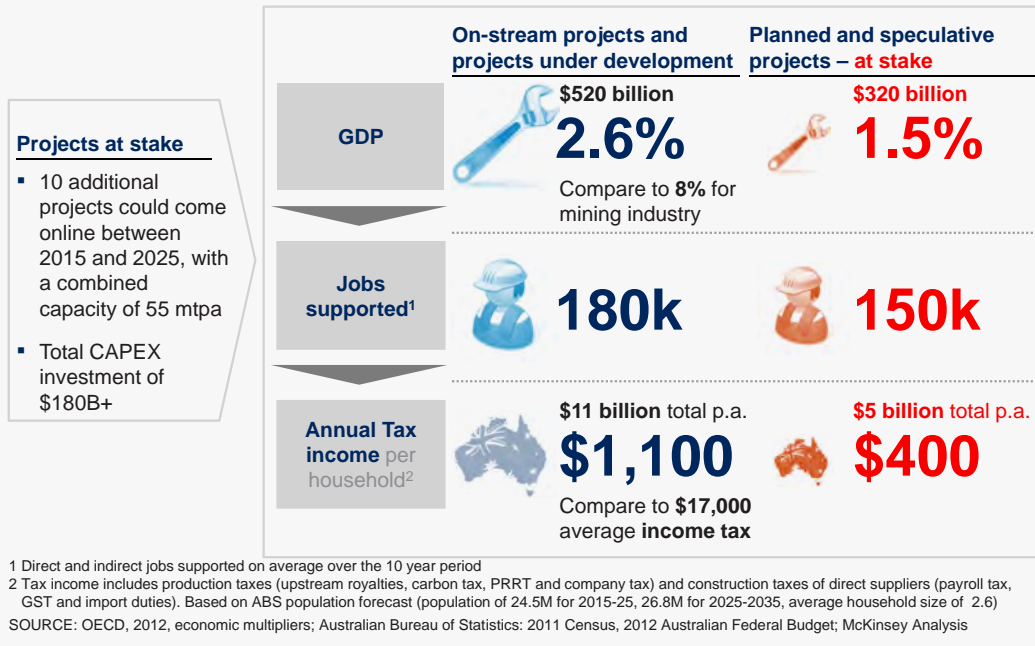
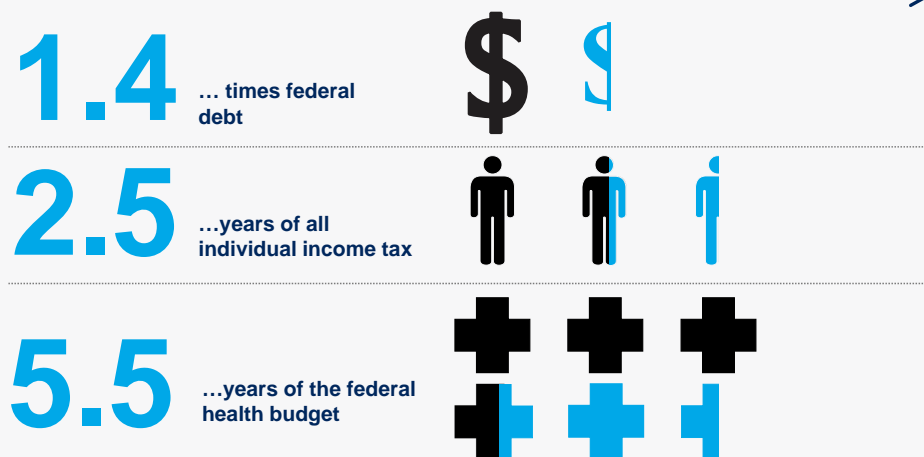


Exhibit 4

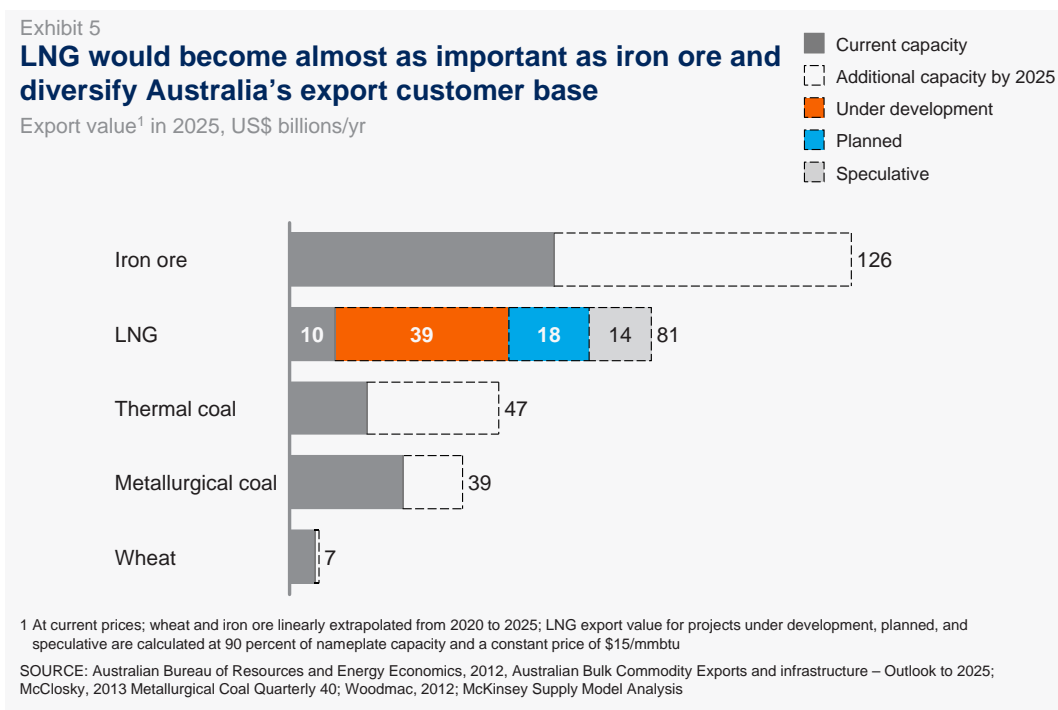
## Tax revenue from LNG could have substantial impact on government finances

Australian tax revenue<sup>1</sup> from LNG projects between 2015 and 2035 could equal...



SOURCE: Reserve Bank of Australia, Australian Bureau of Statistics, 2012, Budget Papers (pre-April 2013 budget); McKinsey analysis

<sup>1</sup> Note that these numbers do not account for any costs to government of encouraging the LNG projects to go ahead. Includes both direct and indirect tax effects. Excludes royalties, based on FY2012 figures



While the potential for current and future Australia LNG projects to have long-term benefits across the economy is clear, this forecast is not without challenge. The magnitude of benefit captured depends on how many of the planned future LNG projects prove economical.

Further developing Australia's gas resources would have impact beyond the purely economic. For example, it also has the potential to impact the environment. While not a focus area of this report, these impacts must be taken into account when considering if and how to develop Australia's gas reserves.

## 1.2 THE CHALLENGE

Australia has a strong history in LNG. Since its beginning in 1989, Australia has produced 342 million tonnes of LNG—generating about A\$68 billion in taxes and royalties.<sup>6</sup> The growth rate in LNG production from 1989 (when the first LNG cargoes were shipped from the North West Shelf) to 2012 has been 10 percent per year. As LNG projects currently under construction are completed (between now and 2020), this growth rate is going to accelerate to around 20 percent per year.<sup>7</sup> This will lift Australia's share of global LNG supply from about 8 percent to more than 25 percent.<sup>8</sup>

This represents an extraordinary success, and Australia is well poised for further growth, given its substantial gas resources and its proximity to Asia, the region with the biggest demand growth. Australian gas resource estimates have grown from 2.7 in 2001 to 3.7 tcm in 2010, due to a significant exploration program and the improved understanding of the potential of coal seam and shale gas.<sup>9</sup> As a result, another 10 planned and speculative LNG projects in Australia await approval, with a combined capacity of 55 mtpa.

Until recently, Australia was considered one of the most attractive destinations to develop LNG. However, its cost and risk profile, combined with new competitive players on the international scene,

<sup>6</sup> Wood Mackenzie Global Economic Model – includes Royalty, PRRT/Excise, Corporation Tax, and Carbon Tax.

<sup>7</sup> Based on McKinsey Energy Insights Global Gas Model, Australian LNG exports were 15 mtpa in 2012 and are calculated to be about 70 mtpa by 2020.

<sup>8</sup> International Gas Union, World LNG report 2011, <[www.igu.org/gas-knowhow/publications/igu-publications/LNG percent20Report percent202011.pdf](http://www.igu.org/gas-knowhow/publications/igu-publications/LNG%20Report%202011.pdf)>.

<sup>9</sup> BP Statistical Review of World Energy, June 2010, <[bp.com/statisticalreview](http://bp.com/statisticalreview)>.

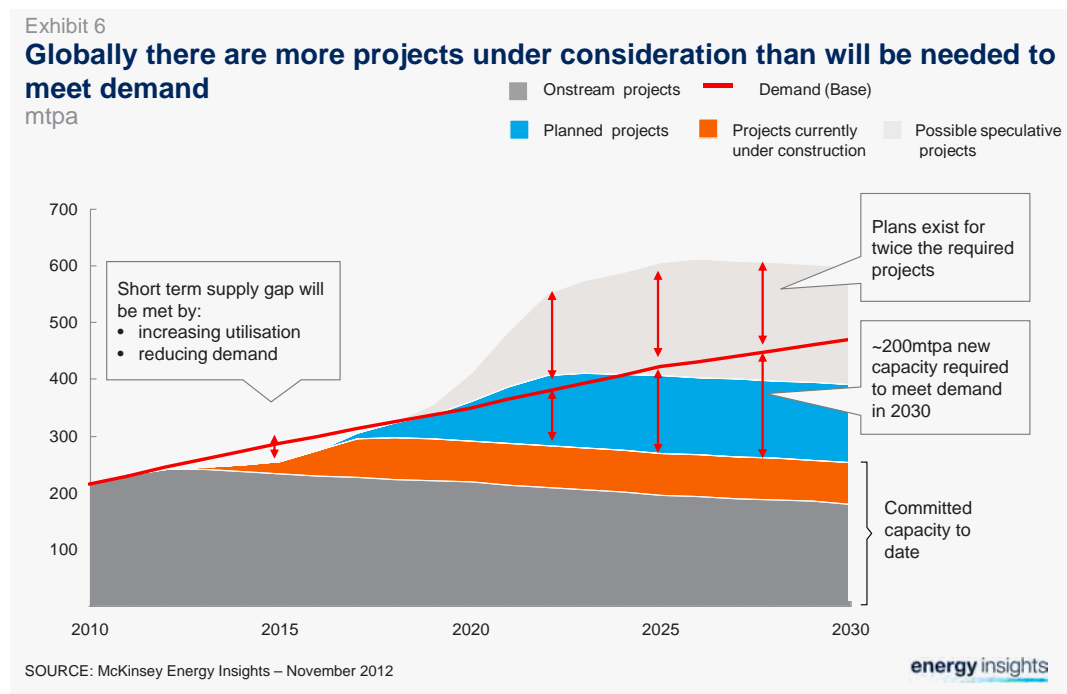
is making it harder for Australia to retain this preferred position. For instance, for new projects it will cost 20–30 percent more to deliver LNG from Australia to Japan than competing projects in Canada.

This gap can only be addressed by increasing productivity in the sector. The big drivers of productivity are the outputs that can be achieved by labour employed and capital invested. Labour costs account for slightly less than half of all costs of conventional LNG plant costs, where the cost of equipment and materials is about a third. The biggest drivers to improve productivity are to reduce the time needed to build a new LNG plant, and to reduce the costs of doing so. These in turn are driven by the efficiency of the supply chain, the tax and regulatory regime, and the cost and productivity of labour in Australia.

While meeting the productivity imperative will not be easy, Australia also has some natural advantages. One important factor is that demand for LNG is set to increase and a significant amount of this new demand will be in Australia's backyard—Asia.

Global LNG demand is expected to grow towards 470 mtpa by 2030 (Exhibit 6)—although the longer term the forecasts the greater the uncertainty. Existing projects and those already under construction will provide 250 mtpa of this demand. To satisfy the remaining 220 mtpa of unmet demand in 2030, there are about 60 projects under consideration in 22 countries. These projects represent about 340 mtpa in capacity—much more than the 220 mtpa required in the base case demand scenario.

The challenge lies in ensuring that individual companies make the substantial commitment to (continue to) invest in Australian projects—and such a commitment depends on Australian projects being sufficiently competitive against other LNG supply options.





## 2. The productivity gap

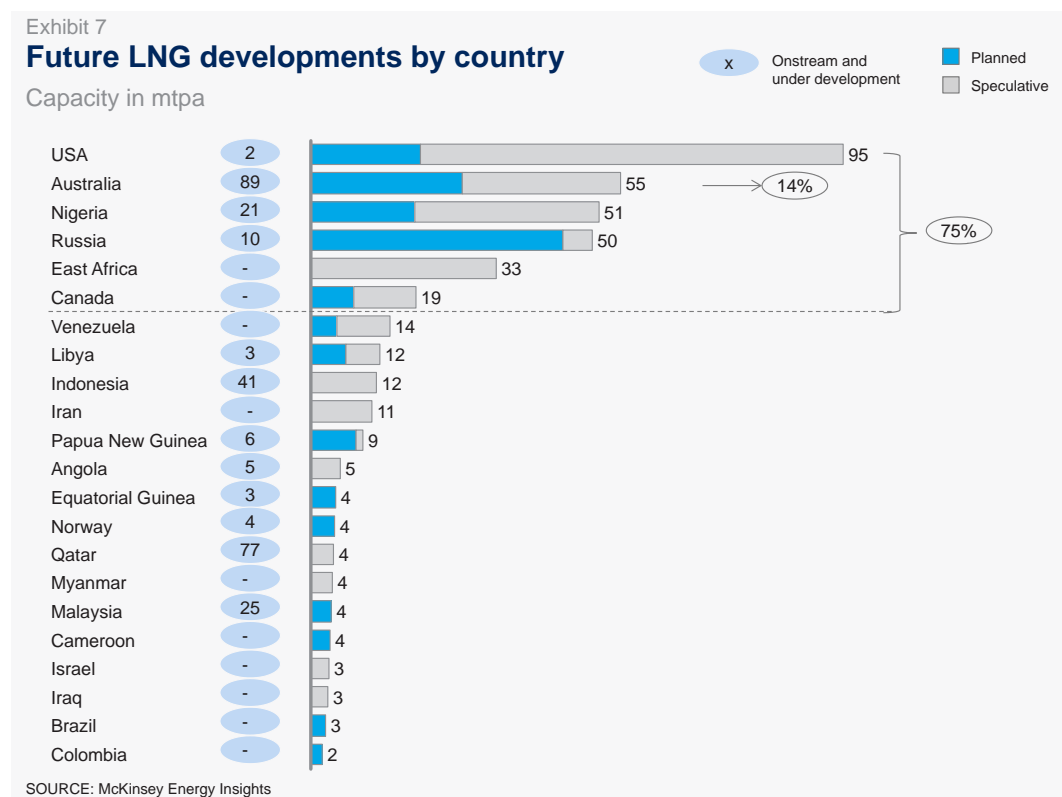
Australian LNG projects that are currently on the drawing board but not yet approved, if realised, would contribute A\$320 billion to the Australian economy over 2015–2025. The challenge lies in ensuring that individual companies make the substantial commitment to invest in Australian projects. This in turn depends on the productivity of the capital needed to build them.

Chapter 2 compares the competitiveness of potential Australian LNG projects with other suppliers across the world. The picture this paints is stark. Increased domestic costs and imposts, combined with new efficient competitors, negatively affect Australia's attractiveness as an investment destination.

### 2.1 HOW DOES AUSTRALIA COMPARE TO ITS COMPETITORS?

Exhibit 7 shows where the next LNG developments are globally, including planned and speculative capacity. It shows that the top six regions represent 75 percent of global capacity on the drawing board, with Australia at second place with 14 percent. It is an unrisks view.

As Chapter 1 states, the combined output of all projects would exceed the expected growth in LNG demand, and therefore not all projects will be realised. In choosing which projects to develop, project owners will consider cost, risks (including country risk), and ability to access the resources. In the past, Australia has been relatively well positioned on each of these dimensions.



However, over the past decade, Australia's relative competitive position has faltered, due to several factors:

- **Emergence of North American LNG exports**—driven by the development of shale gas in the US and in Canada. Until 2004 North America (in particular the US) was considered to have substantial need to import increasing amounts of LNG. However, it is now poised to become a major exporter as a result of its shale gas position, if it can agree how much gas to export. A second big change from North America is the potential for gas prices to be linked to the Henry Hub gas price (the benchmark US domestic gas price), rather than to international crude oil prices. At today's Henry Hub and crude oil prices, this could lead to downward pressure on LNG prices, exerting further pressure on Australian LNG project costs. These two developments have changed LNG market dynamics fundamentally. However, the full extent of the change depends on the further development of LNG projects in the US, which in turn depend on whether the US grants additional exporting licences to proposed developments—for which the outlook is uncertain.
- **Potential of gas exports from East Africa**—76 tcf of gas has been discovered in East Africa over the past five years. The companies involved are planning to export this gas to Asia. Projects totalling 33 mtpa are on the drawing board already, where five years ago there were none. This represents a new source of competition for Australia in the Asian LNG markets.
- **Perception of increased Australian risk**—an uncertain investment environment has emerged (evidenced by the number of announcements of increased cost in LNG projects in 2012) and has contributed to an increased risk profile.

A further competitive dynamic plays out in Russia and Nigeria. While Russia has extensive plans for developing LNG facilities, access for international oil companies is difficult. Likewise, although Nigeria is relatively accessible, it has a very different risk profile to Australia, and is better placed to serve the Atlantic market rather than Asia.

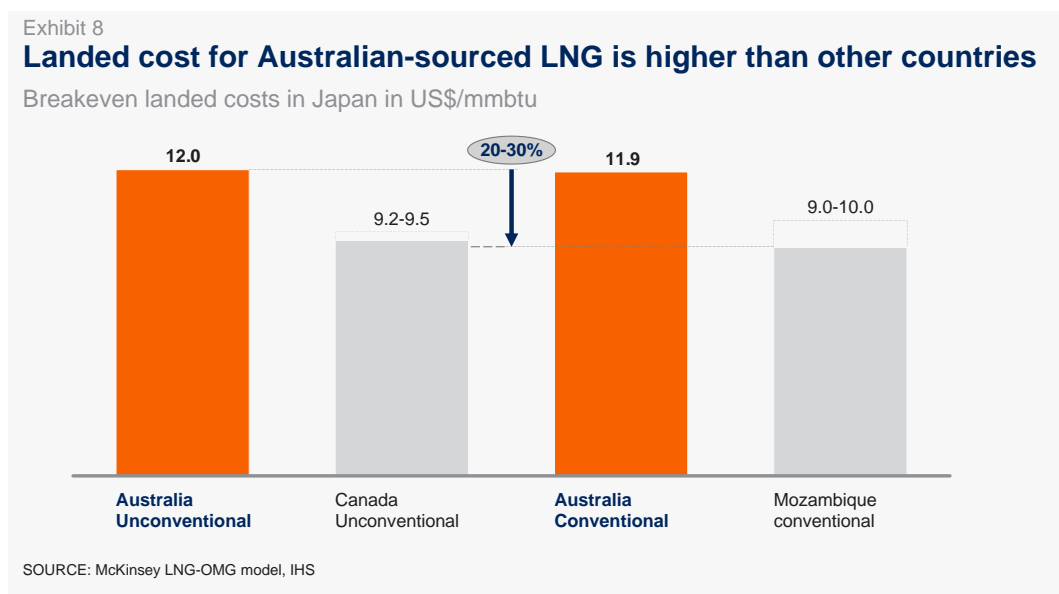
It is the two new major LNG regions, North America and East Africa (which have open access to companies that also invest in Australia and are relatively well positioned to serve Asian markets) that form a major competitive threat to Australian investment. If Australia is to convince operators to develop their LNG facilities in Australia rather than in East Africa or North America, the landed costs in Asia of Australian-supplied LNG must be competitive.

Therefore, this report compares the landed cost of future Australian projects with two generic projects in the North American and East African regions:

- Competitor case study: Canada. A coal seam gas (CSG) onshore project in Australia is compared to an unconventional gas project in Canada, as a proxy for North America.<sup>10</sup>
- Competitor case study: Mozambique. A conventional offshore project in Australia is compared to a conventional offshore project in Mozambique, as a proxy for East Africa.

Exhibit 8 shows that Australian costs for delivering LNG to Japan are 20 to 30 percent higher than competing projects in Canada and Mozambique. The comparison is done on nominal lifecycle costs of the project, expressed in break-even US\$/mmbtu landed costs in Japan.

<sup>10</sup> US projects may be more competitive than Canadian projects due to higher productivity and the potential for brownfield economics by turning import terminals into export terminals. However, at the time of writing, it is not clear whether the US Government will allow substantial gas exports. In addition, while the costs differences between US and Australia are expected to be larger than between Australia and Canada, the breakdown of the differences is assumed to be similar (and therefore the lessons learned, similar).



The landed cost numbers cited in this report were generated using a model (Box 3) developed via an internal McKinsey knowledge investment. Details of model structure and assumptions leading to the calculation of landed costs are given in the Appendices:

- Appendix 1: LNG Optimisation Model for Growth (LNG-OMG) landed cost methodology
- Appendix 2: Assumptions for LNG-OMG landed cost model
- Appendix 3: Capex profiles for standard projects
- Appendix 4: Assumptions for well productivity calculations
- Appendix 5: Explanations & examples of productivity improvement measures
- Appendix 6: Assumptions for calculation of productivity improvement measures

The landed cost comparison is for projects that are yet to be sanctioned, thus simulating the point at which companies decide whether to make a substantial commitment to these projects, and also keeping the comparison between countries consistent (i.e. at the same stage of the project development cycle). Cost estimates for new territories, such as East Africa, are uncertain as no historical data exists.

□ □ □


Why are Australian projects higher cost than its competitors? To answer this question, it is instructive to compare Australian performance with that of Canada. Of course, Australian outputs will compete head to head with LNG production from all countries. However, comparing ourselves with Canada allows better examination of the productivity gap. Australia's economic, governmental, commercial and legal framework is more easily compared to North America's than to East Africa's.

The next section details the main drivers for the cost difference shown in Exhibit 8 by comparing a coal seam gas onshore project in eastern Australia and an unconventional gas onshore project in Canada.

### BOX 3: LNG-OMG MODEL TO CALCULATE COMPETITIVE LANDED COST

**Projects compared.** The model compares four projects all with an onshore LNG facility:

- Australian CBM onshore
- Canada shale/CBM onshore
- Australia conventional offshore
- Mozambique conventional offshore

Inputs	Description
Physical specifications	<ul style="list-style-type: none"> <li>■ Specifications for the upstream, midstream and downstream projects listed above were provided to IHS</li> <li>■ IHS then determined the types and quantities of equipment and material on a ~600-800 line item basis across the phases of construction and operations</li> </ul>
Productivity and rates	<ul style="list-style-type: none"> <li>■ Labour productivity (hours worked per quantity) were provided by IHS and cross checked against the Productivity Commission report and other sources</li> <li>■ Equipment and materials rates have been provided by IHS</li> </ul>
Timing	<ul style="list-style-type: none"> <li>■ Capex costs are spread out across life of project according to construction profiles provided by IHS</li> <li>■ Key capex timings include: <ul style="list-style-type: none"> <li>— ~10 years for conventional drilling and ~20 years for unconventional drilling</li> <li>— 3 years for construction of export pipeline</li> <li>— 5 years for construction of each liquefaction train</li> </ul> </li> <li>■ Opex costs are incurred annually once production begins but are variable year to year to account for shutdown and refurbishment schedules</li> </ul>
Inflation	<ul style="list-style-type: none"> <li>■ Opex costs are inflated at the in-country inflation rate across the life of the project</li> <li>■ Capex costs include expected escalation and are therefore not inflated</li> </ul>
Tax	<ul style="list-style-type: none"> <li>■ Taxes on profit are calculated separately for upstream and downstream components of a profile using a transfer price</li> <li>■ Corporate tax calculation assumes that any tax losses are used to offset against broader company taxes (i.e. cash inflows from corporate tax are possible)</li> </ul>
Measures	<ul style="list-style-type: none"> <li>■ Measures are specific initiatives that improve productivity outcomes, e.g. modularising design, reducing cost, improving timing and utilisation. Examples are in Chapter 3 and further detailed in Appendix 5</li> </ul>
	
Landed cost in Japan	<ul style="list-style-type: none"> <li>■ Landed cost in Japan is calculated as the gas price per mmbtu in 2012 USD required to yield an IRR of 8%</li> <li>■ Date of first gas is also calculated</li> </ul>
Source: Expert interviews; McKinsey & Company	

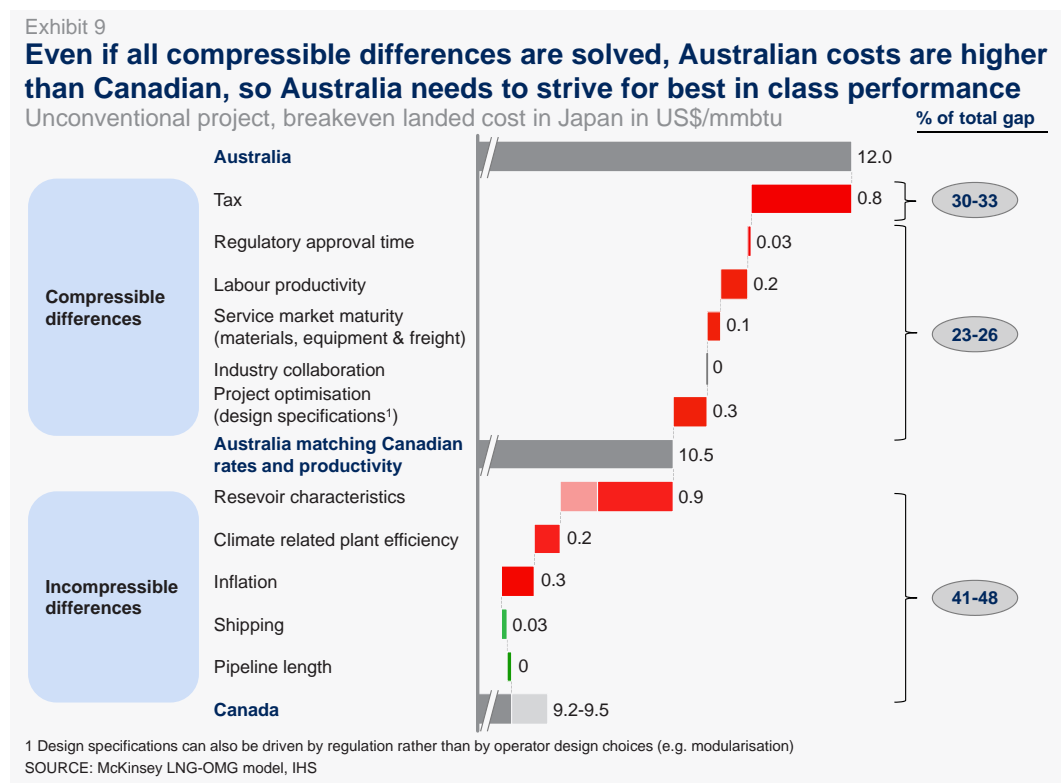
## 2.2 WHY IS AUSTRALIA LESS PRODUCTIVE?

Productivity is about the cost of converting inputs into outputs. Proposed LNG projects in Canada will be more productive than Australia (based on the two projects: a CSG onshore project in eastern Australia and an unconventional gas onshore project in Canada) because it will cost Canada less to build and operate per unit of capacity its LNG facilities.

Exhibit 9 outlines the landed cost differences between Australia and Canada, categorised into compressible differences (i.e. within the technical or managerial control of the operator or of policy makers) and incompressible differences (i.e. reservoir characteristics and other asset-related fixed costs). The comparison is expressed in US\$. Australia has a relative disadvantage in compressible costs driven primarily by higher taxes, labour productivity costs, materials and freight, and more onerous equipment and infrastructure specifications.

In effect, Exhibit 9 lays out elements of capital productivity. Tax must feature in country comparisons because tax is an element of international competitiveness. However, leaving aside tax for a moment, 70–75 percent of the difference between Canada and Australia in our analysis can be explained largely as a capital productivity problem. For the purposes of this report, we regard labour productivity as a subset of capital productivity. To that extent, labour productivity equates to 7–8 percent of the total gap.

For an overview of the methodology used to construct Exhibit 9, please refer to Appendix 4. The following section discusses: first, compressible cost differences as they relate to the build-up of landed costs; second, incompressible costs.



### Compressible cost differences (Exhibit 9, top half)

Australia incurs higher compressible unit rates in five areas:

- *Tax, including royalties, duties and tariffs, depreciation, capital allowances, carbon tax.* Tax is a compressible cost from a macroeconomic point of view, given that policy makers will want to consider the competitive outcomes of export-oriented industries like LNG. Taxes on gas in Australia are 0.8 US\$/mmbtu higher than taxes in Canada, driven by a higher corporate tax rate (Australia at 30 percent; Canada at 25 percent), and the absence of a Canadian equivalent to the Petroleum Resource Rent Tax (PRRT).

- *Regulatory approval time expended, driven by tiers of compliance, approval process efficiency, etc.* Competitively significant approval intervals can be caused by multiple factors—for example, the time needed for regulatory approvals or project problems due to insufficient planning. On average, an Australian environmental impact statement (EIS) takes 3 months longer than a Canadian EIS. It is assumed that Australian projects experience a 3 month longer FEED (front end engineering and design) period, resulting from a longer time required for permits and approvals, leading to additional costs of 0.03 US\$/mmbtu.
- *Labour Productivity, driven by availability of skilled personnel, work patterns, work processes, etc.* The difference in labour productivity between Australia and Canada adds 0.2 US\$/mmbtu to Australian landed costs. Australian workers (engineers, construction, EPC [engineering, procurement and construction] and operations) take roughly 8 percent longer time to complete the same amount of work as their Canadian counterparts. This can be driven by a number of factors:
  - Australian workers spend less time at work as a result of different shift patterns, to some extent driven by the remote locations of LNG developments.
  - When at work, time spent working productively is lower due to multiple causes, such as material and equipment not being available.
  - When working, time is spent less effectively due to relatively less experienced workers, which can lead to rework.
  - Productivity in the US is even higher than that of Canada—Australian workers take 30 percent more time to complete the same work as do their counterparts in the US.<sup>11</sup>
  - Construction labour costs are subject to variation because estimates differ from source to source, with some showing Australian labour at higher cost and others at lower cost than Canada. However, it is clear that both Australian and Canadian labour costs are higher than many other countries. For example, Australian construction labour rates are 20–30 percent higher than in the United States.<sup>12</sup>
- *Service market maturity, including local supply chains, logistics and infrastructure.* Freight rates for material and equipment are 0.2 US\$/mmbtu higher in Australia, predominantly due to relative geographic isolation and lack of infrastructure in remote areas where the LNG projects are typically located. Equipment in Australia is a little more expensive, but raw materials are cheaper, hence the total for this category is 0.1 US\$/mmbtu.
- *Project optimisation via lean design engineering and production, best-in-class contract management and best-in-class claims management.* This encompasses all differences in the quantities of equipment, material or labour needed to produce one mmbtu of gas, driven by design. These add 0.3 US\$/mmbtu to Australian costs, and can be caused by:<sup>13</sup>
  - Operator's choice of design leading to higher costs due to higher labour, materials or equipment requirements compared to a competing design
  - Design choices enforced by tighter regulation, or the interpretation of regulation in Australia
  - Economies of scale—the Canadian project used in this benchmarking is larger in capacity than the Australian project, resulting in minor scale advantages on a per unit of production basis.

We have assumed no country-specific differences in industry collaboration (i.e. optimisation of work via standardisation in procurement and certification, savings in demand planning, sharing of infrastructure, facilities, maintenance, HSE provision), since collaboration savings vary mostly on a case-by-case basis.

11 Press scan; Productivity Commission 2009, *Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector*, British Columbia Environmental Assessment Office.

12 IPA 2012, *The Performance of Australian Industrial Projects*.

13 Another driver for design specifications is local conditions. Three major local conditions have already been identified (pipeline length, reservoir characteristics and climate) and are added to the incompressible costs. There may be other local conditions that lead to the need for a different design and therefore higher costs.

### Incompressible cost differences (Exhibit 9, bottom half)

Exhibit 9 also illustrates the extent to which Australian projects incur higher or lower costs than Canadian projects due to factors that cannot be controlled. Five incompressible factors have been identified:

- *Inflation rates* in Australia are higher than in Canada (2.8 percent versus 2.0 percent, respectively), leading to 0.3 US\$/mmbtu higher costs.<sup>14</sup>
- *Pipeline length*. The Canadian field considered would require a 460 km pipeline to the LNG facility, whereas Australian CSG fields are closer to the coast, needing only a 340 km pipeline, leading to a slight advantage for Australian projects.
- *Reservoir characteristics*. Different reservoirs require a different number of wells to produce the same amount of gas, which drives upstream costs of the project. In general, shale reservoirs produce higher amounts of gas per well than CSG reservoirs. Also, productivity of the wells differs from country to country and from basin to basin. This report assumes that the Australian project requires 20 to 30 percent more wells per mtpa than the Canadian project, in line with recent experience in North American unconventional gas.<sup>15</sup> In this case, reservoir characteristics add 0.6–0.9 US\$/mmbtu to Australian costs.
- *Climate-related plant efficiency*. Due to higher air temperatures in Australia, gas turbines are less efficient and, therefore, the liquefaction facilities require a larger capacity than in Canada for the same gas flow. This adds 0.2 US\$/mmbtu to Australian landed costs.
- *Shipping distance*. The closer proximity of Australia to Japan compared to Canada gives Australia a cost advantage of 0.1 US\$/mmbtu.

## 2.3 IMPLICATIONS

The costs of a typical Canadian unconventional LNG project are 20–30 percent lower than a typical Australian unconventional LNG project (in our example comparison, circa 9.2 versus 12.0 US\$/mmbtu), driven both by factors that can be influenced and by factors beyond the operators' control. A similar gap exists between a typical Australian conventional LNG project and typical East African conventional LNG project.

To fully understand Australia's challenge, one needs to realise that if Australia eliminates all compressible cost disadvantages, it will still have a higher cost level than Canada because of the incompressible disadvantages (see Exhibit 9 which shows a US\$1–1.3/mmbtu incompressible disadvantage). Therefore Australia does not only need to close the compressible productivity gap, it also needs to exceed the productivity of its competitors who have the structural advantages of lower incompressible costs for the next tranche of projects.

The same is true for Australia's competitive challenge in respect of other regions—for example, Mozambique. Because reservoirs that we modelled in Mozambique are expected to be more productive than Australian reservoirs that we modelled, 70 percent more wells would be required to get the same amount of gas in Australia versus Mozambique.<sup>16</sup> Of course, this will vary from project to project. This results in a cost disadvantage of 1.6 US\$/mmbtu for Australia which must be overcome by finding other sources of advantage in Australia.



The inescapable conclusion is that Australia must go beyond simply addressing the compressible disadvantages against its competitors. It must also seek additional competitively significant productivity improvements. Chapter 3 describes how this could be done through a set of improvement measures directed at improving the landed cost of Australian-sourced LNG.

<sup>14</sup> ABS, Statistics Canada, Geometric average over the past 10 years.

<sup>15</sup> Assumes EUR (expected ultimate recovery) of 2000 Million Standard Cubic Feet (MMscf)/well for Australia and 2600 MMscf/well for Canada.

<sup>16</sup> Based on IHS well productivity estimates.

### 3. Closing the gap and beyond

As Chapter 2 shows, Australia will need to achieve landed costs in Asia around 9 US\$/mmbtu to be competitive on cost with the expected East African and North American exports.

There are improvement options for all parties. These require choices between strategies to close the competitive productivity gap, the selection of effective measures, and the specification of implementation approaches to maximise the result, including its delivery.

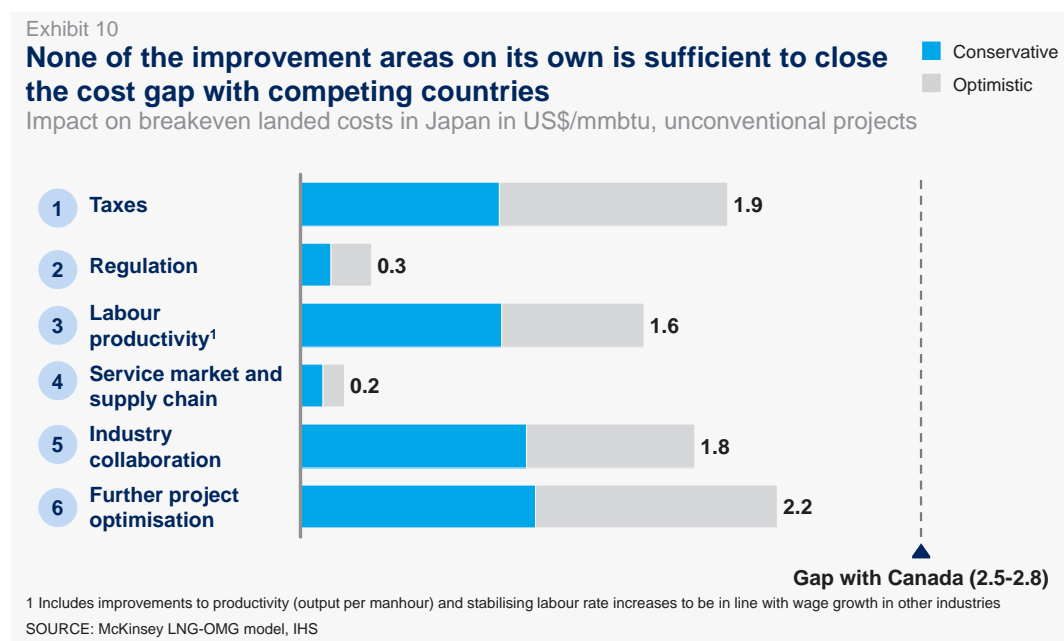
These measures relate to labour costs, taxes, regulation, management practices, and arrangements with suppliers. The options need to be assessed by policy makers, regulators, companies, communities, workers, management and suppliers. Chapter 3 lays out the measures that are the starting points for consideration in any strategy development to lift the productivity outcome. The measures are quantified illustratively to demonstrate possible impact on landed costs. The aim is to lay out the full scope of measures for improving Australia's landed cost position, while not prescribing which options, or combination of options, should be adopted.

Exhibit 10 shows the improvement potential of the measures, grouped in six categories, and the theoretical potential of each. We do not attempt to quantify the expenditure required to implement individual measures because it is contingent on the scale of action. Many measures will provide a better outcome if pursued in partnership with the full array of parties.

It is important to note that the impact of the measures cannot simply be combined to achieve a productivity outcome. Measures are interrelated and therefore the extent to which they can be implemented as an integrated strategy determines the total impact.

Also, the improvement measures listed have already been implemented to various extent somewhere in the world. Therefore, we consider each of them to be feasible to implement in Australian LNG.

In the sections below, the six categories are explored in detail as a set of possible measures which could be considered as a means of driving greater productivity in Australia's LNG sector in the future.





Several of the measures involve important, long term policy considerations, in which decision makers will need to balance both individual stakeholder issues across the public, private and community sectors with a view to the longer term national interest. Deciding which options to implement will require additional discussion between parties and consideration of trade-offs.

Appendices 5 and 6 provide assumptions and explanations, and broad calculations of possible productivity impacts.

### 3.1 TAXES

The current fiscal system in Australia applies the PRRT, corporate tax, carbon tax, royalties and import tariffs and duties to Australian LNG projects. Overall, this system adds 2.7 US\$/mmbtu to the landed costs of Australian LNG projects.

It is beyond our scope to comment on policy settings at any level of government, or the trade-offs that go into those settings. However, policy makers can explore the fiscal regime as it plays out on LNG projects in light of the capital competitiveness findings of this and other research regarding the future viability of substantial LNG projects. Trade-offs for Australia's policy makers include changes to the tax system that improve the financial viability of individual projects and reduce operator risk in the early phases of a project. Policy makers would need to take a view that fiscal adjustments could reduce or defer tax revenue on certain projects, enabling investments in new projects that otherwise would not proceed. How these taxes could be recouped at a later date is also a matter for consideration.

The total cost improvement that could come from changes to tax is 0.9–1.9 US\$/mmbtu, based on 5 potential measures described below:

#### ■ **Royalties**

All onshore and Commonwealth projects are subject to royalties and PRRT.<sup>17</sup> Royalties are paid as a percentage of revenues, while PRRT is paid as a percentage of profit. Replacing royalties by PRRT would improve costs by 0.23–0.44 US\$/mmbtu. This is due to the combined effect of: (i) delayed payment, as taxes are only payable when the project makes a profit, while royalties are levied on revenues; and (ii) potentially lower overall tax (depending on the profitability of the project). A third positive effect, which has not been translated into savings in this study, would be to lower the risk for owners as they only start to pay taxes when profitable. A successful example of this measure is the Norwegian oil and gas industry which changed from a royalty-based fiscal system to a profit tax-based system in 1975.

#### ■ **Import duties and tariffs**

Import duties and tariffs are currently 0 percent or 5 percent, depending on the item. In LNG projects, many items are already exempt from import duties and tariffs. Increasing the number of items that fall in the 0 percent category would further reduce upfront investments before first gas, and can, partly, be regained via taxes during the production phase. The impact of this measure would be 0.01–0.02 US\$/mmbtu assuming that 50–100 percent of all items in the 5 percent category move to the 0 percent category. Gulf Cooperation Council countries, such as Saudi Arabia, Bahrain and the UAE, utilise exemptions on, or rebates of, import duties as a way of encouraging foreign direct investment across different industries.

#### ■ **Accelerated depreciation**

Current allowable depreciable life for corporate tax is 15 years for unconventional upstream projects and LNG projects, and 20 years for conventional upstream projects. Allowing faster depreciation would improve costs by 0.35–0.79 US\$/mmbtu, assuming depreciation periods of 10 and 5 years respectively. For example, Malaysia and Qatar have depreciation

<sup>17</sup> Onshore and Commonwealth projects are subject to royalties, PRRT and production excise, North West Shelf is subject to PRRT, Commonwealth Royalty and Production Excise and all other offshore projects are subject to PRRT only.

periods of 4 to 10 years. The Australian Government has used a similar measure to support other industries, such as the A\$350 million tax concession for small businesses based on accelerated depreciation schedules for new car purchases.

- **Capital allowances**

To incentivise marginal investments, additional capital allowances could be provided to specific fields. Allowing an additional 25–50 percent of upstream capex to be deducted against corporate tax would improve landed costs by 0.21–0.42 US\$/mmbtu. Other countries have similar arrangements, for example Angola provides a 30–40 percent additional capital allowance based on the profitability of the block, and Denmark provides a 250 percent uplift on qualifying exploration costs.

- **Carbon tax**

Carbon tax is levied on a maximum 50 percent of the CO<sub>2</sub> emissions of LNG projects. Reducing carbon tax by 50–100 percent would improve landed costs of projects by 0.08–0.16 US\$/mmbtu. The Australian Government has previously provided exemptions to the carbon tax for the benefit of industry and consumers, such as the exemption on transport fuel.

## 3.2 REGULATION

Changes to the regulatory system could improve costs by 0.14–0.30 US\$/mmbtu, based on four potential measures described below.

- **Consistency**

Without compromising environmental or safety standards in Australia, there are examples of regulations that differ from other industries and from international standards. For instance, standards for treatment and monitoring of CSG water are higher than mining industry water standards, leading to higher costs. Also, electric wiring standards on land-based rigs in Australia are different from international standards, and rigs require rewiring before they can be used in Australia. A reduction of landed costs of 0.04–0.06 US\$/mmbtu could be achieved, based on bringing CSG water treatment, utilisation and monitoring regulation in line with the mining industry, and making rig electric wiring standards equal to international standards. There are likely more opportunities in this category that we have not explored.

- **Efficiency**

The regulatory process governing the Australian gas industry involves multiple bodies with overlapping jurisdictions. This results in additional time for regulatory processes such as approvals. For example, an Australian environmental impact statement (EIS) takes 3 months longer than a Canadian EIS. The Productivity Commission report considers it reasonable to reduce the time by 6–9 months. Assuming a saving of 3–9 months in the time it takes to do front end engineering and design (FEED), the impact of this measure would be 0.03–0.08 US\$/mmbtu.

- **Stability**

When a change in regulation occurs, operators must retrospectively change their design, leading to additional costs and schedule slippage. Avoiding changes in regulation for projects that have already received their permits would lead to an impact of 0.03–0.07 US\$/mmbtu. This impact assumes the avoidance of 1-month delay in FEED, and of multiple changes during the construction phase in the range of A\$10–100 million per change, based on the experience of Australian contractors.

- **Limits**

At times, regulators require compliance to more stringent standards than prescribed in the relevant regulation. For example, in interviews, operators indicated that regulators added 500 conditions to CSG water approvals. Sometimes, operators' own compliance standards exceed regulatory requirements. This is intended to avoid subsequent rework in case the

content or regulator's interpretation of regulation changes during the project. Overall, our calculation suggests that this could add up to 1 percent of total capex to the project. Avoiding this cost addition could lead to 0.06–0.11 US\$/mmbtu impact on landed costs.

### 3.3 LABOUR RATES AND PRODUCTIVITY

The total cost improvement identified in labour productivity and costs could be 0.9–1.6 US\$/mmbtu, driven by four potential measures.

#### ■ Residential communities close to LNG sites

Reducing travel time for workers by housing them in nearby communities instead of flying them in from further away would have the effect of increasing average working hours by 14 percent. A potential additional cost improvement could come from higher productivity through reduced pressure on long shifts and increased stability in team composition. Assuming a 5–10 percent increase in the number of construction workers and operatives living in nearby communities, and an additional 6 percent productivity improvement for these workers would result in a cost improvement of 0.03–0.06 US\$/mmbtu.<sup>18</sup> An example of this is the community of Karratha, where state and local governments are planning an expansion of residential dwellings from 5,000 to 25,000.

#### ■ Shift patterns

Australian workers generally spend more time travelling than workers in other countries, due to different shift patterns. For companies that haven't already done so, optimising shift patterns can reduce travelling time. Assuming that an additional 5–10 percent of workers in construction and operations could switch to shifts that allow more time at work, labour productivity would improve by 1–2 percent which would result in 0.03–0.06 US\$/mmbtu lower costs. For example, an underground coal miner moved to a 7 on/7 off roster that increased available production time by 15 percent and improved communication and training schedules.<sup>19</sup>

#### ■ Site productivity improvements including lean construction

Productivity at construction sites could be further improved by reducing inefficiencies at the work place and improving the supply chain. This could be achieved by improving management processes and systems to assure equipment and materials are available on time, by insuring adequate supervision, and by fully removing waste in activities with a focus on compressing the critical path. Improving training for supervisors and project managers is a must to capture increased productivity. Assuming an impact of about 15–30 percent on labour productivity, about 7–15 percent on use of rental equipment, and a 2–3 months saving in construction time, this would lower costs by 0.80–1.40 US\$/mmbtu. These techniques have been successfully applied in the last five years on a number of major projects in the infrastructure, energy, mining and other industries with commensurate results. Efforts to improve site productivity would be enhanced by considering appropriate additional workforce flexibility.

#### ■ Skilled labour

Ensuring a sufficient supply of skilled workers would have the twin effects of reducing above average wage increases in the oil and gas industry towards average Australian wage increases, and increasing productivity by about 1–2 percent by creating more experience within the labour force. The combined effect of these could be 0.07–0.14 US\$/mmbtu. For example, Brazil increased its skilled workforce supply by increasing work permit approvals for foreigners by 25 percent when activity in industrial sectors (primarily oil and gas) increased.<sup>20</sup>

18 Expenditures required for this measure have not been included in the calculations (as with all measures).

19 McKinsey BMI Practice case study.

20 Brazilian Ministry of Labor and Employment; Literature search.

### 3.4 SERVICE MARKET AND SUPPLY CHAIN

Australian rates have been higher for rental equipment and freight. Two related measures could bring rates in line with international levels.

- **Increase competition by facilitating a deeper local service market**

For example, increase the investment in the auxiliary industry (goods, inputs and services), promote the establishment of local supplier clusters, and increase local manufacturing capacity to encourage technological innovation. For example: a project of the world-class supplier development program by Codelco and BHP Billiton aims to develop 250 world-class suppliers based in Chile by 2020. Our analysis shows that, generically, the impact could be 0.03–0.06 US\$/mmbtu, assuming Australian rates for materials and equipment reach 50–100 percent of those of Canada.

- **Improve access in remote areas through infrastructure development**

The impact could be 0.07–0.14 US\$/mmbtu, based on an assumption of 15–30 percent reduction of freight costs by bringing freight costs towards Canadian levels (which is also comparable to an infrastructure expansion program in Brazil that is expected to lead to 30 percent savings in freight).<sup>21</sup>

### 3.5 INDUSTRY COLLABORATION

Industry collaboration relates to sharing of resources and infrastructure between operators and collaborating and standardising best practices across operators while maintaining competition between players. The total cost improvement could be 1.0–1.8 US\$/mmbtu, based on five potential measures described below.

- **Industry-wide standardisation**

To reduce time and effort in procurement, industry could jointly qualify suppliers and standardise contracts between the industry and suppliers. Industry could work towards joint specifications for non-confidential equipment/technology. The combined impact of these measures could be 0.16–0.32 US\$/mmbtu, based on an assumption of 1–3 months saved in upstream and downstream construction time. Additional cost savings via lower costs of components have not been calculated. There have been a number of industry collaboration standardisation and prequalification efforts in the oil and gas industry—including First Point Assessment Limited which registered over 3,000 suppliers and over 85 purchasing organisations in the UK, Ireland and Netherlands.

- **Smoother demand**

Without limiting competition, project owners could pace the timing of elements of the construction schedule to capture two possible gains: reduction of wage inflation in oil and gas towards average Australian wage inflation; and, a reduction in the costs for rental equipment due to lower mobilisation and demobilisation costs and less simultaneous competition for resources. Assuming a reduction of international rig mobilisation costs of 50–100 percent, a reduction of all internationally sourced rental equipment of 2–4 percent, and a reduction in wage inflation towards the Australian average, the impact of smoothing demand would be 0.05–0.09 US\$/mmbtu. An example of this is PILOT Forward Workplan, an initiative of the UK's oil and gas industry, which currently has in excess of 190 signatories including Chevron, ConocoPhillips and ExxonMobil. In this initiative, buyers of oil and gas support services enter details of services required, indicative contract value, and likely contract date. This helps both buyers and providers plan their activities around expected market demand.<sup>22</sup>

21 Brazil Government Fact Sheet: Logistics Investment Program: Highways and Railways, 2012 <[www.brasil.gov.br/para/press/reference-texts/logistics-investment-program-highways-and-railways](http://www.brasil.gov.br/para/press/reference-texts/logistics-investment-program-highways-and-railways)>.

22 Oil & Gas UK, Supply Chain Code of Practice (SCCoP), <[www.oilandgasuk.co.uk/knowledgecentre/SupplyChainCodeofPractice.cfm](http://www.oilandgasuk.co.uk/knowledgecentre/SupplyChainCodeofPractice.cfm)>.

#### ■ **Share plant infrastructure**

New capacity could be built next to an existing plant to share infrastructure. This would lead to reduced capex (e.g. storage facilities, jetty, offloading dock, with savings ranging from 10–100 percent per item), reduced engineering labour for the design of these facilities (20–40 percent), savings in FEED (3–6 months), in downstream construction time (2–4 months), and reduced opex (about 20–40 percent) from economies of scale. Overall the impact of this measure would be 0.77–1.37 US\$/mmbtu. Box 4 provides more information on the impact of ‘brownfield’ sharing of plant infrastructure and the potential in Australia. Of course, this is not always straightforward for operators to execute because there are often overriding commercial, or other reasons why they may choose not to share infrastructure. But the size of the potential impact on project economics is significant, and therefore should be explored, and unnecessary barriers to such infrastructure sharing removed.

#### ■ **Joint operation and maintenance companies**

Industry could share operating and maintenance facilities across plants, to increase economies of scale. This measure could be applied to projects under development as well as operating projects, and could lead to an impact of 0.10–0.14 US\$/mmbtu, assuming a 10–20 percent reduction in opex.

#### ■ **Cooperation on health, safety and environmental standards**

Industry could work together in defining common health, safety and environmental standards and investing in joint health, safety and environment infrastructure. This could lead to 0.03–0.05 US\$/mmbtu reduction in landed costs. A good example is the shared subsea response kit that Australian industry set up following the Deepwater Horizon oil spill in the US Gulf.

### 3.6 FURTHER PROJECT OPTIMISATION

Further project optimisation relates to operator actions to reduce excess project costs by applying lean practices end-to-end throughout the project: engineering and design, construction and operations.<sup>23</sup> Further project optimisation could lead to 1.1–2.2 US\$/mmbtu through six measures described below.

#### ■ **Lean engineering**

Operators could reduce rework and engineering hours through application of lean practices such as integrated planning, standardising and simplifying processes, practices and tools and continuous and visible monitoring of target KPIs. Additionally, operators could reduce the engineering cost per hour by further leveraging lower-cost locations. This could result in a reduction of landed costs by 0.16–0.28 US\$/mmbtu, based on an assumption of a 3–6 months reduction in FEED time and a reduction of overall engineering costs of 20–40 percent.

#### ■ **Lean concept and design**

Lean design consists of four elements:

- Set ambitious targets based on limits, not benchmarks
- Generate and tightly evaluate alternative concepts. For the leading concept(s), simplify scope, remove all ‘gold-plating’ in specifications, and develop a compact layout with simplified design specifications
- Standardise design to reduce costs/schedules for following projects and to facilitate greater outsourcing of detailed engineering
- Increase modularisation further to reduce the cost and duration of construction. Modularisation refers to the practice of building more complete modules in more productive workshops (rather than in field locations), and then transporting these modules to site for final assembly.

<sup>23</sup> Lean construction is addressed in the labour productivity section through site productivity improvements.

Applying these lean design elements to an Australian LNG project could reduce landed costs by 0.66–1.47 US\$/mmbtu, assuming 5–30 percent reduction of materials, equipment and engineering and construction labour, and a transition from 50 percent modularised to 70–90 percent modularised. For example, a US refinery increased the NPV of its FCC (fluid catalytic cracking) unit construction by 20–25 percent through scope optimisation. Technology advancements have enabled an ‘extreme’ form of modularisation—Floating Liquid Natural Gas (FLNG). We explain this technology and its potential to contribute to closing the productivity gap in Box 5.

#### ■ **Best-in-class contract management**

EPC rates could be further optimised by improving the scope of contracts (e.g. only passing on unmanageable risks, dividing the project into optimal lots), improving contract terms (e.g. incentivising value improvement from the first day until the end of construction), and improving the contract reward process. Best-in-class contract management could deliver a 0.21–0.42 US\$/mmbtu cost improvement, assuming 5–10 percent reduction in EPC fees and contingencies, a 1-month saving in FEED time, and a 1–2-months saving in construction time.

#### ■ **Claims management**

To improve EPC performance and reduce the costs of claims, EPCs could be continuously monitored to address potential obstacles to performance and minimise impact of change orders. Through lower claims and reduced risk, this measure could reduce costs by 0.02–0.03 US\$/mmbtu, assuming a 50 percent reduction in claims—equivalent to a 5–10 percent reduction of EPC fees.

#### ■ **Lean operations in production**

To improve productivity in the operations phase of a project, operators could maximise tool-time of maintenance crews (planning, permitting, execution), and optimise planned shutdown times to reduce costs and unplanned downtime. Assuming an overall improvement of 5–10 percent on all operations labour, this measure would reduce costs by 0.05–0.10 US\$/mmbtu.

### **BOX 4: OPPORTUNITIES FOR BROWNFIELD DEVELOPMENT**

Brownfield refers to an expansion or revamp of existing facilities, as compared to Greenfield which refers to new facilities. Brownfields are developed by operators expanding their own fields or third parties collaborating with existing facilities. They can reduce costs in four ways:

- **Sharing of physical infrastructure, such as pipelines or a jetty.** This avoids replicating infrastructure, and thereby lowers capital expenditure. Examples are shared pipelines to bring gas to shore, shared processing or backup power generation. In addition, savings can be realised by achieving economies of scale in workers’ quarters, LNG storage, and utility lines. Sharing infrastructure is assumed to reduce downstream (liquefaction) capex by about 7 percent, resulting in landed cost savings of US\$0.70/mmbtu. This equates in NPV to sharing 500 km of pipeline.
- **Shared maintenance and operations.** This lowers the direct requirements for labour, spare parts, etc. by economies of scale; and diffuses best practices thereby improving efficiency. Shared operations are assumed to reduce costs by about 5 percent. This equates to a 30 percent saving in downstream capital and operating spares.
- **Replication of existing plant designs and best practices.** This decreases time and effort in design and construction. The risk of cost overrun is lessened as the design will have been proven at least once. The impact of replication of designs is assumed to be a schedule acceleration of 4 months for downstream construction. This can lower landed costs by US\$0.51/mmbtu. A possible negative impact on production capacity or operating costs has not been taken into account (a standardised design might be less optimised for specific field characteristics than a customised design. However, the benefits of the replicated design have been assumed conservatively).



- **Reduced approval time.** Re-using technology, infrastructure and sites can accelerate regulatory and environmental processes. For example, the time required for an environmental impact assessment of a pipe tie-in is likely to be shorter than that for a new pipe. The impact has been assumed to be 6 months in FEED, plus a 40 percent reduction in FEED engineering costs. This would lower landed costs by US\$0.14/mmbtu.

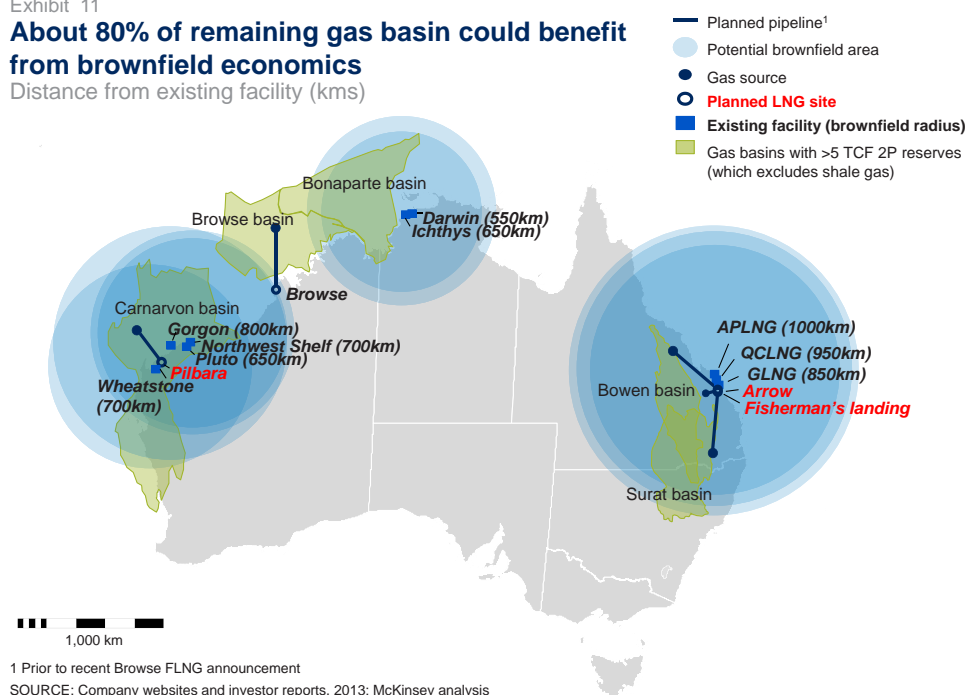
To assess whether a project could benefit from brownfield development, its distance to existing projects is critical. The cost of transporting 'new' gas to a brownfield location must be offset by the expected gains. The map (Exhibit 11) shows where adding two trains to an existing LNG facility would be more economical than constructing a new facility. Roughly 80 percent of remaining major gas basins with more than 5 tcf of 2P reserves can potentially be served by re-using existing infrastructure.

A second consideration is the lifecycle stage of projects. Sharing infrastructure is easier to agree on when both parties are developing projects. If one company has built infrastructure and a new player wants access, the case for the original owner is less clear cut as they might be cautious to help a competitor.

Exhibit 11

### About 80% of remaining gas basin could benefit from brownfield economics

Distance from existing facility (kms)



## BOX 5: TECHNOLOGICAL BREAKTHROUGH – FLNG EXAMPLE

Technological breakthroughs could also reduce costs. Since they are by nature hard to predict, these have not been assumed as a measure in Chapter 3. One promising technology that is close to maturation is Floating LNG, or FLNG. The first FLNG project globally will be in Australia: 'Prelude', which is currently being built, and first gas is expected in 2016. More projects are likely: FLNG has been cited as a serious candidate for the Greater Sunrise, Bonaparte, Scarborough, and Browse projects.

This section looks at the cost differences between FLNG and traditional LNG concepts. Other countries may also choose FLNG options, though not all fields and geographies lend themselves to the concept, and the most advanced projects are in Australia.

A floating LNG facility processes and liquefies the gas, stores the LNG and other petroleum liquids and loads these into carrier ships entirely as an offshore floating facility.

This removes the need to pipe gas to shore for processing and liquefaction, as is done traditionally for offshore gas fields.

This box investigates the cost differences between an FLNG and a traditional on-shore LNG concept. This might not always be the right comparison; floating or no LNG plant at all could also be the case, either for economical or geological reasons. It does not look at other differences, such as the fact that FLNG can be moved or staged if field properties turn out to be different from what was expected.

FLNG facilities will typically be built outside the host country, for example in Korea or China. As a consequence, there is much less footprint in the host country in the construction phase of these platforms. For example, there are no onshore civil works and no camps to host construction labour. This may be partially offset by a more elaborate supply base onshore. The need for host-country labour is also much reduced in the construction phase compared to an onshore plant, while in operations FLNG will require more people. If Australia were to develop a deeper local expertise market, leveraging the fact that it is the first country that will have FLNG in operation, it might attract a larger share of the jobs. This has not been modelled as this is not currently the case.

Construction of an FLNG facility for use in Australia presents a number of potential cost differences across the project's phases. In summary, FLNG plants are likely to be cheaper to construct, but more expensive to operate. Below is a breakdown of how costs compare to an on-shore solution. Obviously, if a project is more distant to shore or has a challenging onshore operating environment the cost differences will increase.

- **FEED.** The industry expects to achieve a higher level of repeatability in the design of FLNG facilities than achieved in onshore plants, as there is less need to take into account differences in geography and any on-shore restrictions. This would reduce the costs needed for FLNG FEED by around 20-25% (or around \$0.05/mmbtu) compared to FEED for onshore plants driven by higher potential for repeatability and reduced scope (no export pipeline or extensive onshore facilities).
- **Upstream.** Unlike onshore plants, FLNG plants do not require separate offshore platforms (e.g., production and central processing facility platforms). They will also have no export pipeline compression and flow assurance costs. The impact of this is calculated to be around US\$0.7-0.8/mmbtu.
- **Midstream.** An FLNG platform does not require the construction of an export gas pipeline from field to liquefaction plant, saving US\$0.5-0.8bn for every 100km of conventional gas pipeline that would be required. Assuming a 400km pipeline, this would reduce landed cost by US\$0.6-0.7/mmbtu.
- **Downstream**
  - FLNG platforms are typically fabricated entirely in specially constructed ship building facilities that offer more cost competitive design and construction technology and experience (in the example of Prelude, in Samsung shipyards in Korea) before being hauled to their intended site of use. Modern onshore facilities can also be built overseas as several large modules. However, assembly and commission are still required onsite. FLNG removes the need for onshore civil works (e.g. site preparation, dredging, construction camp and related support infrastructure), onshore storage (potentially replaced with floating hulls), off-loading facilities and marine facilities (e.g. breakwater, berths). Unlike onshore facilities which are air-cooled, FLNG units are cooled using seawater which provides more consistent cooling and requires less capex. Altogether, the net difference in downstream capex between FLNG and an onshore concept is estimated at US\$0.2–0.3/mmbtu.
  - Increasing the proportion of materials fabricated in more cost competitive conditions from 50% in the base onshore case to 100% reduces capex by ~5% (and landed cost by a corresponding amount of US\$0.15/mmbtu). In case of a highly modular design, host-country labour requirements during construction phase will



be lower as more construction work will be done in the construction yards rather than at the plant site.

■ **Operations**

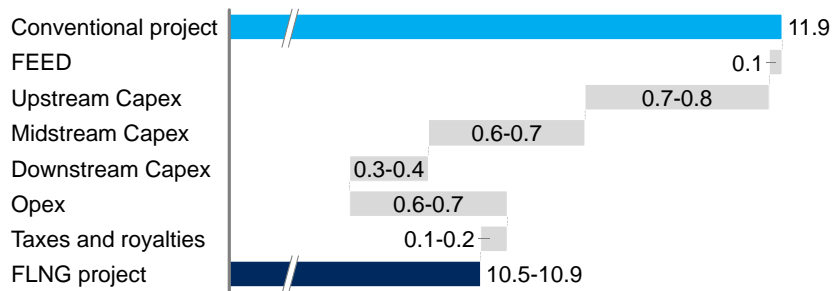
- FLNG experiences roughly 20–25% higher downstream operating costs than onshore facilities. This is driven by the more challenging offshore operating environment for FLNG and lower synergies in case of multiple liquefaction units compared with onshore, because each FLNG facility has a stand-alone crew. The landed cost impact of higher opex is estimated at US\$0.6–0.7/mmbtu in landed costs for FLNG compared with onshore LNG.
- Nonetheless, due to greater weather resilience for export loading operations, and less onerous demobilisation and remobilisation requirements, FLNG plants are expected to have 2–3% more uptime than onshore plants.

- **Abandonment.** Due to their mobility, following depletion of a gas field, FLNG units can be either redeployed at another field or taken to a yard for conversion to scrap. Consequently, they have lower abandonment costs than fixed platforms..

Based on the above, constructing an FLNG plant as opposed to a traditional onshore LNG facility could reduce landed cost by roughly \$1–1.4/mmbtu (Exhibit 12), including impact on government revenues and other costs; assuming a 2-train 8-mtpa development and cost of capital of 7.8% over 40 years life of field).

In addition to these cost factors, there are a number of other areas in which FLNG differs from onshore that are harder to quantify. On the potentially positive side, there is potential for less cost and effort needed around environmental and safety procedures, due to the lack of onshore components and a pipeline. FLNG also allows for a more phased development approach, which would allow de-risking of the development. On the potentially negative side, the experience with operating FLNG is not as deep as with traditional platforms, and regulatory processes might actually take longer as there are no/few precedents.

Exhibit 12  
**Breakthrough technology such as FLNG has the potential to make marginal projects more economically viable**  
Landed cost in Japan in US\$/mmbtu,



SOURCE: McKinsey LNG-OMG model

3.7 IMPLICATIONS

Industry as a collective, operators individually and policy makers have options for a broad range of measures that could significantly improve the costs of Australian LNG projects. The suite of potential measures is more than sufficient to close the landed cost gap with the competing LNG projects in Canada and Mozambique.

## 4. The path to Australian LNG productivity

Future Australian LNG projects will need to reach a landed cost level of not higher than US\$9–10/mmbtu in North Asia to be cost competitive with expected future exports from East Africa and North America. Chapter 3 suggests a range of measures that operators, policy makers and other parties can pursue to improve the competitiveness of future LNG projects and concludes that no single measure can bridge the entire productivity gap.

Chapter 4 considers the players in a productivity improvement effort, and the cooperation that may be desirable to achieve a maximum outcome. In putting forward these considerations, our intention is to illuminate some of the choices Australia has to close the gap, without taking a position which way is preferable.

### 4.1 INDIVIDUAL EFFORT REQUIRED

Some of the choices, and the measures to realise a landed cost improvement from them, can be dealt with individually. Some require cooperation between operators, or between operators and various policy makers. Historically, Australian operators have exhibited a preference for individual action. As Chapter 2 demonstrates, even if all the individual measures are implemented, this will not close the gap to Canada. Also, as we have already shown, the window of opportunity in LNG may be closing. Hence, industry players should pursue such individual measures they are comfortable doing in pursuit of reduced landed costs, and also cooperate to implement sufficient measures to close the remaining gap.

### 4.2 COOPERATION IS NEEDED ALONGSIDE INDIVIDUAL EFFORTS

If operators and policy makers were to implement all the measures under their exclusive control, the impact would be US\$1.70/mmbtu, which closes about 60 percent of the cost gap of US\$2.80/mmbtu.<sup>24</sup>

While, clearly, implementing individual measures on a one-operator basis is essential, it will not be enough to close the gap. And, when considering the current competitive fragility of Australian LNG in a global landscape of new discoveries and substitutes, operators will need to determine their approach to maintain their competitive position from within their own capabilities. Cooperation without loss of competition is needed to close the remaining elements of the gap.

In the first instance, forms of cooperation are really an extension of some of the individual efforts. For example, standardisation of some equipment across a company could be extended to standardisation across the industry. Cooperation provides gains through synergies, exploitation of scale and standardisation, elimination of duplicated action and investment, and other shared effort. In this instance, operators cooperate to secure the improvements from industry-wide measures (such as expanding logistics infrastructure, see Chapter 3).

Beyond these measures, the industry can work with policy makers to assist in other areas such as increasing the provision of skilled labour. In all cases, it will be necessary for Australian players to increase their acceptance of shared solutions.

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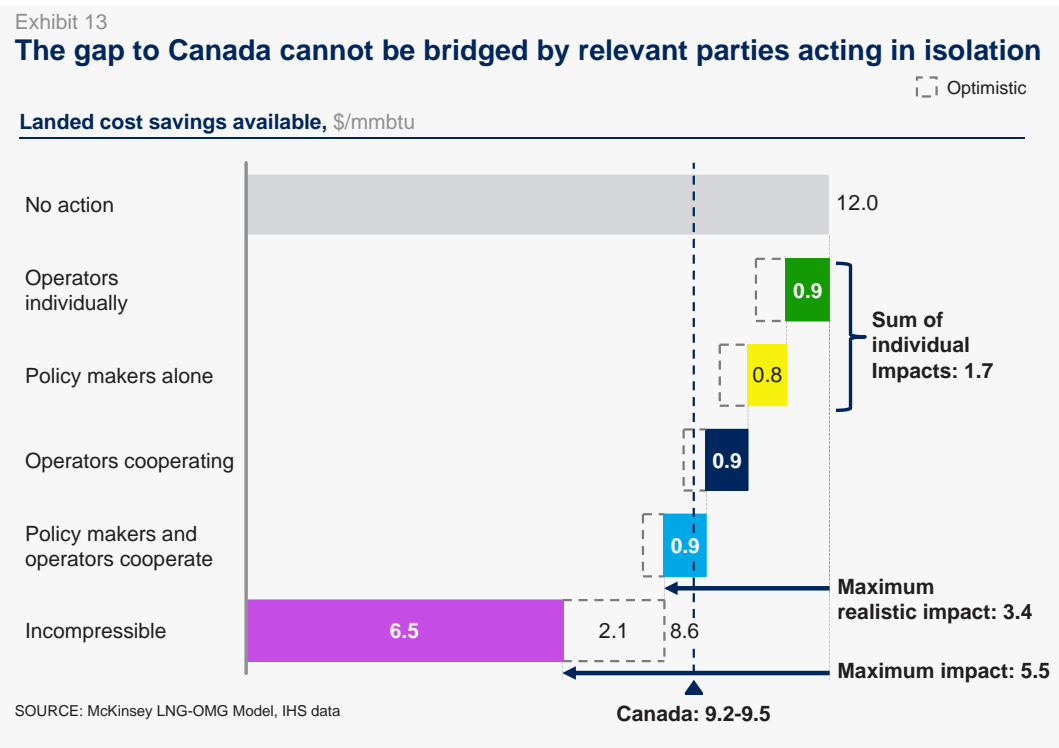
<sup>24</sup> Implementation of all measures to their full potential would close the entire gap, but this is deemed unrealistic as the full potential is quite ambitious for some measures.

Different combinations of measures and effort could lead to landed costs equal to or less than Canada. Implementing every available measure would save US\$3.4/mmbtu (or up to US\$5.5/mmbtu depending on the level of determination and the success of implementation). Only 80% of this is needed to close the US\$2.8/mmbtu cost gap with Canada. This allows some choice and prioritisation of measures, and might give a buffer if the impact of some measures doesn't full materialize as planned. See exhibit 13 below.

Exhibit 13 also shows that even if operators and the government were to implement all measures at their disposal that don't require cooperation between players, the gap would still not be closed fully. In other words, additional measures, that require cooperation, are needed.

The mix needed to close the cost gap with Canada between measures that can be taken by a single actor and those that require cooperation is not fixed. A large variety of mixes is possible, for example:

- **Across the board:** Implement 80 percent of all measures independent of who the owner of the measure is and whether or not cooperation is needed
- **Focus on individual measures:** Implement 90 percent of all measures controlled by operators and policy makers individually, and 70 percent of all measures that require more than one actor
- **Tilted towards industry:** Implement 95 percent of operator controlled measures, 90 percent of industry controlled measures, and 70 percent of all measures that involve policy makers
- **Tilted towards policy makers:** Implement 90 percent of all measures involving policy makers, and 70 percent of all measures involving industry.



### 4.3 OTHER COUNTRIES HAVE COOPERATED SUCCESSFULLY

In choosing a path forward, Australia can also draw on the experience of other countries.

For example, Norway and the UK successfully anticipated changes in industry dynamics and productivity and their effect on national revenues. Their experience demonstrates the value of forethought and a nuanced but managed evolution in industry arrangements. Although the challenges and stage of industry development were different to Australia's in these cases, we offer them to illustrate what is possible, and what were the choices that these other countries made.

- Norway built a successful oil and gas industry with the government playing an active role in shaping the sector from the start (Box 6)—and indeed going so far as to coordinate it.
- In the North Sea, the industry has driven cost savings through increased cooperation (Box 7).

Extended cooperation presupposes a particular view of the value and sustainability of joint solutions, particularly at the earlier phases of the industry's evolution. If there is little inclination to pursue a joint solutions approach, there is still a need to face up to the productivity gap. In this case, it may be instructive to consider the United States model. The US has no centrally controlled plan, lighter regulation and limited government intervention.

### 4.4 DECIDING ON A PATH TO PRODUCTIVITY

We are aware that many project operators, their partners and contractors have long since embraced the continuous improvement mindset. It is this openness to optimisation that is industry's best foundation for a further concerted effort to close the productivity gap.

The question of what to do from here is first one of belief and aspiration. Specifically, is the prize big enough (Chapter 1 makes the case that it is)? Second, is additional and challenging action required (Chapter 2 makes the case that it is)?

Next, it is a question of degree. However far the productivity ratchet has turned to date, a further turn is called for. If you believe that the gap is real, large and important to competitive success, then the size of the gap implies that the focus must be on far more than incremental improvement.

The sensible thing is then to devise a plan to progress the measures that we lay out in Chapter 3 as being among the levers that matter most. The plan must allow the industry—represented as individual projects or collectively—to make risk-weighted business judgments about where the landed-cost improvement opportunities are, then to pursue them with rigour. It must also allow policy makers to consider what actions they should take to enable the industry to compete more effectively.

The scope of any program of improvements, and its leadership, must reflect its importance to the commercial prize that must be won. The five biggest measures, of the total 25 that we illustrate, account for a third of the potential impact, and are equally distributed between players. They are: site productivity improvements, applying lean concept and design, sharing plant infrastructure, allowing accelerated depreciation and additional capex allowances. Hence they deserve special attention. Further details on these measures (and indeed on all the measures outlined in this report) can be found in Appendices 5 and 6. Exhibit 14 provides a snapshot of the details included in these appendices.

Exhibit 14

The appendices offer further detail in several areas

Input assumptions – Appendices 1,2,3 & 4

1. LNG Optimisation Model for Growth (LNG-OMG model) landed cost methodology
2. LNG-OMG landed cost assumptions
3. Capex profiles for standard projects
4. Assumptions for well productivity calculations

Improvement measures – Appendices 5 & 6

5. Explanations and examples

6b Lean concept and design

6. Assumptions for calculations

## BOX 6: NORWAY—GOVERNMENT COORDINATED DEVELOPMENT

Norway took a coordinated approach from the beginning of the country's oil and gas development. While Australia's industry is now well past its initial stages, the Norwegian example does offer some proven ideas to increase local industry competitiveness which stakeholders may consider.

As of 2010, Norway was the world's third largest gas exporter and fifth largest oil exporter (source: BP Statistical Review of World Energy, June 2012). Oil and gas has driven much of Norway's GDP growth over the last 40 years (GDP in 2010 was 3.5 times higher than GDP in 1970, with average annual GDP growth 0.5 to 1.2 percent higher than its Scandinavian peers), and the industry now contributes about 17 percent of mainland GDP.

The evolution and success of Norway's oil and gas industry can be traced to 1971 when the government published the 'Ten Oil Commandments'. These emphasised that government should play an active role in resource development. Since then, government has pursued four policies:

- **Supportive fiscal regime.** The government adjusts its fiscal regime to meet industry needs. For example, profit-based taxes (corporate and special) for new fields have replaced revenue-based royalties since the late 1980s. Capex allowances for investments (reduction of the special tax base by 30 percent of the investment value over a 4-year period), and capex allowances for exploration and R&D (reducing those costs by 78 percent), provide incentives to innovate and invest in high capex fields. Oil companies pay ecological taxes for CO<sub>2</sub> and NO<sub>x</sub> emissions. Corporate taxes and special taxes are based on imputed earnings. It uses real oil prices over a time period to forecast revenue and all costs are controlled by the Norwegian Petroleum Directorate which enables the government to calculate profits.
- **Promotion of innovation.** The government provides companies with incentives to carry out research in Norway. In addition to tax incentives, the government awards points to operators for R&D and knowledge transfer to Norwegian institutions. These points are taken into account during next licensing rounds. Support for R&D is also pursued by government coordinating and a co-investing in R&D programs and centres (e.g. OG21, PETROMAKS, DEMO 2000).
- **Access to the Norwegian Continental Shelf.** While competition has always been assured, the overall licensing strategy originally favoured national companies.
- **Role of national companies.** Norway uses national companies (Statoil, Norsk Hydro, SDFI, Petoro) to manage the government's stake in the sector.

The government also played a defining role in developing the oil field services and equipment industry. This serves local operators, and has evolved into a major centre that serves the industry globally. It achieved NOK118 billion in international sales in 2009 (A\$20 billion). Several companies are top-ranked internationally (e.g. Seadrill, Aker Solutions, Kvaerner). In the earlier stages, government supported local related industries by ensuring they got preferences from oil companies, using soft measures that did not introduce high barriers to international competition, including: recommendations for licensees to use local goods and services, if they are competitive; and requirements for concessionary bidders to present a plan of localisation and knowledge transfer to local institutions. In Norway, the government has a right to increase competition by adding qualified local suppliers to lists of tender participants.

### BOX 7: UK CONTINENTAL SHELF—INDUSTRY COLLABORATION

In contrast to Norway, the UK let the oil and gas industry develop with less policy maker control or steering. When the industry found it was no longer sufficiently competitive in the 1990s, operators decided to increase intra-industry collaboration and launched a Cost Reduction Initiative for the New Era (CRINE). This standardised working practices, contracting and equipment, and reduced costs of development by as much as 30 percent (UK Department of Trade and Industry, Oil and Gas Energy Reports, 'The Brown Book').

Following CRINE's success, PILOT, the UK oil and gas taskforce which facilitates cooperation between industry and policy maker, established the UKCS Supply Chain Code of Practice (SCCoP)—a set of best practice guidelines for the industry. The initiative was launched in 2002 and as of December 2012 had 193 signatories (source: < [www.oilandgasuk.co.uk](http://www.oilandgasuk.co.uk) >) including Shell, Chevron, ExxonMobil and BP, which also are major players in Australia. Among other functions, SSCoP achieves:

- **Standardisation of supplier qualification.** This increases the ease with which operators can determine which suppliers are best suited for their needs, thus reducing time, cost and risk. The online platform First Point Assessment Ltd. (FPAL), which has over 2,500 registered suppliers and 95 registered buyers (<[www.fpall.co.uk](http://www.fpall.co.uk)>), qualifies suppliers through standardised online assessment and onsite auditing. They also provide benchmarking tools to compare suppliers. Purchasers of oil and gas services provide performance feedback during or after execution of a contract according to a standard report format.
- **Standardisation of contracts and invitations to tender (ITTs).** This has the dual benefit of reducing documentation and contracting costs, and sharing best practices on contracting. The SSCoP provides free standard contracts, covering multiple areas including construction, design, well services and supply of mobile drilling rigs. It also provides ITT templates which incorporate best practices and includes guidelines on completing ITTs.
- **Sharing of forecast service requirements.** Participants post forecasts of their service requirements to the market to enable better coordination and planning from both operators and services providers. There are two main mechanisms for this sharing. The first is via the PILOT forward workplan: a standard template hosted on the FPAL system on which operators indicate what services they require in the future, along with when and for how long. The second is via the PILOT Share Fair: an annual event where operators and contractors discuss their plans for the next 18 months. The 2012 event attracted 1,200 attendees (<[www.subseauk.com/3404/pilot-share-fair](http://www.subseauk.com/3404/pilot-share-fair)>).

Of course, trade-offs always have to be made, and while standardisation has clear cost benefits, it reduces the flexibility of the operator to customise and optimise designs to suit individual preferences and constraints. For example, standardisation to single train arrangements diminishes the redundancy benefits of multi-train processing facilities. This contributes to the somewhat mixed reputation of CRINE era facilities today; however overall their asset efficiencies are not statistically different from assets constructed before or after.



## 5. First steps on the path to productivity

This report is designed to share a fact base about the growing importance of LNG to the Australian economy, the Australian industry's relative competitive position and what could be done to improve the competitiveness of Australian LNG projects. We hope it equips relevant parties with the insight needed to choose the best package of measures to close the gap. As such, it does not recommend any specific measure or set of measures. Each suite of measures will have its own implications and next steps, and will involve a different set of parties.

Each party can undertake a number of measures individually, which can make significant improvements to productivity. However, as Chapter 4 shows, even if industry players and policy makers implement all measures that do not need the other party, this would only close 60 percent of the gap. So to achieve the required productivity gains, cooperation is required on top of individual effort by policy makers, operators, and the industry as a whole.

There will also be a role for cooperation with a wider range of parties, such as employer organisations, NGOs, unions, etc. Given the economic and other gains that can be achieved, and the magnitude of the challenges involved, the desire to find common cause should be compelling.

The suggestion to seek areas of cooperation to improve the industry's competitiveness should not be mistaken as implying more than is intended. We simply suggest exploring options for cooperation in a similar manner as in some other countries that have faced similar situations. For instance, the UK has achieved its cooperation regime while maintaining a highly competitive environment. The UK PILOT program is a taskforce with representatives from industry, policy makers and trade unions chaired by the Secretary of State for Energy and Climate Change and vice chaired by a Minister of State for Energy and Climate Change. The cooperation creates a climate for the UK Continental Shelf which allows it to retain its position as a pre-eminent and active centre of oil and gas exploration and production. The taskforce has subgroups focusing on competitiveness, innovation and technology, skills and training, regulation, licensing and fiscal issues.

Given the challenge that LNG faces in Australia, with unprecedented competition on volumes and costs from established and emerging gas players, it may appeal to the parties to pursue a more structured cooperative position. It is individual company and government action PLUS cooperation that will make it more likely that the sector will overcome the significant cost challenges LNG projects face.

If Australia does not prioritise LNG productivity, the country risks foregoing the opportunity it has to develop the next wave of LNG projects, and the economic benefits they will bring. Therefore a next step could be for the key parties to jointly develop an agreed view on which measures should be taken to develop the LNG landscape, and the role that each of the parties will play to implement them.

□ □ □

A practical way to do this might contain the following steps. First, for industry, policy makers and possibly other stakeholders to coalesce around the facts in this report, and to agree on the order-of-magnitude of the gap to overcome, and the degree to which each group of measures would close it. Then, for each party (or parties) to decide which measures to implement individually. Companies, for example, can set ambitious targets for their next project. Governments can train more Australians in needed skills, possibly with industry support. Third, agree on a way to close the remaining gap through enhanced cooperation. Fourth, periodically review to monitor and rebalance as required.



# Glossary

Capex	Capital expenditure
CSG	Coal seam gas
EIS	Environmental impact statement
EPC	Engineering, procurement & construction
FCC	Fluid catalytic cracking
FEED	Front end engineering and design
GDP	Gross domestic product
HSE	Health, safety and environment
KPI	Key performance indicator
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
NGO	Non-governmental organisation
NPV	Net present value
O&G	Oil and gas
Opex	Operational expenditure
PILOT	Partnership between the UK oil and gas industry and government (formerly the Oil and Gas Taskforce)
PRRT	Australian petroleum resource rent tax

# Appendices

## APPENDIX 1: LNG OPTIMISATION MODEL FOR GROWTH (LNG-OMG) LANDED COST METHODOLOGY

### APPENDIX 1

### LNG Optimisation Model for Growth (LNG-OMG) landed cost methodology

#### Projects

The model compares four projects all with an onshore LNG facility:

- Australian unconventional (CSG) onshore
- Canada unconventional onshore
- Australia conventional offshore
- Mozambique conventional offshore

Inputs	Description
<b>Physical specifications</b>	<ul style="list-style-type: none"> <li>▪ ~600-800 line-items across the phases of construction and operations for the types and quantities of equipment and material needed for the specified projects, amongst other sources based on IHS input data, for upstream, midstream and downstream</li> </ul>
<b>Productivity and rates</b>	<ul style="list-style-type: none"> <li>▪ Labour productivity (manhours per quantity) includes data provided by IHS and Australian Productivity Commission reports and other sources</li> <li>▪ Equipment and materials rates includes data provided by IHS</li> </ul>
<b>Timing</b>	<ul style="list-style-type: none"> <li>▪ Total capex costs are spread out across life of project according to construction profiles, including those provided by IHS</li> <li>▪ Key capex timings include:               <ul style="list-style-type: none"> <li>— ~10 years for conventional drilling and ~20 years for unconventional drilling</li> <li>— 3 years for construction of export pipeline</li> <li>— 5 years for construction of each liquefaction train</li> </ul> </li> <li>▪ Opex costs are incurred annually once production begins but are variable year to year to account for shutdown and refurbishment schedules</li> </ul>
<b>Inflation</b>	<ul style="list-style-type: none"> <li>▪ Opex costs are inflated at the in-country inflation rate across the life of the project</li> <li>▪ Capex costs include expected escalation and are therefore not inflated</li> </ul>
<b>Tax</b>	<ul style="list-style-type: none"> <li>▪ Taxes on profit are calculated separately for upstream and downstream components of a profile using a transfer price</li> <li>▪ Corporate tax calculation assumes that any tax losses are used to offset against broader company taxes (i.e. cash inflows from corporate tax are possible)</li> </ul>
<b>Measures</b>	<ul style="list-style-type: none"> <li>▪ Measures reduce specific line items or categories costs, timings or utilisation rates as laid out in Appendix 5</li> </ul>

<b>Landed cost in Japan</b>	<ul style="list-style-type: none"> <li>▪ Landed cost in Japan is calculated as the gas price per mmbtu in 2012 USD required to yield an IRR of 8%</li> <li>▪ Date of first gas is also calculated</li> </ul>
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SOURCE: Expert interviews; McKinsey Analysis

## APPENDIX 2: LNG-OMG LANDED COST MODEL ASSUMPTIONS

### APPENDIX 2

### LNG-OMG landed cost model assumptions

#### Economic assumptions

Topic	Description
<b>Inflation</b>	<ul style="list-style-type: none"> <li>Australia domestic inflation rate: 2.8% pa<sup>1</sup></li> <li>Canada domestic inflation rate: 2.0% pa<sup>2</sup></li> <li>Mozambique domestic inflation rate: 2.8% pa<sup>3</sup></li> </ul>
<b>Exchange rate</b>	<ul style="list-style-type: none"> <li>AUD/USD exchange rate: constant at 1.0285<sup>4</sup></li> <li>Other exchange rates: remain constant throughout life of project (i.e. no exchange rate effects)</li> </ul>

#### Project assumptions

Topic	Description
<b>Discount rate</b>	<ul style="list-style-type: none"> <li>WACC: 8% nominal</li> </ul>
<b>Timing</b>	<ul style="list-style-type: none"> <li>FEED: 2 years</li> <li>Construction period: 5 years</li> <li>Unconventional production life: 40 years</li> <li>Conventional production life: 37 years</li> </ul>
<b>Modularisation</b>	<ul style="list-style-type: none"> <li>Australian project modularisation: 50%</li> <li>Canadian/Mozambique project modularisation: 50%<sup>5</sup></li> </ul>
<b>Plant capacity</b>	<ul style="list-style-type: none"> <li>Australian project capacity: 8.2 mtpa</li> <li>Canadian project capacity: 10.3 mtpa</li> <li>Mozambique project capacity: 10.0 mtpa</li> </ul>
<b>Reservoir characteristics</b>	<ul style="list-style-type: none"> <li>Australian conventional water depth: 275m, reservoir depth: 4600m</li> <li>Australian unconventional reservoir depth: 520m</li> <li>Mozambique conventional water depth: 1200m, reservoir depth: 3500m</li> <li>Canadian unconventional reservoir depth: 400m</li> </ul>

1 Average inflation over past 10 years from ABS

2 Average inflation over past 10 years from StatCan

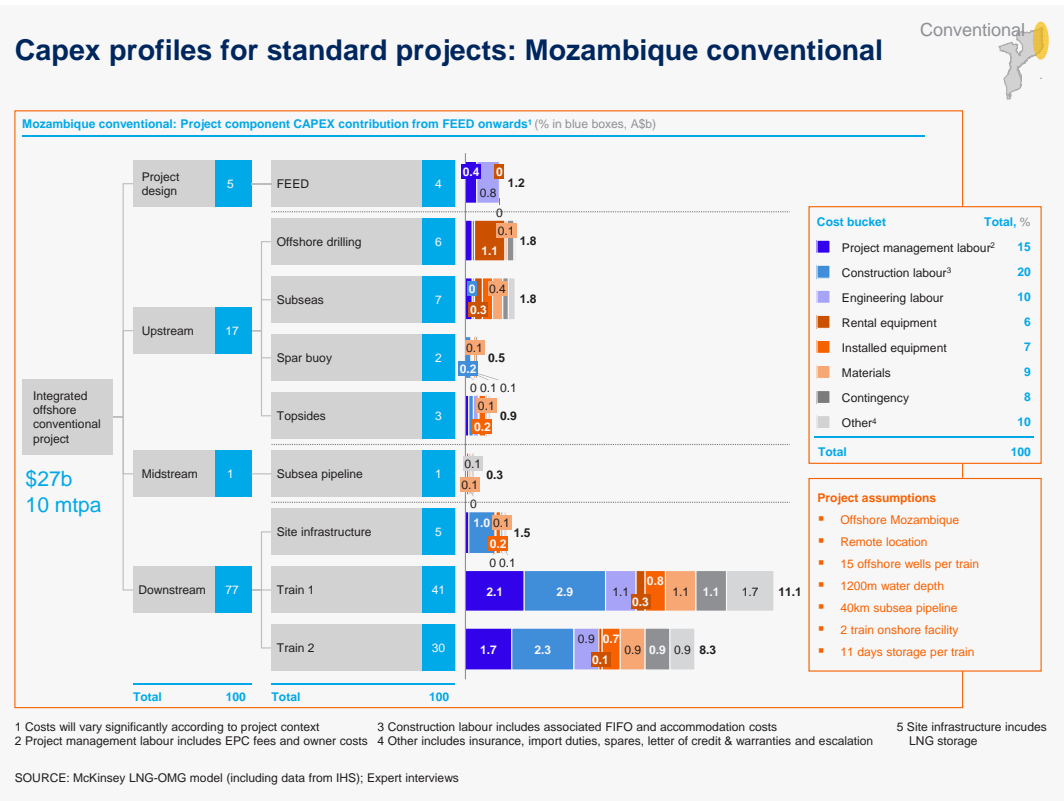
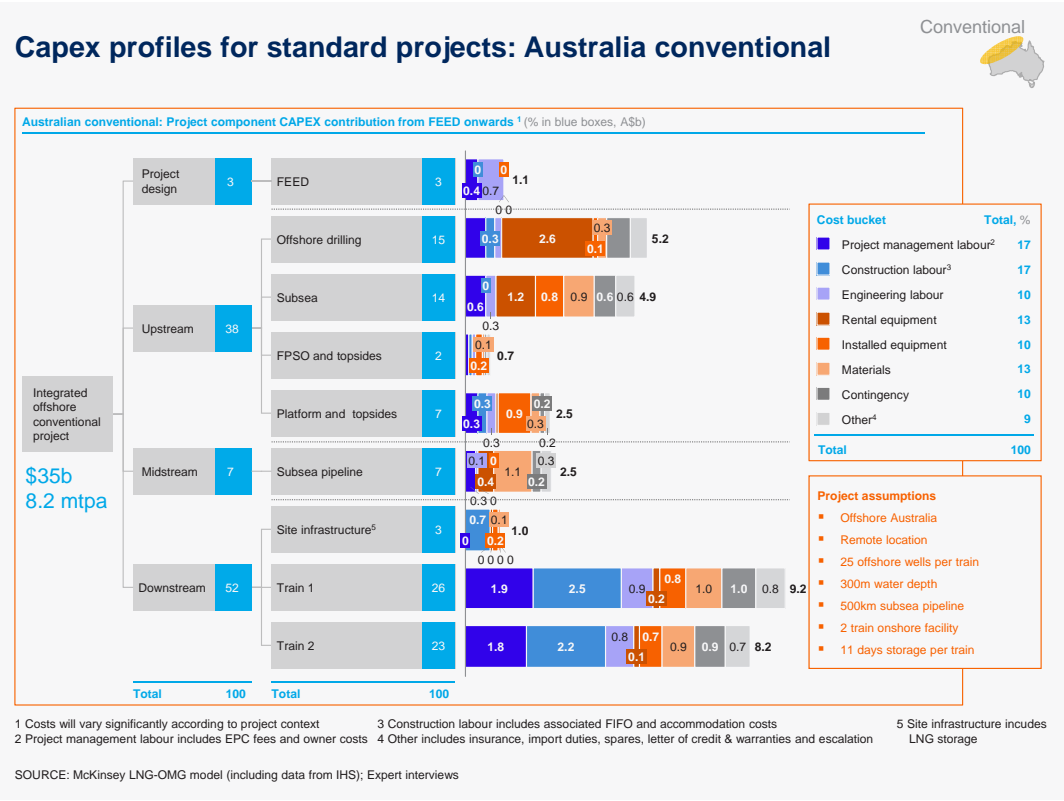
3 Assumed same as Australia due to lack of certainty on forecast inflation

4 Exchange rate at Mar 2013 from RBA

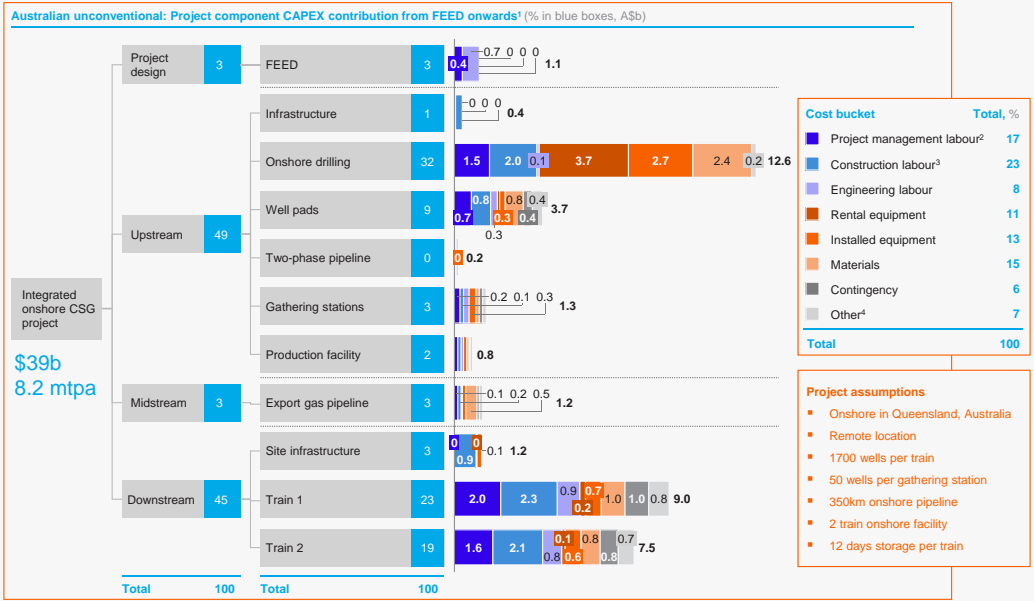
5 Canada is assumed to have the same level as modularisation as Australia, but this results in lower cost savings since Canada is further away from countries with significant lower wages

SOURCE: Expert interviews; McKinsey Analysis

APPENDIX 3: CAPEX PROFILES FOR STANDARD PROJECTS



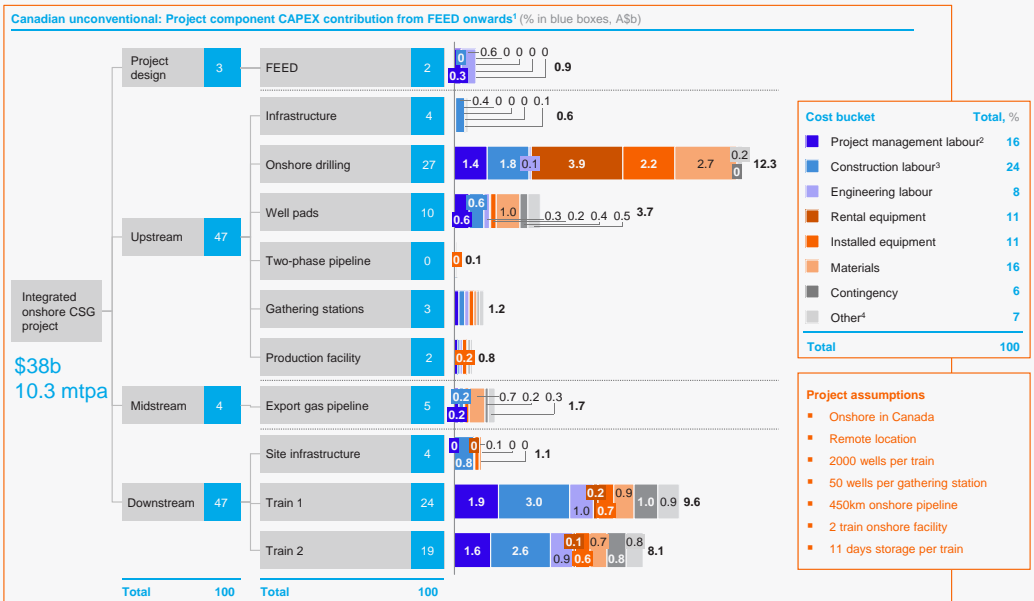
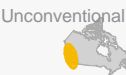
Capex profiles for standard projects: Australia unconventional



1 Costs will vary significantly according to project context  
2 Project management labour includes EPC fees and owner costs  
3 Construction labour includes associated FIFO and accommodation costs  
4 Other includes insurance, import duties, spares, letter of credit & warranties and escalation  
5 Site infrastructure includes LNG storage

SOURCE: McKinsey LNG-OMG model (including data from IHS); Expert interviews

Capex profiles for standard projects: Canada unconventional



1 Costs will vary significantly according to project context  
2 Project management labour includes EPC fees and owner costs  
3 Construction labour includes associated FIFO and accommodation costs  
4 Other includes insurance, import duties, spares, letter of credit & warranties and escalation  
5 Site infrastructure includes LNG storage

SOURCE: McKinsey LNG-OMG model (including data from IHS); Expert interviews

APPENDIX 4: ASSUMPTIONS FOR WELL PRODUCTIVITY CALCULATIONS

APPENDIX 4

Assumptions for well productivity calculations

Canada unconventional project

Chapter 2 compares a Canadian unconventional project with an Australian unconventional project, in order to:

- Determine how large the cost gap is between Australia and competing Canadian projects
- Explore the main drivers for this cost difference

For the first objective, the most likely actual project that could be competing in Japan with the Australian projects would be a shale gas project. Therefore, Australian CSG projects need to be cost competitive with Canadian shale gas projects.

However, to make a like for like comparison on main drivers for cost difference based on differences in rates and quantities, a comparison between two CSG projects is most insightful.

As the main difference between shale gas projects and CSG projects is the well productivity, this report compares the detailed cost structure of a CSG project, which is adjusted for shale gas reservoir characteristics (i.e. assuming a higher well productivity). This is illustrated in Exhibit 8 where a range is shown for reservoir characteristics. This is based on range of ~20% more (in case of CSG) to ~90% more wells needed (in case of shale) than for Australian projects. The assumptions behind this are shown below.

CSG well productivity Canada

- As there is no data available for Canadian CSG well productivity yet, US CSG wells have been taken as a proxy
- The top 10% most productive CSG wells drilled in the US from 2011 have an average month 1 production of 16,000 MCF
- Applying the average decline rate of San Juan / Raton over 20 years, the expected ultimate recovery per well is 54 kT

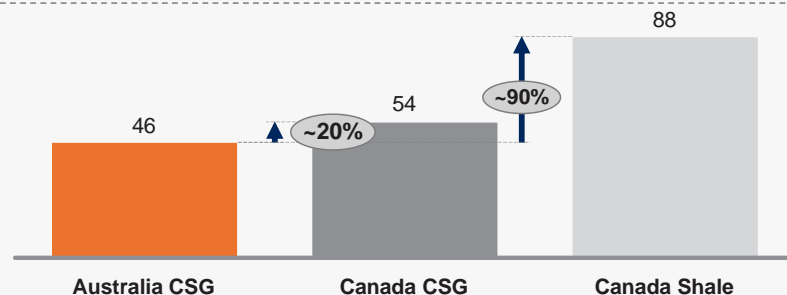
Shale well productivity Canada

- Taking an average of the productivities of Horn River and Montney vertical shale gas wells, weighted by the estimated remaining reserves, the expected ultimate recovery per well is assumed to be 88 kT

CSG well productivity Australia

- Expected ultimate recovery per well is assumed to be 46 kT, which is in line with announcements

Comparison of ultimate recovery (kT)



SOURCE: Expert interviews; IHS; McKinsey Analysis, Company websites

## APPENDIX 5: EXPLANATIONS AND EXAMPLES OF PRODUCTIVITY IMPROVEMENT MEASURES

This appendix provides a page of detail and examples around the improvement measures described in Chapter 3:

1. **Taxes**
  - a. Royalties
  - b. Import duties and tariffs
  - c. Accelerated depreciation
  - d. Capital allowances
  - e. Carbon tax
2. **Regulation**
  - a. Consistency
  - b. Efficiency
  - c. Frequency
  - d. Limits
3. **Labour productivity**
  - a. Residential communities close to LNG sites
  - b. Shift patterns
  - c. Site productivity improvements through lean construction
  - d. Skilled labour
4. **Service market and supply chain**
  - a. Local service market
  - b. Remote infrastructure
5. **Industry collaboration**
  - a. Industry wide standardisation
  - b. Smoother demand
  - c. Share plant infrastructure
  - d. Joint operation and maintenance companies
  - e. Cooperate on health, safety and environmental standards
6. **Further project optimisation**
  - a. Lean engineering
  - b. Lean concept and design
  - c. Contract management
  - d. Claims management
  - e. Lean operations in production

### TAXES

#### 1a Royalties

Legislative change at state level to evolve taxation regime from revenue-based royalties to sharing PRRT revenues in order to increase viability of projects, particularly marginal projects

**Actions**

- ✓ Conduct economic analysis of effect on states and project operators of state royalties on existing and proposed gas projects, particularly marginal projects
- ✓ Develop PRRT revenue-sharing scheme with states to enable states to remove royalties on gas projects
  - Define the scope (new and/or existing projects)
  - Agree compensation regime for states where Commonwealth distributes PRRT revenue among the affected states
  - Draft relevant legislative instruments
- ✓ Pass legislation in Commonwealth and state parliaments

**Approximate Timing**

- 2 -4 years

**What you need to believe for these actions to have impact**

- Affected states (mainly QLD, SA, WA) could be incentivised to accept greater volatility of PRRT revenue rather than a revenue-based royalty
- Government willing to share PRRT revenue
- To conduct an accurate economic analysis, policy makers can obtain sufficient information from industry to accurately understand economics of gas projects (e.g. required IRR for project viability)

**Example: Norway's oil & gas industry**

- Norway's oil & gas industry is one of the most successful in the world, assisted by an evolving fiscal regime
  - Norway is the 3<sup>rd</sup> biggest gas exporter and 5<sup>th</sup> biggest oil exporter in the world
  - During 'tough' tax policy (mainly royalties then profit taxes) of 1972–87, oil production increased by 49mtpa; during 'liberal' tax policy (lower profit taxes, more capex uplifts) of 1987–2002, production increased by 107mtpa
- The industry's tax regime has evolved from revenue-based (royalties in 1970s) to profit-based—allows investors to receive a positive cash flow from any field when the total development costs are lower than the oil price
- Corporate taxes and special taxes are calculated based on imputed earnings calculated by the government
  - Government uses real oil prices over a time period to forecast revenue
  - All costs are controlled by Norwegian Petroleum Directorate, thus allowing the government to calculate profits

**Likelihood**

**Responsibility**

Low

Medium

High

Government

Industry

Operator

0.23 – 0.44  
US\$/mmbtu  
impact expected

**TAXES**

## 1b Import duties and tariffs

Legislative change at Commonwealth level to apply waivers to, or change to 0%, all import duties/tariffs for imported materials, rental equipment and installed equipment of gas projects to decrease investment needed before first revenues

Likelihood	Responsibility
Low	Government
Medium	Industry
High	Operator

**Actions**

- ✓ Conduct economic analysis of effect on Commonwealth and project operators of duties/tariffs for imported materials, rental equipment and installed equipment of gas projects
- ✓ Conduct feasibility study of neutralising duties/imports for all relevant products by either
  - Reducing all import duties/tariffs to 0%
  - Granting a waiver for all import duties/tariffs
  - Expanding the Enhanced Project By-law Scheme (EPBS)
- Draft relevant legislative instruments
- Draft Regulation Impact Statement (RIS) to accompany draft regulation
- ✓ Amend regulations to set duty / tariff levels to 0% or grant waivers

**Approximate Timing**

- ~12 months

**What you need to believe for these actions to have impact**

- Government could be incentivised to reduce its revenue from import duties and tariffs relating to gas projects—government would need to believe that after lowering import duties and tariffs:
  - There would be increased profit taxation of projects after first gas
  - Either
    - No increase in total amount of imported (vs. domestic) material and equipment; or
    - Increase in total amount of imported (vs. domestic) material and equipment, but it is better that a project goes ahead than not go ahead

**Example: Gulf Cooperation Council (GCC) import duty relief**

- GCC has implemented a suite of tax incentives to encourage foreign direct investment (FDI) across all industries
- This includes relief from import duties and tariffs in some countries:
  - Saudi Arabia: exemption on machinery, equipment, tools and spare parts imported for industrial projects
  - Bahrain: 100% rebate of customs duties for the first five years in all industries
  - UAE: Exemption from all taxes and duties levied on profits or production
- Recent successful FDI in GCC countries include Carrefour (UAE), Geant (Bahrain), Giordano (UAE)

**0.01-0.02 US\$/mmbtu impact expected**

SOURCE: McKinsey & Company analysis

**TAXES**

## 1c Accelerated depreciation

Legislative change at Commonwealth level to reduce depreciable life of project assets by 5–10 years to defer taxes to improve viability of projects, particularly marginal

Likelihood	Responsibility
Low	Government
Medium	Industry
High	Operator

**Actions**

- ✓ Conduct economic analysis of effect on Commonwealth taxation revenue (company tax) of reduction in depreciation life of gas project assets
- ✓ Conduct consultation process with relevant stakeholders (e.g. gas operators, accounting firms, corporate bodies)
- ✓ Amend regulations to change depreciation schedule of relevant assets
  - Draft any required legislative instruments
  - Draft any required Regulation Impact Statements (RIS) to accompany draft regulation

**Approximate Timing**

- ~12 months

**What you need to believe for these actions to have impact**

- Government is willing to defer tax revenue in order to increase NPV of gas projects
- Government is convinced that reducing depreciable life of assets will have positive economic impact, e.g. increase investment in gas project development given operators' higher cost of capital than government

**Examples**

**Australia small business car tax incentive**

- Small businesses are eligible for an immediate tax write-off of up to \$5000 on new motor vehicles purchased from 1 July 2012—provides a tax benefit as it accelerates the standard depreciation schedule
- The car tax write-off is intended as a stimulatory measure to lead to increased motor vehicle sales, as part of a much broader assistance package to the Australian car industry following the global financial crisis
- This tax concession is estimated at \$350m cost to Government

**0.35 – 0.79 US\$/mmbtu impact expected**

SOURCE: Australian Taxation Office; McKinsey & Company Oil and Gas Practice



**TAXES**

## 1d Capital allowances

Legislative change at Commonwealth level to provide additional deductibility for capex expenditures in targeted projects (e.g. shale gas, fields with certain water depth) to improve viability

Likelihood	Responsibility
Low	Government
Medium	Industry
High	Operator

**Actions**

- ✓ Conduct economic analysis of effect on Commonwealth taxation revenue (company tax only) of further deductibility of capex expenditures (e.g. more than 100%) for certain projects (small, very far offshore, unconventional)
- ✓ Conduct consultation process with relevant stakeholders (e.g. gas operators, accounting firms, corporate bodies)
- ✓ Amend regulations to change tax deductibility for capital expenditures
  - Draft any required legislative instruments or amending regulations
  - Draft any required Regulation Impact Statements (RIS) to accompany draft regulation

**Approximate Timing**

- ~12 months

**What you need to believe for these actions to have impact**

- Government is willing to reduce tax revenue in order to increase NPV of marginal or higher-risk gas projects
- Government is convinced that increasing tax deductibility of certain projects will have positive economic impact, e.g. increase investment in gas project pipeline

**Examples**

**Australian Research & Development tax incentive**

- The R&D tax incentive applied from 2011 to all industries to expenditure incurred and the use of depreciating assets
  - Equivalent to a 150% deduction for small companies (<\$20m revenue)
  - Equivalent to a 133% deduction for larger companies (>\$20m revenue)
- Unused offset amounts can be carried forward
- Intended as an incentive for innovation in new ideas, products and services

**Angola capex uplift for exploration**

- O&G investment allowances (uplift on development expenses) may be granted by the Government
- Uplift may range between 30–40%, based on the profitability of the block

**0.21 – 0.42 US\$/mmbtu impact expected**

SOURCE: Australian Taxation Office; McKinsey & Company analysis

**TAXES**

## 1e Carbon tax

Legislative change at Commonwealth level to provide exemption from carbon tax for upstream and downstream gas projects to improve viability of projects

Likelihood	Responsibility
Low	Government
Medium	Industry
High	Operator

**Actions**

- ✓ Conduct environmental and economic analysis on effect of carbon tax exemption for gas projects
  - Impact on taxation revenue for Commonwealth vs. NPV impact on operators
  - Impact on CO2 emissions for increasing gas in energy mix
- ✓ Conduct consultation process with relevant stakeholders (e.g. gas operators, accounting firms, corporate bodies)
- ✓ Amend regulations to grant carbon tax exemption to gas projects
  - Draft any required legislative instruments or amending regulations
  - Draft any required Regulation Impact Statements (RIS) to accompany draft regulation

**Approximate Timing**

- ~12 months

**What you need to believe for these actions to have impact**

- Government is willing to reduce tax revenue in order to increase NPV of gas projects
- Government is convinced that decreasing gas operators' tax liability will have positive economic and/or environmental impact, e.g. lowering global dependence on brown and black coal energy where sensible

**Example: Transport fuel carbon tax exemption**

- Fuel used by households, on-road business use of light vehicles and the agriculture, forestry and fishery industries are exempt from the carbon tax

**0.08 – 0.16 US\$/mmbtu impact expected**

SOURCE: Parliament of Australia; Minister for Infrastructure; McKinsey & Company analysis

**REGULATION**

## 2a Consistency

Regulatory change at Commonwealth, State and local levels to harmonise compliance requirements to reduce costs of compliance and ensure Australian regulations are not unnecessarily onerous

Likelihood	Responsibility
Low	Government
Medium	Industry
High	Operator

**Actions**

- ✓ Establish a 'harmonisation' task force to do an audit across all Australian resource industries and internationally accepted standards (e.g. CSG water) for gas projects to show the alignments and differences in regulatory requirements and propose appropriate changes
- ✓ Conduct consultation process with relevant stakeholders (e.g. gas operators, engineering firms, environmental consultancies, corporate bodies)
- ✓ Amend regulations to align with new agreed standards
  - Draft any required legislative instruments or amending regulations
  - Draft any required Regulation Impact Statements (RIS) to accompany draft regulation

**Approximate Timing**

- ~12 months

**What you need to believe for these actions to have impact**

- Long-term harmonisation of standards is worth the short-term complexity of having old and new assets with different standards
- Government is able to allocate sufficient resources for comprehensive and timely audit across industries and jurisdictions

**Example: Reserve Bank of Australia's (RBA) New Financial Stability Standards**

- RBA has developed new Financial Stability Standards, aiming to align the Australian regulation for clearing and settlement facilities with new international standards (developed by multilateral organisations of central banks)
- RBA proposes to adopt the international standards in Australian regulation in the following way:
  - International standards would represent the minimum standards against which Australian banks will be assessed
  - International standards would be adapted to the Australian context where appropriate, including ensuring no weakening relative to the current Australian regulations
- The benefits of this alignment include:
  - Harmonising the interests of the RBA with other central banks
  - Better regulatory coverage when foreign banks are licensed to operate in Australia (reducing regulatory burden on those banks as their home regulatory regime would be considered 'sufficiently equivalent' to the Australian regime for the purposes of Australian law)

**0.04 - 0.06 US\$/mmbtu impact expected**

SOURCE: Reserve Bank of Australia; McKinsey & Company analysis

**REGULATION**

## 2b Efficiency

Streamline and increase speed of regulatory processes, including removing duplicated work by different regulators or across different jurisdictions, to decrease time needed for approvals

Likelihood	Responsibility
Low	Government
Medium	Industry
High	Operator

**Actions**

- ✓ Build on existing Productivity Commission work and conduct analysis to identify inefficiencies (e.g. delay, duplication of work, unnecessary or competing requirements) and suggest improvements
- ✓ Conduct consultation process with relevant stakeholders (e.g. gas operators, engineering firms, environmental consultancies, corporate bodies) about proposed optimisation changes to regulatory process and operating model
- ✓ Amend regulations to align with new agreed standards
  - Change the scope of certain regulators
  - Remove duplicate processes across regulators
  - Implement KPIs for regulators to align to new standards

**Approximate Timing**

- ~12 months

**What you need to believe for these actions to have impact**

- It would be possible to remove layers of regulation and otherwise optimise the regulatory processes

**Example: Iowa (US) state lean initiative**

Iowa (US) instituted a 'Lean Initiative' in 2003 that significantly improved the efficiency of its agencies

- Achieved impact includes:
  - Reduced air quality construction approvals from 62 to 6 days
  - Increased number of food benefit recipients by 44%
  - Improved rate of <45 day tax refunds from 75% to 94% (various agencies)
- Method was an opt-in approach based on incentivisation:
  - Participating agencies committed to operational targets and cost savings
  - Agencies participated in return for retaining asset sale proceeds, admin rule waivers, technical assistance and additional grant funding

**0.03 - 0.08 US\$/mmbtu impact expected**

SOURCE: McKinsey & Company analysis

**REGULATION**

## 2c Stability

Identify and limit regulatory uncertainty in gas project development through cross-regulator scheme to prevent re-work and additional costs for operator

Likelihood	Responsibility
Low	Government
Medium	Industry
High	Operator

**Actions**

- ✓ Design process for reducing regulatory change to existing and future projects
  - Perform historic review of regulatory changes
  - Identify drivers of change and rules around change implementation
  - Produce a set of guidelines for regulators on when changes should be conducted
- ✓ Conduct consultation process with relevant stakeholders (e.g. gas operators, engineering firms, environmental consultancies, corporate bodies)
- ✓ Ensure each new regulation performs a value assessment to see if all operating resources should be changed or if changes only apply to new constructions

**Approximate Timing**

- ~12 months and ongoing

**What you need to believe for these actions to have impact**

- Policy makers would be willing to 'freeze' compliance standards (subject to certain exceptions) for the life of existing projects, despite changes that could occur during life of those projects
- Government, regulators and industry could agree in a form of regulatory standards to apply to projects in the development pipeline

**Example: UK tax relief for decommissioning oil & gas assets**

- In 2011 O&G operators in the UK were concerned that tax relief available for decommissioning offshore fields and infrastructure could be removed before decommissioning occurred—concern was prompted by Budget 2011 which announced the decoupling of tax rates charged on profits and relief available for decommissioning costs
- O&G consultants Hannon Westwood estimated that certainty on decommissioning tax relief would enhance the province's productive life by an additional 1.7b boe and decommissioning could be postponed by 5–7 years on average
- Government and industry recognised that achieving certainty over decommissioning tax relief would facilitate asset sales, free up capital tied up in security for decommissioning and increase the attractiveness of the UK as a jurisdiction for large scale long-term investment decisions
- In 2012 the Government announced certainty on this tax relief and is proposing a contractual mechanism to achieve it

**0.03- 0.07 US\$/mmbtu impact expected**

SOURCE: Oil & Gas UK (Fiscal Insight, Oct 2012); McKinsey & Company analysis

**REGULATION**

## 2d Limits

Identify and limit over-compliance with regulation, either where imposed by regulators or self-imposed by operators, to reduce costs

Likelihood	Responsibility
Low	Government
Medium	Industry
High	Operator

**Actions**

- ✓✓ Conduct analysis of main sources of over-compliance performed by operators or required by regulators
- ✓✓ Conduct consultation process on draft guidance on compliance with relevant stakeholders (e.g. gas operators, engineering firms, environmental consultancies, corporate bodies)
- ✓✓ Publish final guidance on compliance and provide mechanisms to implement this (e.g. automatic approval where certain conditions are met)
- ✓✓ Perform audits of regulatory bodies to ensure that targets are not exceeded and consult with operators to ensure they are not over-complying

**Approximate Timing**

- ~12 months

**What you need to believe for these actions to have impact**

- The requirements imposed by current regulations can be defined with sufficient clarity for regulators and operators
- Regulators and operators can be sufficiently disciplined to comply with the guidance and not 'over-comply' with it
- Operators have sufficient certainty that interpretation of the regulation will not change leading to required changes, in e.g. in design

**Example: Australian corporate regulation (continuous disclosure) of public companies**

- 'Continuous disclosure' regulations require public companies to immediately disclose materially price sensitive information, but the extent of this regulatory burden was unclear and source of anxiety for companies and the regulator
  - Enforcement through the courts by the corporate regulator (ASIC) failed to clarify the regulations sufficiently
  - Retailer David Jones in July 2012 arguably 'over-complied' with the regulation by disclosing an unsolicited 'fake' takeover offer, which caused significant share price volatility
- Australian Stock Exchange issued a guidance note (draft for public consultation in Oct 2012; final note published in March 2013) to explain the content of the regulation (particularly the 'murkier' aspects of its operation) and how it would be applied and enforced by the regulators
  - Extensive public consultation with and support of companies, industry associations and corporate advisers
  - Drafting of guidance note was also led by ASIC and the final guidance note received its broad agreement







**0.06 – 0.11 US\$/mmbtu impact expected**

SOURCE: Australian Stock Exchange; Media releases; McKinsey & Company analysis

LABOUR PRODUCTIVITY

### 3a Residential communities close to LNG sites

Create attractive residential communities near LNG sites to allow adoption of residential shift pattern to increase productivity through decreasing travel time and increasing days at work

Likelihood	Responsibility
 Low	 Government
 Medium	 Industry
 High	 Operator

**Actions**

- ✓ Select appropriate sites sufficiently close to sites to allow residential shifts and where lack of community infrastructure is key factor limiting willingness to live there
- ✓ Provide support and investment for community developments
  - Plan and execute improvements in community infrastructure such as recreational areas, town centers, etc.
  - Provide funding support for both capex and longer term maintenance
  - Build hard infrastructure such as ports and roads to improve local transport
- ✓ Design and build housing developments if and where required
- ✓ Improve tax regime to support remote housing (e.g. extending concession on fringe benefit tax for housing employees remotely)
- ✓ Actively market developments to ensure workers are aware of the investments and their benefits

**Approximate Timing**

- 2 years from concept to securing funding

**What you need to believe for these actions to have impact**

- Government and industry can align on financial investments and ownership structure of new investments

**Example: Karratha – City of the North transformation**

- Karratha's transformation goal is to increase city population from 18,000 (including FiFo) to 50,000 and number of residential dwellings from 5,000 to nearly 25,000
- Approach:
  - State and local government have drawn up city growth plan with timeline highlighting what community developments are required
  - Planned investments include upgrading main shopping, commercial and entertainment precincts, and constructing additional facilities such as sporting reserves, playgrounds and schools
  - For each development, owner (local government vs. hired developers (e.g. Landcorp) vs. private sector), estimated cost, and funding source have been identified
  - Total cost expected to be \$1.8b excluding private development
  - Stage 1 developments (including major central upgrades) complete in 5 years







0.03 – 0.06 US\$/mmbtu impact expected

SOURCE: McKinsey & Company analysis

LABOUR PRODUCTIVITY

### 3b Shift patterns

Change shift patterns to enable increase in productivity through decreasing travel time and increasing days at work

Likelihood	Responsibility
 Low	 Government
 Medium	 Industry
 High	 Operator

**Actions**

- ✓ Agree on changing shift patterns:
  - Assess current shift patterns and most crucial roles to modify shift patterns
  - Change shift patterns cohesively as an industry
- ✓ Alleviate regulatory barriers on shift changes where required
- ✓ Implement adjusted shift patterns
  - Enforce new shift patterns
  - Communicate alternative of moving to residential from FiFo
  - Manage risk of higher attrition rates

**Approximate Timing**

- 1 year to evaluate and begin roll-out

**What you need to believe for these actions to have impact**

- Industry-wide change in shift patterns for specific roles can be achieved
- The increased amount of working hours has no negative impact on productivity during working hours

**Example: Underground coal miner**

- Moved to 7 on-7 off roster leading to multiple advantages:
  - Regular training scheduled at beginning of each shift
  - More efficient communication between mine management and crew
  - 75% reduction in overtime pay
  - ~15% increase in available production time
- Evaluated roster change options through:
  - Determining organisational KPI targets and working hours improvement required to reach targets
  - Assessing alignment with equipment availability
  - Evaluating amount of flexible time available for training

0.03 – 0.06 US\$/mmbtu impact expected

SOURCE: McKinsey & Company analysis

**LABOUR PRODUCTIVITY**

### 3c Site productivity improvements through lean construction

Better on-site planning and coordination, and improved worker mindset and skills to increase productivity through reduced idle and ineffective work time

Likelihood	Responsibility
Low	Government
Medium	Industry
High	Operator

**Actions**

- ✓ Ensure construction sites are set up with right processes (e.g. frontline engagement, work package readiness check, integrated 3 week look ahead planning, visual management and tracking tools)
- ✓ Ensure adequate supervision & project management skills
  - Achieve and maintain appropriate supervisor to worker ratio
  - Hire sufficient project managers to manage long-term planning of all activity vs. just day-to-day
- ✓ Improve contract terms to spur efficiency of EPC-contracted workers (e.g. through implementing penalties for delays, sharing of profits of productivity improvements) *also included in project optimisation levers*
- ✓ Incentivise institutes to collaborate with industry on developing course content (e.g. government partially withholds funding if courses not industry-endorsed)
- ✓ Collaborate with training institutes to improve relevance and quality of training programmes, developing new courses where necessary

**Approximate Timing**

- Pilot phase: 3–6 months
- Deployment: 12–24 months
- Implementation: throughout construction phase

**What you need to believe for these actions to have impact**

- Through rigorous application of project management best practices and lean tools (e.g. planning, work package readiness, front line engagement, visual management) construction manhours could be significantly reduced (or at least could be kept at planned levels)

**Example: Large EPC player constructing a mega-refinery**

- Optimised critical path task resulted in 54% reduction in time to perform critical path task and 34% decrease in FTEs
- Optimisation occurred through:
  - Increasing resource coordination to eliminate bottlenecks
  - Introducing automatic welding machinery to increase efficiency
  - Adding welding machines at all stations to cut down on transport
  - Using training and incentives to improve preparation and welding skills

**0.80 – 1.40 US\$/mmbtu impact expected**

SOURCE: McKinsey & Company analysis

**LABOUR PRODUCTIVITY**

### 3d Skilled labour

Attract or build sufficient labour in scarce areas to increase size of the available talent pool to increase productivity and to decrease wage escalation

Likelihood	Responsibility
Low	Government
Medium	Industry
High	Operator

**Actions**

- ✓ Forecast critical skills gaps
- ✓ Increase labour mobility
  - Update visa restrictions for identified skills and ensure no ceilings or stringent regulations form a barrier to entry
  - Reduce ambiguity in interpretation and application of immigration law
  - Ensure efficiency of process to reduce administration time and cost
- ✓ Establish local skill-building institutions

**Approximate Timing**

- 12 months to implement initial changes

**What you need to believe for these actions to have impact**

- Sufficient alignment on most critical skills gaps
- Sufficient labour mobility to close skills gaps
- Sufficient resources to establish local skill-building institution(s)

**Example: Brazil industrial sector**

- Brazil traditionally takes a conservative stance towards foreign labour
  - All companies must have at least 2/3 Brazilian personnel employed at all times
  - Temporary work permits granted for only 2 years each time and must be tied to full-time employment
- When activity in industrial sectors (primarily O&G-related) increased, government increased work permit approval by 25% from 43,000 in 2009 to 53,500 in 2010

**Example: Operator training centres**

- Shell's Learning@EPICentre in Rijswijk trains and Exxon Mobil's Upstream Technical Training Center in Houston both train up to 5000 students annually

**0.07 – 0.14 US\$/mmbtu impact expected**

SOURCE: McKinsey & Company analysis

**SERVICE MARKET & SUPPLY CHAIN**

### 4a Local service market

Improve local O&G service market to reduce costs for materials and equipment

Likelihood	Responsibility
Low	Government
Medium	Industry
High	Operator

**Actions**

- ✓ Prioritise service market segments to develop
  - Where costs for Australian operators are highest relative to overseas competitors
  - Relative importance/size of the service market segment
  - Any quick wins (e.g. collaboration with other industries)
- ✓ Incentivise service provider development
  - Provide incentives to local suppliers to expand in the market
  - Target areas of the market identified by industry

**Approximate Timing**

- At least 2 years until sufficient service market growth

**What you need to believe for these actions to have impact**

- Additional players will bring down prices to levels experienced in service markets outside Australia
- Sufficient security to suppliers provided in order to enter the market

**Example: CORFO**

- CORFO working with Chilean Ministry of Mining developed the Mining Cluster Program to increase investment and innovation in mining supplies industry
- Currently, only 1% of Chile's 5,000 mining-service companies are active technology innovators
- Codelco and BHP Biliton with support from CORFO aim to develop 250 world-class suppliers in Chile by 2020

**0.03 – 0.06 US\$/mmbtu impact expected**

SOURCE: McKinsey & Company analysis

**SERVICE MARKET & SUPPLY CHAIN**

### 4b Remote infrastructure

Expand accessible logistics infrastructure in remote areas to reduce costs of transporting materials and equipment

Likelihood	Responsibility
Low	Government
Medium	Industry
High	Operator

**Actions**

- ✓ Identify where new infrastructure development would be most beneficial and submit proposals to government with details of expected benefits
- ✓ Develop infrastructure by:
  - Providing funding for infrastructure development and maintenance
  - Working with industry to establish timeline of construction and operation

**Approximate Timing**

- 2 years to develop plans and secure funding

**What you need to believe for these actions to have impact**

- Government funds available
- Government and industry can align on financial investments and ownership structure of new investments

**Example: Brazil – Logistics Investment Program**

- National Logistics Investment Program launched in August 2012 to upgrade transportation system
- Initial focus on roads and railways but ~\$30b investment in ports expected
- Logistics costs expected to decline by >30% following programme







**0.07 – 0.14 US\$/mmbtu impact expected**

SOURCE: McKinsey & Company analysis

**INDUSTRY COLLABORATION**

### 5a Industry wide standardisation

Standardise the supply chain across operators (joint certification, standardised contracts and use of standardised modules) to reduce time and costs in the procurement process

Likelihood	Responsibility
 Low	 Government
 Medium	 Industry
 High	 Operator

**Actions**

- ✓ Set up new association of Australian gas operators and their suppliers, or formally expand the Achilles Australia & New Zealand network, including governance model and funding structure (could be combined with other industry levers)

**Approximate Timing**

- 12 months to establish structure, governance and processes

**What you need to believe for these actions to have impact**

- Operators are willing to share some non-competitive information with other operators
- Vendors are willing and able to standardise their credentials, contracts and products
- Operators will not be in breach of Australian competition law due to sharing arrangements

**Example: CRINE standardisation initiatives reduced North Sea development costs by 30%**

- CRINE initiative led to savings in capital and operating costs of 30%
  - BP and Weir pumps reduced contracting manhours by 25% and documentation by 75%
  - Kraemer standard NNM unmanned platforms achieved 30% cost reductions
- Programme developed in early 90s with the support of government in the face of \$12/bbl oil prices
- Programme focused on innovating on standardising working practices, contracts and equipment with a commitment to cultural change in the industry







**0.16 – 0.32 US\$/mmbtu impact expected**

SOURCE: FPAL; Achilles; McKinsey & Company analysis

**INDUSTRY COLLABORATION**

### 5b Smoother demand

Operators to coordinate on use of services to reduce simultaneous demand pressures for rental equipment and labour

Likelihood	Responsibility
 Low	 Government
 Medium	 Industry
 High	 Operator

**Actions**

- ✓ Setting up a small association including governance structure and funding structure (could be combined with other industry groups)

**Approximate Timing**

- 12 months to establish cooperation structure, governance and processes

**What you need to believe for these actions to have impact**

- Operators are willing to cooperate with competitors (often in the same geographic area) for the use of rental equipment, particularly used in construction, even if this leads to delays in schedule
- Operators will not be in breach of Australian competition law due to information sharing arrangements

**Example: PILOT forward workplan**

- Part of UK O&G industry's supply chain code of practice
- Buyers of O&G support services input information to a database including services required, indicative contract value, contract term, and likely contract date
- Information on database is made available to all registered operators and suppliers
- Initiative helps both service buyers and service providers plan their activities around expected market demand
- Current operators who have provided information include Apache, BG, BP, Chevron and Shell

**0.05 – 0.09 US\$/mmbtu impact expected**

SOURCE: Media searches; McKinsey & Company analysis

**INDUSTRY COLLABORATION**

### 5c Share plant infrastructure

Operators to jointly build, own and share LNG plant infrastructure to reduce costs

Likelihood	Responsibility
Low	Government
Medium	Industry
High	Operator

**Actions**

- ✓ Identify potential opportunities for brownfield development and other infrastructure sharing based on operator expansion plans and locations

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- ✓ Operators with potential for sharing infrastructure discuss structure of potential collaboration, e.g.:
  - Scope of sharing of infrastructure
  - Sharing of benefits

**Approximate Timing**

- 2 years to finalise negotiations

**What you need to believe for these actions to have impact**

- Operators are willing to cooperate with each other
- Companies will not be in breach of Australian competition law due to sharing arrangements

**Example: ENI-Anadarko collaborate on development of offshore Mozambique reserves**

- ENI and Anadarko (two independent oil and gas firms) have agreed to co-ordinate the development of their discoveries in Mozambique and jointly plan and construct an LNG plant in the country
- Analysts expect that combining resources will reduce development and financing costs potentially by more than \$1b (initial phase expected to cost \$15b)
- Both the companies will carry out separate but coordinated offshore activities in the Rovuma Basin reserves that they separately operate, and bring onshore to a single, jointly operated LNG facility

**0.77 – 1.37 US\$/mmbtu impact expected**

SOURCE: Media search; McKinsey & Company analysis

**INDUSTRY COLLABORATION**

### 5d Joint operations and maintenance companies

Joint and coordinated industry action on operations and maintenance of projects to benefit from economies of scale

Likelihood	Responsibility
Low	Government
Medium	Industry
High	Operator

**Actions**

- ✓ Set up legal structure of operating (NewCo) to provide operations and maintenance services to its member shareholders, including contribution of start-up capital by each member

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- ✓ Establish governance and funding structure for association

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- ✓ NewCo board to determine scope of operations and maintenance work, including capabilities, schedule, resources and technology required to sufficiently service all members' projects

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- ✓ NewCo to purchase, lease or hire necessary resources (e.g. personnel and equipment)

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- ✓ NewCo to service member projects

**Approximate Timing**

- 6-12 months to establish company and contribute capital

**What you need to believe for these actions to have impact**

- Industry is willing to jointly support operations and maintenance requirements of projects in rational cooperation where it is economically advantageous to do so
- NewCo members have willingness and ability to fund, resource and contribute to non-profit industry venture
- Collaboration on operations and maintenance is more effective for the industry and regulation than individual companies' focus on these issues, especially where projects are geographically close

**Example: Atlantic LNG**

- Atlantic LNG is an operating company set up to operate a four train LNG facility (14.8 mtpa) in Point Fortin in Trinidad
- It has five shareholders: BP, BG, Repsol, Summer Soca LNG Liquefaction S.A (a subsidiary of the China Investment Corporation) and the National Gas Company of Trinidad and Tobago (NGC)
- Atlantic LNG is in the middle of the gas value chain and is located - the shareholders own and operate their own fields upstream and supply gas to Atlantic LNG. Atlantic LNG then processes and liquefies the gas and provides back to the shareholders loaded into vessels for delivery

**0.10 – 0.14 US\$/mmbtu impact expected**

SOURCE: Atlantic LNG web site; McKinsey & Company analysis



**INDUSTRY COLLABORATION**

## 5e Cooperate on health, safety and environment

Joint industry action on environmental and safety measures to improve reliability and decrease costs by sharing investments

Likelihood	Responsibility
Low	Government
Medium	Industry
High	Operator

**Actions**

- ✓ Set up a non-profit company (NewCo) to provide environmental and safety products and services to its member shareholders, including contribution of start-up capital by each member (could be combined with other industry levers)
- ✓ NewCo board to determine scope of environment and safety agenda, including defining the most important issues to address
- ✓ NewCo to draft voluntary codes of conduct based on environment and safety agenda and syndicate with the relevant regulator
- ✓ NewCo to develop environment and safety protocols and leading technology to be used by all members

**Approximate Timing**

- 6-12 months to establish company and contribute capital

**What you need to believe for these actions to have impact**

- Industry is willing to support the most important safety and environmental issues by engaging in rational cooperation
- NewCo members are willing and able to fund, resource and contribute to non-profit industry venture
- Collaboration on environmental and safety focused technology is more effective for the industry and regulation than individual companies' focus on these issues
- Operators will not be in breach of Australian competition law due to sharing arrangements

**Example: Marine Well Containment Company (Gulf of Mexico)**

- 10 companies manage together > \$1b in well containment response assets
  - Founded by ExxonMobil, Chevron, ConocoPhillips and Shell in July 2010 following the Deepwater Horizon oil spill
- Helped restore confidence in industry in GOM
  - Successful well capping system deployment test
  - 73 new drilling permits in GOM by member companies

**0.03 – 0.05 US\$/mmbtu impact expected**

SOURCE: Marine Well Containment Company; McKinsey & Company analysis

**FURTHER PROJECT OPTIMISATION**

## 6a Lean engineering

Apply lean concepts to engineering phase to reduce rework and utilise offshoring to reduce the engineering hours while maintaining quality of design

Likelihood	Responsibility
Low	Government
Medium	Industry
High	Operator

**Actions**

- ✓ At start of engineering phase develop integrated planning for design phase, including trade-off for offshoring
- ✓ Standardise processes, operating practices, metrics, tools and techniques with target KPIs and progress tracking templates
- ✓ Agree on rapid 'rule based' exception resolution principles
- ✓ Continuous and visible monitoring and tracking of progress and immediate highlighting of roadblocks and issues
- ✓ Assign strong end-to-end responsibility within the organisation with suitable incentives

**Approximate Timing**

- Pilot phase: 3–6 months
- Deployment: 6–12 months
- Implementation: FEED and detailed engineering

**What you need to believe for these actions to have impact**

- Engineering process has scope for further refinement which could lead to shorter FEED and detail engineering periods
- Offshoring levers have not been fully leveraged

**Example: Power equipment manufacturer**

- Reduced product development cost by 30% and time to market by 33%
- Approach:
  - Front loaded design work and employ parallel design efforts
  - Scheduled regular intermediate design releases prior to formal reviews
  - Involved potential suppliers early in process development
  - Focused on rapid prototyping and virtual process development
  - Assigned strong end-to-end project responsibility to the existing organisation
  - Introduced cross-functionally aligned objectives and priorities across organisation
  - Initiated a culture shift from process-driven silos to product-driven cross-functional teams

**0.16 – 0.28 US\$/mmbtu impact expected**

SOURCE: McKinsey & Company analysis

## FURTHER PROJECT OPTIMISATION

**6b Lean concept and design**

Apply lean concepts to design phase to reduce the hours needed in engineering and construction and to reduce the cost per hour in construction

**Likelihood****Responsibility****Actions**

- ✓ Scope optimisation and simplification, develop a streamlined scope where 'gold-plating' has been removed, leading to a more compact layout, and simplified design specifications
- ✓ Package level optimisation of equipment specifications and choice through design-to-cost/design-to-value initiatives
- ✓ Modularise design to reduce labour costs in high cost countries and to boost construction speed/schedule
- ✓ Standardise to reduce costs for current project through streamlined procurement and to reduce cost and schedule for following projects through streamlined procurement and greater outsourcing for the remaining detailed design

**Approximate Timing**

- Pilot phase: 3–6 months
- Deployment: 6–12 months
- Implementation: FEED and detailed engineering

**What you need to believe for these actions to have impact**

- Current/proposed design has 'room' for improvement
- It is possible to assemble a high performing internal/external team to conduct quick design review to identify opportunities for significant value capture
- Lean design ideas will be chosen for implementation after considering operational trade-offs, so no risks are added

**Example: US refinery**

- Through scope optimisation increased NPV of a large processing unit (FCC) construction by 20–25%
- Approach:
  - Modernised existing hydrotreatment unit instead of building from scratch
  - Chose cheaper processes, e.g. air coolers instead of plate heat exchangers
  - Avoided gold-plating by reducing excessive engineering margins to manage feedstock sulphur content (e.g. choose metal class and thickness without building in significant buffer)
  - Relaxed artificial technical constraints on equipment (e.g. pumps, heat exchangers) to allow wider range of suppliers

**0.66 – 1.47  
US\$/mmbtu  
impact expected**

SOURCE: McKinsey & Company analysis

## FURTHER PROJECT OPTIMISATION

**6c Contract management**

Improving contract scope and terms to raise productivity, reduce fees, and reduce cost overflow

**Likelihood****Responsibility****Actions**

- ✓ Select contractors competitively
  - Encourage competitive tendering from contractors by selecting contractors based on capabilities and pricing terms rather than just relationship
  - Continuously qualify and develop new contractors to keep contractor pool competitive
- ✓ Build productivity metrics into contract terms to incentivise productivity from EPC contractors using well thought through terms and conditions such as penalties for delays, productivity incentives for each major critical path milestone and sharing of cost and time savings
- ✓ Improve scope of contracts and risk sharing between contractor and operator
  - Avoid cementing contracts before designs finalised
  - Assign risks to the natural owner instead of allocating everything to the contractor
  - Divide projects into appropriately manageable lots and competitively tender
- ✓ Monitor contractor performance
  - Evaluate contractor performance regularly
  - Enforce terms and conditions of contract on on-going basis
  - Create appropriate SteerCo involving contractor and operator top management (CEO, COO level)
  - Develop adequate capabilities in owners team to manage multiple lots

**Approximate Timing**

- Pilot phase: 3–6 months
- Deployment: 6–12 months
- Implementation: feasibility and pre-feasibility phase

**What you need to believe for these actions to have impact**

- Current contractor market is sufficiently competitive
- Strategic contractor development tools can be leveraged to develop a healthy contractor portfolio to avoid excessive dependence on a few
- Capable and suitably incentivised owner team is in place to manage contractors effectively

**Example: US greenfield refinery example**

- Through contract renegotiation capex of greenfield plant reduced by 30%
- Approach:
  - Employ customised contract re-negotiations with all major construction firms
  - Consolidate rental equipment and materials spend to single site-wide vendors, reducing price through leverage and volume through better collaborative management
  - Compare proposed labour rates and per diems, revealing discrepancies between fair market and contract rates—and negotiate down based on findings
  - Identify over-staffing and expensive labour (e.g. back office, management and safety staffing above benchmark levels)—and negotiate down based on findings

**0.21 – 0.42  
US\$/mmbtu  
impact expected**

SOURCE: McKinsey & Company analysis

**FURTHER PROJECT OPTIMISATION**

## 6d Claims management

Monitor EPC contractor throughout the contract to reduce cost of claims

Likelihood	Responsibility
Low	Government
Medium	Industry
High	Operator

**Actions**

- ✓ Deploy strong owner teams to monitor EPC performance
- ✓ Regularly address potential obstacles caused by owner deliverables to EPC performance
- ✓ Establish tight claims management system to minimise the impact of 'change orders' through early detection and mitigation plan
- ✓ Establish KPIs and audit process to measure effectiveness of claims management process

**Approximate Timing**

- Pilot phase: 3–6 months
- Deployment: 6–12 months
- Implementation: duration of EPC contract (team to be on boarded ~3 months before EPC contract is awarded)

**What you need to believe for these actions to have impact**

- Claims management is a key tool for the owner to avoid 'bad' surprises
- Claims management can be needed to control contractor behaviour and productivity

**Example: US mega refinery**

- Reduced cost of claims by ~70%
- Approach:
  - Establish KPIs to monitor claims management effectiveness
  - Develop early claim 'detection' and prevention plan
  - Create change under approval criteria and make it part of the contract
  - Establish a strong claim management team to manage the whole 'claims management' process
  - Identify root causes of major claim sources and regularly remove them through ensuring timely owner's team deliverables and contract renegotiation/amendments (when unavoidable)

**0.02 – 0.03 US\$/mmbtu impact expected**

SOURCE: McKinsey & Company analysis

**FURTHER PROJECT OPTIMISATION**

## 6e Lean operations in production

Apply lean concepts to the operations phase to improve productivity in operations and maintenance

Likelihood	Responsibility
Low	Government
Medium	Industry
High	Operator

**Actions**

- ✓ Develop a robust preventive maintenance system to avoid any unplanned downtime
- ✓ Ensure robust planning and preparation ahead of any shutdown to 'avoid' any unnecessary delays
- ✓ Maximise 'crew' tool-time and optimise planned shutdown times through improved planning and scheduling and work execution
- ✓ Visual performance management based on cascading KPIs

**Approximate Timing**

- Pilot phase: 3–6 months
- Deployment: 6–12 months
- Implementation: During operations phase

**What you need to believe for these actions to have impact**

- Maximum utilisation of the plant is possible by avoiding any 'unplanned' downtime

**Example: US refinery**

- Maintenance efficiency transformation program led to 20%+ improvement in time on tools, reduction of routine maintenance backlog >50%, ~35% reduction in routine maintenance costs
- Approach:
  - Created more balanced workloads over time and provided greater visibility for operations by scheduling further into the future
  - Decreased craft wait times and increased operations' ownership of the process by improving permitting process
  - Identified root causes of waste through craft waste tracking and instilled an 'efficiency mindset' deep within the organisation
  - Increased front line leader time in field through meeting optimisation and gaining additional administrative support

**0.05 – 0.10 US\$/mmbtu impact expected**

SOURCE: McKinsey & Company analysis

## APPENDIX 6: ASSUMPTIONS FOR CALCULATION OF PRODUCTIVITY IMPROVEMENT MEASURES

### APPENDIX 6

### Assumptions for calculation of productivity improvement measures (1/9)

Overall impact<sup>1</sup>: 0.9 – 1.9

#### Tax and royalty

Measure	Description	Impact on landed costs \$/mmbtu
<b>Royalties</b>	<ul style="list-style-type: none"> <li>Move to a more progressive regime to enable marginal investments, by moving from a revenue tax (royalties) to a profit based tax (PRRT)</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>Royalty rate reduced to 0-5%, PRRT remains at 40%</li> </ul>	0.23-0.44
<b>Import duties and tariffs</b>	<ul style="list-style-type: none"> <li>Reduce import duties further to reduce taxes before first gas; to be partly regained through higher revenues from profit tax during production phase</li> <li>Import duties &amp; tariffs currently 0% or 5% depending on item</li> <li>&gt;50% of items already at 0%, leading to average 2% import duties &amp; tariffs</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>50-100% reduction of import duties &amp; tariffs across imported materials, rental equipment and installed equipment</li> </ul>	0.01-0.02
<b>Accelerated depreciation</b>	<ul style="list-style-type: none"> <li>Accelerate depreciation to delay payment of corporate tax, thereby improving NPV of projects</li> <li>Current allowable depreciable life is 15 years for unconventional upstream and downstream, and 20 years for conventional upstream</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>Reduction of depreciable life by 5-10 years</li> <li>Corporate tax only</li> <li>Both for upstream and downstream</li> </ul>	0.35-0.79
<b>Capital allowances</b>	<ul style="list-style-type: none"> <li>Provide additional deductibility for capex expenditures to incentivise investments</li> <li>This allowance could be targeted to specific fields (e.g. shale gas, fields with certain water depth)</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>Increase total depreciation to 125-150% of capex value</li> <li>Corporate tax only</li> <li>Upstream only</li> </ul>	0.21-0.42
<b>Carbon tax</b>	<ul style="list-style-type: none"> <li>Adjust carbon tax to improve project profitability</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>Reduce carbon tax by 50-100%               <ul style="list-style-type: none"> <li>Carbon tax 25.4 USD/tCO<sub>2</sub> (floating prices assumed to be 2015 price)</li> <li>50% of CO<sub>2</sub> emission eligible for tax</li> <li>CO<sub>2</sub> intensity unconventional upstream: 0.45 tCO<sub>2</sub>/t LNG</li> <li>CO<sub>2</sub> intensity conventional upstream: 0.05 tCO<sub>2</sub>/t LNG</li> <li>CO<sub>2</sub> intensity downstream: 0.50 tCO<sub>2</sub>/t LNG</li> </ul> </li> </ul>	0.08-0.16

<sup>1</sup> Impacts of individual levers not additive due to interdependencies

SOURCE: Expert interviews; McKinsey Analysis

## APPENDIX 6

### Assumptions for calculation of productivity improvement measures (2/9)

#### Regulation

Overall impact<sup>1</sup>: 0.1–0.3

Measure	Description	Impact on landed costs \$/mmbtu
<b>Consistency</b>	<ul style="list-style-type: none"> <li>Example: Standards for CSG water are higher than mining industry standards for same quality water, less costly systems could be used yet still comply with mining industry standards</li> <li>Example: Electric wiring standards on rigs in Australia are different from international standards</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>CSG water in country monitoring CAPEX reduced by 25-50%</li> <li>CSG water in country OPEX reduced by:                             <ul style="list-style-type: none"> <li>15-30% for treatment</li> <li>15-30% for utilisation</li> <li>20-40% for monitoring</li> </ul> </li> <li>25-50% reduction of rig mobilisation costs (due to US\$ 7 mln per rig costs)</li> </ul> <p><i>Note: No extrapolation of impacts to other areas of LNG projects – only water and rig conversion</i></p>	0.04-0.06

<b>Efficiency</b>	<ul style="list-style-type: none"> <li>Remove overlapping jurisdictions between the multiple bodies involved in the regulatory process, thereby reducing chance of competing points of view and additional time to approvals</li> <li>Productivity Commission report considers a 6-9 month improvement in approval times a reasonable objective (i.e., best-practice)</li> <li>Example: A Canadian EIS takes ~3 months less than the average Australian project (excluding Gorgon) to approve</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>3 (towards Canada) to 9 (best practice) months acceleration of FEED</li> </ul>	0.03-0.08
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<sup>1</sup> Impacts of individual levers not additive due to interdependencies

SOURCE: Expert interviews; McKinsey Analysis

## APPENDIX 6

## Assumptions for calculation of productivity improvement measures (3/9)

### Regulation (continued)

Measure	Description	Impact on landed costs <sup>1</sup> \$/mmbtu
<b>Frequency</b>	<ul style="list-style-type: none"> <li>Reducing the changes in regulation applicable to ongoing projects. When a change in regulation occurs, operators must retrospectively change their designs and infrastructure</li> <li>Example: Expanding an accommodation village by 200 houses required additional cyclone measures for existing 2000 houses due to changed regulation, incurring additional costs of \$4 mln</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>Reduce in country labour costs for construction with 0.5-1%, for engineering with 1-3% and for EPC and owner costs with 1-2%, assuming:               <ul style="list-style-type: none"> <li>1 time per project a large regulatory change leading to ~\$100-200 mln additional costs</li> <li>2 to 3 times a year a regulatory change leading to \$1-4 mln</li> <li>7 years before first gas, no changes imposed after first gas</li> <li>Cost decreases allocated to: Construction labour (30%); Engineering labour (30%); Project Management labour (40%)</li> </ul> </li> <li>Accelerate FEED by 1 month (high case only)</li> </ul>	0.03-0.07
<b>Limits</b>	<ul style="list-style-type: none"> <li>Avoid exceeding written standards</li> <li>Standards are often exceeded due to either:               <ul style="list-style-type: none"> <li>Companies choosing to exceed them</li> <li>Regulatory assessments adding conditions which force them to be exceeded</li> </ul> </li> <li>Example: &gt;500 additional conditions apply to CSG water</li> <li>Example: Operator indicates overall 1% project costs added due to additional conditions</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>25-50% reduction of gathering CAPEX</li> <li>20-40% reduction of storage CAPEX</li> </ul>	0.06-0.11

<sup>1</sup> Impacts of individual levers not additive due to interdependencies

SOURCE: Expert interviews; McKinsey Analysis

## APPENDIX 6

### Assumptions for calculation of productivity improvement measures (4/9)

Labour productivity		Overall impact <sup>1</sup> : 0.9– 1.6	Impact on landed costs \$/mmbtu
Measure	Description		
<b>Residential communities close to LNG sites</b>	<ul style="list-style-type: none"> <li>Persuade more people to live in nearby communities, allowing them to work residential shifts that allow more time at work. This will require improving standards of living in these communities</li> <li>Requires investment e.g. housing , schools, infrastructure</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>1-2% reduction of in country labour for construction, EPC and operations labour:                             <ul style="list-style-type: none"> <li>Changing shifts leads to 212 days worked per year instead of 186 days - an improvement of 14%</li> <li>Additional productivity improvement of 6% due to better aligned teams and shorter team shifts</li> <li>~5-10% of people move to new shift (assuming # of permanent houses are equal to number of workers in operations phase)</li> </ul> </li> </ul>		0.03-0.06
<b>Shift patterns</b>	<ul style="list-style-type: none"> <li>Change to shift patterns that allow more time at work for certain labour categories. Might require cross-industry change</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>1-2% reduction of in country labour for construction, EPC and all operations labour:                             <ul style="list-style-type: none"> <li>Improvement of 14% (see above)</li> <li>Additional productivity improvement of 6% due to better aligned teams and shorter team shifts</li> <li>~5-10% of people move to shift that allows more time at work</li> </ul> </li> </ul>		0.03-0.06
<b>Site improvements through lean construction</b>	<ul style="list-style-type: none"> <li>Reduce idle time due to waiting for materials, equipment and documentation through application of Lean practices. This will lead to more effective working hours per day ('tooltime') and more effective use of rental equipment</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>3-6 months acceleration of construction upstream and downstream</li> <li>20-40% productivity improvement for in country labour for construction and EPC                             <ul style="list-style-type: none"> <li>Good project management can reduce idle time, which is 60%, with 30-60%</li> <li>Trained supervisor can get 15% more productivity out of its trained workforce</li> <li>Assuming additional 15-30% trained supervisors</li> </ul> </li> <li>5-15% reduction of rental equipment</li> </ul>		0.80-1.40

<sup>1</sup> Impacts of individual levers not additive due to interdependencies

SOURCE: Expert interviews; McKinsey Analysis

## APPENDIX 6

## Assumptions for calculation of productivity improvement measures (5/9)

### Labour rates and productivity (continued)

Measure	Description	Impact on landed costs \$/mmbtu
<b>Skilled labour</b>	<ul style="list-style-type: none"> <li>Create/attract additional highly skilled labour which will increase productivity, including for the teams they might lead</li> <li>Growing skilled labour pool could bring labour cost increases to the same level as Australian average (for 2010 – 2012 10% versus 14% for LNG related jobs)</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>0.75-1.5% reduction of all in country labour costs for construction, engineering, owner, EPC and operations:               <ul style="list-style-type: none"> <li>2.5-5% higher productivity</li> <li>25-50% less training days which leads to 2.5-5 additional days working on top of current 186 days at work</li> </ul> </li> <li>15-30% reduction of wage escalation for entire in country workforce (effective 7.5-15% reduction as labour is ~50% of total escalation)</li> </ul>	0.07-0.14

### Service market and supply chain

**Overall impact<sup>1</sup> 0.1 – 0.2**

Measure	Description	Impact on landed costs \$/mmbtu
<b>Local service market</b>	<ul style="list-style-type: none"> <li>Creating a deeper local service market to improve quality and costs</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>1-2% reduction in materials; assuming that Australian rates can reduce gap with Canadian levels with 50-100% where higher</li> <li>1.5-3% reduction in installed equipment; assuming Australian rates can reduce gap with Canadian levels with 50-100% where higher</li> <li>5-10% reduction in rental equipment; assuming Australian rates can reduce gap with Canadian levels with 50-100% where higher</li> </ul>	0.03-0.06
<b>Remote infrastructure</b>	<ul style="list-style-type: none"> <li>Bring Australian freight costs closer to Canadian ones (Australian freight costs are higher in Australia (15% of material and equipment costs) than in Canada (5% of material and equipment costs))</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>30-60% reduction of freight costs               <ul style="list-style-type: none"> <li>Assuming Australian freight costs can reduce gap with Canadian freight costs with 50-100%</li> </ul> </li> </ul>	0.07-0.14

<sup>1</sup> Impacts of individual levers not additive due to interdependencies

SOURCE: Expert interview; McKinsey Analysis



## APPENDIX 6

### Assumptions for calculation of productivity improvement measures (6/9)

Overall impact<sup>1</sup>: 1.0 – 1.8

#### Industry collaboration

Measure	Description	Impact on landed costs \$/mmbtu
<b>Cooperate on health, safety and environmental standards</b>	<ul style="list-style-type: none"> <li>Industry could work together in defining required environmental and safety measures and jointly invest in the required assets to save costs</li> <li>Example: Case study from Marine Well Containment Company shows that together 10 companies manage &gt; \$1 bln well containment response assets</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>1.5-3% reduction in materials and installed equipment                             <ul style="list-style-type: none"> <li>\$ 1 bln savings per company, spread over on average 4 projects</li> <li>50% in materials and 50% in installed equipment</li> </ul> </li> </ul>	0.03-0.05
<b>Industry wide standardisation</b>	<ul style="list-style-type: none"> <li>Industry could standardize supplier qualification, contracts and specifications to reduce time and effort in the procurement process</li> <li>Example: FPAL has registered over 3000 suppliers, to be used by over 80 purchasing members, leading to time and effort saved in the procurement process for all parties</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>Upstream and downstream construction phase accelerated by 1-2 months                             <ul style="list-style-type: none"> <li>Contracting period typically 3-6 months</li> <li>Reduction of ~30%</li> </ul> </li> </ul>	0.16-0.32
<b>Smoother demand</b>	<ul style="list-style-type: none"> <li>Reduce overpressure on costs by staggering timing of projects</li> <li>Optimized utilization of internationally sourced rental equipment leads to less mobilization and demobilizing costs, and lower costs due to less competition for equipment</li> <li>Optimizing workforce planning will reduce competition for labourers and reduce wage escalation seen in past years, moving labour cost escalation towards Australian average (for 2010 – 2012 10% versus 14% for LNG related jobs)</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>Conventional: 50-100% reduction of international rig (de)mobilization costs</li> <li>Unconventional: 50-100% reduction of international rig mobilisation (to and from site), which is 10-20% of total mobilization costs</li> <li>2-4% reduction of all internationally sourced rental equipment (including drill rigs)</li> <li>15-30% reduction of wage escalation for entire in country workforce (effective 7.5-15% reduction as labour is ~50% of total escalation)</li> </ul>	0.05-0.09

<sup>1</sup> Impacts of individual levers not additive due to interdependencies

SOURCE: Expert interview; McKinsey Analysis

## APPENDIX 6

## Assumptions for calculation of productivity improvement measures (7/9)

### Industry collaboration (continued)

Measure	Description	Impact on landed costs \$/mmbtu
<b>Share plant infra-structure (e.g. storage, jetties, berthing)<sup>1</sup></b>	<ul style="list-style-type: none"> <li>▪ Sharing infrastructure and pipelines with existing LNG facilities to reduce costs and time needed for construction</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>▪ Capex of new LNG train that will share infra is assumed to be the same as a second train in the same site of the original infra user. Reductions would be               <ul style="list-style-type: none"> <li>— Jetty, breakwater, module offloading dock, berth, emergency power, medical facility, admin building, schooling: 50-100%</li> <li>— LNG flow lines: 40-80%</li> <li>— Construction camp, permanent housing: 30-60%</li> <li>— Export pumping: 25-50%</li> <li>— Safety and utilities (fuel gas, water, nitrogen, etc.): 20-40%</li> <li>— Power generation and distribution, LNG storage: 15-30%</li> <li>— Site preparation, civil construction: 10-20%</li> <li>— Equipment installation: 7.5-15%</li> <li>— Steelwork, piping, instruments, electrical and insulation: 5-10%</li> <li>— Skid/spool erection: 2-4%</li> <li>— Contingency: 12.5-25%</li> <li>— Capital and operating spares, credit and warranties, taxes and import duties, insurance and certification, owner costs: 10-20%</li> <li>— Project mgmt, concept, detail and follow-on engineering, escalation : 5-10%</li> </ul> </li> <li>▪ Opex of train 1 reduced to equal opex of train 2 leading to:               <ul style="list-style-type: none"> <li>— Construction labour: 25-50%</li> <li>— Project management labour: 20-40%</li> <li>— Inspection and maintenance: 12-24%</li> <li>— Materials: 12.5-25%</li> <li>— Engineering labour: 10-20%</li> <li>— Other opex: 10-20%</li> </ul> </li> <li>▪ 20-40% reduction of engineering labour in FEED</li> <li>▪ 2-4 months acceleration of downstream construction and 3-6 months acceleration of FEED</li> </ul> <p><i>NOTE: Assumes pipeline completely rebuilt, if existing pipeline could be used and 70% of pipeline cost are saved, additional savings of 0.18 US\$/mmbtu</i></p>	0.77-1.37
<b>Joint operation and maintenance company</b>	<ul style="list-style-type: none"> <li>▪ Share maintenance facilities across projects</li> <li>▪ Can be leveraged by projects under development as well as those currently operating</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>▪ 10-15% reduction in opex for construction, engineering and EPC labour</li> </ul>	0.10-0.14

<sup>1</sup> Impacts of individual levers not additive due to interdependencies

SOURCE: Expert interviews; McKinsey Analysis

## APPENDIX 6

### Assumptions for calculation of productivity improvement measures (8/9)

#### Further project optimisation

Overall impact<sup>1</sup>: 1.1 – 2.2

Measure	Description	Impact on landed costs \$/mmbtu
<b>Lean engineering</b>	<ul style="list-style-type: none"> <li>Apply lean engineering to reduce rework and engineering hours while maintaining quality of design,</li> <li>Example: Power generation equipment manufacturer reduced product development cost by 30% and time to market by 33% through lean engineering</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>3-6 months FEED acceleration (3-6% reduction of absolute engineering hours)</li> <li>Additional 17-34% engineering labour reduction                             <ul style="list-style-type: none"> <li>Overall impact on engineering manhour assumed to be 40%, which is translated in both accelerated FEED and reduction of total engineering hours</li> </ul> </li> </ul>	0.16-0.28
<b>Lean concept and design</b>	<ul style="list-style-type: none"> <li>Apply lean concept and design to streamline scope and avoid 'gold plating' specifications, leading to more compact layout, and simplified design specifications, e.g.,                             <ul style="list-style-type: none"> <li>Example: Refinery improved NPV by 20-25%</li> </ul> </li> <li>Standardise to reduce cost/schedule for following projects and to facilitate greater outsourcing for the remaining detailed engineering                             <ul style="list-style-type: none"> <li>Example: O&amp;G major reduced capex of upstream by 10-14% and time to first oil by 3-7 months</li> </ul> </li> <li>Scope optimisation, simplification and standardisation of design could lead to 30% saving on all equipment and material costs, and reduced labour costs</li> <li>Increased level of modularisation will increase benefit from cheaper fabrication in lower cost countries which leads to lower cost of construction</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>Scope optimisation and simplification and standardization of design                             <ul style="list-style-type: none"> <li>15-30% reduction of materials</li> <li>15-30% reduction of installed equipment</li> <li>15-30% reduction of rental equipment</li> <li>5-15% reduction of engineering labour</li> <li>5-15% reduction of construction labour</li> <li>2-3 months additional FEED</li> </ul> </li> <li>Move from 50% modularised to 70-90% modularized</li> </ul>	0.66-1.47

<sup>1</sup> Impacts of individual levers not additive due to interdependencies

SOURCE: Expert interviews; McKinsey Analysis

## APPENDIX 6

## Assumptions for calculation of productivity improvement measures (9/9)

### Further project optimisation (continued)

Measure	Description	Impact on landed costs \$/mmbtu
<b>Contract management</b>	<ul style="list-style-type: none"> <li>Improve scope of contracts (e.g. only passing on unmanageable risks to EPC, dividing the project into optimal lots), contract terms (e.g. incentivise value improvement during construction) and contract reward process to achieve maximum savings:</li> <li>Example: Power plant reduced Capex with 20% and construction time with 30%</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>5-10% reduction of EPC fees</li> <li>5-10% reduction of contingencies</li> <li>0-1 month FEED acceleration</li> <li>1-2 months acceleration of construction upstream and downstream</li> </ul>	0.21-0.42
<b>Claims management</b>	<ul style="list-style-type: none"> <li>Monitor EPC performance to address potential obstacles to performance and minimise impact of change orders</li> <li>Example: Refinery reduced cost of claims with -70%</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>50% reduction of claims equivalent to 5-10% reduction of EPC fees (risk reduction, no cost reduction)</li> </ul>	0.02-0.03
<b>Lean operations in production</b>	<ul style="list-style-type: none"> <li>Maximise efficiency (resource productivity, improved planning and scheduling, training of personnel )</li> <li>Improve effectiveness by minimising variability and downtime, e.g.,</li> <li>Example: Maintenance transformation in GoM reduced lifting costs with -33-48%</li> </ul> <p><b>Assumptions:</b></p> <ul style="list-style-type: none"> <li>Efficiency improvement included in labour levers</li> <li>5-10% reduction of OPEX labour through effectiveness improvement</li> </ul>	0.05-0.10

1 Impacts of individual levers not additive due to interdependencies

SOURCE: Expert interviews; McKinsey Analysis







