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Cost benefit analysis of gas market reforms: Final report

Australian Energy Market Commission

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May 2016

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Our report has been limited to estimating the economic impacts of the policy reforms proposed by the AEMC. The direct impacts applied in the modelling for the reforms have been developed from findings of literature reviews, publicly available material and discussions with industry experts and stakeholders. The broad nature of the modelling is such that the results are intended to be indicative only.

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Executive summary

PricewaterhouseCoopers Australia (PwC) was engaged by the Australian Energy Market Commission (AEMC) to develop a robust analytical framework to assess the expected benefits and costs of the AEMC's draft recommendations for reforms to wholesale gas trading markets, pipeline access and information provision. These reforms were put forward in the AEMC's Stage 2 Draft Reports for reviews of the East Coast and Victorian Declared Wholesale Gas Market (DWGM).

It is expected that the outcomes of this analysis will form a key input into a future regulatory impact statement (RIS), and provide the AEMC with a robust information source from which to frame communications with key stakeholders, including Council of Australian Governments (COAG) Energy Council members and market participants.

Our analysis found that, for an implementation cost of $133 million and ongoing annual costs of $18 million to 2040, the proposed reforms lead to higher productivity growth, household consumption, exports and investment, resulting in GDP that is higher by $1.5 billion relative to the case without the reforms.

Importantly, the change in GDP over and above the costs is estimated to be positive in each year following the reforms, amounting to $8.7 billion in present value terms over the 20 years to 2040.

Context

The East Coast wholesale gas market is in the midst of a major structural change. Historically, the market has been relatively-stable, with a low-cost, domestic orientation. The market is now expected to triple in size as new gas fields in Queensland are developed and gas is exported to the international markets as liquefied natural gas (LNG) from Gladstone. This has significantly changed gas market dynamics by impacting the pattern of gas flow, increasing price volatility and affecting the operations of incumbent users, bringing to light several market inefficiencies. These factors have led to a renewed focus on market development and improvements in the fundamentals of gas trading arrangements.

To guide this development, the COAG Energy Council established a set of principles referred to as the Energy Council's Vision for Australia's future gas market. A key priority of the Energy Council's Vision is the establishment of an efficient and transparent reference price for gas. An efficient reference price requires a liquid market with many parties buying and selling gas, which necessarily implies that:

- trade be focused at a point that best serves the needs of participants
- participants are able to readily move gas between trading locations.

Against this backdrop, the AEMC was requested to conduct a review of the design, function and roles of facilitated gas markets and gas transportation arrangements on the east coast of Australia, and a review of the Victorian DWGM (Stage 2). These reviews resulted in the release of the AEMC's Stage 2 Draft Reports for the East Coast and DWGM reviews that outlined a range of issues currently impeding the development of an efficient market and a range of suggested reforms to address them.

Some issues that were identified by the AEMC include:

- greater uncertainty around future prices and more difficulty in accessing long term gas supply agreements
- limited liquidity in the current market

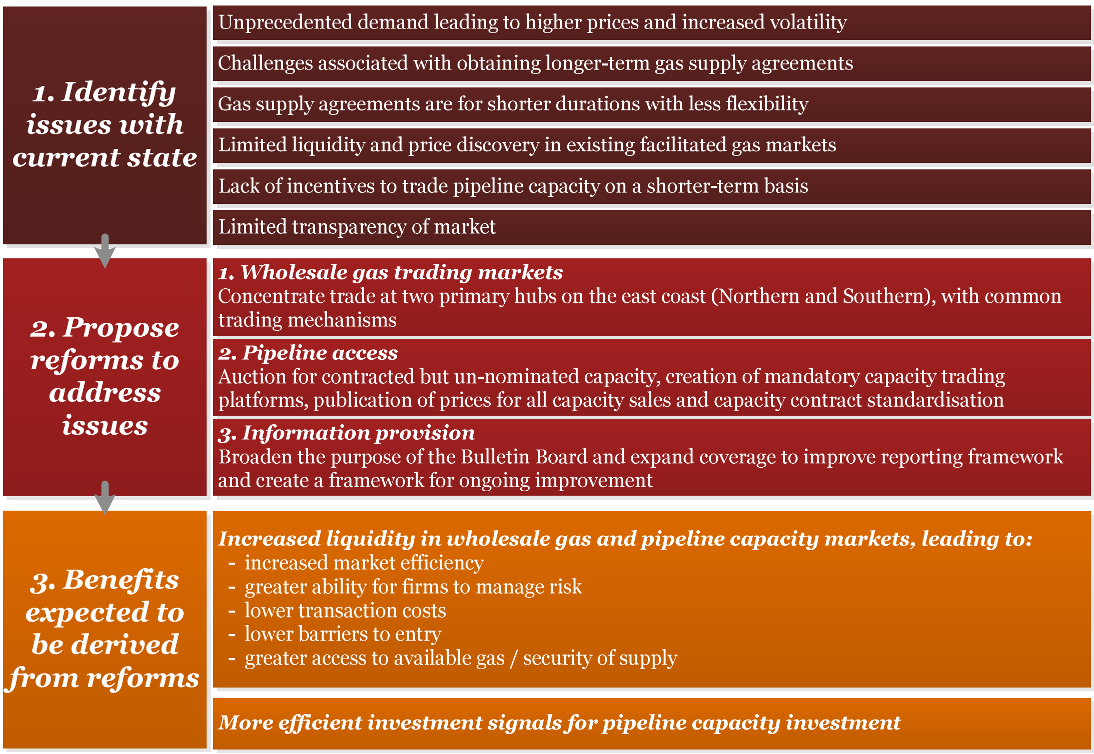
- a lack of incentives to trade secondary pipeline capacity
- limited existence of transparent market information.

The AEMC has proposed a number of inter-related reforms, which can be summarised as:[1]

- changes to wholesale gas trading markets that seek to concentrate trading at two points to reduce complexity and enhance liquidity
- changes in pipeline access arrangements that seek to improve the access to pipeline capacity by introducing market pricing mechanisms and trading platforms
- better provision of information with an expanded Gas Bulletin Board.

Figure 1 summarises the outcomes of the AEMC's work undertaken up to date – it notes the issues identified, the reforms proposed and the likely benefits that will be derived from those reforms.

Figure 1: Outcomes of the AEMC's East Coast and DWGM Reviews



Having noted the complexity in assessing the nature and magnitude of these expected economic impacts[2], the AEMC engaged PwC to undertake an analysis of the indicative economic benefits and the costs of implementing the proposed reforms. The analysis is considered indicative to the extent that:

[1] John Pierce, *Two sides of the energy coin: electricity and gas reform in Australia today: A speech delivered at the WA Power & Gas Conference*, Australian Energy Market Commission, 15 March 2016.

[2] AEMC 2015, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 2 Draft Report, 4 December 2015, Sydney, page 107-108.

- specific details of the reforms are yet to be determined, which has resulted in a wide range of stakeholder estimates surrounding the associated costs of the reform
- the potential benefits are relatively unique in that they are driven by reforms that are a mix of models seen abroad, while the scale and nature of the benefits is difficult to assess as they relate to, in effect, the creation of a new market[3]
- the benefits are diffuse, reflecting the nature of gas as a commodity that is widely used for production processes, heating, export and household consumption.

Notwithstanding this, the approach developed has enabled an estimate of the size of the potential impacts of the reforms on the Australian economy (or the "size of the prize").

Approach to the cost benefit analysis

The cost benefit analysis conducted in this study reflects a case where the benefits are widespread across the economy (including to market participants) and the costs are borne by market participants. Accordingly, our approach estimates the net economic benefits once the reforms are implemented, and for reference, provides an estimate of the investment required by stakeholders to implement the reforms (Figure 2). Consequently, a benefit cost ratio is not presented.

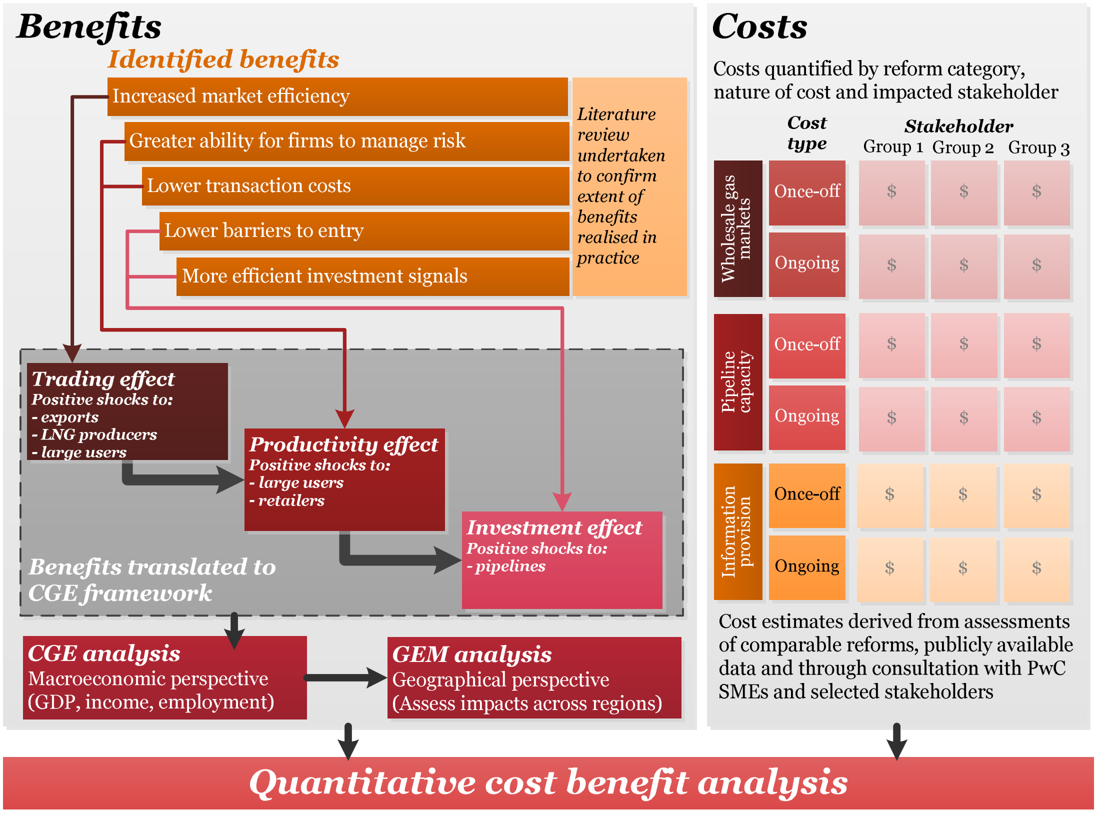
The costs involved in conducting the reforms were analysed through a bottom-up approach informed by publicly available data and stakeholder consultations. Industry submissions were analysed to inform our understanding of the types of costs expected to be borne by industry and the market operator. Based on these submissions a targeted consultation was undertaken to test assumptions and workshop some plausible cost estimates that would be reflective of the costs industry would be likely to face. These include planning costs, upfront implementation costs and ongoing annual costs based on increased effort required to interact with new processes and systems.

The approach to analysing benefits was to assess both the direct and indirect economic impacts through an economy-wide, general equilibrium analysis. This involves quantifying the impact of the reforms on macroeconomic variables such as gross domestic product (GDP), employment and household consumption through a computable general equilibrium (CGE) model.

The economic impacts of the reforms are measured by comparing a base case – that is, projections under the status quo – with a policy case that includes the reforms. The deviation of the policy case from the base case is of interest as this can be attributed to the reforms, while changes in the economy in the future relative to now cannot be attributed to the reforms.

[3] However, we note that broadly similar reforms have been observed in other countries and major reforms related to the National Electricity Market provide some precedent.

Figure 2: PwC's approach to cost benefit analysis



The base case includes assumptions about structural changes in the gas market, including the likely path of projected gas production, LNG exports and domestic use of gas reflected in the Australian Energy Market Operator's (AEMO) forecasts. As such, it takes into account constraints such as moratoria on onshore gas exploration and changes in demand as a result of increased domestic gas prices, which takes into account the main structural changes already underway in the gas market.

The policy case simulates the economy with 'shocks' to the base case to represent the direct impacts of the reforms of gas market participants. These shocks were developed from conservative estimates from empirical literature on similar reforms, which were then confronted with contextual information on the East Coast gas market and consideration of the likely timing of such impacts.

This led to the modelling of three phases of benefits; an immediate **trading effect** taking place from 2020 once the reforms come into effect; a **productivity effect** that begins to take effect immediately and ramps up over the medium term; and a long term **investment effect.** These effects are described in Box 1.

Box 1: Three phases of benefits of the AEMC's gas market reforms

The potential benefits of the AEMC's proposed reforms are varied and widespread but are likely to have a gradual impact over time. Accordingly, they have been modelled within three stylistic phases:

The trading effect reflects improved allocative efficiency in the wholesale gas market – that is, gas can be used by those who value it most. For example, it supplements the need for large industrial users and gas suppliers to negotiate bi-lateral agreements by allowing them to fine tune their positions in simpler exchange-based markets. This could occur when large industrial users need to fill gas supply deficits or sell surplus gas to higher value uses, or when LNG producers need to sell excess supply when parts of LNG plants are down for maintenance.

The productivity effect reflects lower transaction costs for trading and improved risk management options for market participants. It is assumed the benefits of these efficiencies take some time to be realised. Hence, they gradually phase in over the medium term. The literature shows that improved stability of cash flows and improved firm value can be realised by those firms who use hedging products to mitigate their exposure to risks (such as weather hedging products in the case of electricity and gas in the US, jet fuel hedging in the case of US airlines and currency hedging in the case of non-financial firms in the US). We assume large gas-intensive industrial users and retailers might achieve similar benefits in this context.

The investment effect captures the concept of improved information transparency and gas prices that are linked to supply and demand fundamentals leading to better informed decisions on future pipeline investments.

Note that while these are modelled as three separate phases, they are all linked to the package of reforms rather than any one specific recommendation. For this reason they indicate the overall magnitude of benefits of the reforms but not the relative magnitude of benefits of different elements of the reforms.

Estimated benefits

By 2040, the estimated net impact of the reforms is that GDP would be between 0.01 per cent and 0.10 per cent higher than the base case (0.04 per cent higher in the central scenario). This equates to GDP being between $0.50 billion to $3.33 billion higher in 2040 (or $1.51 billion in GDP in the central scenario) than it would otherwise have been. The range of the results highlights the sensitivity of the model outcomes to the predicted impacts on the gas market. Successful and timely implementation is required for the estimated benefits to be realised.

Table 1: Impacts of the reforms on GDP (deviation from baseline)

	2020		2030		2040		PV
	%	$ bn	%	$ bn	%	$ bn	$ bn
Low scenario	0.01%	0.10	0.01%	0.37	0.01%	0.50	2.88
Central scenario	0.02%	0.49	0.04%	1.08	0.04%	1.51	8.72
High scenario	0.05%	0.98	0.09%	2.41	0.10%	3.33	19.3

Note: Results show deviation from baseline, including the impact on all states and territories. Values are rounded to two decimal places. Values are $2015-16. Present values are calculated using a real discount rate of 7 per cent.

Source: PwC analysis

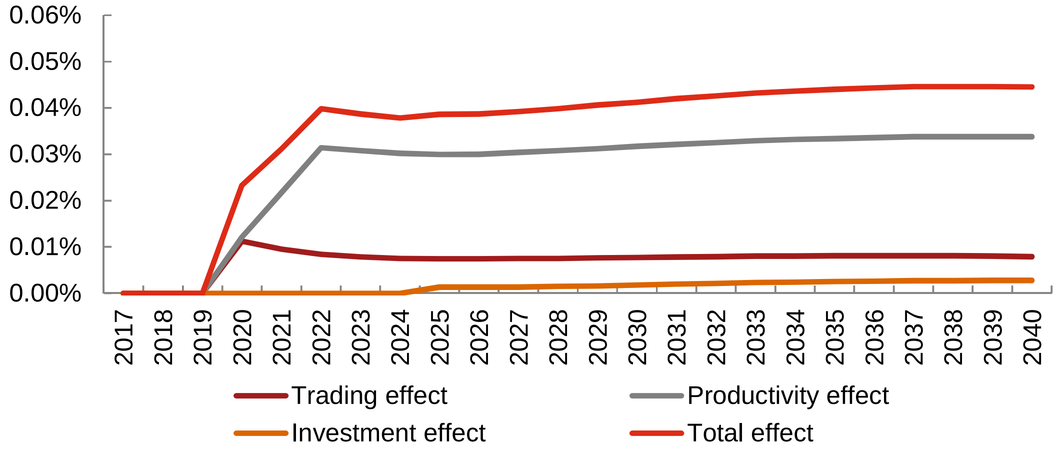
The gains to Australia's GDP are driven by the following impacts (also shown in Figure 3, below):

- **The trading effect** contributes an additional 0.01 per cent to GDP ($0.27 billion) by 2040 in the central scenario.

- **The productivity effect** contributes an additional 0.03 per cent to GDP ($1.14 billion) by 2040 in the central scenario.

- **The investment effect** contributes less than 0.005 per cent to incremental GDP ($0.09 billion) in 2040 in the central scenario.

Figure 3: GDP deviation from baseline by individual effect (%)



Note: Figures illustrate the percentage deviation from base case GDP in each particular year. It does not illustrate a cumulative impact, discounted back to the present. Rather it aims to show the impact of the shock over time.

Source: PwC analysis

The estimated gains from the reforms are pervasive and wide-spread across the eastern seaboard. The findings included:

- The manufacturing industry is estimated to be a primary beneficiary, reflecting a moderate step-change in productivity in gas-intensive sectors such as chemical, cement and plastic manufacturing.

- Other key industries linked to the gas market, such as gas retailing and distribution and pipeline transport also gain from improved capital productivity and investment signals respectively.

- There is evidence of broad second round impacts, particularly in service industries, which benefit from an expansion of investment and household consumption.

- Queensland and Victoria are estimated to be the most impacted (where their gross state product grows by 0.14 per cent and 0.09 per cent respectively) accounting for most of the growth in GDP. Queensland gains through the expansion of the LNG sector and gas-intensive manufacturing industries. In Victoria the manufacturing sector and supporting sectors (like business services) contribute to growth.

- Gains are expected to be prevalent in urban areas with intensive manufacturing or retail gas industries. However, more service-orientated urban areas, such as Greater Sydney and inner Melbourne, also benefit from the second-round flow-on effects to the property and business services, construction and trade industries.

Estimated costs

In order to estimate the costs of implementing these reforms we have drawn upon:

- information from stakeholder submissions to the AEMC's 3 March 2016 East Coast and DWGM discussion papers
- recent and past estimates of costs from similar reforms in the sector
- findings from a targeted process of stakeholder consultations.

The submissions provided little quantitative information. For this reason, the estimates included in this analysis are conservative (high cost) and it is possible that costs could be significantly lower. In general, the submissions noted pipeline access reforms were supported by industry and a number of submitters stated that benefits will be larger than the costs. Some submissions did raise concerns about particular elements of reform (some of which related to distributional impacts that will affect particular businesses).

The AEMC is currently looking into options for the design and implementation of the trading platform and auction process. There may be different benefits and costs associated with these different options, however for this analysis we have assumed that liquidity does develop and that pipeline operators develop their own capacity trading platforms and auctions (a multi-platform approach). This should not be taken to imply that this is a settled policy position from the AEMC. Instead, this assumption was chosen because it is conservative (high cost).

The estimated costs of the reform are set out in Table 2.

Table 2: Estimated total costs by reform package ($m 2015-16)

	Once off implementation costs			Ongoing annual costs			Total costs over 10 years (discounted)			Total costs to 2040 (discounted)		
	H	C	L	H	C	L	H	C	L	H	C	L
Pipeline access	62.3	38.6	16.8	7.8	4.3	1.2	100.4	59.2	21.9	135.0	78.3	27.2
Wholesale gas trading market	146.6	90.1	57.4	27.3	13.6	8.2	227.2	126.5	78.3	348.7	187.1	114.7
Information provision	6.6	4.3	2.8	0.3	0.2	0.2	8.2	5.3	3.6	9.5	6.2	4.3
Total	215.6	133.0	77.0	35.4	18.1	9.5	335.8	191.0	103.9	493.2	271.6	146.2

Note: Totals are subject to rounding. L = Low, H = High, C = Central. Discounted costs are calculated using a real discount rate of 7 per cent.

These costs are estimated to total between $146 and $493 million by 2040 (in present value terms). The largest costs are associated with reforms to pipeline access and the wholesale gas trading market. Key costs components include:

- Pipeline access:
  - Large participants are expected to bear the majority of the costs with $21.1 million in upfront costs and $3.1 million each year on an ongoing basis. This totals to $38.4 million over ten years (present value).
  - Pipeline operators are expected to bear the second highest costs with $7.9 million in upfront costs and $0.3 million each year on an ongoing basis. This totals to $9.5 million over ten years (present value).
- Wholesale trading market:

- Large participants are expected to bear the majority of the costs with $35.5 million in upfront costs and $9.2 million each year on an ongoing basis. This totals to $72.3 million over ten years (present value).
- The market operator is expected to bear the second highest costs with $26.6 million in upfront costs and $0.3 million each year on an ongoing basis. This totals to $29.2 million over ten years (present value).
- The planning and consultative phase is expected to cost industry $6.7 million in upfront costs over the two year planning stage.

Implications

The results indicate that for an implementation cost of between $77 and $216 million, and ongoing annual costs between $10 and $35 million, the proposed reforms could lead to higher productivity growth, consumption, exports and investment, resulting in GDP that is between $500 million and $3.3 billion higher in 2040.

Importantly, the change in GDP over and above the costs is estimated to be positive in each year following the reforms. That is, the reforms drive a 'level shift' in GDP that, in the central case, amounts to an estimated $8.7 billion of additional output in present value terms over the 20 years to 2040.

Abbreviations

Acronym	Description
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
CBA	Cost benefit analysis
CGE	Computerised general equilibrium
COAG	Council of Australian Governments
CoPS	Centre of Policy Studies
CPI	Consumer price index
DTS	Declared transmission system
DWGM	Declared wholesale gas market
FTE	Full time equivalent
GBB	Gas Bulletin Board
GDP	Gross domestic product
GEM	Geospatial economic model
GRP	Gross regional product
GSA	Gas supply agreement
GSP	Gross state product
GTA	Gas transfer agreement
GVA	Gross value added
LNG	Liquefied natural gas
PPI	Producer price index
PwC	PricewaterhouseCoopers Australia
RIS	Regulatory impact statement
STTM	Short term trading market
WPI	Wage price index

Contents

1 Introduction

Background

The Australian Energy Market Commission (AEMC) was requested by the Council of Australian Governments (COAG) Energy Council to review the design, function and roles of facilitated gas markets and gas transportation arrangements on the east coast of Australia (the East Coast Wholesale Gas Market and Pipeline Frameworks Review or “the East Coast Review”). The Energy Council, at the request of the Victorian Government, also asked the AEMC to undertake a detailed review of the Victorian Declared Wholesale Gas Market (“the DWGM Review”).

In December 2015, the AEMC released its Stage 2 Draft Reports for the East Coast and DWGM Reviews, outlining a range of issues currently impeding the development of an efficient east coast gas market, as well as a range of reforms to address these issues. The AEMC expects to release its Stage 2 Final Report in May 2016.

Through the reviews, the AEMC has identified a range of issues affecting the east coast gas market. By and large these issues have emerged as a result of unprecedented growth in demand for gas, driven by the LNG export sector. This has placed upward pressure on prices and significantly increased volatility in the spot market.

Key issues identified by the AEMC include:

- Greater uncertainty around future price movements, which has made longer term (15 to 20 year) gas supply agreements (GSAs) more difficult and/or expensive for users to enter into with suppliers (GSAs have traditionally been the preferred means through which gas is bought and sold).

- New GSAs that have been offered are reportedly for shorter durations, at higher prices, and with less flexibility. This has reduced the extent to which major gas users can manage risk through long term bilateral agreements.

- Limited liquidity in existing facilitated gas markets creates uncertainty that the quoted ‘market price’ reflects the underlying value of gas. This uncertainty may be contributing to the limited use of derivatives, further decreasing the attractiveness of purchasing gas on the market or indexing bilateral contracts to the market price.

- Lack of incentives for shippers and pipeline owners to trade pipeline capacity on a short term basis (e.g. day ahead) reduces market efficiency (i.e. gas flowing to the user valuing it the most) and liquidity.

- Limited existence of transparent, easily obtainable information available to market participants to assist with price discovery and support market liquidity.

Project purpose

PwC has been engaged by the AEMC to develop a robust analytical framework to assess the expected benefits and costs associated with the proposed reforms. It is expected that the outcomes of this analysis will form a key input into a future regulatory impact statement (RIS), and provide the AEMC with a robust information source from which to frame communications with key stakeholders, including COAG Energy Council members and market participants.

Proposed Reforms

In its Stage 2 Draft Report, the AEMC put forward a suite of recommendations to address the issues outlined above. The recommendations broadly fall under three categories:

1 Wholesale gas trading markets

2 Pipeline access

3 Information provision

The AEMC's recommendations, as noted in the Stage 2 draft report, are summarised in the table below.

Table 3: Summary of the AEMC's recommendations

Market development area	Recommendation
Wholesale gas trading markets	Two primary trading hubs on the east coast, one in the north and one in the south, with common trading mechanisms applying to each.
	The Northern Hub to be defined as (the existing) physical hub at Wallumbilla (consistent with AEMO's ongoing reform), with the potential for a virtual hub at a later date.
	The Southern Hub to consist of a virtual hub covering the Victorian transmission system, with an entry-exit regime for allocating capacity.
	Simplification of the STTM hubs to a balancing role once liquidity has developed at the Northern and Southern hubs and in pipeline capacity trading.
Pipeline access	Introduction of an auction for contracted but un-nominated capacity with a regulated reserve price on all pipelines.
	Mandatory creation of capacity trading platforms, through which information regarding all capacity trades, including prices, must be published. Capacity product standardisation would facilitate trading through the platform.
	Publication of the actual price of all primary capacity sales, and terms and conditions of those sales, which might impact the price.
Information provision	Broaden the purpose of the (Gas) Bulletin Board in the National Gas Rules to reflect the wider role that information plays in the sector
	Expand the coverage of the (Gas) Bulletin Board and improve and strengthen the reporting framework.
	Make the (Gas) Bulletin Board more responsive to changes in market conditions by removing funding methodology from National Gas Rules and creating a framework to support ongoing improvement.

Source: AEMC 2015, East Coast Wholesale Gas Market and Pipeline Frameworks Review, Stage 2 Draft Report, 4 December 2015, Sydney.

2 Approach

This chapter sets out the overall approach to developing estimates of the costs and benefits of the reforms.

Figure 4 outlines the conceptual framework underpinning the proposed methodology for the cost benefit analysis. This builds on work undertaken by the AEMC through the two reviews to provide a quantified cost benefit analysis.

The merits of the proposed reforms are assessed through a cost benefit analysis (CBA) framework. CBA is a form of economic evaluation that seeks to quantify in monetary values the benefits derived, and costs incurred, by those parties affected by a particular policy change or investment to determine its net impact to society.

Under the CBA framework, the benefits and costs are calculated by applying a policy change, or shock, to a base or reference case and calculating, in dollar terms, incremental costs and benefits of the change. A comparison of costs with benefits is used to determine if an activity is worthwhile (also called the net present value). If the net present value is positive, benefits exceed the costs and the proposed reforms are worth undertaking.

There are several approaches to measuring the costs and benefits of a change in policy – some quantitative, others qualitative. One approach is to measure benefits as the welfare change of producers, consumers and the community in partial equilibrium. That is, taking other economic factors, such as the price of other goods and services and household income levels as fixed, it estimates the increase in economic surplus, in present value dollars, and compares it to present value costs. Typical benefits would include, for example, increased consumer surplus if a portion of gas is re-distributed to users whose marginal value of gas is higher than that of the user in the base case.

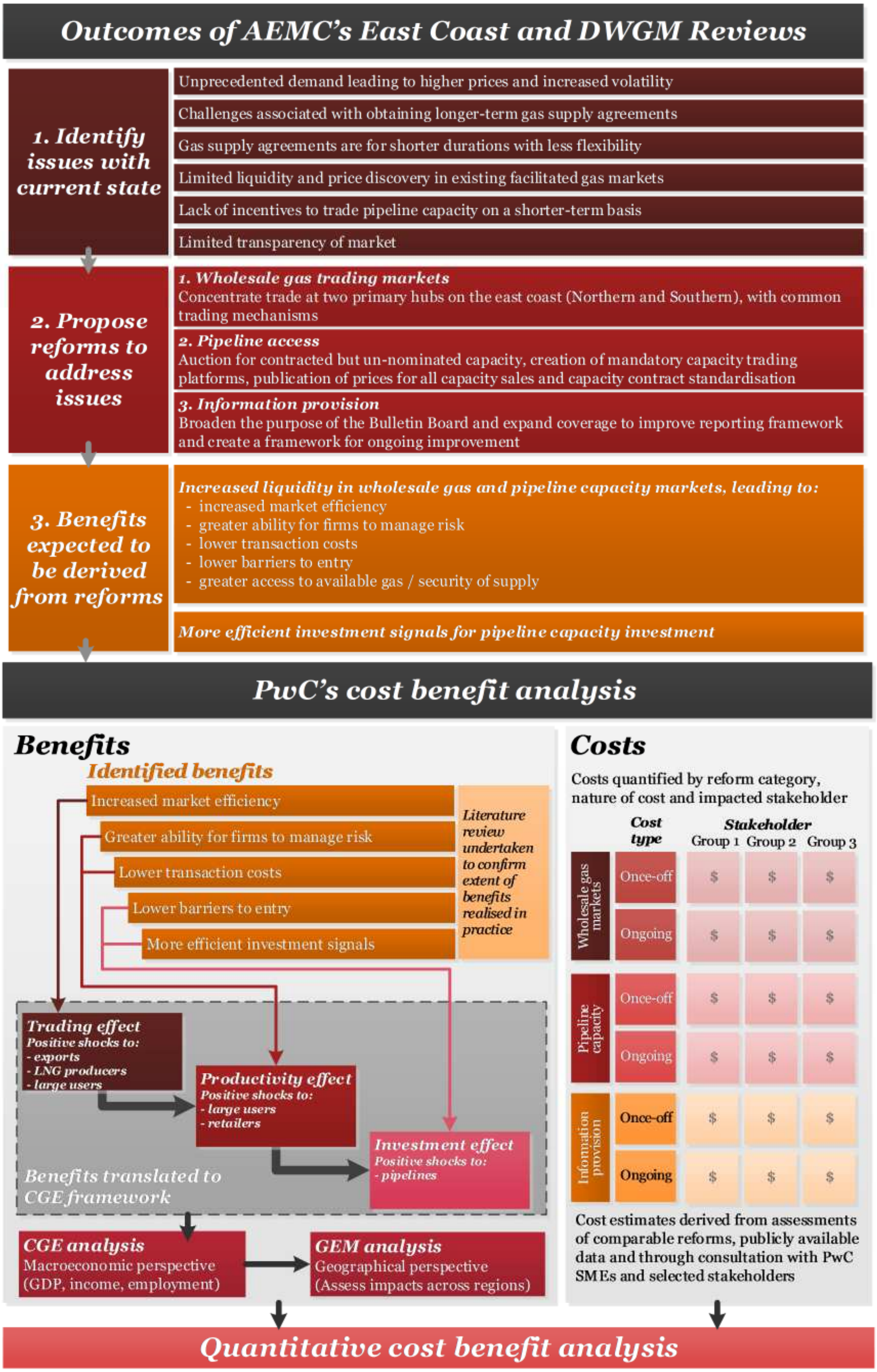
Another approach is to assess the benefits in terms of the general equilibrium impact. This approach expands on partial equilibrium analysis by estimating the flow on impact in other markets in the economy rather than just those directly affected by the change. It quantifies the impact of the reforms on macroeconomic equivalents of welfare, such as GDP, income, employment and household consumption. The economic impacts are measured through a Computable General Equilibrium (CGE) model of the Australian economy, which simulates the impact of the reforms (or shocks) in the gas sector, taking into account the responses of producers, households, financial markets and governments to price and quantity signals. CGE modelling is described in more detail in Appendix A.

This study adopts the general equilibrium approach to analysing the reforms' benefits, using a carefully calibrated CGE model of the Australian economy. The key benefit of CGE modelling is that it has the ability to capture flow-on impacts of changes in the gas market to other participants in the economy in an integrated framework. This is particularly relevant to the extent that the reforms improve price signals and allocative efficiency in the gas market. In sectors such as gas production and supply, which have pervasive linkages with the rest of the economy, it is not only the response of gas market participants that is relevant, but the subsequent responses of other sectors that will also be a key factor.

The costs of the reforms are informed by detailed bottom-up calculations, and stakeholder engagement to capture the incremental change in costs to gas market participants.

Accordingly, our approach estimates the net economic benefits once the reforms are implemented, and for reference, provides an estimate of the investment required by stakeholders to implement the reforms. Consequently, a benefit cost ratio or net present value is not presented.

Figure 4: Overview of cost benefit analysis



2.1 Framework for modelling expected benefits

Measuring the overall benefits of the reforms first required an assessment of the likely impact of the policy on gas market participants (the partial equilibrium impacts). This was then used to shock the base case for the CGE model to determine the aggregate impact on the economy, its regions and sectors.

The AEMC has proposed that the benefits of the reforms will include:

- increased market efficiency from greater price transparency and more efficient price discovery
- greater ability for firms to manage risk
- lower transaction costs
- lower barriers to entry
- more efficient investment signals.

A review of international and Australian literature on gas, commodity and financial markets provides support that the proposed reforms could drive these benefits (see Appendix B). Notwithstanding the nuances of the Australian gas market, such as relatively low levels of market participants and consumption, and long distance transportation,[4] it is plausible that the effects will be broadly similar to those observed elsewhere.

To that end, we aim to estimate the economic benefit from a series of foreseeable shocks that would likely eventuate from reforms aimed at facilitating greater trade, allocative efficiency and improved price transparency in the gas market, guided by results observed in the literature review.

Simulating the benefits requires the need to consider all the effects of the reforms, whether they are independent or dependant. To simplify the impacts, the proposed benefits of the reforms were modelled through three phases: a trading effect, a productivity effect and an investment effect (Figure 5).

This framework aims to measure the impact of the reforms by considering them as a whole package[5], which would drive different economic effects over time. It reflects that the efficiency benefits, which are driven by greater trading opportunities, could occur relatively quickly, but that it takes time for producers to adapt to the changes before production patterns and investment plans can be fully reflective of improved market operations.

Many elements of the reform will individually lead to similar observable effects on economic activity. For example, increased profitability and greater investment are likely to be encouraged by an economically efficient allocation of gas, reduction of transaction costs and increasing use of risk management options. To account for this, we have produced direct impacts that cover off on all of the likely impacts that are material while avoiding impacts that double-count one another.

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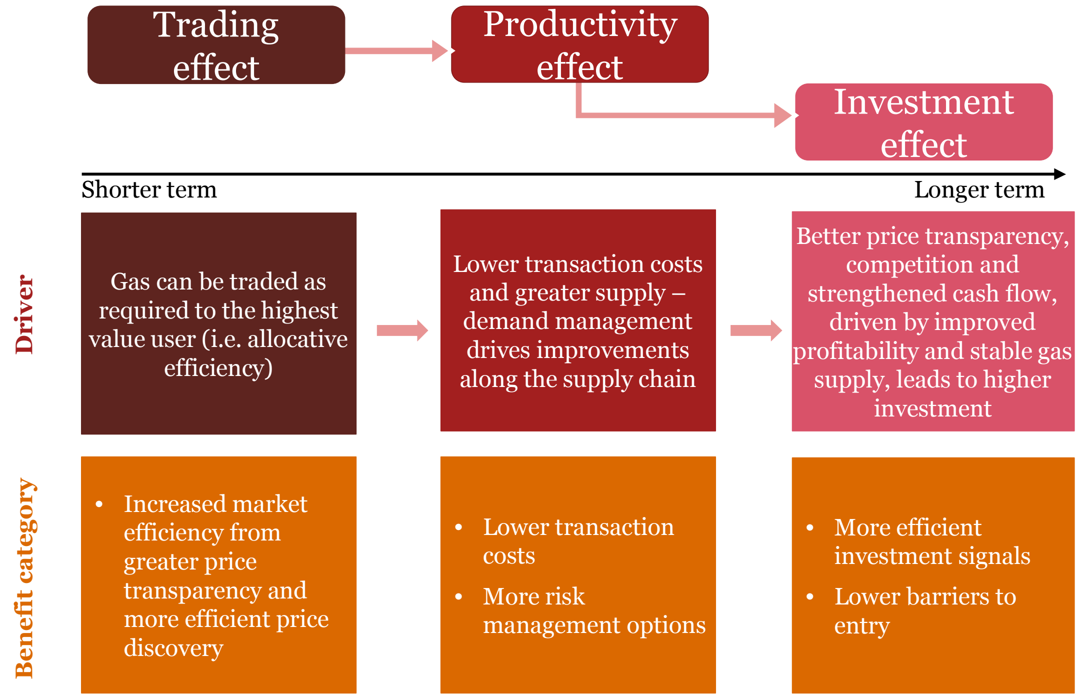
4 As noted in stakeholder submissions in: AEMC 2015, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 2 Draft Report, 4 December 2015, Sydney.

5 Note that while these are modelled as three separate phases, they are all linked to the package of reforms rather than any one specific recommendation. For this reason they indicate the overall magnitude of benefits of the reforms but not the relative magnitude of benefits of different elements of the reforms.

Figure 5: Proposed economic lenses for the impact of gas market reforms



Source: PwC analysis

2.2 *Framework for modelling expected costs*

Costs that have been considered can be broken into:

- once off costs to capture the implementation
- costs to capture the change in ongoing effort required.

The quantification of these costs focuses on the marginal change from the reforms – i.e. the additional level of effort required on an on-going basis relative to the base case.

As indicated in this table, the level of analysis is high level and focuses on the broad categories of reforms rather than the specific details of each recommendation. This was necessary due to the time available and the level of detail of the reforms.

Table 4: Framework of costs considered in analysis

Reform	Costs	Market operator	Pipeline operator	Market participants
Pipeline capacity markets	**Planning**			
	Industry council and working groups	✔	✔	✔
	Implementation			
	Methodologies, system development, project management		✔	✔
	Contract renegotiation			✔
	Cost of interfacing with multiple platforms			✔
	On-going costs			
	Additional operational staff required		✔	✔
	IT systems support			✔
Reform	**Costs**	**Market operator**	**Pipeline operator**	**Shippers**
Southern Hub Reforms	**Planning**			
	Working groups	✔	✔	✔
	Implementation			
	Methodologies, system development, project management	✔	✔	✔
	Cost of expert guidance		✔	
	On-going costs			
	Additional operational staff required	✔		✔
	Additional IT, risk management and finance burden			✔
Reform	**Costs**	**Market operator**	**Major existing participants**	**New GBB participants and pipeline operators**
Information Provision	**Implementation**	✔		✔
	On-going costs			
	Additional staff required	✔		

3 Net benefits

This chapter sets out the analysis of net benefits of the AEMC's reforms. Some technical details of the analysis are briefly described below with supplementary technical details provided in Appendix C. This is followed by the results of the analysis.

3.1 Framework

The economy-wide benefits of the reforms are estimated through an economic impact analysis conducted using a CGE model. CGE models provide a robust, coherent framework for assessing the general equilibrium effects of shocks to the gas market, by accounting for the flow on effects to other industries, households and prices over time.

We have used the Victoria University Regional Model (VURM), which is a multi-regional, dynamic CGE model[6] that distinguishes up to eight Australian regions (six States and two Territories) and up to 144 commodities/industries.

The model includes producers, investors, households, foreign consumers, and governments and accounts for regional and international trade flows. As each region is modelled as a mini-economy, VURM is ideally suited to determining the impact of region-specific economic shocks. Second round effects are captured via the model's industry (input-output) linkages and account for economy-wide and international constraints. This framework is described in further detail in Appendix A.

The economic impacts of the reforms are quantified by comparing a base case – that is projections under the status quo – with a policy case that includes the reforms. The policy case simulates the economy with 'shocks' to the base case to represent the direct impacts of the reforms. That is, the study does not aim to measure if the reforms are optimally designed or timed, but rather the benefits of the reforms relative to a continuation of the status quo.

The shocks were developed taking into account the literature review (described in Appendix B), but considering the nature of the east-coast gas market based on market and economic statistics. The economic impact of the reforms is measured using outputs from the model under the policy case as a deviation from the policy case.

Outputs from the model include but are not limited to projections of output and employment by sector and region, income and trade flows. While GDP, a measure of aggregate output is the primary measure of economic impact, this does not consider economic returns to foreign owned capital (resulting in additional income accruing to foreign entities). For this reason, household consumption is also reported as an alternative welfare measure, to the extent that it represents improved consumption opportunities (which generate utility) resulting from additional income growth to domestic households.

A stylised example of general equilibrium modelling is discussed below in Box 2.

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6 VURM is the latest incarnation of the Centre of Policy Studies' MMRF model. The name change was triggered by CoPS move from Monash University to Victoria University in 2014.

Box 2: How to interpret results from general equilibrium modelling

A CGE model is a stylised representation of the Australian economy. It assumes the starting point is the economy is in equilibrium and therefore does not include business or commodity price cycles or monopolistic characteristics of certain sectors. The interpretation and relevance of CGE results can be seen in the context of an example; in this case the construction of a new hospital in Victoria.

A CGE model would describe the number of jobs created by the hospital, the degree to which it inflated the local wage and bid workers away from other industries, and the likely impact on gross state product. However, it would not reflect disequilibrium properties in the short run (e.g. the time required to train new labour to work in the hospital, financing issues associated with acquiring capital (such as X-ray machines)). Further the results would be 'all other things equal': they would not reflect an unforeseen decline in labour supply that emerged five years down the line (unless the modeller inserted this change). In this way, CGE models present an over-arching 'big picture' impact of a change, once it has resolved itself in the economy.

The formulation of the base and project case is described below.

3.1.1 Base case

The base case represents the economic future under the status quo. The base case includes structural changes in the nature of the gas market that are expected to happen regardless of whether the reform goes ahead, such that economic impacts can be measured as incremental benefits from the policy changes. The base case in VURM required a number of adjustments to ensure it accurately reflected the future path of economy, including:

- an internally consistent set of macroeconomic forecasts for the states and territories, based on mid-year state and federal budget outlooks[7]
- structural changes in gas use as embodied in AEMO's central demand forecasts,[8] which included a significant ramp-up in Queensland LNG exports and shifts in consumption for the power generating and industrial using sector (Figure 6)
- a large expansion in gas supply originating out of the Surat and Bowen basins, consistent with AEMO's 2016 Gas Statement of Opportunities (GSOO)[9].

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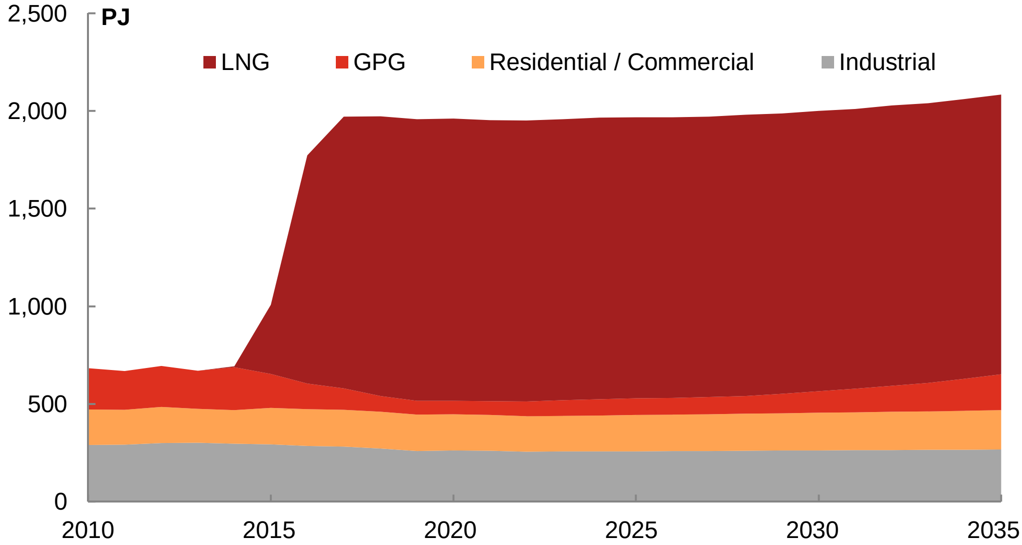
[7] At the time this analysis was undertaken, the 2016-17 Federal Budget had not been released. However, it is unlikely that incorporating these forecasts into the base case would make a material impact on the incremental impact of the reforms derived from the project case.

[8] Australian Energy Market Operator, *2015 National Gas Forecasting Report for Eastern and South-Eastern Australia*, December 2015.

[9] Australian Energy Market Operator, *Gas statement of opportunities for Eastern and South-Eastern Australia*, March 2016.

Figure 6: Projected east-coast gas consumption by use



Source: AEMO, 2015

3.1.2 Policy case

The policy case includes shocks to the base case, which alter the projected path of the economy. The resulting deviations of this path from the base case represent the economic impact of the policies. The reforms (shocks) are assumed to begin in 2020; however their associated effects are expected to occur gradually over three stages (and then result in second round-effects).

- **trading effects** are assumed to be realised immediately from 2020 over one year
- **productivity effects** are assumed to begin from 2020, but are phased in over three years, reflecting the gradual incorporation of improved risk management practices and optimisation of productive processes
- **investment effects** are assumed to occur from 2025 over one year, as the expected equilibrium rate of return is expected to increase with a lag, allowing sufficient time for clearer investment signals to be established.

The formulation of these shocks requires an assessment of how the reforms will affect the price and/or quantity of gas traded – that is, the partial equilibrium impact on the gas market. The theoretical nature of these impacts along with supporting evidence from the literature review is discussed below.

Trading effect

Issues in base case

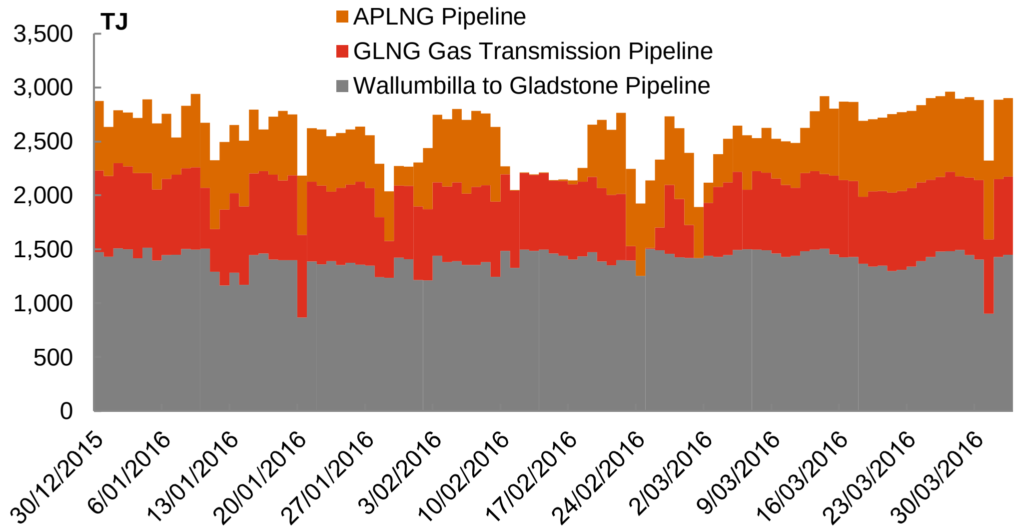
Transmission constraints and the complexity in negotiating gas supply from gas producers and gas users prevent trades that would occur in an efficient market from happening. This results in two potential inefficiencies in the gas market:

1 Large industrial gas users have had difficulty accessing gas (as reported by manufacturing companies and associations).[10]

[10] For example, the ACCC has noted that there is "...evidence that many domestic users went from a market where they received, say, 3 – 5 offers of supply on terms that were able to be negotiated, to one [in recent years] where they received zero or one true

2 During periods in which an LNG plant requires maintenance or a tanker is late, daily flows to the Curtis Island LNG demand zone (CIDZ) can be severely disrupted, resulting in excess gas supply (Figure 7) that is left to flow southwards to other users at lower prices. However, the lack of flexibility within current contracts means that this gas may not, in effect, reach its most valuable use.

Figure 7: Daily gas flows in the Curtis Island LNG demand zone (TJ)



Source: AEMO gas bulletin board, 2016

During periods where LNG plants are being loaded up, gas prices increase (in QLD in particular). For some users who can make commercial decisions to lower their gas consumption and make use of higher prices for export, the current process of trading gas may make this difficult as gas fired generation and industrial consumers have, for example, limited access to pipeline capacity and face illiquid trading markets.

Solutions in policy case

The creation of gas supply trading and pipeline capacity auctioning platforms establishes a mechanism that enables gas to be more easily traded between market participants as required. The effect of this is that each unit of gas produced generates a higher amount of value than otherwise, since it can be more easily sold to those willing to pay for it. For example,

- manufacturers can more easily access gas and convert it into plastics
- LNG producers can more easily release gas in periods of excess supply to users who value it more, rather than those who have better access arrangements and flexibility
- when it makes sense to do so, large users, absent of contractual constraints, may choose to take advantage of higher LNG export prices and sell their gas instead of consume it themselves, thereby increasing LNG export volumes.

This may result in domestic gas prices increasing as a result of increased competition for supply, signalling for further investment in gas production. A stylised depiction of the economic impacts of these issues and solutions is shown below in Box 3.

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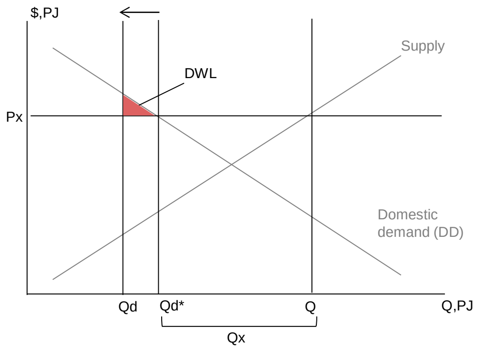
offer, on largely take-it-or-leave-it, inflexible terms." https://www.accc.gov.au/media-release/the-importance-of-adequate-competition-for-the-east-coast-gas-market

Box 3: The partial equilibrium impacts of trading constraints

A stylised depiction of the economic cost, or 'deadweight loss', associated with trading constraints can be shown diagrammatically using a simplified demand and supply analysis for natural gas in the domestic and export market.

As shown in Figure 8, for a given export parity price[11], Px, a quantity of Qx would be exported while Qd* is demanded for domestic use. However, prohibitive transaction costs, or a lack of available sellers, mean that the domestic market can only consume Qd. This leads to a loss of surplus –an economic inefficiency - equal to the area of the shaded triangle, which is one of the potential gains from the reforms.

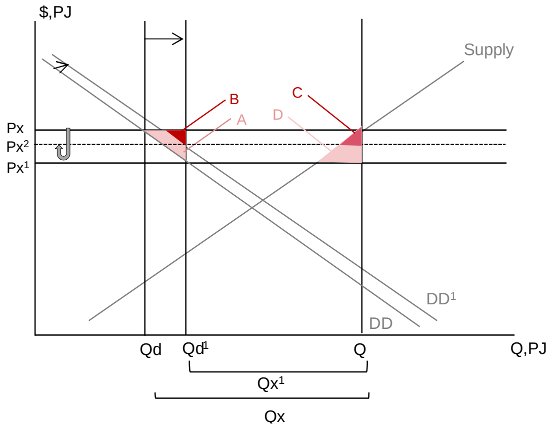
Figure 8: Stylised depiction of the economic impact of constrained trading capacity



Source: PwC analysis

Figure 9 shows the impact of trading constraints with excess gas supply. Again, in normal conditions Qd of gas is used domestically and Qx is exported. During an unexpected LNG plant shutdown, excess gas (Qd1-Qd) needs to be sold off, reducing the export parity price (via a reduction in wholesale prices) to Px1 at the original demand curve (DD). This results in a deadweight loss of A+B+C+D. With the reforms, greater trading flexibility lowers transaction costs, increasing domestic demand (DD to DD1); such that the price only needs to fall to Px2 instead of Px1. This reduces the cost to areas B+C, reflecting a higher value use.

Figure 9: Stylised illustration of the economic impact of an LNG plant shutdown with and without reform



Source: PwC analysis

[11] The export parity price is equal to the Freight on Board price less the cost of exporting gas.

Evidence and implications

Recent reports indicate that gas users are experiencing major issues sourcing gas supply on reasonable terms, and in some cases, receiving no offers at all.[12] In one example, Incitec Pivot has had to secure supply from the future North East Interconnector pipeline.[13]

In this context, it was assessed as reasonable to assume that the establishment of a liquid energy trading facility could improve price discovery and market efficiency, ultimately linking prices more closely with demand-supply fundamentals and overcoming transmission constraints for current gas market participants. Further, the literature review found statistically robust evidence that the development of a futures market, a key element of the reforms, leads to increased market efficiency through more efficient price discovery in a range of other sectors.[14]

Shock formulation

Three shocks were developed to reflect this effect (with further information on key data sources found in Appendix C):

- **Shock 1:** A positive productivity shock to the industrial use sector[15] of 5 per cent from being able to source additional gas. This is modelled as a capital productivity improvement; i.e. existing capital is better utilised given an increase in intermediate production inputs. This assumes that some, but not all, of these constraints are alleviated through the improved capacity trading platforms. The shock was assessed as small enough to allow for the fact that not all capital will be lying in production assets and was scaled downwards according to different degrees of gas intensity relative to the most gas intensive industrial user.[16]

- **Shock 2:** A positive shock to total factor productivity of LNG producers of 0.2 per cent from being able to sell excess gas during periods in which an LNG plant is shut for maintenance or a vessel is late. The magnitude of the shock reflects the frequency of LNG plant disruptions (due to planned or unplanned outages); the magnitude of the excess supply observed during historical disruptions; and an assumed reduction in deadweight loss from this 'average' level of excess supply.

- **Shock 3:** A positive shock to LNG exports of 1 per cent, as a result of surplus gas traded from the domestic sector to the export sector. This is small because the gas consumed by the east coast export market is approximately three times the size of gas consumed domestically and this will only be a marginal impact whereby exporters are able to top up their production volumes. This equates to an estimated four additional LNG ships worth

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12 ACCC, 2015, The importance of adequate competition for the east coast gas market., Available at: https://www.accc.gov.au/media-release/the-importance-of-adequate-competition-for-the-east-coast-gas-market

13 Incitec Pivot Limited, *IPL announces long term gas agreement for Phosphate Hill Fertiliser Manufacturing Plant*, 17 November 2015.

14 We reviewed papers in a number of sectors that showed this to be the case. This included the US & UK oil sectors - Tabak and Cajueiro (2007), the European gas sector - Schultz and Sweiring (2002), the European electricity sector - Hongming, Sidong, Yongxi, Xiao (2009) and Indian agriculture - Dhankhar (2009). The findings from these papers are summarised in Appendix B.

15 We have categorised industrial users as including the cement, alumina, non-metal construction products, paper products, steel, chemicals, other metals, and rubber and plastics sectors. These sectors were chosen as being relevant large users by looking at the sectors which are most gas reliant on a cost basis in the VURM CGE model. We excluded the gas sector itself and gas electricity production (as it is generally reducing its gas use over the foreseeable future in AEMO forecasts and hence does not appear to have issues accessing gas). We also considered including other sectors like the food manufacturing sector as some food manufacturers are large users. Given the broad nature of the sector (with some food manufacturers more inclined to use gas than others) with many small firms (which are less likely to be participants in the wholesale gas market) we decided the shock at the industry-wide level would be relatively immaterial.

16 In the subset of industrial users, this was the cement manufacturing sector.

of gas per annum compared to the 360 ships expected to depart each year from Gladstone.[17]

Productivity effect

Issues in base case

A continuation of multiple hub and STTM/DTS design means that transactions are complex, costly and traded at the end of long transmission pipelines, increasing barriers to market entry. In particular:

- Industrial users are often unable to secure flexible, long term GSAs, resulting in higher and increasing transaction costs. Some large users are becoming more reliant (or are completely reliant) on the spot markets.[18] With greater volatility in the spot market (caused by large volumes of gas flowing for export or onto the domestic market when LNG demand turns down), business risks are also increasing.

- Small retailers and retailers who are not involved in upstream activities have greater business risks in trading gas than businesses that are able to naturally hedge fluctuation in gas prices through their own gas production.

Solutions in policy case

A new wholesale trading platform improves the ability to continually trade gas, while lowering transaction costs for market participants, by enabling the introduction of a futures market to supplement bilateral trades and GSAs. This flows onto lower intermediate costs for gas users. Further, increasing use of a liquid derivatives market ensures price risks can be hedged.

This will mean lowered transaction costs will result in a higher than otherwise operating surplus for market participants while improved risk management improves working capital productivity to the benefit of incumbent users and new entrants.

A stylised depiction of the economic impacts of these issues and solutions is shown below in Box 4.

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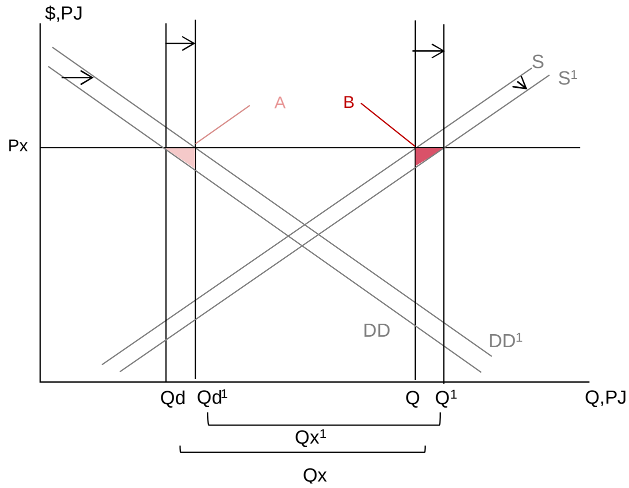
[17] http://www.abc.net.au/news/2015-01-06/first-lng-from-csg-ship-leaves-queensland/6002446 Accessed 15 April 2016.

[18] Australian Competition and Consumer Commission, The importance of adequate competition for the east coast gas market, 17 September 2015, https://www.accc.gov.au/speech/the-importance-of-adequate-competition-for-the-east-coast-gas-market

Box 4: The partial equilibrium impacts of high transaction costs

A stylised illustration of the economic costs associated with higher than otherwise transaction costs for market participants is displayed below in Figure 10. Transaction costs can be considered as equivalent to a tax on transactions, resulting in supply and demand curves shifting inward from where they would otherwise be. When market participants' transaction costs of purchasing and trading gas are lowered, it results in an outward shift in both the supply and demand curves. For a given export parity price, this results in the quantity produced and consumed shifting from Q to Q1, resulting in improved producer and consumer surplus of A + B.

Figure 10: Stylised illustration of the economic gain associated with high transaction costs



Source: PwC analysis

Evidence and implications

International literature suggests that derivatives markets have lowered transaction costs and increased average firm values:

- In the US aviation sector, airlines who opted to hedge jet fuel (a cost that comprises about 1/3rd of their total costs), increased their value by 12-16 per cent relative to airlines that opted not to hedge their fuel costs.[19] This gain was more likely to be captured by large firms.

- In the US gas and electricity sector, the introduction of weather derivatives allowed firms to hedge their exposure to volatility in electricity demand on hot days, and gas demand on cold days. The use of hedging was found to correlate to a 6-8 per cent increase in firm value.[20]

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[19] Carter, D. Rogers, D. Simkins, B. (2003). Does fuel hedging make economic sense: the case of the US Airline industry. Unpublished. Accessed: http://www.gresi-cetai.hec.ca/cref/sem/documents/030923.pdf, 10/03/2016.

[20] Perez-Gonzalez, F and Yun, H (2013) 'Risk Management and Firm Value: Evidence from Weather Derivatives'. The Journal of Finance, 68(5), p. 23-26.

- Likewise, in non-financial firms hedging foreign exchange risk, the 'hedging risk premium' was found to increase firm value by 4.87 per cent.[21]

- The introduction of futures trading for emissions in the European Union reduced the bid-ask spread (or costs of transacting) by 90 per cent.[22]

This provides evidence to support the notion that the costs of transacting in a liquid wholesale market will be lower than through continually negotiating by GSAs. It also shows that the potential introduction of hedging products to the market may lead to improved productivity for wholesale gas market participants.

Shocks modelled

Two shocks were developed to simulate these impacts:

- A positive productivity shock of 4.9 per cent applied to the industrial users, derived from a lower cost structure and improved risk management options.[23]
  - The magnitude of this shock represents the lowest bound of the data from the literature. Industry data was scaled according to gas intensity, in line with data from the VURM CGE model.
- An equivalent shock to the gas retailer sector of 4.9 per cent.
  - This excludes retailers that are vertically integrated with gas production, since they are assumed to have a natural hedge advantage and so will gain less from the improved risk management options.

We note that some small retailers have raised issues with the Southern Hub recommendations[24] and that the main impact will be to increase costs. In our central estimate we have assumed that these concerns are not reflective of the impact on the broader retail market as the parties raising these issues have a small market share.[25] However, this is acknowledged and tested as a sensitivity (the sensitivity analysis is described further in Chapter 5).

Investment effect

Issues in base case

The lack of clear pricing signals and insufficient liquidity in the derivatives market mean that gas prices are difficult to hedge and investment signals are decoupled from supply and demand fundamentals.

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[21] Allayannis, G. and Weston, JP. (2001). 'The use of foreign currency derivatives and firm market value', *Review of financial studies*. 14(1), p. 267.

[22] Frino, A., Kruk, J., & Lepone, A. (2010). Liquidity and transaction costs in the European carbon futures market. Journal of Derivatives & Hedge Funds, 16(2), p. 108.

[23] This considers that increasing firm value-add can drive higher firm value at an industry wide level.

[24] http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-Victorian-Declared-Wholesale-Gas-Mar Accessed 15 April 2016

[25] These views are provided by ERM Power and Covau – see http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-Victorian-Declared-Wholesale-Gas-Mar Accessed 15 April 2016. These retailers do not materially feature in the small residential customer market (Australian Energy Regulator, State of the Energy Market 2015, March 2016, p 125-126), which comprises the majority of customer numbers, and a large component of the retail market by revenue (IBIS World, Gas supply in Australia, IBISWorld Industry Report D2700, October 2015, p. 14).

Solutions in policy case

In the policy case we assume gas users' business plans adjust to a more reliable means of acquiring gas and additional participants enter the market. With prices adjusting to reflect supply and demand fundamentals, and cash flow improved from greater risk management, the climate for upstream and downstream investment becomes more favourable.

Furthermore, the reforms could enable pipeline investments to be more efficiently allocated, with clearer investment signals that are linked to supply and demand fundamentals through improved price discovery from benchmark prices on the Northern and Southern hubs.

Evidence

Australian literature suggests that investment signals in the water and electricity sector improved following major reforms (e.g. Gonzalez and Yun, 2013[26], showed that the introduction of weather derivatives to the electricity and gas market in the US was linked to increased investment levels), while major energy market reforms abroad have assisted in increasing retail competition.[27] We consider it likely that similar affects would be observed for gas market participants. However, these effects are outcomes of the productivity effect and so are not modelled as additional exogenous shocks to the model.

As noted above, there is evidence to show that futures markets lead to more efficient price discovery. It is reasonable to assume that more transparent information on the supply and demand fundamentals across the east coast market would improve the level of information available for pipeline investment decisions. This would be facilitated through the provision of two benchmark prices from liquid markets and the pricing of entry-exit points in the southern hub. Therefore it is plausible to assume that this flows onto increased efficiency for future investments.

Shocks modelled

We model a small decrease in the expected equilibrium rate of return required on investment for pipelines of one per cent. The expected equilibrium rate of return is what is required to attract a certain amount of investment. Lowering this slightly increases the amount of investment in the industry.[28] It is important to note that this does not necessarily equate to a change in the regulated rates of return for parts of the gas network that are regulated by the Australian Energy Regulator. Nor does it follow that any benefits necessarily accrue to pipeline owners; the CGE model provides a stylised framework of the economy and while it has a sector for the transmission of gas, it does not include specific behaviours surrounding regulatory oversight.[29]

3.2 Estimation of impacts/shocks

This section describes the results of the CGE modelling and quantifies the economic benefits of the reforms at an aggregated, regional and sectoral level.

The reforms are assumed to begin in 2020. However, their associated effects are expected to occur gradually over three stages (and then resulting in second round-effects).

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[26] Perez-Gonzalez, F and Yun, H (2013) 'Risk Management and Firm Value: Evidence from Weather Derivatives', The Journal of Finance, 68(5) pp 2143-2176.

[27] For example, electricity market reforms in the Czech Republic in the last decade led to a substantial increase in the number of retail customers switching suppliers (ACER/CEER, *Annual report on the results of monitoring the internal electricity and natural gas markets in 2013,* 2014).

[28] Lowering the expected equilibrium rate of return required increases the amount of investment in the industry as investment does not need to be expected to be quite so profitable in order to be undertaken. Another variable in the CGE model that could have been shocked is capital productivity however that would affect existing capital and this impact is intentionally on new capital as it will be affecting investment decisions.

[29] Neither does the CGE model assume that these benefits necessarily accrue to pipeline owners.

The main results reflect the set of central shocks, as described in Chapter 3 above, with tests of robustness undertaken through the use of 'high' and 'low' alternatives. Unless specified, the results consider the trading, productivity and investment effects combined.

Values are expressed in $2015-16. Industry level output is escalated to $2015-16 using the implicit price deflator (IPD) for that industry's output, while state and national output is escalated using the GDP deflator.[30]

3.2.1 Aggregate impact

Simulations of the combined package of reforms in an economy wide-model indicate that they are expected to have substantial, widespread impacts on the east-coast economy. In aggregate the reforms are expected to lift GDP, relative to the baseline, by $1.1 billion per year after 10 years, and by $1.5 billion per year after 2040 (Table 5). The increase in income generated flows through to an extra $820 million of household consumption by 2040 and the employment of an additional 900 people relative to the base case. The increased productivity impacts mean the economic gains are mainly in higher real wages rather than employment.

In present value terms, the reforms drive an additional $8.7 billion of GDP including $3.7 billion of household consumption over the 20 years to 2040.

Table 5: Cumulative impacts of reforms on real GDP and employment ($, m 2013-14)

Indicator	2020	2030	2040	PV
Increase in GDP above baseline (%)	0.02%	0.04%	0.04%	-
Increase in GDP above baseline ($m)	490	1,080	1,510	8,720
Increase in household consumption above baseline (%)	0.01%	0.04%	0.05%	-
Increase in household consumption above baseline ($m)	130	490	820	3,750
Increase in employment above baseline (%)	0.02%	0.01%	0.01%	-
Increase in employment above baseline ('000)	2.1	0.9	0.9	-

Note: Results show deviation from baseline, including the impact on all states and territories. Values are $2015-16. Present values are calculated to 2040 using a 7% real discount rate.

Source: PwC analysis

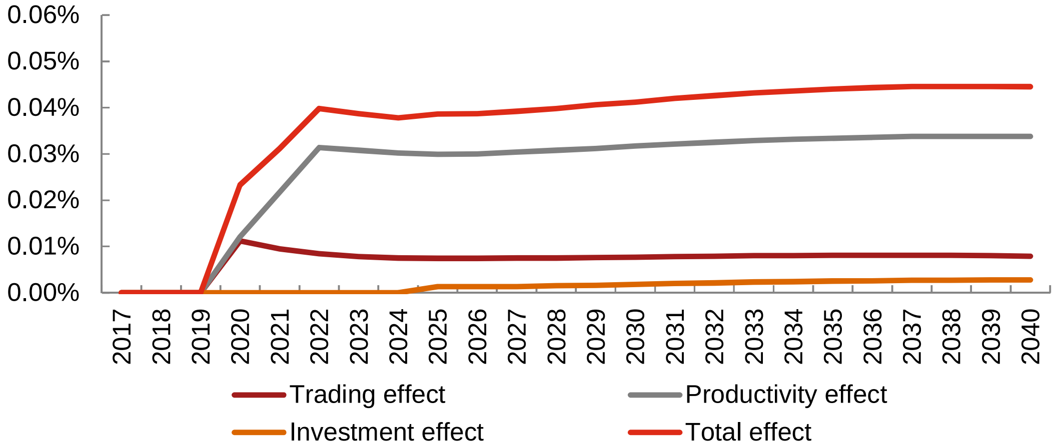
All elements of the reforms are expected to contribute to higher real income. The largest impact on productivity comes from lower transaction costs and improved risk management capabilities, which are estimated to produce the largest benefit (increasing GDP by around 0.04 per cent) relative to the base case. This is illustrated in Figure 11, which shows the cumulative impacts on GDP over time with individual simulations for the trading, productivity and investment effects.

The impacts accumulate over time as the different effects come into play. This is due to the assumptions about the timing of the benefits outlined above. While the productivity effect and the investment effect exhibit a step change in GDP, the trading effect shows an initial spike that is then offset. This pattern is attributed to the increased exports increasing

[30] Industry level IPD's and the GDP deflator are derived using ABS catalogue 5204.0. 2015-16 values are estimated using national forecasts contained in the 2015 Commonwealth Mid-Year Economic and Fiscal Outlook. The mining industry IPD is estimated by extrapolating the relationship between its movements and the terms of trade observed in 2014-15, while the IPD for other industries is derived to ensure that the GDP moves in line with the forecast movements in the non-farm GDP deflator.

resource demands in the LNG production sector and an appreciation in the real exchange rate. Both of these effects impact other export orientated sectors and this offsets the initial growth.

Figure 11: GDP deviation from baseline by individual effect (%, deviation from baseline GDP)



Source: PwC analysis

3.2.2 Sectoral impact

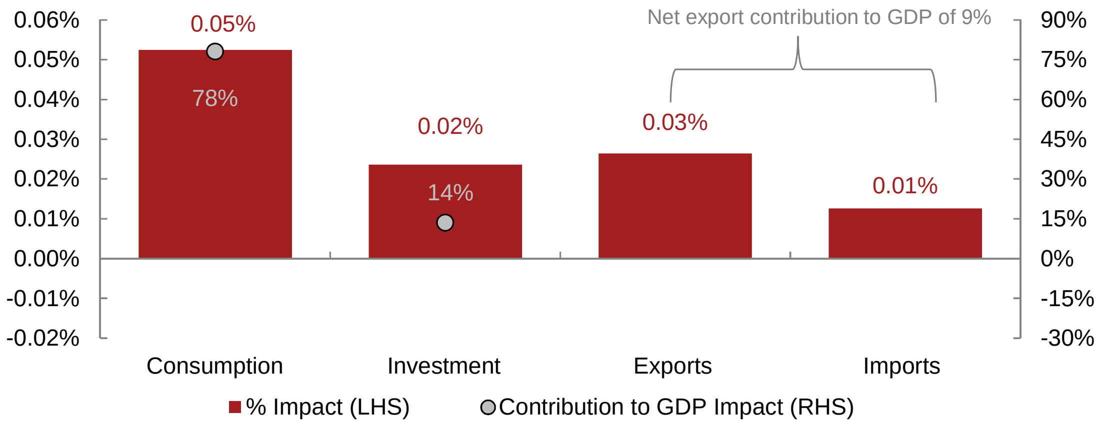
The effects of the reforms were also assessed in terms of their impact on different industries and sectors within the economy (the sectoral impact). This includes both the direct impact of the reforms on gas market participants and the broader second-round affect to other industries through economic linkages.

The results are driven by several economic adjustments that occur as a result of the shock. In particular:

- The productivity of gas-using and producing industries is increased relative to the status quo, increasing the returns from its factors of production relative to industries that use similar factors of production elsewhere.
- The expansion of output in these industries increases the demand for intermediate goods and services from other industries, increasing the value-added of those supplying industries.
- The increase in sales also results in higher investment, which, together with increased productivity, flows back to households through higher real wages, resulting in additional consumption spending.
- At the same time an expansion in LNG and other exports, driven by the productivity gains, places upward pressure on the exchange rate, reducing the competitiveness of a number of trade exposed industries.

The relative contribution of the impacts on consumption, investment and trade are shown below in Figure 12. This highlights that while the estimated appreciation of the exchange rate had a dampening effect on trade exposed sectors, the reforms contribute significantly to domestic economic activity, with consumption and investment (both private and public) driving the majority of the increase in GDP relative to the baseline.

Figure 12: Impact on GDP by expenditure component in 2040 (% deviation from baseline level)



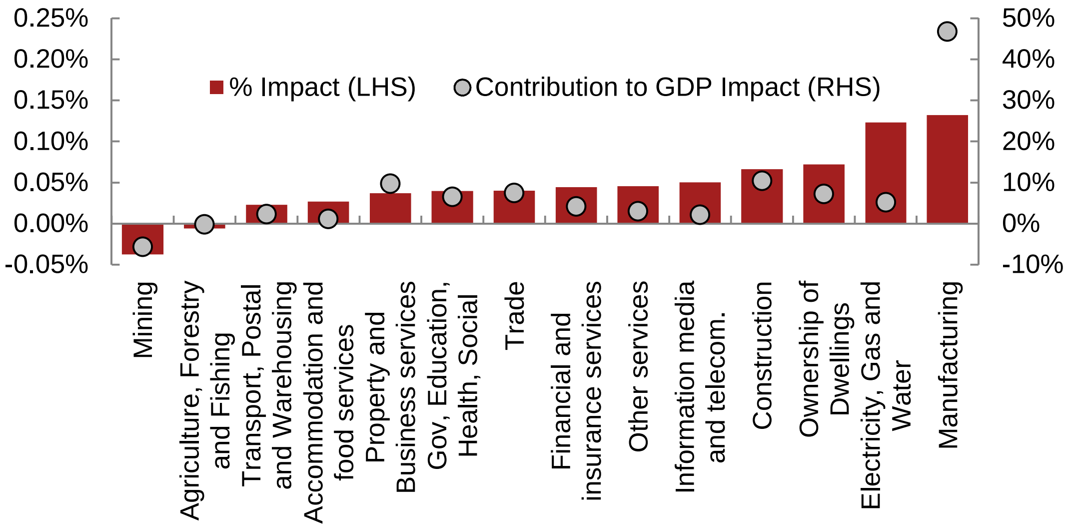
Source: PwC analysis

As shown in Figure 13, the overall outcome is that reforms are expected to have pervasive sectoral impacts.[31] In particular:

- Manufacturing output (Gross Value Added (GVA)) is estimated to expand by around 0.15 per cent relative to the baseline, accounting for nearly 50 per cent of the incremental change in GDP. This reflects a step change in production possibilities for gas intensive manufacturers.
- Other key industries linked to the gas market, such as gas retailing and distribution (counted in the electricity, gas and water) and pipeline transport (counted in the transport, postal and warehousing) also gain from improved productivity and investment signals respectively.
- The output of the mining industry (which includes natural gas extraction and LNG production) is estimated to be smaller than the base case despite productivity improvements in the gas extraction industry. This reflects the effects of a higher than otherwise exchange rate and competition for labour and intermediate goods with other extractive industries. These offset the gains in the gas sector so that when combined, the mining sector output is smaller.
- There is evidence of broad second round impact, particularly in services industries, which benefit from an expansion of investment and household consumption.

[31] Shows impacts by broad ANZSIC category, which is standard for ABS national accounting purposes. See Appendix C for more detail on the concordance between industry classification and the shocks described in this chapter.

Figure 13: Impact on industry output in 2040 (% deviation from baseline GVA)



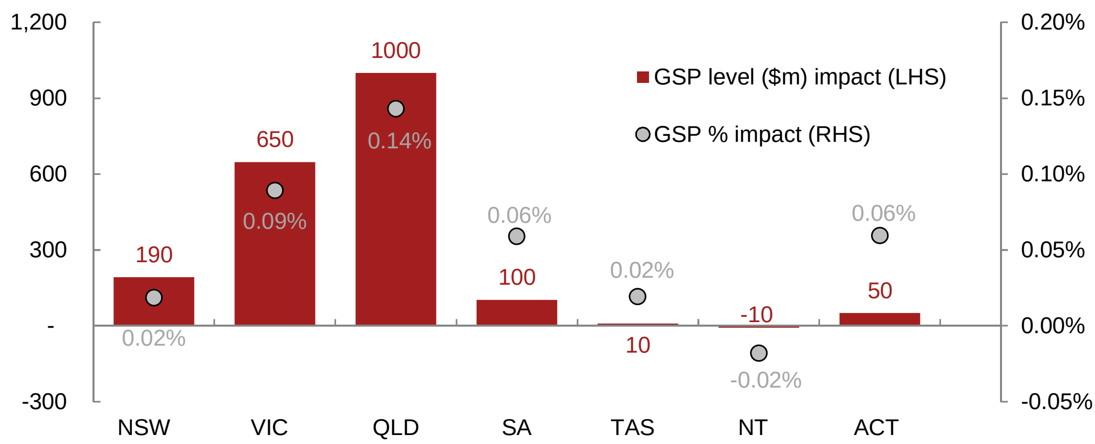
Source: PwC analysis

3.2.3 Impact by state and region

As was the case with industries, not all states and territory will experience equal economic impacts, given that each region has different gas supply and demand and different industry characteristics. This is highlighted below in:

- Figure 14, which displays the impact of the reforms on Gross State Product (GSP)
- Figure 15, which shows the impact on industry output.

Figure 14: Impact on Gross State Product (GSP, %) and level impact in 2040 ($m)



Note: WA is not shown as it is not part of the east coast wholesale gas market. It is estimated that WA's GSP will decline relative to the base case, driven by the reallocation of resources in search of higher returns.

Source: PwC analysis

The output suggests that the benefits of the reforms are expected to be widespread across regions, although the concentration varies. Some key findings include:

- **Queensland** is estimated to contribute the most to the aggregate impact (with GSP larger by 0.14 per cent, or around two thirds of the aggregate impact). This is driven by higher productivity in gas production and liquefaction (driven by the trading effect) and industrial manufacturing (particularly alumina, cement and construction materials).

- **Victoria** was estimated to have a more moderate expansion (0.09 per cent) that is domestically focused and broad-based, reflecting the more significant role played by manufacturing and the retail gas industry.

- **South Australia** is estimated to gain, although to a smaller extent (GSP is 0.06 per cent higher). The main contributors to this are the utility and construction sectors, along with gas production and industrial manufacturing.

- **NT** was estimated to decline marginally relative to the base case, reflecting the net effects of a higher exchange rate on its exporting industries.

- **Other east coast economies** are estimated to be only modestly larger than in the base case given that gas plays a smaller role in these economies. The impacts are also expected to be broad based, and largely reflect improved supply for residential and commercial consumers of retail gas in urban areas.

Figure 15: Impact on industry output in 2040 (% deviation from baseline GVA) (aggregate)

	NSW	VIC	QLD	SA
Agriculture, Forestry and Fishing	-0.01%	0.01%	-0.01%	0.00%
Mining	0.01%	0.08%	0.09%	0.13%
Manufacturing	0.01%	0.14%	0.86%	0.13%
Electricity, Gas and Water	0.08%	0.12%	0.27%	0.16%
Construction	0.06%	0.14%	0.16%	0.15%
Trade	0.01%	0.09%	0.13%	0.05%
Accommodation and food services	0.00%	0.07%	0.06%	0.04%
Transport, Postal and Warehousing	-0.01%	0.08%	0.14%	0.06%
Information media and telecom.	0.02%	0.13%	0.05%	0.08%
Financial and insurance services	0.03%	0.07%	0.08%	0.05%
Property and Business services	0.01%	0.09%	0.12%	0.07%
Gov, Education, Health, Social	0.03%	0.06%	0.07%	0.05%
Other services	0.03%	0.1%	0.09%	0.05%

	TAS	NT	ACT
Agriculture, Forestry and Fishing	0.00%	-0.01%	0.06%
Mining	0.00%	-0.02%	0.00%
Manufacturing	0.03%	0.04%	0.02%
Electricity, Gas and Water	0.07%	-0.01%	0.07%
Construction	0.08%	0.00%	0.11%
Trade	0.01%	-0.02%	0.06%
Accommodation and food services	0.02%	-0.02%	0.05%
Transport, Postal and Warehousing	0.04%	-0.06%	0.01%
Information media and telecom.	-0.02%	-0.04%	0.04%
Financial and insurance services	0.01%	-0.04%	0.05%
Property and Business services	-0.01%	-0.04%	0.05%
Gov, Education, Health, Social	0.03%	0.02%	0.05%
Other services	0.03%	0.01%	0.07%

Source: PwC analysis

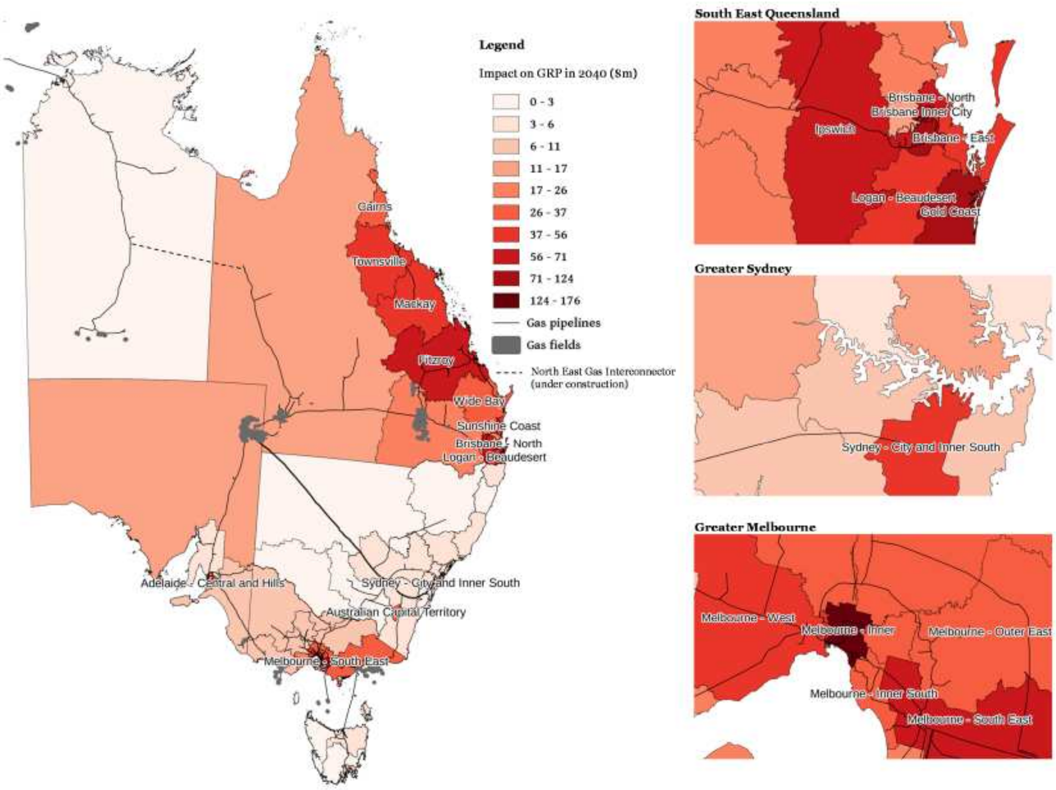
The economic impacts of the reforms on different regions were also analysed using PwC's Geospatial Economic Model (GEM). GEM is a framework that contains economic and social accounts for 2,214 locations across Australia, providing a lens for analysing the implications of industry impacts, as estimated in the CGE model, for different regions across Australia. Further detail on GEM can be found in Appendix D.

The impact of the reform on regions at the SA4 level[32] is highlighted in Figure 16, which shows the impact on Gross Regional Product (GRP and Figure 17, which shows the impact on manufacturing output.). Some key outcomes include:

- The benefits of the reforms are expected to benefit both urban and regional areas; however the impact on regional Australia is expected to be strongest in Queensland and South Australia. This reflects the location of key production basins in regional SA (Cooper basin) and Queensland (Surat/Bowen) along with LNG plants in regional and gas intensive manufacturing operations along the central Queensland coast.

- Greater capital city regions are all expected to benefit. However, this is more weighted towards a broader range of services industries and retail gas in Greater Melbourne than Greater Brisbane, which has impacts that are more concentrated in the manufacturing industry.

Figure 16: Economic Impacts on gross regional product in 2040

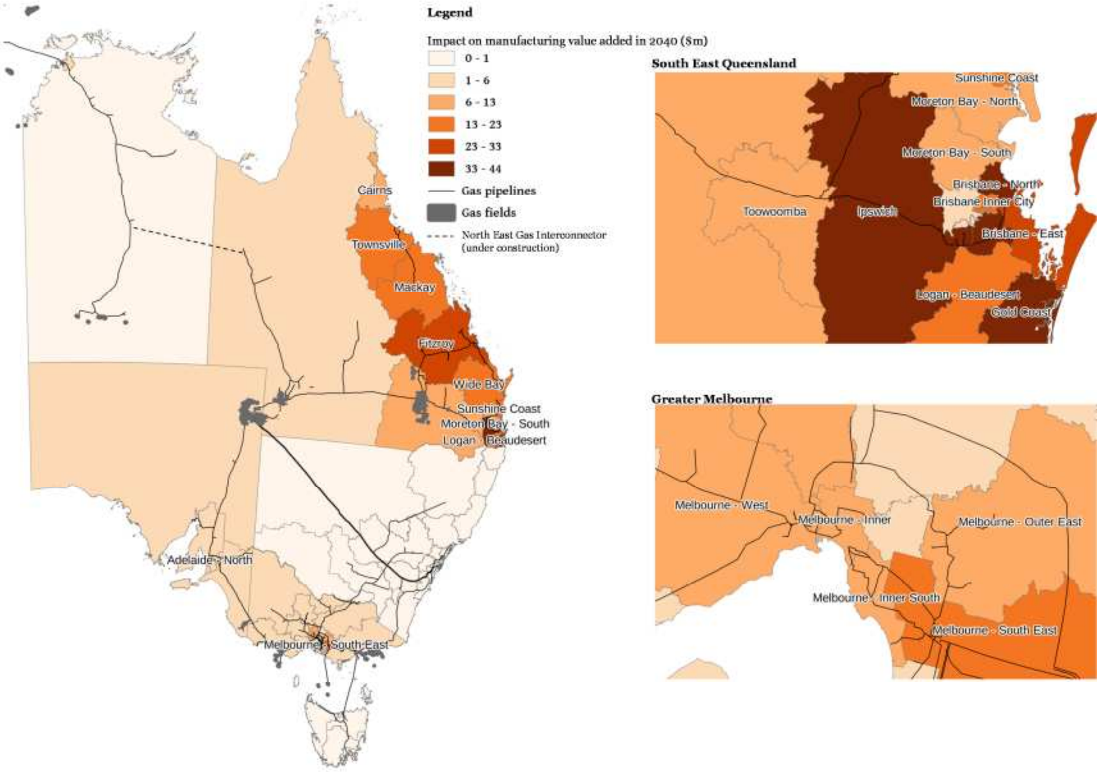


Note: Regions represented are Statistical Areas 4 as defined by the ABS. Values are in 2015-16 dollars. Regions with the largest impacts are named. Western Australia is not included here as it is not part of the east coast gas market; however, as is noted above, the impact is to reallocate some resources away from Western Australia.

Source: PwC analysis.

32 Statistical Area 4 (SA4) are the largest sub-State regions, as classified by the ABS.

Figure 17: Impacts on manufacturing GVA in 2040 by region



Note: Regions represented are Statistical Areas 4 as defined by the ABS. Values are in 2015-16 dollars. Regions with the largest impacts are named. Western Australia is not included here as it is not part of the east coast gas market; however, as is noted above, the impact is to reallocate some resources away from Western Australia.

Source: PwC analysis.

4 Reform costs

This chapter describes and quantifies, at a high level, the direct costs associated with the AEMC's proposed reforms. Our approach to this cost benefit analysis has been to estimate the net economic benefits once the reforms are implemented (these are outlined in detail in chapter 3), and for reference, provide an estimate of the investment required by stakeholders in order to implement the reforms. The costs are detailed in this chapter. To be clear, these costs are not net of the benefits. While the nature and quantum of costs incurred by stakeholders will depend on the final recommendations put forward by the AEMC, consultation has allowed us to provide indicative estimates of costs based on informed assumptions of the way that the reforms may be implemented and operated. The sensitivity analysis (provided in Chapter 5) provides low, central and high estimates of the costs to show the range of potential costs. The central estimate represents the most likely scenario of costs as expressed by stakeholders and assumed by PwC. This chapter describes assumptions and results estimated under the central scenario, further detail is provided in Appendix E.

4.1 Overview

4.1.1 Framework

A discounted cash flow framework is used to capture the various costs (e.g. planning, IT systems, labour) expected to be incurred by stakeholders as the reforms are implemented. A bottom up approach is used to capture three broad cost types:

- ***Planning costs:*** Costs associated with working groups and related work streams to design elements of various reforms.

- ***Implementations costs:*** "Up front" costs incurred on a one-off basis in relation to systems development and implementation, and any training costs (net of any necessary improvements, upgrades or maintenance that would happen under the base case of no reforms).

- ***Ongoing costs:*** Any additional costs incurred on an ongoing basis such as labour and systems maintenance costs of new systems.

We have broadly captured costs across the three reform areas that have been identified by the AEMC, namely:

- costs associated with pipeline capacity reforms (the development of a capacity trading and auction platform)

- costs associated with wholesale gas market reforms (the transition from the current Declared Wholesale Gas Market framework in Victoria to a voluntary entry-exit model)[33]

- costs associated with information provision reforms (requirements for existing businesses reporting to the Gas Bulletin Board to provide additional information and for other new businesses to provide information for the first time).

[33] While the proposed wholesale gas market reforms also include supporting the development of a Northern Hub, the additional costs associated with this component of the reforms are assumed to be minor given that developments are occurring independently of the AEMC's work (e.g. work on optional hub services at Wallumbilla has already been undertaken by AEMO).

Costs are captured over two time periods – the first ten years of the reform period (2016 to 2026), as well as out to 2040 (to align with the benefits analysis in Chapter 3). All costs are discounted to 2015-16 dollars using a real discount rate of 7 per cent[34].

4.1.2 Data sources

In order to build up indicative cost estimates across the reform categories stakeholder submissions were analysed and a targeted round of consultation was undertaken with a small number of industry stakeholders to test assumptions around the types of costs likely to be associated with the reforms, and where possible more accurately quantify potential costs. Quantified estimates of costs gathered from stakeholder consultations and submissions are assumed to be provided in 2015-16 dollars unless otherwise stated.

Where stakeholder submissions and consultations could not inform estimates we have drawn upon existing analysis undertaken in regard to previous reforms to Australia's gas market, namely the development of the Sydney and Adelaide Short Term Trading Market (STTM) hubs and the Wallumbilla Gas Supply Hub (GSH). These are relevant because they include similar stakeholders and types of costs.

4.2 Cost estimates

The following section provides the results of the cost analysis across the three reform areas – pipeline capacity trading, wholesale gas markets and information provision.

4.2.1 Pipeline capacity trading reforms

For the purposes of this assessment, we have assumed that pipeline operators develop independent capacity trading and auction platforms, as opposed to a single capacity trading and auction platform.

Should a single party be responsible for developing a single capacity trading and/or auction platform, this would likely result in a redistribution of costs amongst stakeholders, including:

- Higher costs for the party hosting the platform to design and implement platforms, and to operate these on an ongoing basis. In particular, this relates to the costs associated with designing a single daily auction.

- Higher upfront and ongoing costs for pipeline operators to ensure that their systems interface effectively with the host party's systems. As noted above, consultation has indicated that these include interface costs associated with the operation of a single auction platform.

- Lower costs for market participants as interfacing with a single capacity trading and auction system would reduce systems costs relative to a multiple platform approach.

Timing

The timeframes for implementation are broadly based on implementation timeframes outlined by the AEMC in its Stage 2 Draft report:

- commencement of the reform planning and design process is assumed to follow the COAG decision in July 2016 and occur over an 18 month period to December 2017

- systems implementation occurs over a one year period from January 2017

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[34] Department of Prime Minister and Cabinet: Office of Best Practice Regulation, (2016), Guidance note: Cost benefit analysis, https://www.dpmc.gov.au/sites/default/files/publications/006_Cost-benefit_analysis_0.pdf, page 7.

- capacity trading and auctions commence in January 2018.[35]

Planning costs

Based on stakeholder consultations we have assumed that four working groups would be formed in order to plan and implement pipeline capacity trading. This captures the possibility that more than one working group may be required for the main reform elements of standardisation, trading platform design and auction design (e.g. separate working groups may be formed for primary and secondary standardisation). These assumptions are based on a complex process of implementation and are therefore conservative (high cost). Some stakeholders have expressed that this process may be less complicated, the sensitivity analysis in Chapter 5, captures this. Other assumptions under the central cost estimates are:

- 15 members for each of the four working groups (this is based on stakeholder consultation that typically gas market working groups attract up to 20 attendees per meeting).
- frequency of working group meetings of once per month for the first year, and fortnightly for the final six months (24 meetings per working group)
- an average meeting duration of 4 hours (half day workshops)
- 50 per cent of attendees are required to travel
- additional support per working group member at a rate of twice the duration of working group meetings (i.e. 8 hours of support for each meeting)
- additional consultation time per working group member at a rate of twice the duration of working group meetings (i.e. 8 hours of consultation for each meeting).

We note that additional incidental costs may be associated with the planning process (for example venue hire); however these are not expected to be material and have not been included in our estimates.

Additionally stakeholder submissions suggested that an industry steering committee would be formed to oversee the reforms and operation of the new capacity trading market in the early years. We assume that this steering committee will exist for four years to implement and monitor the reform process from an industry perspective. Stakeholder submissions suggested that there would be eight members, meeting monthly for three hours. Assumptions about travel, support and consultation are consistent with those for the working groups noted above.

Based on these above assumptions, total planning costs in relation to pipeline capacity trading reforms are estimated to be $3.9 million in present value terms.

AEMO costs

Total costs expected to be incurred by AEMO depend on the extent to which it is given responsibility for developing, implementing and operating the resulting platform/s.

Assuming that pipeline operators are responsible for developing capacity trading and auction platforms, we assume that design and implementation costs incurred by AEMO are negligible (though AEMO would be expected to incur some of the planning costs outlined

[35] We note that in its submission, the Australian Pipelines and Gas Association expects that under its proposed industry-led approach, an earlier start date of October 2017 is assumed. From a cost perspective, the marginally longer assumed planning period is not expected to impact costs materially.

above).[36] We note that costs incurred by AEMO are generally recovered from market participants through fees.

Pipeline operator costs

Pipeline operators will incur up-front costs to develop capacity trading and auction platforms. Assuming four platforms were developed (as advised by the AEMC), total up-front implementation costs are estimated to be $7.9 million in present value terms.

Pipeline capacity trading reforms are expected to result in additional ongoing costs being incurred. Stakeholder consultation indicated that this is likely to be in line with costs incurred in relation to the STTMs. Based on this assumption, ongoing costs are estimated at $1.6 million in present value terms over ten years.

Large market participant costs

The scale of costs incurred by market participants (e.g. producers, large retailers, small retailers, self-contracting end-users) is expected to differ based on the size of the entity, and the frequency with which the entity utilises any platforms. As a simplifying assumption, we have estimated costs for two types of market participants – large participants and small participants. For the purposes of this costing analysis large participants are assumed to comprise of major gas retailers and producers.

Stakeholder consultation indicates that systems upgrades will need to be undertaken in relation to both pipeline capacity trading reforms as well as transitioning to a voluntary entry-exit market in Victoria (i.e. the wholesale gas market reforms). The magnitude of these costs is largely attributable to the fact that large participants will likely require custom IT solutions to be developed, as opposed to utilising an ‘off the shelf’ trading product (which would be a more feasible option for small participants and new entrants). Large trading participants have unique needs and preferences that are reflected in their automated systems and IT platforms, moving to an off the shelf product is not feasible for large participants and as such their costs will be higher.

Upfront costs include IT systems costs and an additional allowance to interface with multiple platforms, training costs and legal and commercial costs to renegotiate existing agreements.

In total, upfront costs for large participants are estimated at $21.1 million in present value terms.

Ongoing costs are expected to be incurred in the form of IT systems maintenance and additional staff. Stakeholder consultation indicates that three additional FTE positions would be required (as a midpoint) in relation to trading functions for both pipeline capacity reforms and wholesale gas market reforms. Further, an additional 2.25 risk and settlement staff would also be required (as a midpoint estimate). Therefore we have allowed for 5.25 total additional FTEs. Again, we have assumed that 25 per cent of ongoing costs in the form of IT maintenance and additional labour requirements are attributable to pipeline capacity trading reforms.

Total ongoing costs for large participants are estimated at $17.3 million in present value terms over ten years. Total costs (up-front and ongoing) incurred by large market participants are estimated to be $38.4 million in present value terms, over ten years.

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[36] Were AEMO to lead the development of capacity trading and auction platforms, initial discussions with AEMO suggest that very high level costs estimates would be in the range of $1 million to $3 million in upfront IT costs, with an additional $1 million to $3 million for design and legal costs. AEMO would also incur ongoing costs to operate both platforms.

Small market participants

The number of small market participants expected to engage in pipeline capacity trading platforms is uncertain. As a mid-range estimate, we have assumed that the number of participants on the platforms will be the same as the Victorian DWGM. Based on the AEMC's data we estimate that there are 25 participants in the DWGM.[37] Assuming that six of these are large participants, this would result in 19 small participants.

Similar to large participants, small participants will also incur costs to implement new systems. Based on consultation it is expected that that these costs will be lower than for large participants, as off the shelf trading products are more likely to be utilised as opposed to developing customised IT solutions. We have assumed an up-front cost of $109,000 per small market participant based on estimated implementation costs provided to AEMO in relation to the Wallumbilla GSH[38]. Total upfront costs across small market participants are estimated at $1.9 million in present value terms, over ten years.

Ongoing costs are also likely to be incurred, though again these are expected to be relatively minor compared to larger participants. Stakeholder consultation suggests that pipeline capacity trading will largely be absorbed into existing trading functions, though it should be noted that for end-users currently lacking trading capabilities, ongoing costs would be higher. Our central estimate is that an additional 0.25 FTE would be employed per small market participant. This results in ongoing costs of $5.4 million in present value terms, over ten years.

4.2.2 Southern Hub wholesale gas market reforms

Similar to the pipeline capacity trading reforms, many specific details of reforms to the DWGM are still being developed. For the purposes of this analysis we assume that the system operator role remains with AEMO under the voluntary entry-exit market.[39]

Timing

Similar to timing assumptions for pipeline capacity reforms, we have based our assumptions on high level timeframes outlined by the AEMC in its Stage 2 Draft Report. Key assumptions are:

- a two year planning process commencing in January 2017
- an one year implementation process commencing January 2019
- market operation commencing in January 2020.[40]

Planning costs

Stakeholder feedback indicates that the planning processes for changes to the Victorian market are expected to be more complex than those for pipeline capacity trading. Our mid-range assumption is for a planning period of two years.

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37 Australian Energy Market Commission, 2015, Stage 1 Draft Report: East Coast Wholesale Gas Market and Pipeline Frameworks Review, Sydney, NSW.

38 Australian Energy Market Operator 2012, Detailed design for a gas supply hub at Wallumbilla, 19 October 2012, indexed to 2015-16 dollars using the consumer price index, (Australian Bureau of Statistics (2016) Consumer Price Index, Australia. December 2015).

39 While the proposed wholesale gas market reforms also include supporting the development of a Northern Hub, the additional costs associated with this component of the reforms is assumed to be minor given that developments are occurring independently of the AEMC's work (e.g. work around optional hub services at Wallumbilla has already been undertaken by AEMO).

40 AEMC, 2015, Stage 2 draft report; East coast wholesale gas market and pipeline frameworks review. 4 Dec 2015. p. vii.

Based on stakeholder consultations we have assumed that six working groups would be formed in order to plan and implement a transition to a voluntary entry-exit model. As stakeholders have indicated that the Southern Hub reforms are more complex, the assumptions for the running of working groups are the same as for pipeline capacity reforms except for:

- working groups will run for two years (compared to 18 months)
- frequency of working group meetings of once per month for the first year, and fortnightly for the final year (36 meetings per working group compared to 24)
- 25 per cent of attendees are required to travel (compared to 50 per cent as these participants are mainly Victorian based).

We note that additional incidental costs may be associated with the planning process (for example venue hire); however these are not expected to be material and have not been included in our estimates.

Based on these above assumptions, total planning costs in relation to pipeline capacity trading reforms are estimated to be $6.7 million in present value terms, over ten years.

AEMO costs

Consultation with AEMO indicates that costs associated with the transition to a new market model in Victoria are expected to be material.

At a high level, the nature of costs expected to be incurred relate to IT systems, design and legal costs and planning. Stakeholder consultation provided high-level cost estimates, with the caveat that there is a high degree of uncertainty around costs. AEMO indicated that costs of these reforms would be higher than they were for the STTM, with further consultation providing an estimated implementation cost of approximately double that of the STTM reforms. This equates to $26.6 million in present value terms, over ten years.[41]

Stakeholder consultation raised the point that AEMO is likely to require significant upgrades of its systems in coming years irrespective of whether the DWGM reforms are implemented. While we have attributed the total costs to the reforms in order to be conservative, we note that this likely overstates costs attributable to the reforms, given a proportion of costs are likely to be incurred under the base case.

In terms of ongoing costs we assume that AEMO will retain responsibility as the system operator, as well as market operator. It is unclear the extent to which ongoing costs under a new market structure will differ from existing ongoing costs. Changes to the DWGM may require AEMO to take on additional roles not currently required . We have used the estimated ongoing costs of the Wallumbilla GSH as a proxy for additional ongoing costs incurred under the new operating model.[42] This results in ongoing costs of $2.5 million in present value terms, over ten years.

Total costs incurred by AEMO are estimated to be $29.2 million in present value terms, over ten years (these are expected to be recovered from market participants through fees).

Pipeline owner operator

Under the AEMC’s proposed allocation of responsibilities, the pipeline owner in Victoria (APA Group) would be responsible for auctioning entry and exit rights. Additionally, up-

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[41] This figure is lower than the STTM budget due to the effects of discounting future cash flows.

[42] Australian Energy Market Operator 2012, *Detailed design for a gas supply hub at Wallumbilla*, 19 October 2012, Australia.

front costs would be incurred in order to develop a new tariff model, likely requiring external expertise from overseas markets. We have estimated upfront costs associated with designing an auction system and developing a tariff model to be in the range of $1.0 million in present value terms, over ten years.

It is expected that the current regulatory process undertaken with the Australian Energy Regulator (AER) would continue, with ongoing costs likely to remain similar to what they otherwise would have been.

Large market participants

Similar to pipeline capacity reforms, we assume that there will be six large market participants in the Southern Hub. As described in Section 4.2.1 large market participants are likely to incur upfront systems costs in relation to both pipeline capacity trading and the proposed Southern Hub reforms. We have apportioned 75 per cent of estimated systems costs to the Southern Hub reforms, totalling $35.5 million in present value terms over ten years.

Ongoing costs will be incurred in relation to additional trading staff (given market participants will need to continuously monitor and balance their position) as well as additional finance, risk and settlements staff. Ongoing IT systems maintenance costs will also be incurred. Similar to upfront IT costs, 75 per cent of total ongoing costs are allocated to the Southern Hub reforms. In total, ongoing costs are estimated at $36.8 million in present value terms, over ten years.

Total costs incurred by large market participants are estimated at $72.3 million in present value terms, over ten years.

Small market participants

Some small participant stakeholders have expressed concerns that reforms may decrease market liquidity and create new barriers to entry for potential participants.[43] Although these concerns are valid, they constitute transfers between stakeholders and are not expected to affect the total cost of reforms. Such distributional impacts may be considered further in any subsequent analysis such as a regulatory impact statement.

In terms of the affected population, we have assumed that 19 “small” entities will participate in the Southern Hub market. In addition to large market participants, this results in a total of 25 participants, in line with assumptions relating to the pipeline capacity trading platform.[44]

Given the extent of reforms proposed in Victoria, we have assumed that small participants would incur costs in relation to training of staff ($25,000 per participant) and systems development (approximately $110,000 per participant). These costs total $2.0 million in present value terms, over ten years across all participants.

Small participants will also incur additional ongoing costs given there will be a need to balance gas positions on a continual basis. We assume one additional FTE per small market participant, in order to give them capacity to trade 24 hours a day, resulting in ongoing costs of $15.4 million in present value terms, over ten years.

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43 These views are provided by ERM Power and Covau – see http://www.aemc.gov.au/Markets-Reviews-Advice/Review-of-the-Victorian-Declared-Wholesale-Gas-Mar Accessed 15 April 2016.

44 Our analysis of available information has found differing figures in relation to the number of current participants in the DWGM. AEMC’s Stage 1 Final report noted there were 52 participants currently. ERM Power in its response to the Review of the Victorian Declared Wholesale Gas Market Discussion Paper provided analysis suggesting this figure was overstated (including estimates of STTM participants), the total was in fact 18 participants. We have assumed 25 participants in total as our mid-range estimate.

4.2.3 Information provision reforms

Timing

Timeframes assumed in the model are based on those outlined by the AEMC in its Stage 2 Draft Report.

- Implementation will commence immediately following COAG decision in July 2016 and will run for six months.
- Information provision will commence in January 2017.[45]

AEMO costs

In order to allow for the publication of proposed additional information on the Gas Bulletin Board, some upgrades to existing systems would be required. These costs are estimated by AEMO to be in the order of $1.9 million, in present value terms, over ten years.

Furthermore, AEMO will incur ongoing costs in relation to quality assurance, compliance and reporting. Ongoing costs are estimated to be $1.3 million in present value terms, over ten years (AEMO is likely to recover these costs through fees levied on market participants).

Pipeline operators

Consultation with pipeline operators indicates systems upgrades costs will be required in order to provide additional information for the Gas Bulletin Board. These costs are estimated at $1.3 million in present value terms. We assume no ongoing costs are incurred by pipeline operators. As a simplifying assumption, we assume that the extra information will be published in the same way and with the same simplicity as the current information requirements.

Existing Gas Bulletin Board participants

The AEMC's proposed information provision reforms will require existing Gas Bulletin Board participants (in addition to pipeline operators) to provide additional information to AEMO. Consultation with the AEMC indicates the majority of this additional information is already collected, and will simply require transmission to AEMO both as a one-off and on an ongoing basis. Given this information is largely already collected, we assume additional costs to be negligible.

New Gas Bulletin Board participants

New Gas Bulletin Board participants will be required to set up new systems to collect and report information that is not currently required by AEMO. Consultation with the AEMC indicates that approximately 35 new entities will be required to report information. We have applied a high-level assumption that one-off costs to set up these systems will be in the order of $25,000 per entity. We have considered that in some cases the information is already collected, hence this cost only reflects the need to report it to a new entity (and in some cases to collect new information). This results in total costs of $0.8 million in present value terms. Ongoing costs to new participants are not expected to be material.

4.2.4 Considerations

As outlined above, there are large ranges associated with cost estimates given the high degree of uncertainty around specific elements of the proposed reforms. In particular estimates are sensitive to:

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45 We understand that it is now unlikely information provision changes will commence in January 2017 given the need for a rule change request but the assumption is consistent with the AEMC's original estimate in the Stage 2 Draft Report.

- A number of roles and responsibilities are yet to be determined (e.g. the extent to which design and planning for pipeline capacity trading reforms are industry-led vs regulator-led) and thus the implementation and ongoing costs are uncertain.

- The final design of certain reforms remain uncertain, influencing the ongoing costs that industry participants can expect to incur to participate (e.g. whether AEMO will develop and operate a single pipeline capacity trading platform, or pipeline operators will develop and operate multiple platforms).

- The extent to which certain reforms will be implemented (e.g. the extent of standardisation of pipeline capacity trading terms is expected to influence the resulting legal and commercial costs incurred to renegotiate existing contracts).

We have made the best effort to apply relevant proxies (i.e. cost estimates derived in previous analysis) where possible and to test these assumptions through a limited consultation process with some stakeholders. Participants in the consultation process emphasised the difficulty in providing firm cost estimates, and that any figures provided were indicative only and subject to final recommendations.

Finally, the costs estimated relate to planning, systems design and implementation, and ongoing labour costs that are all directly associated with the reforms. We have not estimated transfers that may occur as a result of the reforms nor potential distributional impacts. Whilst distributional impacts are important (and may be explored further in any subsequent analysis such as a regulatory impact statement) the focus of this analysis has been on the net economic costs which are not influenced by transfers between stakeholders.

Given the noted limitations, all cost estimates should be seen as indicative only and would be developed further through the consultative RIS process prior to any final decision or implementation occurring.

4.3 Summary

The following table summarises the costs that have been described above in detail. It also includes the undiscounted upfront and annual costs as well as the total costs at 2040.

Table 6: Estimated total costs by reform package ($m 2015-16)

	Once off implementation costs	Ongoing annual costs	Total costs over 10 years (discounted)	Total costs to 2040 (discounted)
Pipeline access	38.6	4.3	59.2	78.3
Wholesale gas trading market	90.1	13.6	126.5	187.1
Information provision	4.3	0.2	5.3	6.2
Total	133.0	18.1	191.0	271.6

Note: Totals are subject to rounding.

5 Summary and sensitivity analysis

5.1 Overall impact

The analysis in the central scenario indicates that, for an implementation cost between $133 million and ongoing annual costs between $18 million, the proposed reforms could lead to greater productivity growth, consumption, exports and investment, resulting in GDP that in net terms is $1.5 billion higher than it would have otherwise been in 2040.

Importantly, the change in GDP over and above the costs is estimated to be positive in each year following the reforms. That is, the reforms drive a 'level shift' in GDP that, in the central case, amounts to an estimated $8.7 billion of additional output in present value terms over the 20 years to 2040.

We note, however, that the estimated economic impacts and costs should be considered indicative. While the analysis is conducted using a robust analytical framework, the proposed reforms are still in a relatively early stage of development, and guidance on direct economic benefits has been sought from broadly comparable, but not equivalent policy experience elsewhere.

Accordingly, high and low sensitivities for the net benefits and the costs of reform are considered in the section below.

5.2 Sensitivity analysis

Net benefits:

High and low sensitivity tests were conducted to test the robustness of the results to changes in inputs (see Table 7). A comparison of the high and low scenario assumptions with the central scenario is shown in Table 8.

Table 7: Economic shock assumptions in high and low scenario

Indicator	Central	High scenario		Low scenario	
		%	Comment	%	Comment
Trading effect					
Capital productivity shock to industrial users	5%	7.5%	50% increase	0%	Lack of quantitative data
Factor productivity shock to LNG producers	0.2%	0.3%	50% increase	0.1%	50% decrease
Increase in gas exports	1%	1.5%	50% increase	0%	Lack of quantitative data

Indicator	Central	High scenario		Low scenario	
Productivity effect					
Factor productivity shock to industrial users	4.9%	12%	The low end of another research paper.[46]	2.45 %	50% decrease
Factor productivity shock for gas retail industry	4.9%	12%	As above, but shock is applied to all retailers	0%	Assumes that no retailers gain, reflecting concerns of some smaller retailers
Investment effect					
Equilibrium rate of return shock to pipeline investment	1%	1.5%	50% increase	0%	No benefit to pipeline operators, reflecting the concerns of some.

Source: PwC analysis

The results of the simulations under the high and low scenarios are shown below in Table 8. They indicate that the reforms are estimated to increase GDP by a range of 0.02 to 0.10 per cent relative to the baseline by 2040 (or around $0.5 to $3.3 billion in $2015-16).

Table 8: Sensitivity of simulation to alternative assumptions (% deviation from baseline)

Indicator	2020	2030	2040
GDP			
High scenario	0.05	0.09	0.10
Central scenario	0.02	0.04	0.04
Low scenario	0.01	0.01	0.01
Employment			
High scenario	0.03	0.01	0.01
Central scenario	0.02	0.01	0.01
Low scenario	0.00	0.00	0.00
Household consumption			
High scenario	0.03	0.09	0.12
Central scenario	0.01	0.04	0.05
Low scenario	0.00	0.01	0.02

46 Carter, D. Rogers, D. Simkins, B. (2003). Does fuel hedging make economic sense: the case of the US Airline industry. Unpublished. Accessed: http://www.gresi-cetai.hec.ca/cref/sem/documents/030923.pdf, 10/03/2016.

Source: PwC analysis.

Even under the low scenario, in which aggregate benefits to the economy are solely underpinned by productivity gains to industrial users sourcing gas through wholesale markets and efficiency gains from improved trading of excess gas supply, the new GDP generated, relative to the baseline, is material.

Costs:

Table 9 shows the range in the low and high estimates of costs relative to the central estimate presented in Chapter 4.

Where possible high and low estimates have been formulated from the upper and lower bounds of cost information supplied by stakeholders. Where that was not possible additional assumptions were made that the low estimate would be 25 per cent lower and the high estimate is 50 per cent higher, this uplift or 'discount' was applied to the smallest units possible (e.g. number of meetings each working group would have and the number of members who would attend, rather than a percentage uplift over the entire cost). This shows that the implementation costs could be between $77 million and $216 million while the ongoing costs could range from $10 million to $35 million.

Table 9: Costs estimates ($m 2015-16)

	Once off implementation costs			Ongoing annual costs			Total costs over 10 years (discounted)			Total costs to 2040 (discounted)		
	H	C	L	H	C	L	H	C	L	H	C	L
Pipeline access	62.3	38.6	16.8	7.8	4.3	1.2	100.4	59.2	21.9	135.0	78.3	27.2
Wholesale gas trading market	146.6	90.1	57.4	27.3	13.6	8.2	227.2	126.5	78.3	348.7	187.1	114.7
Information provision	6.6	4.3	2.8	0.3	0.2	0.2	8.2	5.3	3.6	9.5	6.2	4.3
Total	215.6	133.0	77.0	35.4	18.1	9.5	335.8	191.0	103.9	493.2	271.6	146.2

Note: Totals are subject to rounding. L = Low, H = High, C = Central

Appendices

Appendix A CGE model overview

Computable General Equilibrium (CGE) modelling is an economic modelling technique used to evaluate the direct and indirect impacts of policy reforms, environmental impacts, and other economy-wide changes. This appendix outlines what CGE models are; what they can and cannot do; and the CGE model that we propose to use in this engagement.

What are CGE models?

CGE models are detailed representations of the Australia economy, combining a real-world database (sourced from ABS input–output tables) with economic theory. These models are used to estimate the impact of external changes on the real economy. Based on the input–output National Accounting framework, they focus on the productive economy by looking at the way that different industries demand labour, capital and intermediate inputs subject to economic capacity constraints. Prices in the model are market clearing by default for all goods and services (although this assumption can be relaxed). The models include numerous industries, regions, and labour types, as well as several types of final demand (consumption, investment, state and federal governments, and exports).

CGE models are used to examine the economy-wide impacts of reform. By including each industry's demand for intermediate inputs, inter-state trade connections, and labour–capital intensity, the degree to which one industry impacts on another can be estimated. This not only includes the productive output of all industries, but also the income flows associated payments to labour, capital and governments (through taxation). In this way CGE models are used to examine three changes associated with an external impact to the economy (called a 'shock'):

- The degree to which the shock impacts directly on the industries targeted by the change
- The degree to which other industries are indirectly impacted by their connections to the directly targeted industry
- The degree to which economy-wide aggregates (such as gross state or national product, household consumption or real wages) are impacted, through the aggregation and interaction of all the industries in the economy.

Due to the detail in CGE models, they are able to report on a large number of industry, regional, and macroeconomic results. At the industry level, CGE models can report changes in activity level, employment, capital utilisation, wages, and prices, amongst others. At the regional level, they can report domestic and international trade flows, final demands, and population movements. At the macroeconomic level, they can be used to examine:

- gross domestic product (GDP)
- final demand
- trade balances
- government accounts
- various price aggregates (e.g. CPI and the GDP deflator).

Assumptions within the CGE model can also be controlled to reflect the nature of the scenario being examined. Short-run policies (approximately five years) can be examined, as can longer run policies (estimating the impact of policy in 20+ years). Further, the models can be tailored to reflect certain characteristics of the economy unique to the modelling: the nature of government balances, drivers of government spending, and household consumption.

What the results of CGE models mean

CGE models are principally used to look at the impacts of policy changes on real economic variables, such as employment or the productive capital stock. They are used to estimate the relative expansion or contraction of industries or regions relative to one another. The models themselves are built on a strong and well researched academic foundation: including a variety of price responses and substitution affects.

However, CGE results should not be interpreted as a prediction of exactly where the economy will be at a certain point in the future. CGE models are based on the economic concept of the general equilibrium: the point at which the markets for all goods and services clear.[47] As a result, CGE models do not incorporate the range of disequilibrium impacts seen in the short run in the real world. As a result, CGE model results can be thought of as the medium-to long-run impact that would result on the baseline level of output in the economy, abstracting from nominal and short-run disequilibrium effects.

CGE models only show the impact of the policy under investigation. They are not a broader tool for economic forecasting. As a result, any given CGE simulation will likely omit a range of external influences that are not directly relevant to the policy under investigation. Consequently, CGE results represent the change in the baseline level in the economic variables under investigation, solely attributable to the policy in question.

The interpretation and relevance of CGE results can be seen in the context of an example; in this case the construction of a new hospital in Victoria. A CGE model would describe the number of jobs created by the hospital, the degree to which it inflated the local wage and bid workers away from other industries, and the likely impact on gross state product. However, it would not reflect disequilibrium properties in the short run (e.g. the time required to train new labour to work in the hospital, financing issues associated with acquiring a capital (such as X-ray machines)). Further the results would be ‘all other things equal’: they would not reflect an unforeseen decline in labour supply that emerged five years down the line (unless the modeller inserted this change). In this way, CGE models present an over-arching ‘big picture’ impact of a change, once it has resolved itself in the economy and become part of the economic baseline.

CGE models do not include financial markets. It is argued that financial markets have no long-run persistent impacts on the real economy, only having real impacts in the short run. These short-run, disequilibrium states are not included in CGE results. Long-run impacts resulting from financial markets — such as changes in consumer preferences resulting from stocks of wealth — must be inserted in to the modelling externally. Further, CGE models are built around the ABS National Accounts Input–Output framework (as mentioned above), which does not include financial data. To include them would upset the balances in the national accounting.

47 Note that this does not imply that the markets have to clear efficiently. We can insert taxes, or uncompetitive behaviour moving the market to an inefficient market clearing price.

The VURM model

The Victoria University Regional Model (VURM) is a multi-regional, dynamic CGE model.[48] It distinguishes up to eight Australian regions (six States and two Territories) and up to 144 commodities/industries. The model recognises:

- domestic producers classified by industry and domestic region
- investors similarly classified
- up to eight region-specific household sectors
- an aggregate foreign purchaser of the domestic economy's exports
- flows of greenhouse gas emissions and energy usage by fuel and user
- up to eight state and territory governments
- the Commonwealth Government

The model contains explicit representations of intra-regional, inter-regional and international trade flows based on regional input-output data developed at the Centre of Policy Studies (CoPS), and includes detailed data on state and Federal governments' budgets. As each region is modelled as a mini-economy, VURM is ideally suited to determining the impact of region-specific economic shocks. Second round effects are captured via the model's input-output linkages and account for economy-wide and international constraints.

Outputs from the model include projections of:

- GDP and aggregate national employment
- sectoral output, value-added and employment by region
- export earnings, import expenditure and the balance of trade
- greenhouse gas emissions by fuel, fuel user and region of fuel use
- energy usage by fuel, energy user and region of energy use
- State and Territory revenues and expenditures
- regional gross products and employment
- regional international export earnings, international import expenditures and international balance of payments.

[48] VURM is the latest incarnation of the Centre of Policy Studies' MMRF model. The name change was triggered by CoPS move from Monash University to Victoria University in 2014.

Appendix B Literature review

This section presents the detailed findings of the literature review undertaken to assess the extent to which expected benefits are likely to be realised following the reforms. The aim of the literature review was to find quantitative data on the potential benefits of the AEMC's reforms. The literature review investigated a range of sectors (both in Australia and abroad) where more liquid markets have been introduced. The following tables note the qualitative findings of the references. The review is set out by the benefit categories outlined in Section 3.1.

Table 10: Findings on increased market efficiency from greater price transparency and more efficient price discovery

Sector	Value	Source and description
Oil (US and UK)	N/A	Tabak and Cajueiro (2007)[49] found that inefficiencies of the market (ability to predict prices based on past price data) have decreased dramatically in the 1990s, coinciding with the introduction of oil futures contracts and the overall deregulation of the market in the UK and the US.[50]
Oil	N/A	Silverio and Szklo (2012)[51] aim to empirically measure the degree of contribution of financial markets to the price discovery process in the spot markets for benchmark crude oil. They utilise two unique periods of sharp increases in the number of futures contracts on the market to measure the degree to which the futures market influences the spot price. They estimate a time varying coefficient that is always positive but below one; indicating that futures prices do not fully explain spot market prices.

49 Tabak, BM. And Cajueiro, DO. (2007). Are the crude oil markets becoming weakly efficient over time? A test for time-varying long-range dependence in prices and volatility. Energy Economics. 29(1). 28-36.

50 Important note – the market is still inefficient just less so (1980's Hurst 0.60-0.65 and 1990's Hurst 0.55-0.6). In the US there is a similar trend. Hurst's* are still well above 0.5 and indicate that the market is still far from efficient.

*Hurst coefficients or exponents can be thought of like correlation coefficients for autocorrelation, a value above 0.5 indicates that there is substantial long range autocorrelation and the prices of the past are a good indicators of the prices a long way into the future. Less than 0.5 indicates that the past prices do not provide much information on the future prices. When the Hurst is above 0.5 the market is inefficient because it is not following a random walk.

51 Silverio, R. and Szklo, A. (2012). The Effect of the financial sector on the evolution of oil prices: Analysis of the contribution of the futures market to the price discovery process in the WTI spot market. Energy Economics. 34 (6), 1799-1808

Sector	Value	Source and description
Oil (US)	Introduction of NYMEX crude oil futures. Volume and open interest in the market increased by 500% over the first year.	Fleming and Ostdiek (1999)[52] investigate both the short term and long term effects of the introduction of NYMEX (New York Mercantile Exchange) crude oil futures on the volatility of the crude oil market. They also investigate the effect on the depth and liquidity of the crude oil market. They find that within the first three weeks of introduction volatility increased sharply from 6.87 per cent to 14.52 per cent (p. 153). Over the next year the volatility appears to revert back to pre-trend levels, however the long term mean is 23.29 per cent (p. 154), indicating that volatility did increase in the long term as volume and open interest in the market increased. Open interest refers to the number of contracts outstanding in futures markets at any one time and volume refers to the total number of barrels contracted at the end of the day. The extent to which open interest and volume in the futures market impact volatility in the spot markets vary. For volume they vary between 0.644 per cent to 1.839 per cent, for open interest -0.158 per cent to -0.754 per cent (p. 162). This indicates that increasing the number of contracts (open interest) will decrease volatility while increasing volume will increase volatility. They conclude that futures contracts do improve depth and liquidity in the spot market.
Gas (EU)	N/A	Schultz and Sweiring (2002) [53] found that the 'financialisation' of commodity markets has had a clear impact on the price determination process. They present evidence that suggests price discovery occurs primarily via futures rather than the spot market, given its capacity to more rapidly incorporate new information. This was based on monthly expiring UK natural gas futures traded on the Intercontinental Exchange displaying greater price discovery than physical trading at the major hubs in North West Europe, particularly in the longer-term.
Electricity (EU)	N/A	Yang et al (2009)[54] find that the operation of the Nordic electricity futures market is efficient. More specifically, they find that the futures market plays a dominant role in the price discovery; the hedge reduces the risk of transaction to a certain extent; and the operation efficiency during 2000-2003 is higher than that during 1996-1999.

52 Fleming, J. and Ostdiek, B. (1999). The impact of energy derivatives on the crude oil market. Energy Economics. 21(2). 135-167.

53 Dwyer, A., Holloway, J. & Wright, M. (2012). Bulletin: Commodity Market Financialisation: A closer look at the evidence. Reserve Bank of Australia.
Lo, A. & MacKinlay, C. (1988). Stock market prices do not follow random walks: Evidence from a simple specification test. The Review of Financial Studies. 1:1 (41-66).
Schultz, E. & Swieringa, J. (2013). Price discovery in European natural gas markets. Energy Policy. 61 (628-634).
Asche, F. Osmundsen, P. & Tveteras, R. (2002). European market integration for gas? Volume flexibility and political risk. 24:3 (249-265).

54 Yang, Hongming; Liu, Sidong; Zhang, Yongxi; and Luo, Xiao (2009) "Empirical Research on Efficiency of the Electricity Futures Market," International Journal of Emerging Electric Power Systems: 10(2)

Sector	Value	Source and description
Electricity (Australia)	N/A	Anderson et al (2007)[55] note that the existence of forward contracts changes the behaviour of generators in the spot market. Across a range of different market structures, a player who already holds a contract for some part of their possible production will choose to offer at a lower price in the spot market. Because a firm's optimal reaction function is more competitive if it holds a forward contract, in equilibrium this results in a lower price in the spot market. Since forward contracts increase competition among generators in the spot market, the spot market price will be lower than when the contracts were not signed. Therefore, those retailers or users who have entered contracts with generators will have paid a (high) contract price to bring the spot market price down and those who do not contract will benefit from the lower spot market price without incurring any cost. Evidence from analysis of the NEM indicates that spot prices were lower than forward prices between 2003 and 2005 on average, and the vast majority of survey respondents believe that in the absence of forward contracts, spot prices would rise.
Agriculture (India)	N/A	Dhankhar (2009)[56] describes the improvements in efficiency of price discovery in agriculture markets through futures trading. Farmers are able to mitigate price risk they face in a spot market with variable prices through hedging. The analysis found that information flows from future to spot market (price discovery occurs in the futures market and is transmitted to the spot market). This implies price discovery in futures markets is more efficient than in the spot market.
Finance	N/A	Elumalai, Rangasamy and Sharma (2009)[57] discuss the role futures play in price discovery and how the consequent increase in information in the market decreases spot price variability. Mizrach and Neely (2007)[58] discovered that 30 year futures contracts contribute to price discovery in the Treasury market.
Finance	N/A	Chakravarty, Gulen and Mayhew (2004)[59] find that option prices on individual equities reflect market conditions more accurately than the underlying assets do. The fact that option prices reflect fundamental supply and demand conditions more accurately than the underlying assets improves the level of information in the market, increasing efficiency. The options price reflects the underlying supply and demand conditions in the market which provides a signal to where the resources need to be distributed, improving overall efficiency.
Finance	N/A	Fleming, Ostdiek, and Whaley (1996)[60] find derivatives lead the spot market through assessing the S&P 500 stock index, futures contracts and index funds.

55 Anderson EJ, X. Hu and D Winchester (2007) Forward Contracts in Electricity Markets: the Australian Experience. Energy Policy 35(5), 2089-103

56 Dhankhar, J.N. (2009) Futures Market in Indian Agriculture and Its Impact on Production and Prices. Indian Journal of Agricultural Economics. 64(3): pp. 521-525

57 Elumalai, K. Rangasamy, N. and R.K. Sharma,R.K. (2009) Futures Market in India and Its Impact on Production and Prices. Indian Journal of Agricultural Economics 64(3): pp. 315-323

58 Mizrach, B. and Neely, C. (2007) The Microstructure of the U.S. Treasury Market. Federal Reserve Bank of St. Louis Working Papers 2007-052B

59 Chakravarty, S., Gulen, H., and Mayhew, S. (2004) Informed Trading in Sotck and Option markets. Journal of Finance 59(3): pp. 1235-1257

60 Fleming, J., Ostdiek, N. and Whaley, R. (1996) Trading Costs and the Relative Rates of Price Discovery in the Stock, Futures and Option Markets. Journal of Futures Markets 16(1996): pp. 353-387

Table 11: Greater ability for firms to manage risk

Sector	Value	Source and description
Brent Crude Oil (UK)	N/A	Antoniou and Foster (1992)[61], show that the futures market has a significant positive benefit on information flowing to the spot markets – this is an efficiency improvement. Furthermore it means that market volatility decreased. They also show that although volatility remains unchanged, it is now less important to market participants since price risk can be hedged. There is no evidence that there has been a spill-over of volatility from futures to the spot market.
Aviation (US)	Increase in firm value (hedging premium) of between 12% - 16%	Carter, Rogers and Simkins (2003)[62] find that in the US airline industry hedging for jet fuel prices increases firm value by between 12 and 16 per cent (p.9, this is a range that comes from multiple specifications). This is sometimes referred to as the hedging premium (the amount of extra value that the firm can demand given that they hedge). This is explained by a reduction in underinvestment as risk premiums are reduced. The authors test this assumption through an interaction of capital expenditure and hedging – this allows them to show that firm value is only significantly increased when capital expenditure is accompanied by hedging. Importantly the only type of hedging that was shown to provide value was using derivative securities (pass through agreements and charging through to the customer were shown to be ineffective). They identify that only large firms tend to utilise derivatives hedging due to high start-up costs.
Non-financial firms with foreign exchange risk (US)	Hedging premium of 4.87%	Allayannis and Weston (2001)[63] find that the hedging premium in non-financial firms who hedge foreign currency risk is 4.87 per cent (p. 267). Since they have not discriminated by industry this could be a better estimate for the underlying or average value added through hedging.
Electricity and gas utilities (US)	Increase in firm value in the range of 6-8 per cent (conservative estimate) Increased investment (capex relative to asset values) of between 1-5 per cent	Gonzalez and Yun (2013)[64] study the impact of weather derivative use on firm value and investment after their introduction to the US in 2007. The authors find that the use of weather derivatives leads to an economically important and statistically significant increase in market-to-book ratios of at least six per cent. After controlling for potential alternative effects, there is robust evidence of a causal link between hedging and firm value. Improved risk management is also found to increase investment, with capital expenditure relative to asset values increasing by between one to five percentage points (depending on the statistical method applied) for firms that use weather derivatives to manage risk.

61 Antoniou, A and Foster, AJ. (1992). The effect of futures trading on spot price volatility: evidence for Brent crude oil using GARCH. Journal of Business, Finance and Accounting. 19(4). 473-484.

62 Carter, D. Rogers, D. Simkins, B. (2003). Does fuel hedging make economic sense: the case of the US Airline industry. Unpublished. Accessed: http://www.gresi-cetai.hec.ca/cref/sem/documents/030923.pdf, 10/03/2016.

63 Allayannis, G. and Weston, JP. (2001). The use of foreign currency derivatives and firm market value. Review of financial studies. 14(1). 243-276.

64 Perez-Gonzalez, F and Yun, H (2013) 'Risk Management and Firm Value: Evidence from Weather Derivatives'. The Journal of Finance, 68(5) pp 2143-2176.

Sector	Value	Source and description
Electricity (Australia)	N/A	In regard to the benefit / purpose of forward and future contracts in the electricity sector, Anderson et al (2007)[65] note that in practice the dominant motivation for contracts is that they fulfil a hedging role, to enable participants in the market to reduce their risk, given highly volatile prices in the spot market. Here the generators and retailers form natural hedging counter-parties: a forward contract serves to reduce the risk for both of them. In addition we might expect that in these markets there would be opportunities for risk averse players to sign contracts with speculators (risk takers). In this environment risk averse players pay risk premiums to enter contracts with other parties and transfer some risk to the sellers of the contracts.
Electricity	N/A	Deng and Oren (2006)[66] note that credit risks are lower when trading futures (as opposed to forwards) since exchanges implement strict margin requirements to ensure performance of all trading parties (settling margins at the end of each day).

Table 12: Findings on lower transaction costs

Sector	Value	Source and description
European Emissions trading market	Bid-ask spreads reduced by 92.1% following introduction of futures	Frino, Kruk, & Lepone (2010)[67] measured average transaction costs through the bid-ask spread. They found that in 2005 (pre-introduction of futures contracts) the spot market for carbon had a bid-ask of 0.55 Euro. Following the introduction of futures contracts (2008) bid-ask reduced to 0.043 Euro.
Electricity	N/A	Deng and Oren (2006)[68] note that in relation to futures (traded through an exchange) – settling futures contracts with financial payments (as opposed to physical delivery) lowers transaction costs for participants. Monitoring costs in trading futures are lower than trading forwards as counterparty risk is largely eliminated.
Stock market (NYSE and AMEX)	Transaction costs 10.3% for small firms. 1.2% for large firms.	Lesmond, Ogden & Trzcinka (1999)[69] found that there were significant differences in the transaction costs experienced by large and small firms and that costs are not uniform for all market participants.
US Non-Financial Firms	N/A	Bodnar, Hayt, Marston & Smithson (1995)[70] noted from the Warton survey of derivatives usage that small firms are less likely to begin derivatives trading than large firms. This is explained by high fixed costs in setting up a derivatives trading scheme compared to forward trading or no risk hedging strategy.

65 Anderson EJ, X. Hu and D Winchester (2007) Forward Contracts in Electricity Markets: the Australian Experience. Energy Policy 35(5), 2089-103

66 Deng SJ, Oren SS (2006) Electricity Derivatives and Risk Management. Energy (31) pp. 940-953.

67 Frino, A., Kruk, J., & Lepone, A. (2010). Liquidity and transaction costs in the european carbon futures market. Journal of Derivatives & Hedge Funds, 16(2), 100-115.

68 Deng SJ, Oren SS (2006) Electricity Derivatives and Risk Management. Energy (31) pp. 940-953.

69 Lesmond, D., Ogden, J. & Trzcinka, C. (1999). A new estimate of transaction costs. The review of financial studies. 12(5), 1113-1141.

70 Bodnar, G., Hayt, G., Marston, R. & Smithson, C. (1995). Wharton survey of derivatives usage by US non-financial firms. Financial management. 24 (2). 104-114.

Table 13: Findings on lower barriers to entry

Sector	Value	Source and description
Electricity (Australia)	N/A	Review of Energy Related Financial Markets (2006)[71] notes that impressive growth in electricity futures market following release of new contracts in 2002 provided valuable window for market participants, particularly new entrants, to assess and price the cost of hedging exposures. A rejuvenated futures market (re-launched in 2002) contributed to overall liquidity in forward markets, providing new retailers entering the NEM access to cost effective and credit efficient risk-management products to manage their load risks.

Table 14: Findings on greater access to available gas / security of supply

Sector	Value	Source and description
Water / agriculture (Australia)	N/A	Heaney et al (2004)[72] argue that temporary water permit trades allow irrigators to manage the production risk associated with seasonal factors. The temporary permit market allows for excess water to be traded between irrigators on the Murray-Darling Basin as a complement to long-term water entitlements. This mechanism enables irrigators with the highest marginal value of water to purchase water from irrigators with lower marginal values of water, improving allocative efficiency.
Electricity (Australia)	N/A	Regarding allocative efficiency in the NEM, Simshauser (2006)[73] notes: *"From an allocative efficiency perspective, spot and contract prices in the wholesale market have followed cost structures down, and are now at both competitive and world benchmark levels."*

Table 15: Findings on more efficient investment signals

Sector	Value	Source and description
Electricity (Australia)	N/A	While noting a number of ongoing issues with the NEM, Simshauser (2008)[74] noted that the commencement of the NEM contributed to significant improvements in the Australian electricity sector, noting that prior to reform, there had been significant over-investment in baseload capacity, and prices that were substantially above competitive levels. Of particular note was the imbalance between baseload and peaking capacity, with baseload generation *overweight*, and peaking generation *underweight*. Between 1997/98 and 2004/05, from a dynamic efficiency perspective there was a decrease in oversupply from 2,700MW to 400MW (though the imbalance between baseload and peaking capacity remained). The investment value of supply-side 'structural faults' fell from $5.1 billion (13 per cent of aggregate investment) to $3.1 billion (seven per cent of aggregate investment). This represents a dynamic efficiency gain of $212 million per annum through lower capital charges.

71 KPMG (2006) Review of Energy Related Financial Markets – Electricity Trading.

72 Heaney, A., Thorpe, S. Klijn, N. Beare, S. and Want, S. (2004) Water Charges and Interregional Trade in the Southern Murray Darling Basin. ABARE Conference paper 04.14

73 Simshauser, P (2006). The conditions necessary for the microeconomic reform of a power generation industry, Economic Policy and Analysis, 34(2).

74 Simshauser, P (2008) The dynamic efficiency gains from introducing capacity payments in the NEM Gross Pool. Australian Economic Review, Vol 41(4), pp.349-370.

Sector	Value	Source and description
Agriculture	N/A	Cordier (2010)[75] discusses the relationship between futures and price discovery and how this provides famers with a market signal to inform investment decisions on the inputs of production (such as fertilizer). Improved price discovery assists farmers about the conditions impacting supply and demand of a given commodity. For example, a high futures price implies an increase in demand which may require greater investment in the inputs of production to meet demand, improving overall efficiency.
Water / agriculture (Australia)	N/A	National Water Commission (2012)[76] found that the introduction of tradeable water permits in the Southern Murray Darling Basin has incentivised irrigators to invest in productively efficient technologies and reduce inefficient water use. Since trading of water permits allows water to be distributed to its highest value use, there is a strong incentive for irrigators to improve the efficiency of their water use. This creates an incentive for investment in R&D.
Water / agriculture (Australia)	N/A	Heaney et al (2004)[77] states that the trading of permanent entitlements incentivises irrigators to invest in activities that will enhance productive capacity or efficiency; investments that typically involve large initial upfront capital expenditure.

75 Cordier, J. (2010) How Farmers Benefit from Futures Markets. Agro Campus Ouest. OECD Workshop 22-23 November 2010

76 Australian Government, National Water Commission (2012) The Aggregate Impacts of Water Trading in the Southern Murray-Darling Basin between 2006-07 and 2010-11. http://archive.nwc.gov.au/library/topic/rural/impacts-of-trade-2012

77 Heaney, A., Thorpe, S. Klijn, N. Beare, S. and Want, S. (2004) Water Charges and Interregional Trade in the Southern Murray Darling Basin. ABARE Conference paper 04.14

Appendix C Net benefit methodology

Market segmentation

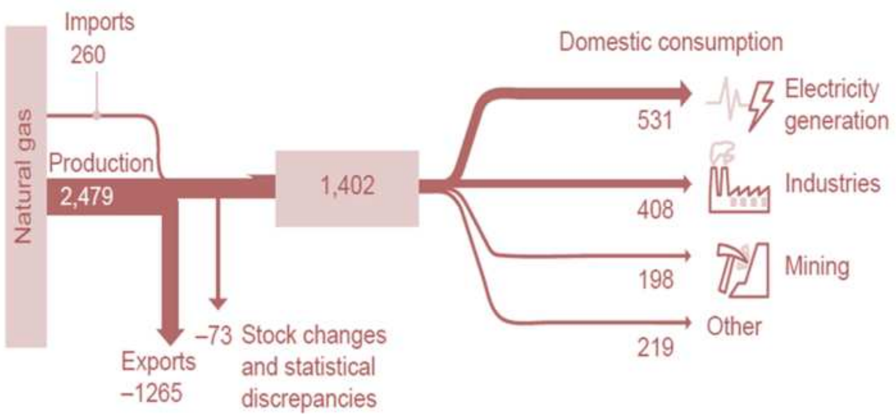
While there are many participants in the east coast gas market, they can be broadly segmented and analysed according to the role they play in the value chain.

At a high level the market can be split into the production, domestic consumption and export markets. Once LNG processing facilities in Gladstone are running at full capacity (expected in 2017) around half of gas produced on the east coast, and around 90 per cent of gas produced in Queensland, is expected to be for export.

Domestically, gas is largely used for manufacturing (either for heat or steam raising activities or as a feedstock), for electricity generation, or for residential use. Key industrial consumers include the chemical manufacturing, non-ferrous metal manufacturing and mining industries.

In total, around 38 per cent of gas consumed domestically is for electricity generation, around 48 per cent by industry, 11 per cent in residential use, and 3 per cent for conversion into other fuels.[78] Aggregate gas flows in 2013-14 are shown below in Figure 18.

Figure 18: Supply and use of natural gas (2013-14, PJ)

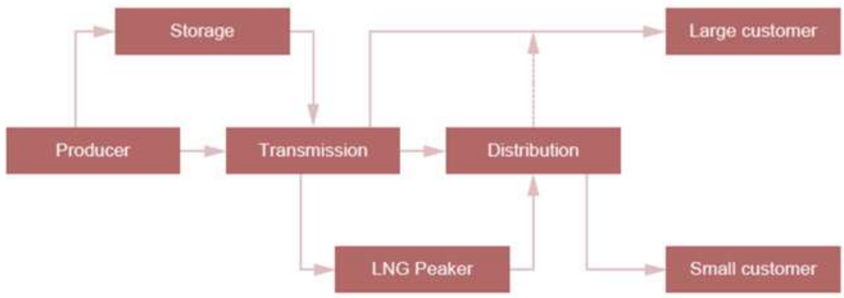


Source: Department of Industry and Science (2015), Energy statistics

Domestic customers can also be split into small (or retail) customers who are supplied off the distribution networks and consume less than 10 PJ annually, and large customers who are mainly supplied from the transmission pipelines and are generally large enough (consuming more than 10 PJ annually) to negotiate their own supply arrangements (Figure 19).

[78] Department of Industry and Science (2015), energy statistics

Figure 19: Domestic market physical value chain



Source: Lewis Grey Advisory (2015) Gas Market Model Review, displayed in the Department of Industry (2015) Gas Market Review

While there are significant levels of vertical integration in the gas market, the proposed reforms will affect participants in the value chain differently. Accordingly, shocks are considered with respect to the specific participant(s) affected rather than applied to the gas market as a whole.

The VURM CGE model, like most macroeconomic models, considers businesses/producers at the industry level. In order to identify the type of gas users we are interested in, we need to identify the relevant industries in the model. Some sectors are obvious but to identify the relevant large use sectors we look at the input-output data that VURM is based on to see which industries in the model have the gas commodity as a relatively large input into their costs. Based on these measured patterns of gas use, we apply the industry mapping to the gas market sectors as shown in Table 16.

Table 16: VURM industry concordance with gas market sector

Gas market participant	VURM industry	ANZSIC classification
Natural gas production	Gas	Mining
LNG export	Gas	Mining
Pipelines	Water, pipeline and transport services	Transport, Postal and Warehousing
Industrial Use	Alumina manufacturing	Manufacturing
	Non-metal construction product manufacturing	Manufacturing
	Paper product manufacturing	Manufacturing
	Steel manufacturing	Manufacturing
	Chemical manufacturing	Manufacturing
	Other Metal manufacturing	Manufacturing
	Rubber and plastic manufacturing	Manufacturing
Retail and distribution	Gas supply	Electricity, Gas, Water and Waste Services
Gas power generation	Electricity generation - gas	Electricity, Gas, Water and Waste Services

Source: PwC

Where appropriate, shocks have been scaled to exclude parts of the industry that are not relevant to the shock in question (for example, due to a sub-industry of low gas intensity that is part of a broader gas-intensive industry).

Shock assumptions

Considering the market segmentation above, key assumptions were developed in the level and type of shock taking into account available data on the gas market and the findings of the literature review (detailed in Appendix B). This section provides more detail around the formulation of these assumptions, as summarised in Chapter 3.

Trading effect shocks

Shock	Supporting data and assumptions
Large industrial gas users in all east coast market Capital productivity is higher by 0-5% depending on gas 'intensity' (cost of gas relative to total costs)	• Recent reports that gas users are experiencing major issue sourcing gas supply on reasonable terms and in some casing receiving no offers at all.[79] In one example, Incitec Pivot has elected to secure supply for its Mt Isa site by underwriting the future North East Gas Interconnector pipeline connecting the Northern Territory to the east coast gas market.[80] • We assume that the direct benefits are focused on gas-intensive manufacturing industries (cement, metals, plastic, paper and chemicals manufacturing), of which gas makes up an estimated 1% to 30% of production costs.
LNG producers in QLD **Total factor productivity higher by 0.2%**	• Daily gas consumption for LNG production on Curtis Island was reduced by 416TJ (16%) below average over 20 of the last 95 days (Dec 2015-April 2016).[81] • The excess supply of gas has resulted in large price reductions[82]. As illustrated in Figure 9, market constraints mean that this is more volatile than it would be if pipeline capacity and gas supply could be more easily traded under the reforms. • It is difficult to predict the frequency of future LNG demand shortages; however it is likely that they will be less frequent once operations mature. Accordingly, we assumed 10 such days a year occur on average (when flows fall by the average of 16%), or around 1.7 annual days of shutdown per train. This is broadly consistent with evidence of shutdown frequencies observed or assumed in related projects.[83]

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79 ACCC, The importance of adequate competition for the east coast gas market, 2015. Available at: https://www.accc.gov.au/media-release/the-importance-of-adequate-competition-for-the-east-coast-gas-market

80 Incitec Pivot, Long term gas agreement for Phosphate Hill Fertiliser Manufacturing Plant, 17 November 2015.

81 The period from 30 December 2015 was chosen as all three LNG plants had ramped up production from this point (with daily gas consumption stabilising around 2.6 TJ according to AEMO gas bulletin board data).

82 For example, reduced flows on QCLNG and GLNG's pipelines coincided with a fall in Brisbane STTM prices of around 20 per cent during the week 29 November to 5 December 2015 (AER, *Weekly gas market report - 28 November – 5 December*, 2015.

83 While there is scant evidence on the frequency of shutdowns of LNG processing facilities, several pieces of evidence suggest that a range of 0- 10 days per year is appropriate. This includes: workforce planning documents in the *Queensland CSG to LNG industry Workforce Plan*, which contains estimates of major shutdowns (30 days per LNG train) in years 1, 3, 5 and every 5 years thereafter, and minor shutdowns (5 days per train) are expected bi-annually; and unplanned shutdowns that have occurred at other processing facilities, such as Sakhalin LNG (2 trains – reports of multiple 'periods of days' of unplanned shutdowns over the past year), the Muda Field Processing Platform (reportedly 6 days a year prior to recent figures) and Pluto LNG (two lengthy unplanned shutdowns over the past 3 years).

	• We assume that the reforms mitigate the fall in price by 50%, as it potentially allows a wider range of willing buyers to access the gas. • Since LNG production is counted in the gas supply industry (which includes extraction), the shock is scaled to reflect additional value added for the LNG sector only. We assume LNG value added accounts for 46% of LNG export values (at free -on-board prices). This is derived by netting estimated production costs from export prices, including: – an assumed long run export price of $13.7/GJ[84] – production and transmission costs of $5.3/GJ[85] – liquefaction costs of $2.0/GJ.[86] • We apply this to gas producers in Queensland only as this is the only location where LNG production for export takes place.
Gas exporters (QLD) LNG export volumes higher by 1%	• With improved ability to auction capacity and trade domestic gas, where it makes sense to do so, large gas users may choose to make use of fluctuation in prices available in the international market rather than consume gas in their operations. • We assume a 1% increase in gas exports could occur as a result. We choose this as it is a small change and it is also plausible as noted below: – Gas flow data suggests that pipeline capacity would be sufficient to accommodate a 1% increase in volumes – daily gas flows to the CIDZ can vary in excess of 5% of average flows.[87] – An extra 1% of volumes (around 14 PJ) would require an extra 4 vessels per year based on an average LNG capacity of 140k m3 (this compares to ~360 vessels estimated to be sent each year)[88]

84 Based on the 2016 AEMO GSOO and EnergyQuest Energy Quarterly, March 2016

85 Based on average Bowen Basin coal seam gas production costs and Roma-Brisbane Transmission costs, as estimated in Core Energy Group (2015), Gas Production and Transmission Costs, Eastern and South East Australia,

86 Based on analysis of LNG netback prices contained in EnergyQuest Energy Quarterly, March 2016, extrapolated to the long-run gas price assumptions contained in the GSOO.

87 Based on estimated daily flows in the CIDZ (including the Wallumbilla to Gladstone, GLNG Gas Transmission and APLNG Pipelines) as at 2 April 2016, obtained from the AEMO gas bulletin board.

88 Number of vessels calculated by applying an assumed average vessel capacity of 140mmcm, an energy to volume conversion rate of 25.78 (MMCM per PJ) and a gas to LNG volume conversion rate of 1/600. 360 vessels per year was taken from public commentary, for example http://www.afr.com/news/special-reports/australia-energy-future/lng-exports-underway-from-gladstone-20150810-givp7w.

Productivity effect shocks

Shock	Supporting data and assumptions
Large industrial gas users in all east coast market states Total factor productivity higher by 0-4.9% depending on gas intensity.	• Draws on findings from literature review about gains in the aviation, non-financial and utilities sectors where the use of hedging products increased the firm value through greater certainty over costs (findings are detailed in Appendix B). • Using value-added as a proxy for firm value at an industry wide level, we assume value-added increases from higher productivity. • Data from the economy-wide CGE model shows the intensity of inputs for gas users (e.g. 29% of cement industry's costs and 1% of the rubber and plastics industry's costs are gas). • Where sectors shocked include sub-sectors that are not large gas users, the shocks are scaled appropriately to represent a weighted average shock to the broader sector. For example, pharmaceuticals are excluded from the 'chemicals' industry, as they are assumed to be of low gas dependence.
Small retailers in all east-coast market states Total factor productivity of gas retailers higher 0-4.9%, depending on degree of vertical integration	• As above, draws on the review of gains in the aviation, non-financial and utilities sectors where the use of hedging products increased the firm value. • Adjustments are made to the model to ensure only gas retail is picked up in the "gas supply" industry. • Further adjustments are made to exclude Origin Energy from the analysis, since they are also heavily involved in production.

Investment effect shocks

Shock	Supporting data and assumptions
Gas transmission owners (all east coast market states) Decrease expected equilibrium rate of return required on pipeline investment of 1%	• This assumption of a 1% change is chosen as a conservative assumption, reflecting a lack of available data on the link between energy market reforms and investment in gas pipelines. • The estimate is applied to the 'water transport, pipeline transport and transport services industry'. To ensure only gas pipelines are considered, the shock was scaled back to reflect the gas pipeline industry's share of activity in the broader industry classification (around 6%, taking into account transport margins generated from the supply of gas into this industry).

Appendix D GEM overview and methodology

GEM: What is it?

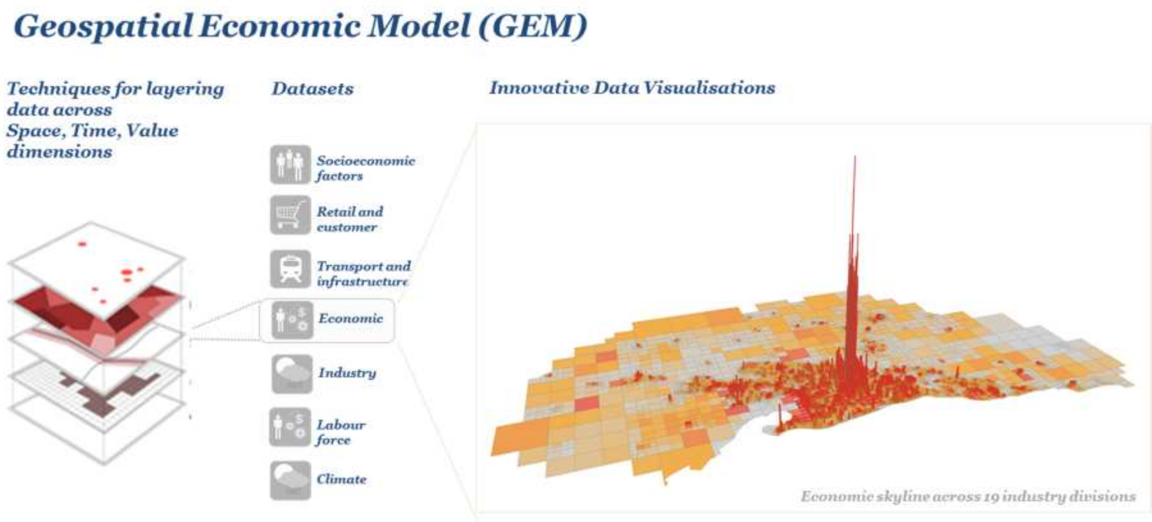
PwC created a big data modelling platform that captures the macroeconomic trends of small area economics that shape Australia. GEM was developed to provide a more granular understanding of Australia's economic geography. By understanding the underlying smaller economies that make up the States and Territories, allows us to understand the differing contributions of various small areas to each State and Territory's economic value by industry and across time. We can see how industry employment and output grow or shrink through time across these small areas, and examine how policies and other shocks play out in different geographies.

Our Small Area Economics work provides economic, social and demographic insights in 2,214 locations across Australia where business and government operate. By adding the "where" dimension to analysis and reporting, we assist clients to take advantage of geospatial insights that are not apparent using traditional, non-spatial methods. 'Locations' refer to socially and economically distinct areas (Statistical Areas – level 2 as defined by the ABS) that have, on average, a population of approximately 10,000 people.

GEM comprises a spatial library containing Australia economic data from 2001 to 2015, which is consistent and reconcilable with ABS data. Forecasts are also available out to 2050 which are consistent and reconcilable with Treasury's intergenerational model. As is the case with all economic data, including the underlying ABS GDP and employment data that are used to build GEM, these are estimates. None of these should be treated as 100% accurate, and GEM is no different. Noting this, the methodology we've developed working closely with the ABS and our own experienced economists gives us great confidence in the model's outputs.

The GEM platform supports the collection, fusion and distribution of spatial as well as non-spatial data originating from a variety of sources (see Figure 20). We use a variety of desktop and server-side GIS, data visualisation and web mapping tools that allow spatial analyses to be published and shared with chosen audiences in a variety of printed and digital formats. The GEM platform consists of a server-side ecosystem and toolbox for near real-time bespoke analysis, and provides the opportunity to support consulting projects with extensive insights across a range of factors that typically drive or affect business performance.

Figure 20: GEM allows for a wide range of datasets to be layered and fused in near-real-time



Analysing data through a spatial lens can help to identify problems that are of local concern even if they are not a high priority at a state or national level - and can therefore assist in advocating for local funding initiatives and the tailoring of services based on specific community or market needs. Similarly, spatial analysis can enable top-down strategies and initiatives to be targeted more effectively in the areas where they are needed most.

Within GEM, we have compiled a range of significant Australian datasets across key subject areas including population and demographics, infrastructure and the economy. These datasets provide important context for the subsequent understanding, analysis and enrichment of data. The GEM platform can easily integrate a wide range of variables and data types, from customer transaction data through to fleet vehicle, network sensor and incident-related data.

How has GEM been used in this project?

The CGE modelling approach described in earlier sections of this report delivered estimates of the proposed reforms' impacts at a State and Industry level for Australia's eight States and Territories. These estimates were used to compute a cumulative impact against 2040 projected baseline levels that could occur as a result of implementation of the proposed reforms, for each considered industry in each State/Territory.

These estimates were then distributed among each State/Territory's subregions using GEM. The subregions used in this analysis were Statistical Areas 4 (SA4s), which reflect labour markets within each State and Territory and comprise regions of approximately 100,000 persons. The allocation was performed according to each region's relative contribution to industry Gross State Product in 2015. This approach provided estimates of the cumulative impact to 2040 flowing from the proposed reforms for each industry in each subregion.

This methodology was applied across all considered industries and locations. The resulting estimates were used to understand how different subregions of Australia would potentially benefit from the proposed reforms.

Appendix E Reform cost methodology

This section includes more detail on the process undertaken to estimate the cost of the proposed reforms.

Table 17 includes a summary of the general assumptions used to discount and index costs estimates within the model. Table 18 details the timing assumptions that were made and utilised to model the expected start and finish dates of phases of the reforms and their development processes. Figure 21 to Figure 26 illustrate the process that we have undertaken to estimate the costs and Table 19 includes a detailed description of specific cost inputs and how they were sourced. In particular, it details where assumptions were made by PwC, sourced through stakeholder consultation or based on past reforms in the Australian gas market.

Table 17: General assumptions

Description	Rate
Discount rate (real)	7.00%
Inflation forecast	2.50%
CPI 2005-06 to 2016-17	1.27
CPI 2011-12 to 2016-17	1.09
CPI 2013-14 to 2016-17	1.03
WPI (all industries) 2005-06 to 2016-17	1.39
WPI (all industries) 2011-12 to 2016-17	1.11
WPI (all industries) 2013-14 to 2016-17	1.05
PPI (Data processing, web hosting and electronic information storage services) 2005-06 to 2016-17	1.06
PPI (Data processing, web hosting and electronic information storage services) 2011-12 to 2016-17	1.05
PPI (Data processing, web hosting and electronic information storage services) 2013-14 to 2016-17	1.01

Sources: Commonwealth Government Office of Best Practice Regulation. Australian Bureau of Statistics (ABS 2016), 6401.0 - Consumer Price Index, Australia, Mar 2016. Australian Bureau of Statistics (ABS 2016), 6345.0 - Wage Price Index, Australia, Mar 2016. Australian Bureau of Statistics (ABS 2016), 6427.0 - Producer Price Index, Australia, Mar 2016.

Table 18: Timing assumptions

Pipeline capacity reforms	
Industry steering committee	
Commencement of industry steering committee	1-July-16
Number of years of industry steering committee operation	10
Completion date of industry steering committee	30-June-26
Planning (working groups)	
Commencement of working groups	1-July-16
Completion of working groups	30-October-17
Implementation	
Implementation commencement	1-January-17
Implementation completion	30-December-17
Operation	1-January-18
Southern Hub Reforms	
Planning (working groups)	
Commencement of working groups	1-January-17

Completion of working groups	30-Dec-18
Implementation	
Implementation commencement	1-January-19
Implementation completion	30-December-19
Operation	
Market operation commencement	1-January-20
Information provision reforms	
Implementation	
Implementation commencement	1-July-16
Implementation completion	30-December-16
Operation	
Information provision commencement	1-January-17

Source: PwC assumptions, stakeholder submissions and AEMC (2015), Stage 2 draft report: East coast wholesale gas market and pipeline frameworks review, Sydney, Australia, page vii.

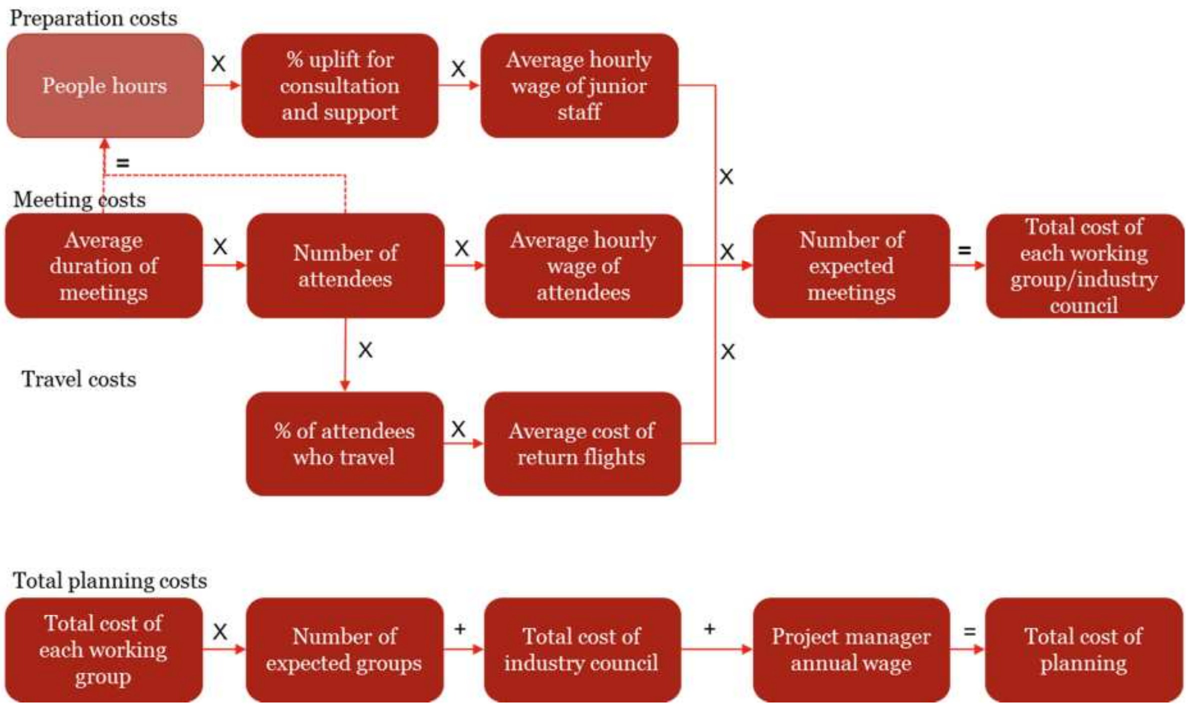
Planning costs

Planning costs refers to working groups and the proposed industry council. Costs for planning groups can be broken into three streams

- preparation costs, which refers to completing submissions, consulting within the business and with experts
- meeting costs, which refers to the cost of time spent in meetings directly
- travel costs, which refers to the expected costs for some representatives to travel to attend the group.

Working groups are proposed for pipeline access reforms and for wholesale gas market reforms. The assumptions underpinning working groups for each of these reforms and for the industry council are summarised in Table 19. Figure 21 shows how the planning costs are calculated.

Figure 21: Planning costs



Pipeline capacity reform costs

Figure 22 and Figure 23 show how the pipeline capacity reform costs are estimated. Upfront costs (see Figure 22) do not include costs for planning that are included above. These costs are once off and will be incurred by pipeline operators, large and small participants. The market operator is not expected to incur upfront costs due to the assumption that pipeline operators will implement their own trading platforms and auction platforms.

Figure 22: Pipeline capacity reforms: upfront costs

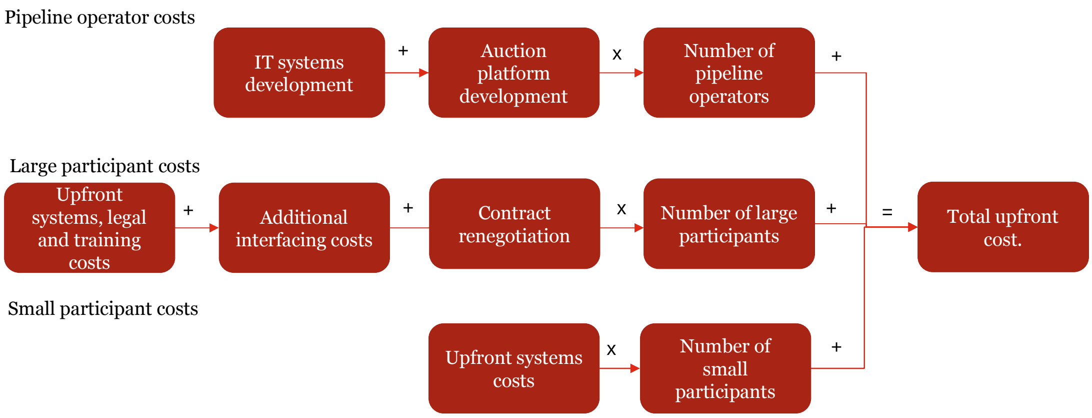


Figure 23: Pipeline capacity reforms: ongoing costs

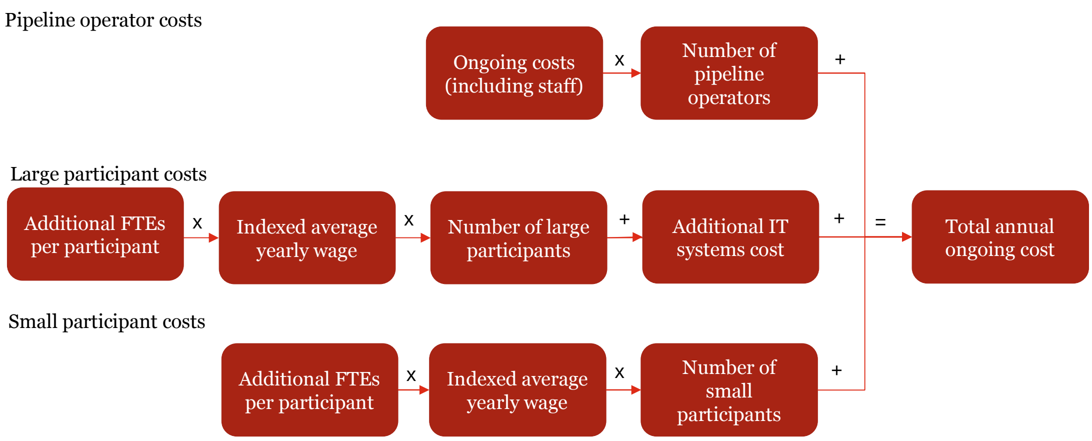


Figure 23 shows how the ongoing costs are estimated using figures and assumptions presented in Table 19. These costs are expected to accrue each year that the participants and operators interact with the proposed new access platform. Compared to small participants, large participants have reported additional IT systems costs in consultations because they operate customised IT systems as opposed to the off-the-shelf systems that small participants use. As with the upfront costs, the market operator is not expected to accrue any additional costs for the pipeline access reforms under the assumption that pipeline operators develop their own platforms.

Wholesale gas market (Southern Hub) reforms

Figure 24 shows how the upfront costs associated with implementing the Southern Hub reforms are estimated. These costs do not include costs for working groups and planning, as these are represented in Figure 21. Upfront costs are expected to accrue to all stakeholders.

Figure 24: Wholesale gas market reforms: upfront costs

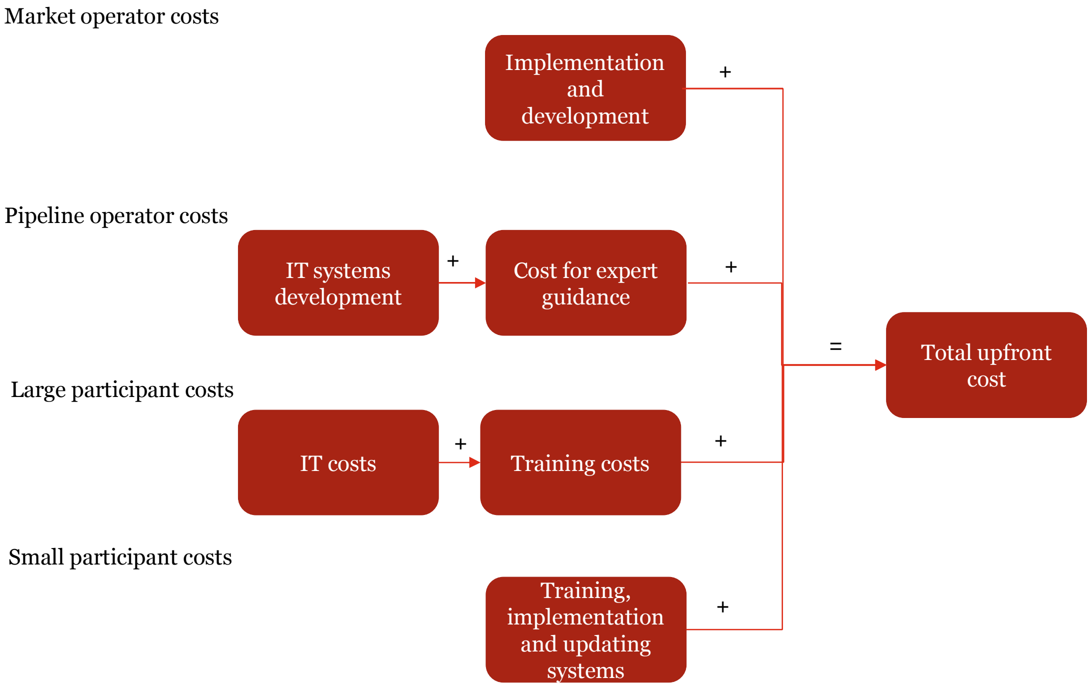
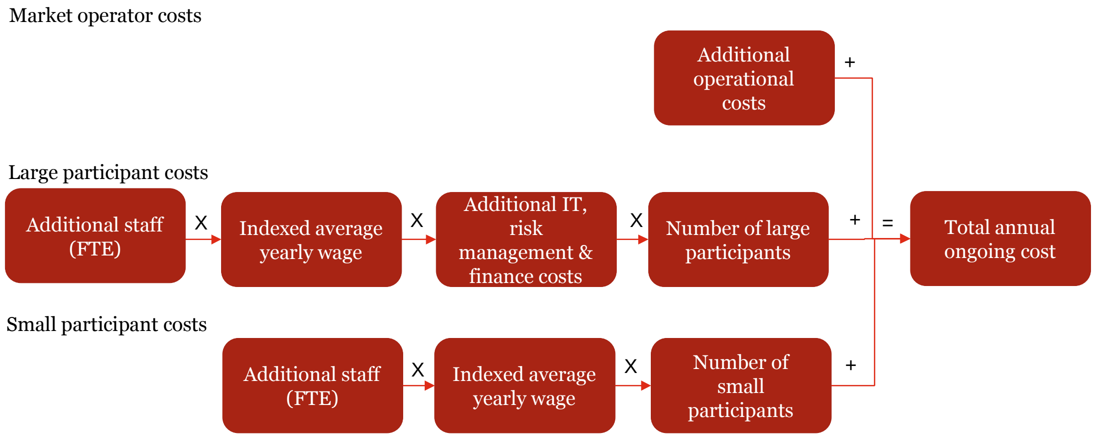


Figure 25 shows how the estimated ongoing costs are calculated. These costs are expected to accrue in all years that participants and operators interact with the proposed Southern Hub wholesale gas trading platform. Stakeholder consultations indicated large participants are expected to incur additional IT, risk management and finance costs. Pipeline operators are not expected to accrue any additional ongoing costs as consultations indicated the proposed reforms do not materially alter their role or function in the gas supply framework.

Figure 25: Wholesale gas market (Southern Hub) reforms: ongoing costs



Information provision

Upfront costs of information provision are expected to accrue to the market operator, pipeline operators and new participants. Major participants who already provide information to AEMO are not expected to accrue extra costs given that the changes are marginal. The costs are summarised in Figure 26. Ongoing costs are only expected to accrue to the market operator for additional reporting requirements and compliance support required.

Figure 26: Information provision reforms: upfront costs

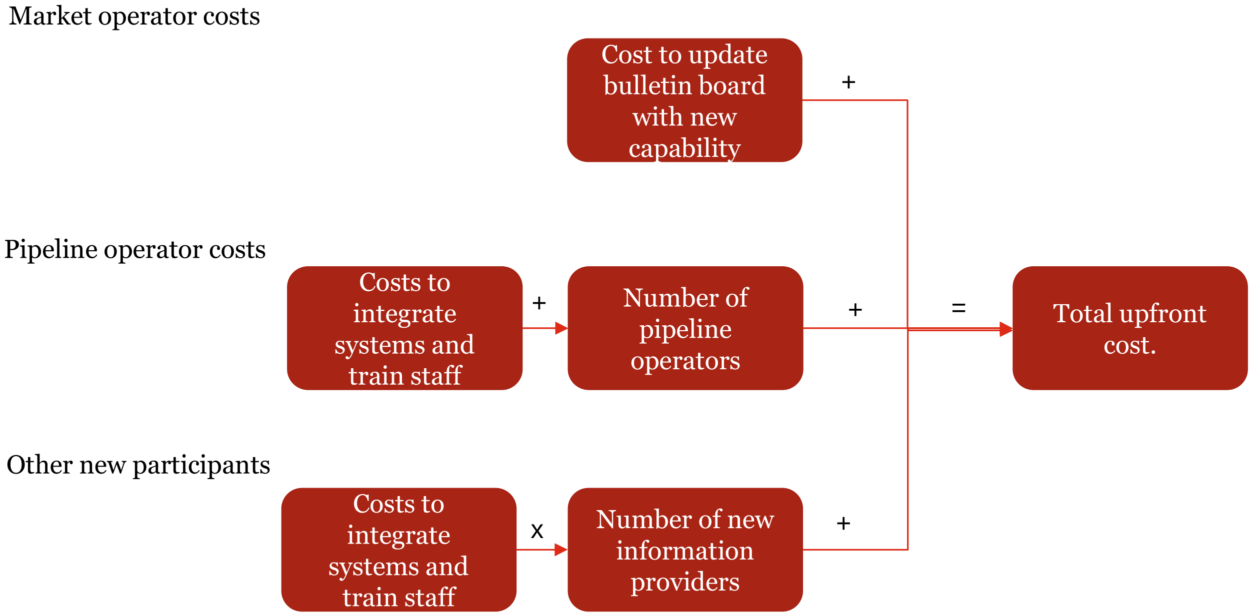


Table 19: Cost Inputs and Assumptions

Pipeline capacity trading reforms				
Stakeholder	**Cost**	**Central estimate**	**Description**	**Source**
Pipeline operator	Number of pipeline operators	4	Assumption that a capacity trading platform would be developed by: APA, Jemena, Epic Energy and one other.	AEMC
Large market participants	Number of large participants	6	Assumption is the following major producers and/or retailers will incur significant costs in relation to reforms: Energy Australia, Origin, AGL, Santos, BHP Billiton and Esso	PwC assumption
Small market participants	Number of small participants	19	Number of unique participants on STTM across three hubs is 25. This is the residual figure to get to 25 assuming there are 6 majors that participate.	PwC assumption
All	**Working groups and industry committee assumptions**			
All	Average hourly cost of attendees	$174	Indexed to 2015-16 dollars, based on senior personnel wage and on-costs and overheads.	MMA[89]
All	% uplift for consultation and support	200%	Applied to the total time commitment of attendees to reflect time to prepare submissions, questions and consult within their business.	PwC assumption
All	Average hourly cost of junior staff	$87	Indexed to 2015-16 dollars, based on junior personnel wage and on-costs and overheads.	MMA[90]
All	% of attendees who travel	50%	Applied to the number of attendees to reflect the extra cost of attending meetings.	PwC assumption
All	Average cost of return flight	$400	Estimate of the cost to fly return between the major cities.	PwC assumption
All	**Industry steering committee**		AEMO suggests industry steering committee (SC) will likely be created, with working groups reporting to this body. We have assumed that the SC will exist over the duration of the reform process (mid-2016 to mid-2020).	
All	Number of expected groups	1		Consultation with AEMO
All	Number of meetings per group	48	Meetings are assumed to be monthly over four years	PwC assumption

89 McLennan Magasanik Associates 2006, Gas Market Options Cost benefit Analysis, Report to Gas Market Leaders Group and MCE Standing Committee of Officials, Melbourne.

90 Ibid.

All	Number of attendees at each meeting	8	We assume an average of 8 attendees, understanding that attendance at each meeting will vary based on a number of factors.	Stakeholder submissions
All	Average duration of meetings	3 hours	Meetings are expected to be shorter than work shops	PwC assumption
All	**Working groups**		AEMO suggests working groups will be used to develop and implement the reforms.	
All	Number of expected groups	4	There is potential for more than one work stream per issue (three issues include standardisation, capacity trading platform and auction).	Consultation with AEMO
All	Number of meetings per group	24	Meetings are assumed to be monthly for the first year and fortnightly for the final six months.	PwC assumption
All	Number of attendees at each meeting	15	We assume an average of 20 attendees, understanding that attendance at each meeting will vary based on a number of factors.	Stakeholder consultation
All	Average duration of meetings	4hrs	Workshops are expected to be half day.	Stakeholder consultation
All	Project manager annual wage	$0.3 million	Project management is expected to be required for 1 year, estimate is based on MMA and indexed to 2015-16 dollars using WPI.	MMA[91]
All	Indexed average yearly wage	$0.2 million	Average manager salary 2014, indexed to 2015-16 dollars using WPI and adjusting for an overheads cost multiplier assumed to be 0.75.	ABS[92]
Pipeline operator	IT systems development	$1.3 million	Estimated provided by a pipeline operator.	Stakeholder consultation
Pipeline operator	Auction platform development	$0.9 million	Estimated provided by a pipeline operator.	Stakeholder consultation
Pipeline operator	Ongoing costs	$70,000	Additional cost similar to STTM costs, would include additional staff cost.	Stakeholder consultation
Large market participants	Upfront systems	$2.4 million	A retailer's advice is that a new system is needed to meet requirements of both pipeline capacity and DWGM reforms, and a single IT figure was provided. Assumption has been made that 25% of cost is attributable to pipeline capacity reforms, and 75% attributable to DWGM reforms. A mid-range estimate was taken from stakeholder consultation and the upper bound of the MMA's cost estimate for the STTM and GBB reforms to	Stakeholder consultation and MMA[93]

91 McLennan Magasanik Associates 2006, Gas Market Options Cost benefit Analysis, Report to Gas Market Leaders Group and MCE Standing Committee of Officials, Melbourne.

92 Australian Bureau of Statistics, 6306.0 – Employee earnings and hours, Australia, May 2014, Released 22 January 2015. Escalated to 2015-16 dollars.

93 McLennan Magasanik Associates 2006, Gas Market Options Cost benefit Analysis, Report to Gas Market Leaders Group and MCE Standing Committee of Officials, Melbourne.

			estimate the total costs, this was then apportioned based on the 25 / 75% approach. Significant costs were estimated due to the fact that custom systems are required - large businesses hold significant gas portfolios that need to be represented within a system and hence these businesses do not use an off the shelf product.	
Large market participants	Up-front legal	$1.4 million	The standardisation process may require renegotiation of existing contracts. This will result in legal and commercial advisory costs. This estimate is high level only. It will be influenced by the number of counterparties that each business must renegotiate with and the extent to which standardisation occurs (i.e. only secondary, or primary and secondary). This is based on two counter parties per large participant, $700,000 per counterparty for both legal and commercial advisory.	Stakeholder consultation
Large market participants	Up-front training cost	$50,000	Stakeholder consultation estimated $200,000 for training costs across pipeline and DWGM reforms (25/75% assumption applied).	Stakeholder assumption
Large market participants	Additional FTEs per participant	1.31 FTE	Similar to upfront costs, ongoing additional FTE costs were provided as a single estimate for both reforms. Assumption made that 25% are attributable to pipeline capacity reforms, with the remainder attributable to wholesale gas reforms. For additional trading, three extra FTEs are assumed as the mid-point (0.75 FTE attributed to pipeline capacity reforms), additional financial, risk and settlements staff are estimated at 2.25 FTEs (0.56 FTEs attributed to pipeline capacity reforms.). 0.75 + 0.56 FTE = 1.31 FTE.	Stakeholder consultation
Large market participants	Additional IT systems cost	$0.2 million	The large retailer consulted indicated ongoing IT costs were difficult to estimate. Low to high estimate of ongoing IT costs was $1.5m to $5m. As these ongoing costs are significantly higher than initial estimates and MMA figures for the STTM, we have applied a simplifying assumption that ongoing IT costs will be 10% of up-front costs. This is based on the share of ongoing STTM IT costs ($760k) in 2015-16 forecast as a proportion of upfront IT costs for STTM ($7.4 million in $2015-16).	PwC assumption
Small market participants	Upfront systems costs	$0.1 million	Consultation with small retailers suggests that upfront costs associated with pipeline capacity reforms will not be particularly significant. Have used implementation cost estimate from AEMO's Wallumbilla costing document, escalated to 2015-16 dollars using WPI. Costs are lower compared to large businesses due to an assumption that off the shelf products will be used.	Stakeholder consultation & AEMO[94]
Small market participants	Additional FTEs per participant	0.25 FTE	Consultation with a small retailer suggested that pipeline capacity trading reforms will have only incremental effect on ongoing costs – they will become part of traders' jobs. Note that some small participants, particularly end-users, are unlikely to have trading teams.	Stakeholder consultation
Wholesale gas market reforms				
All	**Working groups**			

94 Australian Energy Market Operator, Detailed design for a gas supply hub at Wallumbilla, 19 October 2012.

All	Number of working groups	6	This reform is assumed to be more complex than those undertaken in the past by AEMO, as such they have estimated six working groups will be required to cover all of the issues.	AEMO
All	Number of meetings	36	First 12 months of planning, assume monthly meetings for final 12 months, assume fortnightly meetings, 36 meetings total, over two years.	Stakeholder and AEMO consultation.
All	Percentage of attendees who will travel	25%	Given this is a Victorian reform, most participants are located in Melbourne. It is still expected that these reforms will attract participants from other states into the Victorian market and as such some attendees will travel.	AEMC
Market operator	IT costs	$8.8 million	Based on consultation with the AEMO suggesting that these reforms are more significant than the STTM, we have assumed double the costs from MMA's analysis.	AEMO consultation, MMA[95], PwC assumption
Market operator	Design, implementation and legal	$9.3 million	Based on consultation with the AEMO suggesting that these reforms are more significant than the STTM, we have assumed double the costs from MMA's analysis.	AEMO consultation, MMA[96], PwC assumption
Market operator	Process/consultation	$2.1 million	Based on consultation with the AEMO suggesting that these reforms are more significant than the STTM, we have assumed double the costs from MMA's analysis.	AEMO consultation, MMA[97], PwC assumption
Market operator	Additional operational costs (annual)	$0.7 million	The AEMO currently operates the DWGM in Victoria. It is unclear what the incremental operational cost increase (or decrease) would be given the current uncertainty around what the market design will be and who will operate system. A simplified assumption is applied that there will be a slight increase in operational costs; equivalent to the initial Wallumbilla estimated operational costs.	AEMO consultation
Pipeline owner	IT systems development	$0.9 million	Auction system will be required for baseline capacity (allocating entry / exit rights) – we assume that this would be similar to auction costs for secondary pipeline capacity.	Stakeholder consultation
Pipeline owner	Cost for expert guidance	$0.3 million	Expected that external expertise will be required to develop a tariff model. This would likely need to come from an overseas market (Europe) with entry-exit experience. Cost estimate is PwC's assumption based on 1 year FTE at a senior level.	Stakeholder consultation
Pipeline owner	Ongoing cost	0	Assume no additional ongoing costs incurred under new market structure, assuming that AEMO remains system operator	Stakeholder consultation

95 McLennan Magasanik Associates 2006, Gas Market Options Cost benefit Analysis, Report to Gas Market Leaders Group and MCE Standing Committee of Officials, Melbourne.

96 Ibid.

97 Ibid.

Large market participants	Upfront IT costs	$7.3 million	Remaining 75% of costs relating to upfront IT costs.	Stakeholder consultation
Large market participants	Upfront training costs	$0.15 million	Remaining 75% of costs relating to training.	Stakeholder consultation
Large market participants	Additional FTEs per participant	3.94 FTEs	Remaining 75% of costs relating to ongoing staff costs (risk, settlements, and finance) allocated to DWGM reforms.	Stakeholder consultation
Large market participants	Ongoing IT costs	$0.7 million	Remaining 75% of costs relating to ongoing IT costs.	Stakeholder consultation
Small participants	Training, implementation and updating systems	$0.1 million	Assume Wallumbilla gas supply hub implementation costs (escalated) for small participants in relation to DWGM reforms. Based on a small retailer, it is likely that work would be done to develop trading tools - assume 2.5 FTEs for 3 months at $170k per year.	Stakeholder consultation
Small participants	Additional FTEs per participant	1 FTE	Given that DWGM reforms will require participants to continuously be in balance, trading staff would be required. We assume that one additional FTE would be employed.	Stakeholder consultation
Information provision reforms				
Market operator	Implementation costs	$2 million	Based on consultation with AEMO.	AEMO consultation
Market operator	Additional operational costs	$0.2 million	Annual ongoing operational costs.	AEMO consultation
Pipeline operator	Implementation costs	$0.35 million	One pipeline operator estimates that in order to provide additional information requested from AEMO, initial implementation costs of $200,000-$500,000 would be incurred. Assume this cost incurred by four companies. In terms of implementation costs, given they are different companies, it is assumed that they would incur costs separately.	Stakeholder consultation
Major participants	Implementation costs	0	The reforms require participants to report information that is already collected by participants and so it is assumed to be marginal and as such no additional costs have been included here.	Stakeholder consultation
Other new participants	Number of new information providers	35	AEMC estimates that 35 new businesses will be required to provide information to the GBB.	AEMC consultation
Other new participants	Implementation costs	25,000	Minimal once of cost incurred to set up information provision and understand requirements.	PwC assumption

Note: Numbers included in this table have been rounded, exact inputs into the cost model may have more significant figures based on indexing of past estimates to 2015-16 dollars.

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