Major Energy Users Inc.

Australian Energy Markets Commission

Review of the Victorian Declared Wholesale Gas Market
Draft Final Report
Reference: GPR0002

Submission by

The Major Energy Users Inc

October 2015

Assistance in preparing this submission by the Major Energy Users Inc (MEU) was provided by Headberry Partners Pty Ltd and Darach Energy Consulting

This project was part funded by Energy Consumers Australia (www.energyconsumersaustralia.com.au) as part of its grants process for consumer advocacy and research projects for the benefit of consumers of electricity and natural gas.
The views expressed in this document do not necessarily reflect the views of Energy Consumers Australia.

The content and conclusions reached in this submission are entirely the work of the MEU and its consultants.

TABLE OF CONTENTS

1. Introduction

Major Energy Users Inc (MEU) is pleased to respond to the AEMC's Draft Final Report in reference to the Victorian Declared Wholesale Gas Market (DWGM review).

Since early 2015, the MEU (which represents large industrial operations that employ many ordinary Australians, particularly in regional areas) made several submissions to the AEMC and ACCC on the reviews they have been undertaking of the east coast gas markets about the very real threats to these manufacturing industries face due to higher gas prices and potential shortages in gas supply.

More recently the MEU has been an active member of the working group assessing the detailed development of the new model for the Victorian gas market which the AEMC considers should replace the existing DWGM.

What is important to note is that over the last two decades, the Australian electricity and gas markets have undergone massive change. Unfortunately, the promising outcomes from the well thought out energy reforms, begun in the 1990s to enhance Australia's economic development, have been sadly overturned by the loss of our international competitiveness in electricity and, more recently, gas pricing as consumers have seen the prices for electricity and gas more than double (in real terms) and as a result these rises have eroded the competitive advantage Australians had in terms of energy supplies.

At the same time as the competitive energy advantage has waned, the decisions to allow the development and export of gas from our northern waters and more recently the east coast have not delivered the benefits that were envisaged[1]. Further, the decision to allow export of gas from the east coast has resulted in shortages of gas for domestic use[2] on the east coast coupled to significant price increases.

The MEU is pleased that a number of the concerns identified by it during the reviews processes are to be addressed as a result of the ACCC and AEMC assessments undertaken as part of the east coast gas review. However, our involvement in the AEMC working group examining the proposed changes to the DWGM have raised significant concerns in terms of both outcomes and costs to make the change proposed by the AEMC. This response provides more detail about these concerns.

[1] See appendix A.
[2] See Appendix B

1.1 About the MEU

The Major Energy Users Inc (MEU) represents the interests of large energy consumers operating on the east coast gas markets and in other jurisdictions. The MEU comprises some 30 large energy using facilities in NSW, Victoria, SA, WA, NT, Tasmania and Queensland. MEU member companies – from the steel, cement, paper and pulp, automobile, tourism, mining and the mining explosives industries – are major manufacturers served by the east coast gas markets (and in other jurisdictions), are significant employers of labour and contractors, and are located in many regional centres, including Gladstone, Newcastle, Port Kembla, Albury, Western Port, Mount Gambier, Port Pirie, Kwinana and Darwin.

Analysis of the energy usage by the members of MEU shows that in aggregate they consume a significant proportion of the gas used domestically and electricity generated in Australia. As such, they are highly dependent on the competition that applies to the provision of gas and electricity, the retail functions needed to enable the competition to apply and to the transport networks to deliver efficiently the energy so essential to their operations.

Many of the members, being regionally based, are heavily dependent on local suppliers of hardware and services, and have an obligation to represent the views of these local suppliers. With this in mind, the members of the MEU require their views to not only represent the views of large energy users, but also those of smaller power and gas using facilities, and even at the residences used by their workforces that live in the regions where the members operate.

The companies represented by the MEU (and their suppliers) have identified that they have an interest in the **cost** of the energy as well as the associated network services as this comprises a large cost element in their electricity and gas bills.

A failure in the supply of electricity or gas effectively causes every business affected to cease production, and MEU members' experiences are no different. The loss of supply effectively prevents the operations deliver the high products the members make for their markets. Thus the **reliable supply** of electricity and gas is an essential element of each member's business operations.

With the introduction of highly sensitive equipment required to maintain operations at the highest level of productivity, the **quality** of energy supplies has become increasingly important with the focus on the performance of the energy transmission and distribution networks, because the transport systems control the quality of electricity and gas delivered. Variation of electricity voltage (especially voltage sags, momentary interruptions, and transients) and gas pressure, by even small amounts, now has the ability to shut down critical elements of many production processes. Thus member companies have become increasingly more dependent on the quality of electricity and gas services supplied.

Each of the businesses represented by MEU has invested considerable capital in establishing their operations and in order that they can recover the capital costs invested, long-term **sustainability** of energy supplies is required. If sustainable supplies of energy are not available into the future, these investments will have little value.

Accordingly, MEU members are keen to address the issues that impact on the **cost, reliability, quality** and the long term **sustainability** of their gas and electricity supplies.

The members of MEU have identified that in addition to the need for strong competition in the competitive parts of the energy supply chains, energy transport plays a pivotal role in the energy markets. This role encompasses the ability of consumers to identify the optimum location for their investment in their production facilities, and provides the facility for generators and gas producers to also locate where they can provide the lowest cost for energy supplies. Equally, consumers recognise that the cost of providing the transport systems are not an insignificant element of the total cost of delivered energy, and due consideration must be given to ensure there is a balance between the competing elements of price versus reliability, quality and long term security;

The MEU recognises there is tension between the four elements of cost, reliability, quality and long term security and therefore makes its comments in this submission in full knowledge of the need for managing this tension.

1.2 The elephant in the room – a lack of upstream competition

In regard to the issues raised over the duration of the AEMC review of the DWGM, the MEU has identified that there are a number of overarching issues that dominate the domestic gas market operations in Victoria. These concerns have been effectively been "passed over" in the analysis by the AEMC of the DWGM yet their very presence has a massive impact on why the current DWGM market structure has not resulted in the outcomes identified by the AEMC as being in accordance with the CoAG Energy Council's Vision for the east coast gas market.

But the elephant in the room is the lack of upstream competition and diversity of supply

The DWGM is dominated by a very few gas producers and very few gas production facilities. Adding to this, each gas production facility is served by a sole gas pipeline to transport the gas produced to where the gas in used in Victoria. Victoria is fortunate in that it has two significant sources of gas production - Bass Strait (dominated by Esso/BHP at Longford) and Port Campbell dominated by Origin Energy.

The APA Group has control of transport for all gas entering the DWGM and for the only gas that exits the DWGM to interstate users via the Culcairn interconnector; Jemena and SEAGas transport the bulk of the gas that exits Victoria. What is important to note is that the bulk of the gas that enters the DWGM is used within the DWGM with the Culcairn interconnector having the peak capacity of less than 10% of the total capacity in the DWGM.

The importance of upstream competition is exemplified by Jeff Markholm in his book, The Political Economy of Pipelines, where he observes (page 162)

> "Given the number of producers and existing pipeline links between gas fields and consuming areas, Australia would appear to have the structural basis for a competitive gas market. ... The ability for Australia to exploit any competitive potential in gas supply will probably remain unfulfilled as long as (1) two producing consortiums dominate most of the gas flowing in eastern Australian markets ...and (2) the pipeline system remains relatively opaque and unregulated ..."

The view that the DWGM does not provide a futures market is belied by the fact that there is one – albeit not very liquid. This raises the very concern as to whether the lack of liquidity in the DWGM is a result of minimal competition in upstream production or because the market structure is inadequate. That there is a futures market implies that the current DWGM can provide the basis for a liquid futures market if there were more upstream competition.

The AEMC asserted during the workshop analyses that while greater upstream competition and additional supply sources would be beneficial to the functioning of the market, the lack of such multiplicity of supply options can be overcome by a change in market design. This observation runs in the face of reality and experience of competitive energy markets.

The Agency for the Cooperation of Energy Regulators (ACER) recently released its 5th Annual Market Monitoring Report covering 2015: Gas Wholesale Markets findings presented at Ljubljana on 21 September 2016. ACER reported on the relative success of the various European gas markets and highlighted that the Netherlands and UK gas markets were the only European markets performing well. What the report highlights is that the key to good performance is the diversity of supply sources and upstream market concentration. With this in mind, it is little wonder that the DWGM has struggled to be more liquid and that any change to the market will provide little better performance while there is such low diversity of supply and a very concentrated gas supply for Victoria.

This ACER observation is supported by what is being seen in the NEM currently in the SA region – that a lack of competition in upstream supply and low diversity does lead to an illiquid market. There is a consistent view amongst all of the stakeholders involved in the AEMC workshops that the current DWGM would exhibit greater liquidity if there was greater upstream competition, and the MEU concurs with this observation. The AEMC has failed to explain why the change in the market design will result in increased liquidity when there will still be limited upstream competition.

While the MEU notes that the AEMC has consistently commented that it was not briefed to address the lack of upstream competition, the MEU also notes that the AEMC has the responsibility to identify to whether a change in the upstream conditions would result in significant improved outcomes for consumers if the DWGM remained in place[3]. The MEU notes that the cost benefit analysis (discussed later in this document) implies considerable benefit will result from the changed structure, yet there is no examination of the impact of such limited upstream competition will have on the new structure. Implicitly, the benefits from the new structure are seen as if there are few constraints in the upstream sector.

In addition to this overarching concern, it important to also note the other issues that will also impact the ability of any market to deliver better outcomes for consumers. These are:

1.2.1 Government limitations on exploration

> The decisions by the Victorian government to limit exploration and development of new onshore gas fields (especially those based on coal seam gas) means that the likelihood of new sources of gas into the DWGM are unlikely in the near to medium terms.
>
> The decision by the NSW government to cease exploration for gas from coal seams (and the buy back of existing CSG licences) represents a further delay in any new gas supply options for NSW although the SA government is seeking to encourage onshore exploration. It is also noted that the likely SA unconventional gas plays are located in the north of the state and so more likely to provide gas for SA and northern users rather than provide for supplies for Victoria.
>
> These decisions mean that significant competition in gas supplies in Victoria (noting that gas could enter the DWGM via Culcairn) is unlikely in the short to medium term. While new gas finds in SA might impact the flows from Otway (ie less into SA and more into Victoria) this would not increase upstream competition in the DWGM.

[3] For example, would there be increased liquidity in the future market?

1.2.2 The limited amount of gas flowing through the DWGM to interstate

The AEMC draft report also does not explicitly advise on the very small amounts of gas transiting the DWGM to other states. In fact over 85% of the gas moving north from Victoria never enters the DWGM with at most 15% passing through the DTS via Culcairn – this issue is further expanded in section 2.3.3 and in section 4. Further, any gas moving south from Queensland will be absorbed in demand centres well north of Victoria (particularly in Adelaide and Sydney) and only impact the Victorian gas market peripherally.

Currently gas from Longford can go north to Sydney before entering the DWGM, as does gas from Port Campbell go to Adelaide without entering the DWGM. The current piping arrangements do not prevent the Longford or Port Campbell facilities directing gas either northward or to the Declared Transmission System (DTS). This raises the question as to whether the producers at Port Campbell or at Longford would contract differently with users interstate just because the DWGM has changed its structure, especially when this gas doesn't need to enter the DWGM. MEU members have advised that the prices they receive for gas in SA and NSW have little bearing on the price for gas seen in and available to users in the DWGM.

This introduces the reality that changing the DWGM structure is likely to have a minimal price impact external to the price in the DWGM other than for the small amounts of gas transiting through Culcairn.

1.2.3 There is no "clean" gas price

There is an assertion that the DWGM does not deliver a "clean" price for gas. MEU members point out that a number of them do buy gas at the price declared by AEMO so there is, ipso facto, a price that consumers in the DWGM that can purchase gas at the market price. Equally, MEU members outside the DWGM observe that the price they pay does not appear to reflect the DWGM price because the prices they see are opaque[4]. Changing the DWGM to generate a "cleaner" price will not change this reality.

The AEMC observes that the gas price in the DWGM is affected by an opaque entry capacity cost which is in addition to the regulated transport costs for using the DTS. While the DWGM price might not be as "clean" as it could be, perhaps better "cleanliness" can be achieved without the massive change proposed by the AEMC.

---

[4] They are opaque because the EGP, SEAGas and MSP (via Culcairn) are not regulated pipelines and retailers bundle up commodity, transport and standby on production into one price

For example, when the DWGM was settled daily, the prices used to be quite volatile between ex ante and ex post values as there were seen to be a number of uplift charges on the price to reflect the congestion and shortages of supplies which occurred when dispatched and settled over an entire day. The move to five settlement periods in a day has almost eliminated uplift charges, making the price much “cleaner”. Yet further consideration of this issue was not considered by the AEMC to be sufficient to provide a “cleaner” price.

The MEU notes that under the new market structure proposed by the AEMC, there will still be charges allocated to shippers to reflect the costs of balancing that will vary, so there will still be unknown costs ex post.

1.2.4 You don’t know what you don’t know

What is not made clear is that developing and implementing a new market model is not straight forward, particularly as “you don’t know what you don’t know”. While the AEMC may have applied considerable effort in the development of its model there will be aspects that are still unknown and the resolution of which will most likely increase costs and reduce benefits.

In contrast, the DWGM is a proven model (albeit with some problems). This means that there a few unknowns in the current model and clarity on what the shortcomings are.

The MEU considers that this aspect of introducing an entirely new market structure should be looked on with some trepidation.

It appears to the MEU that there are major aspects of the DWGM assessment that have been overlooked or not fully recognised by the AEMC when it made a decision to scrap the current DWGM structure and completely develop a new structure. Further, these aspects will have the impact of reducing the benefits that are assumed to come from implementing change.

2.3 Conclusions

The AEMC has drawn a conclusion that the DWGM is not fit for purpose and needs to be replaced with an entirely new market structure.

What was not investigated by the AEMC is the extent to which the lack of upstream competition has prevented the DWGM from reaching its full potential and whether more modest changes to the DWGM could deliver the needed upside at a much lower cost and risk to consumers.

2. The basis for change

In the initial discussion paper for the DWGM stage 1 review issued 10 September 2015, in the executive summary the AEMC makes the observation that

> "The purpose of the DWGM Review is to consider whether the current Victorian arrangements provide appropriate signals and incentives for investment in pipeline capacity, allow market participants to effectively manage price and volume risk and facilitate the efficient trade of gas to and from adjacent markets. More broadly, the Review is to consider whether, and to what extent, the DWGM continues to effectively promote competition in upstream and downstream markets, in the long-term interest of consumers."

This section addresses the intent expressed in the above observation as the MEU is very concerned about the change proposed and the reasons for which the AEMC decided that a new structure for the Victorian gas market is essential.

2.1 The Declared Transmission System (DTS) is complex as is the market its serves

The MEU is very concerned that the AEMC has not fully appreciated that the DTS is unique in its role as a gas transmission network. While the AEMC asserts that it has considered the unique features, the MEU is not convinced that the AEMC conclusions are valid. Other stakeholders have made similar comments in submissions and during the AEMC workshops.

For example, Larry E Ruff[5] in his paper "Rethinking Gas Markets – and Capacity"[6], characterizes the Victorian market as complex on the basis that it takes gas from several, widely-separated injection points to more than 100 withdrawal points, with storage facilities and interconnections that can be injection points one day and withdrawal points the next, multiple laterals interconnected by a large ring, gas flows that can reverse direction from day to day or within a day, volatile weather that can cause the mostly-residential demand to change significantly and unpredictably from day to day and during the day, and little linepack that must be managed carefully to deal with the unpredictable swings in demand from day to day and within days. Mr Ruff considers the DWGM/DTS is unique.

In most respects, the DTS reflects a distribution network more than a transmission network as it has over 30 exit points for each and every entry

---

[5] Mr Ruff was one of the experts involved in the initial design of the DWGM and DTS arrangements

[6] Available at http://www.marketreform.com/wp-content/uploads/2013/11/LERuff-EEEP-Final-02Jul12.pdf

point. This was recognised during the development of the DWGM but this aspect does not seem to have had the same focus by the AEMC as applied when the DWGM was developed.

It is recognised that a distribution network needs to be based on market carriage and yet the AEMC proposal has the DTS being converted to contract carriage. Market carriage allows all shippers to access the network to the extent they need and this removes risk to shippers involved with managing their entry and exit rights.

The capacity of the DTS is held by consumers via the AMDQ process and consumers are exposed to penalties when congestion occurs when they exceed their AMDQ rights. A major aspect of the AMDQ rights being held by consumers is that they are then not at risk of shippers hoarding capacity[7] and gives end users an easy ability to change retailers.

The AEMC proposal considers that over time these AMDQ or capacity rights would transition to retailer/shippers and this exposes consumers to greater risks of not having sufficient capacity they need to deliver the gas they need. This issue was discussed at length during the development of the DWGM and the concept of consumers owning the rights to transport (via the AMDQ) was recognised as needed in order to protect their ability to have gas transport rights as they had invested significantly in the assets that need gas. A loss of these rights exposes consumers to significant risk as once these capacity rights are transferred to retailer/shippers, consumers have less certainty that they will be able to deliver gas to their facilities and are exposed to retailers using their market power to increase the overall cost of delivered gas.

To partially address this concern, the AEMC proposal has a requirement to auction unused capacity. This introduces risk as there is no certainty that a consumer will be able to acquire the capacity needed and has the potential for higher transport costs as any available capacity will be allocated to the shipper that values it more. This imposes considerable risk on existing consumers who might not be able to get their needed capacity as they cannot afford to pay a premium. Such a scenario applies particularly to consumers that are exposed to international competition. It is important to note that should such a consumer have to cease operations due to a lack of transport capacity, then this enterprise is unlikely ever to recommence activity. The loss of AMDQ rights can cause significant harm and increased risks for consumers.

[7] The issue of capacity hoarding is a significant issue in contract carriage pipelines and this has been recognised by the AEMC and the ACCC in their reports on the east coast gas markets.

2.2 The AEMC decision for change and the process involved

The MEU is very concerned that the decision to make a change was the result of a limited time available to carry out the necessary analysis to prove that change was needed. Specifically, the AEMC developed and published its first paper on the options for change to the Victorian gas market in September 2015. Concurrently the AEMC was also heavily involved in assessments of the wider east coast gas market review in addition to its other duties.

In December 2015, a proposal by the AEMC for changing the DWGM (and other changes to the east coast gas market) was delivered to the CoAG Energy Council (CEC), including a short dissertation as to why all options other than the proposed entry/exit model were discarded by the AEMC along with a high level explanation as to why the proposed entry/exit model was the optimum outcome.

Effectively the AEMC determined that change was needed within a three month period, assuming of course that the AEMC had not decided on a change before it sought input to advise on its decision. The advice that the AEMC received from stakeholders prior to its decision to recommend change was quite muted in any support for change, was mainly focused on high level aspirations that had been enunciated by the CEC but providing a view that improvements to the DWGM needed to be implemented.

The AEMC recommendation for change was quite under-developed and, at the request of the Victorian government, the AEMC had to implement further investigation through the release of a further discussion paper and to hold four workshops to examine the benefits and detriments of the AEMC recommended approach. That this addition research was implemented highlights the concern that the tight time frame for developing its views had not allowed sufficient time to explore in depth all of the benefits and detriments of the proposed option.

This review work commenced in May 2016 and over the subsequent seven months (ie twice as long as the AEMC used to decide that major change was needed), the AEMC proposal was developed to a level that stakeholders could assess the detail of what was proposed. The AEMC has held four day-long workshops as part of this assessment process. As these workshops progressed, stakeholders identified that the AEMC proposal had serious shortcomings and increasingly they recommended that the AEMC should look to examine improvements to the DWGM rather than implementing the major change.

The AEMC ignored these requests and commented to the stakeholders at the workshops that the initial (3 month long) AEMC assessment of the DWGM had been exhaustive, including examination of the upgrade of the existing market arrangements. The MEU considers that the AEMC review of the upgrade option can only have been superficial, based on the time it had to develop the views that were included in its initial draft report to the CEC and Victorian government.

In this regard, the MEU points out the initial development of the DWGM which included a number of the aspects assessed by the AEMC (eg the entry/exit model) took considerably longer than the time devoted by the AEMC to the process to decide change was needed. The initial development process also determined that the entry/exit model was unsuited to the DTS due to its unique characteristics and which still apply.

Despite the concerns raised by stakeholders in the workshops, the AEMC further commented that the review process had moved rapidly and that there should be no delay in developing the new market structure. The AEMC advised the stakeholders at the workshop that any further discussion would be limited to just the AEMC option. The MEU has advised the AEMC that it considers that truncating any discussion of other options will not deliver the optimum outcome for Victorian consumers.

What is very clear from the AEMC statements is that it is not open to any other option than its preferred option – one which it developed in isolation over a very short period of time and which included little detail to support its view that its recommendation was by far the best for Victorian consumers. During the discussions at the workshops, the AEMC stated that it was the responsibility of others to develop other options for analysis. The MEU finds this statement very concerning as it is the responsibility of the AEMC to advise the CEC and the Victorian government of the best solution for Victorian consumers rather than for the AEMC to push its own solution.

The MEU is very concerned that the paucity of detail as it developed its recommendation does not support the AEMC view that its model is the best option for Victorian consumers. Its lack of acceptance of concerns raised during the workshops about its proposed model has resulted in a concern that the outcome from change will be no better than the current DWGM with some added features. The presentation by Seed Advisory at the AEMC forum (see section 3) provides details of where the AEMC model is considered deficient by those stakeholders present during the workshops.

The MEU considers that in order to support the argument for change, there has to be better analysis than the AEMC has carried out to date.

2.3 Aspects of concern about the decision for major change

In its assessment of the shortcomings of the DWGM the AEMC highlighted that its proposed model would deliver better outcome in a number of areas

2.3.1 Better signalling for new investments

The AEMC asserts that a change from market carriage to contract carriage will provide better incentives for new investment. The MEU disagrees on a number of counts. The AEMC draws this conclusion on the basis of comparisons with other pipelines on the east coast, but fails to acknowledge that most pipelines on the east coast are no longer regulated. In contrast, the DTS is and will continue to be regulated.

The DWGM is also based on a market carriage model where new investment is signalled by the asset owner which must then get approval from the regulator for the new investments to be implemented because Victorian consumers have to pay for the investment. In the DWGM, the market operator (AEMO) also looks at whether new investments are needed and provides advice to the regulator.

In the AEMC workshops, the AEMC highlighted that asset owners should be able negotiate directly with parties seeking new capacity and to build these when the counterparty is prepared to fund these as this provides a stronger market signal. This argument was exemplified in that the development of additional capacity through Culcairn was inhibited by the AER. That the AER did slow down this development is true but what is overlooked is that it was Victorian consumers that would have to pay (or at least contribute) to the costs of the augmentation but would gain little or no benefit from it. So the AER was correct to get involved as it has the task of protecting the interests of Victorian consumers against inefficient (from the Victorian consumer viewpoint) investment. Ultimately the augmentation did proceed but the costs were not levied on Victorian consumers, which is the right outcome for Victorian consumers.

The assumption that a contract carriage approach would result in better capacity management is also overstated. For example, APA asked for and was approved by the AER to augment the SWP element of the DTS through adding compression at Brooklyn and this investment was added to the costs consumers pay. These compressors are still not installed. So the argument that investment is curtailed because of market carriage fails when looking at the facts.

Despite the assertion that contract carriage incentivises more timely investment, the MEU notes that in the New England region in the USA which operates under a contract carriage model, consumers are likely to suffer extreme prices due to constraints caused by under investment[8]. In contrast, consumers using the DTS have not suffered any shortages of capacity at all because of under investment despite having centralised assessments for new investment.

---

[8] See appendix C

The MEU points out that the electricity market operates exactly in the same way that the DWGM does and there is no suggestion that the electricity market should become a contract carriage model, moving away from centralised assessments of augmentation need and a regulator assessing the efficiency of proposed augmentations. The MEU finds the arguments proposed by the AEMC for change to be spurious and likely to cause more detriment to consumers than benefit.

The MEU has requested advice from the AEMC as to why what works well in electricity transmission should be considered to work poorly for gas transmission but the AEMC fails to explain the differences.

The AEMC has stated that one of the reasons for a change of carriage approach, is to address the anomaly at Culcairn where the DTS market carriage model interfaces with the Moomba-Sydney contract carriage. The MEU points out that the flows through Culcairn are less than 10% of the peak flows in the DTS so it becomes concerning that such a small interchange of gas should lead to a major change. The MEUU considers that this is not a sufficient reason to impose increased costs and risks on Victorian consumers.

2.3.2 Management of price and volume risk

In the workshops, stakeholders highlighted that the proposed changes proposed by the AEMC will not eliminate the risks affecting price and volume although the actual risks might change from those that exist within the DWGM; some stakeholders observed that the new model might even increase these risks. Certainly, stakeholders have provided examples of the cost increases they will incur from the proposed design change and that the risks also increase (eg continuous balancing, capacity rights at entry and exits). It is important that these costs and risks have been included when considering the other costs and benefits of the proposed model.

Further, the improvement sought by the model to impose a requirement on each participant to continuously balance could provide less benefit than assumed due to the lack of continuous metering for the majority end users have at present. The MEU accepts that a number of the larger gas users have continuous metering but their demand is not the problem as congestion and shortages usually occur with the large upsurge of gas usage by residential and small business users when a cold snap occurs unexpectedly. The market carriage approach and central control of balancing (just like it does in electricity) provides a low cost solution to addressing the problem of long delays in getting meter data and the time delays incurred as gas from new injections transits the pipelines from Longford and Port Campbell to meet the shortages.

An inability for participants to continuously balance will still result in uplift payments as AEMO will incur the costs to provide the "residual" balancing. Other aspects of continuous balancing are addressed in section 2.4.4 below.

2.3.3 Facilitation of efficient trade between regions

What was not recognised in the AEMC review process was the reality of the bulk of the gas exiting Victoria is not transported through the DWGM but is carried on other pipelines (EGP – rated capacity at 351 TJ/d and SEAGas – rated capacity at 314 TJ/d). The only trade from and to the DWGM with other states is via Culcairn which has a rated capacity of ~130 TJ/d in either direction (noting that some of this capacity is used by Victorian consumers in the north of the State) so that the Culcairn peak capacity is about 15% of the total peak capacities of all pipelines from Victoria to other states. So the AEMC proposal is for the DWGM to be changed so that it might be easier for perhaps 15% of the interstate trade that transits the DTS.

To put this flow through Culcairn into context, at most, the amount of gas capable of being transferred via Culcairn is less than 10% of the peak capacity of the DTS; put another way the peak capacity in the DTS is over 10 times the capacity of the Culcairn interconnect. This highlights that the bulk of gas to other regions never transits the DWGM as mentioned in section 1.2.2 above, and the amount that does transit the DTS is small in comparison to the needs served by the DWGM.

The draft report does note that gas from Otway and Longford will bypass the Victorian hub but comments that there are barriers to exporting through Culcairn. These barriers are (page 48):

- "the limited physical capacity of the interconnection at Culcairn;
- the interface between the DWGM and the contract carriage arrangements on the Moomba-Sydney pipeline;
- a perception that AEMO, as system operator of the DTS, has afforded priority to Victorian customers over exports from the DTS;
- the ability of the Victorian DTS to physically support exports at Culcairn at times of high Victorian demand;
- price and uplift payment risk in the DWGM; and
- lack of firm transportation rights in the DWGM, or withdrawal rights at Culcairn, creating uncertainty for shippers, even those with firm rights on the Moomba-Sydney pipeline."

Even if these reasons are valid (and the MEU considers that mostly they are not), it needs to be recognised that the DTS has been built for and funded by Victorian consumers **for the benefit of Victorian consumers**.

To assert that Victorian consumers should face increased risks to change a market so that it is easier to export through Culcairn to facilitate interstate trade, to is to have the Culcairn "tail" wagging the Victorian gas consumer "dog". Effectively changing the market structure for such a small amount of gas flow is overkill when it recognised that the bulk of the interstate trade goes through other facilities.

While interstate trade in gas is to be supported, there also has to be a recognition that the costs Victorian consumers will carry has to reflect the value the Victorian consumer gains from any change rather than for Victorian consumers absorbing costs to enhance interstate trade. This concept has been recognised in the electricity markets with the introduction of the inter-regional transmission use of system (IRTUoS) concept.

Primarily, the DWGM and the DTS need to be structured for the needs of Victorian consumers, not for the small amount of trade that goes via Culcairn.

It is bizarre that the entire Victorian market is considered to be in need of restructure so that there might be easier export via Culcairn when there are already much larger facilities that do not transit the DTS that are the major sources of interstate trade in gas. If there is likely to be significant augmentation of the export capacity from Victoria (and this is doubted due to the known reserves of gas in Victoria), the EGP and SEAGas are more likely to be augmented as the demand for gas will be in Adelaide or Sydney and not Canberra which is supported by Culcairn. To put this another way, why augment an indirect route to demand centres when more direct routes are available!

2.3.4 Promotion of competition upstream and downstream

Since the implementation of the DWGM there have been added a new production facility, BassGas, the underground storage at Iona and an upgrade of the DTS for the Culcairn interconnect. Other facilities have been added to the Victorian gas fields and piping systems external to the DTS such as the Patricia Baleen production facility, EGP, SEAGas pipeline and the Tasmania gas pipeline.

It is quite apparent that the DWGM has demonstrated an ability to facilitate and accommodate new upstream facilities and so enhance upstream competition. It is not clear how the changes proposed by the AEMC will provide even better upstream competition, especially in an environment where the Victorian government has decided to embargo any new developments onshore.

With regard to downstream competition, there have been new retailers enter the market and some gas end users have become market participants. Again, it is not clear how much the change to the market structure will increase competition downstream beyond that provided by the DWGM.

While the AEMC has asserted that its proposed structure will further promote upstream and downstream competition, there has been no demonstration that this will occur upstream, although there is already significant competition in both the industrial and residential sectors downstream[9].

What the AEMC view and the PwC cost benefit analysis both overlook is that the high price of gas in the domestic market has already constrained growth in the use of gas, and continuing high prices will continue to dampen growth in gas consumption. At the large end user of gas, the high cost of gas (amongst other things) has already driven new gas consumption offshore (see for example the decision of Incitec Pivot to locate offshore) and others are finding difficulty maintaining profitability and could close operations. At the residential end of the gas market, new homes are becoming all electric as electric equipment becomes more cost efficient than gas for heating and cooking.

The outcome of this is that domestic gas usage is forecast by AEMO to be declining. It is therefore difficult to see that there will be major benefits from recrafting the gas market in Victoria with declining consumption, especially where the current market has already demonstrated an ability to promote (or at least provide for) increased competition upstream and downstream.

2.4 Other benefits asserted by the AEMC

In addition to the above points outlined in section 2.3 above, the AEMC has observed that there are a number of other aspects where change is needed to deliver improved outcomes for Victorian and other gas users.

2.4.1 Generating a market price for gas

The DWGM already does this. MEU members and others are already buying gas in the DWGM. The MEU fails to see where this price is not a real price.

There is an assertion that the DWGM price for gas includes a cost for access to capacity although the extent to which this distorts the market price is not identified. The MEU considers that the impact on the price for

[9] Or at least up to 2016 when retail competition in gas in Victoria has almost vanished

gas must be relatively minor because when an end user purchases and uses gas in the DWGM it separately pays for transmission transport based on its location.

The MEU does note that there are times when there is congestion or shortage of gas, where the ex post price includes an uplift to reflect the cost of these.

The MEU is also aware that in the electricity market, the price paid in the spot market is different to what might be expected due to congestion on interconnectors or shortages. The spot price-exposed consumer in the electricity market also doesn't know the price it will pay for each electricity settlement period as the price paid is set ex post and includes for the impacts of congestion and shortage. The electricity price also reflects the cost of out-of-merit order dispatch of generation because of intra-regional congestion. Despite these shortcomings, there is no suggestion that the electricity market needs to be changed because of a view that the spot price might not reflect a "real" price.

So why is the DWGM seen as providing any less of a "real" price for gas than the electricity market? In the electricity market, a "real" price from a generator can be assessed by identifying the costs that a generator incurs in generating its electricity and use this as the basis for setting what is the "real" price for electricity, but this is not what is paid. The price really paid is either to spot market price or a hedge price struck between a generator and a buyer. So the market provides three different prices for the same commodity depending on how the buyer wants to access the price. The principles behind the electricity market and the DWGM are essentially the same, with both displaying some distortion of what a "real" price might be. The MEU does not consider that this provides sufficient reason to make a major change to the Victorian market structure.

If the concern is about eliminating the potential for uplifts due to congestion, then the current market could be changed to being settled more frequently and this would avoid the uplifts which cause changes to the ex post price, just as occurred when the daily settlement changed to 5 settlement periods in a day. But if an ex post approach is good enough for electricity why is it not good enough for gas?

Stakeholders have accepted there is a need for some "tweaks" to the DWGM. Changing the settlement durations is one (the move from daily to four hour settlements has virtually eliminated uplifts) but this was not considered by the AEMC in its analysis.

2.4.2 Generating a futures price

The assumption made in the AEMC proposal is that a futures market will develop because of the change to the market model. This assumption is driven in part by the view that the uplift charges are unknown and therefore the futures market cannot readily accommodate this cost. The same argument could be applied to the electricity market as congestion and shortages impact the ex post prices seen in the spot market.

Why there is a futures market in electricity, is that there is (relatively) significant competition between generators. Where there is little competition (such as being currently observed in the SA electricity market), there is an illiquid futures market. So, even where there is a market structure which delivers liquidity in the futures market (such as the NEM), when there is a lack of competition upstream, the liquidity in the futures market disappears.

The import of this observation is that the lack of a futures market in the DWGM is probably more due to the lack of upstream competition rather than a flaw in the market design. While stakeholders have pointed this out frequently, the message seems to be lost.

Despite uplift payments being virtually eliminated by the move to 4 hourly settlements, a liquid futures market has not developed in the DWGM. Yet even the AEMC proposed market still exhibits uncertainty with the problem of occasional congestion, supply shortages and the associated costs for being out of balance. So uncertainty does not go away with the changed design – there will still be unexpected costs that will occur and therefore have a negative impact on the futures market. Yet the AEMC asserts that its design will result in increased liquidity in the futures market

However, the AEMC observation is at odds with views of well respected gas market designers. For example, in addition to his comment noted in section 1.2 above, Jeff Markholm also observes[10]:

> "Ultimately, genuine commodity hubs that can support futures markets ***follow*** **competitive commodity markets**—which depend on the ability of competitors reliably to ship commodities to those points for future delivery—which depends on competitive access to transport. Given the unique nature of gas as a commodity, the demands of a genuine gas futures trading hub are severe.

[10] see appendix D Jeff Markholm "There Is But One True Hub and His Name Is Henry" Natural Gas & Electricity June 2016 page 30, DOI 10.1002/gas. © 2016 Wiley Periodicals, Inc.

> Considering what drives the financial industry's participation in commodities futures markets, it is no surprise that the Henry Hub is the only one." (emphasis added)

The implications of the Markholm comments are that a futures market will not occur without competition upstream ie the presence of a competitive wholesale market. This is probably the cause of problem seen in the DWGM – that the futures market liquidity is limited more by the lack of upstream competition rather than the market structure. That the DWGM has a futures market (albeit quite illiquid) implies that if there were more upstream competition, the DWGM might well exhibit a much more liquid futures market.

2.4.3 Central management of balancing and prices

The central management of the DWGM whether in terms of augmentation, balancing and price setting has worked extremely well and consumers have benefitted from the way the market has performed. Despite the historic performance, the AEMC proposal considers that central management is not as good as making it market driven because there is an assumption that the management of other gas transmission pipelines has been carried out more effectively by the asset owners with shippers contracting to reflect their own needs through bilateral agreements. While this works well for pipelines with a single entry and single exit, the DTS is in reality a distribution network. A distribution network is centrally managed by the asset owner, but the asset owner does not have to provide the additional features of balancing, allocation of balancing costs to multiple shippers and providing a spot price for the gas transported. It was because of these additional features that the DWGM was structured the way it was.

The MEU notes that central management of balancing and prices works very effectively for electricity yet the implications of the proposed change for the DWGM is that gas is so different that there is a need to move these functions back to participants as much as possible. This view is inconsistent with the acceptance that electricity markets need centralised balancing and pricing, and the fact that these have been carried out well and effectively for the DWGM.

The argument to support a move away from a centralised market is that this is inconsistent with the markets applying at the interface between Victoria and the northern states. As pointed out in many points throughout this response, the only interface between the DWGM and interstate is at the Culcairn interconnect and the amounts of gas transiting there is at most only 15% of the total gas capacity for interstate export from Victoria.

2.4.4 Continuous balancing

The proposal from the AEMC requires continuous balancing of gas by the shippers using the DTS. The AEMC considers that allocating this role back to the shippers is more effective.

However, the proposal raises some very significant challenges for market participants as the metering in the DTS and the distribution networks is not necessarily extensive or adequate to provide sufficient information for the retailer/shippers to be able to be certain of the extent to what they are out of balance on a continuous basis[11].

Further, during the AEMC workshops, retailer/shippers pointed out that they see there are costs and risks facing them to continuously balance their gas position and this will impose significant challenges because of the nature of the DTS with its limited line pack and large demand especially in winter months; retailer/shippers highlighted that the requirement to buy capacity at each entry point to provide flexibility on sourcing of gas also increases their costs and risks.

They pointed out that when the cost of balancing is allocated, there is every chance that the costs they are awarded will not reflect their true position because they will be exposed to risks they cannot manage as the exit points to the distribution networks (where the greatest swings in gas demand occur) are essentially open[12]. With open exit points and a market where significant swings in gas usage occur due to weather, retailers out of balance could “free ride” at the potential expense of others; this approach tends to move the allocation of uplift costs away from a causer pays concept.

Stakeholders in the workshops also noted that there is a time lag between identification of a shortfall and the delivery of gas from an entry point, exacerbating their risk profile. They further added, with the limited competition upstream, access to additional gas and having to have entry rights where the gas provider is located, makes continuous balancing more difficult and increases the risk of being out of balance. In contrast, they noted that the DWGM structure allowed them access at any entry point to the DTS and with central balancing, the allocation of cost to causer was more readily achieved, although some improvement should be implemented.

---

[11] AEMC consultant Cambridge Economic Policy Associates (CEPA) also commented on this as an important issue for the AEMC model during workshop #4.

[12] The AEMC proposal recognises that gas demand in the mass market is not controllable and has allowed for the exit of gas to the distribution networks to be open for all shippers ie there is no allocation of capacity to individual shippers at these points

What has also been noted is that very few of the markets based an entry-exit model also require continuous balancing. The challenges for small retailers and some direct customers of this requirement for continuous balancing are yet to be fully explored.[13]

A further complication is that most large users of gas advise their gas needs (and any significant changes) on a daily basis to their retailers, with small users not being required to do this at all. The move to continuous balancing is going to add costs to consumers that they will incur in order to assist their retailers carry out their continuous balancing requirements.

2.4.5 The Entry/exit model

The AEMC proposes that the DWGM should be an entry/exit model. This model was examined at the time of the DWGM development and it was discarded as it provided increased risks for participants with little in the way of balancing benefits.

One of the designers of the DWGM Mr Larry Ruff[14] (see section 2.1) observes that with complex physical networks with variable demands (such as Victoria), as entry/exit models involve forms of "commercial capacity rights", this poses a number of problems. For instance, Ruff states that in a complex network with potential peak constraints and a dynamic gas market (such as in Victoria), while entry/exit models make trading easier and more liquid, they are operationally problematic. Shipper-only trading would result in such a large gap between market and optimal (or even just feasible) outcomes that the Transmission System Operator (TSO) must engage in active capacity and gas trading itself to offset unconstructive/dangerous shipper trades.

Ruff concludes that in complex situations, commercial capacity should be eliminated and replaced with a TSO-operated on-the-day market that prices and allocates physical capacity directly, with financial hedging as an equivalent (or better) substitute for commercial capacity. Ruff notes in his paper[15] that a "simplified" version of such a market has been operating successfully in Victoria since 1999.

While the MEU is not in a position to critically evaluate Ruff's claims, it does raise important issues about the operational risks that might arise in the Victorian market. The MEU considers that the AEMC has not fully

[13] One response to this issue facing small retailers has been to claim 'buyers' with relatively flat load should not find this obligation for continuous balancing too difficult. However, small retailers in Victoria with residential and commercial load have limited diversity of demand and in fact are (relatively) more exposed to inter- and intra-day demand volatility.
[14] "Rethinking Gas Markets – and Capacity"
[15] ibid

appreciated the complexity of the DWGM and the ability of an entry/exit model to address the complexities inherent in the DWGM/DTS.

This point was reinforced during the AEMC workshops where it was pointed out that the entry/exit model introduces significant risks to retailer/shippers having to bid for capacity at each entry and exit. Recognising there is entry at a number of points that cannot readily supply gas to many of the exits points, this requires retailers to pay for entry at points they may not need at all times.

Equally, they may need entry at a point which already constrained in order to deliver to meet their contracts or for balancing, increasing their risks. As each entry point is associated with a specific producer (other than Culcairn) this means that the retailers have to match their gas provider with an entry and ensure that the entry can deliver gas to the required exit. Accepting that there are times when parts of the DTS are constrained, it is quite feasible that a retailer could be out of balance and unable to redress it's out of balance position.

Despite this new risk being explained in detail by gas traders operating in the DWGM, the AEMC proposal is effectively unchanged and remains with this increased risk in place.

An issue that was also addressed is that under the entry/exit model, each shipper will be required to contract for capacity at each entry point, with unused capacity being auctioned on a day ahead basis. With contract carriage transport, any exceedance of the contracted capacity (whether long term contract or bought in the day ahead auction) will incur a penalty. In attempting to balance the gas in the hub, each shipper will need to contract capacity at each injection point to enable it to use gas it has contracted with each source of gas. With the significant swings in demand that the DWGM exhibits, this flexibility is essential to enable each shipper to be in balance. If a shipper exceeds its allowed capacity at an entry it will incur penalties which add risk. This increased attendance on assessing entry capacities will add costs as well as risk premiums. These are costs and risks that are no incurred under the current DWGM.

Further, a core issue for the MEU members and accepted by the AEMC is that there needs to be a method for limiting the hoarding of capacity at each entry point. The AEMC proposal requires the establishment of a day ahead capacity trading market where unused nominated capacity (which might already be have bought by another shipper) will be auctioned. While this might limit the exercise of capacity hoarding, it also exposes shippers to potential over-runs that occur within a day.

2.4.6 Conversion to a contract carriage model

In its earlier responses to the AEMC and ACCC the MEU raised its concerns about capacity hoarding which is a feature of contract carriage. While the AEMC proposal introduces day ahead auctioning of capacity which will reduce the ability to hoard capacity, the risk is not removed entirely. The market carriage model used in the DWGM is superior in regard to eliminating capacity hoarding.

The AEMC decision to move to a contract carriage model is based on the assumption that contract carriage provides a better signal for investment. As noted in section 2.3.1 above the MEU does not agree and points out that market carriage used for gas distribution networks or for electricity transmission and distribution has not resulted significant congestion, even though the arguments used by the AEMC against market carriage are based on market carriage leading to greater congestion.

The MEU also notes that, if the decision to move to contract carriage is to match the DTS access requirements to that of the contract carriage on the Moomba to Sydney pipeline, it is inappropriate to change an entire market structure for what is essentially the small amount of gas that transits the DTS via Culcairn

During the workshops, stakeholders pointed out that under the market carriage model, they have the choice of a number of entry points if they need additional gas for balancing but they do not need to buy this capacity at a specific entry point.

In the detail of the AEMC proposal, new capacity will be initiated by demand for access at entry points. As shippers will have to have capacity contracted at each entry point to allow them to match their needs with the different sources of gas they have contracted, an outcome of this change to contract carriage with an entry/exit model, stakeholders commented, would be the potential for over investment in the DTS rather than ensuring efficient investment.

To address the issue of capacity at each entry point, the AEMC proposes that the AER should develop a baseline capacity for each entry point as a tool to allow spare capacity to be auctioned. To achieve this, a new market based system for auctioning this unused capacity has to be developed. However, in the workshops, stakeholders raised questions as to how the AER would identify the baseline capacities at each entry and exit but this has not addressed by the AEMC.

While the concept might eliminate some drive to over-invest, the risk to shippers is increased as they will not know what capacity might be available when they might need it whereas under the current arrangements, capacity is matched to the ability of the production source to deliver the gas and the overall demand identified.

The risks and costs to implement the four capacity auctions (annual, monthly, day-ahead and with-in day) will increase costs and increase risks to shippers – costs and risks that do not apply now.

2.4.7 Multiple modes of gas purchasing

The AEMC model will provide a hub which allows the purchase of gas through three modes – an exchange, bilaterally using OTC contracts and long term GSAs. The MEU points out that these same products are either available in the DWGM or can be added to the DWGM with little difficulty.

The AEMC states that its new approach would reflect that gas in the hub is fungible (allowing injection at one point and withdrawal at another without arranging transport), the trading point is notional and not at a physical location, and the system operator manages the flows within the hub. The MEU considers that all of these features are present in the DWGM.

Essentially, the MEU does not see that improved commodity trading cannot be a feature of the existing DWGM.

2.5 Conclusions

The AEMC has made many observations that its proposed model is superior to the DWGM even if it were to undergo further refinements. The MEU considers that many of the detriments of the DWGM cited by AEMC are not as significant as is imputed by the AEMC. What is concerning is that the AEMC has elected not to carry out any assessments of an upgraded DWGM (or a hybrid as suggested by Seed Advisory) to assess whether such an option could deliver better outcomes for Victorian consumers without the costs and risks of a major change

In particular the MEU considers that the benefits thought to be delivered through easier interstate trading are significantly overstated as the bulk of the gas traded north from Victoria never transits the DWGM or the AEMC proposed option.

The MEU is also very concerned that the risks inherent in the new model have been downplayed despite the advice delivered to the AEMC during the workshops by practitioners operating in the gas markets, that the new model will introduce different but still significant risks that are not seen in the DWGM.

For example, aspects raised address:

- The AEMC model is more complex in that there are three separate markets for balancing, commodity and capacity. Each of these additional markets will provide some benefit but they also introduce risk
- It is unknown what the impacts on the current GSAs will be
- Will security of supply reduce as a result of less involvement by AEMO?
- Will liquidity actually increase despite the highly concentrated upstream market?
- Will there be liquidity in the voluntary exchange?
- Will as available gas really be available as and when needed?
- Will the negative impacts of a transition be greater than expected?

It is concerning that these issues have been minimalised in the assessments of the benefits of the AEMC model

3. What the Victorian government asked for

In its letter dated 13 May 2016 to the AEMC the Victorian government asked some very specific questions about the AEMC proposal for a new market structure.

The major issue related to the costs to Victorian consumers and the benefits that Victorian consumers would gain from the change. The AEMC in conjunction with consultant PwC has calculated that the costs in NPV terms will be between $58m and $480m. Offsetting these costs, PwC have calculated that the benefits (ie above the baseline) will enhance GDP by between $1.7Bn and $12.2Bn over the period to 2040 with the bulk of the benefit (potentially two thirds[16]) accruing to Victorian consumers. The MEU finds that this amount of benefit is unlikely[17].

The MEU observations about this apparently massive reward follow in section 4 below, but the MEU view is that the PwC report has many assumptions embedded in it that raise serious concerns as to its validity. The three most important of these are that:

1. The PwC report identifies the gross domestic product (GDP) enhancement is significant but this is an Australia wide measure. What is concerning is that the benefits attributed to Victoria (as measured by the gross state product (GSP) is such a large proportion of the total benefit identified. The MEU finds this outcome is inconsistent with:

    a. The impact of the highly concentrated upstream aspect of the Victorian gas supplies which dampen down any benefits of a market based trading scheme (whether the DWGM , the AEMC model or any other)
    b. There is a falling market forecast in the consumption of gas in Victoria, particularly amongst industrial and generation of electricity, in part driven by the increasing cost of gas to export parity levels
    c. The amount of gas that is traded with other states through the DTS is modest
    d. The fact that there is already a market in operation in Victoria which has already delivered considerable benefits. A core aspect of this assessment is (as discussed more fully in section 4.2 below) is that the modelling is based on outcomes derived from

[16] See figure 14 in the PwC report Cost Benefit Analysis of the Victorian DWGM reforms Final report October 2016
[17] As the Victorian gas consumption is currently about 200 PJ/a, extrapolating this at the same usage rate over the period 2020-2040 there will be used some 4,000 PJ of gas in Victoria. This implies that based on the high estimate of the benefit (ie $12 Bn), the effective benefit would be some $3/GJ of gas used. The current price for gas as a commodity is between $8-10/GJ. So the benefit would be to reduce the cost of gas by a third

overseas experience where there has been a transition from no market to an operating market.

e. Modelling has not assessed the costs and benefits of an enhanced DWGM (eg the DWGM improved by exchanged based trading, etc)

f. Theoretical assumptions of benefits of the AEMC model and detriments of the DWGM that are not supported by empirical outcomes.

2. The benefits are calculated above the base case which is the retention of the DWGM as is. The MEU and other stakeholders have identified that change to the DWGM can and should be implemented, but the AEMC has not attempted to examine whether changes to the DWGM might deliver similar benefits but at a lower cost. The AEMC has rejected out of hand that any solution than their own would deliver any significant benefit and therefore advised any investigation of options would be pointless. At the forum to discuss the AEMC proposed option, APA (the owner of the DTS), EnergyAustralia a retailer/shipper using the DTS and Seed Advisory representing the views of a number of retailer/shippers all considered that a hybrid model[18] for the Victorian gas market would deliver considerable benefits to Victorian consumers, probably at a much lower cost and be more readily implemented than the AEMC proposal. Even AEMO, the gas market operator has raised concerns about elements of the AEMC proposal.

3. There are a number of significant concerns with the AEMC proposal that are likely to reduce the benefits of the change and increase the costs. The AEMC has determined that their model can be made to work. However, experience if the developments of the DWGM, the NEM and the STTMs all show that the initial concepts did not work out fully as planned and there were considerable changes to these markets as usage highlighted the shortcomings. As noted earlier in section 1.2.4, “we don’t know what we don’t know” and this will be the source of erosion of the benefits forecast by the AEMC regarding their model.

To support their view that there is a significant benefit to Victorian consumers, throughout the draft report, the AEMC provides assertions about the superiority of their model over the existing DWGM and improvements contemplated both at the time of the initial decision by the AEMC to change the model and subsequently by stakeholders both in submissions and during the AEMC workshops.

What is concerning is that not only has the AEMC devoted little effort to examine such options and condemned such with observations like “they are unconvinced” of the ability of other options to deliver the benefits claimed but at

[18] That is the DWGM incorporating some features of the AEMC model

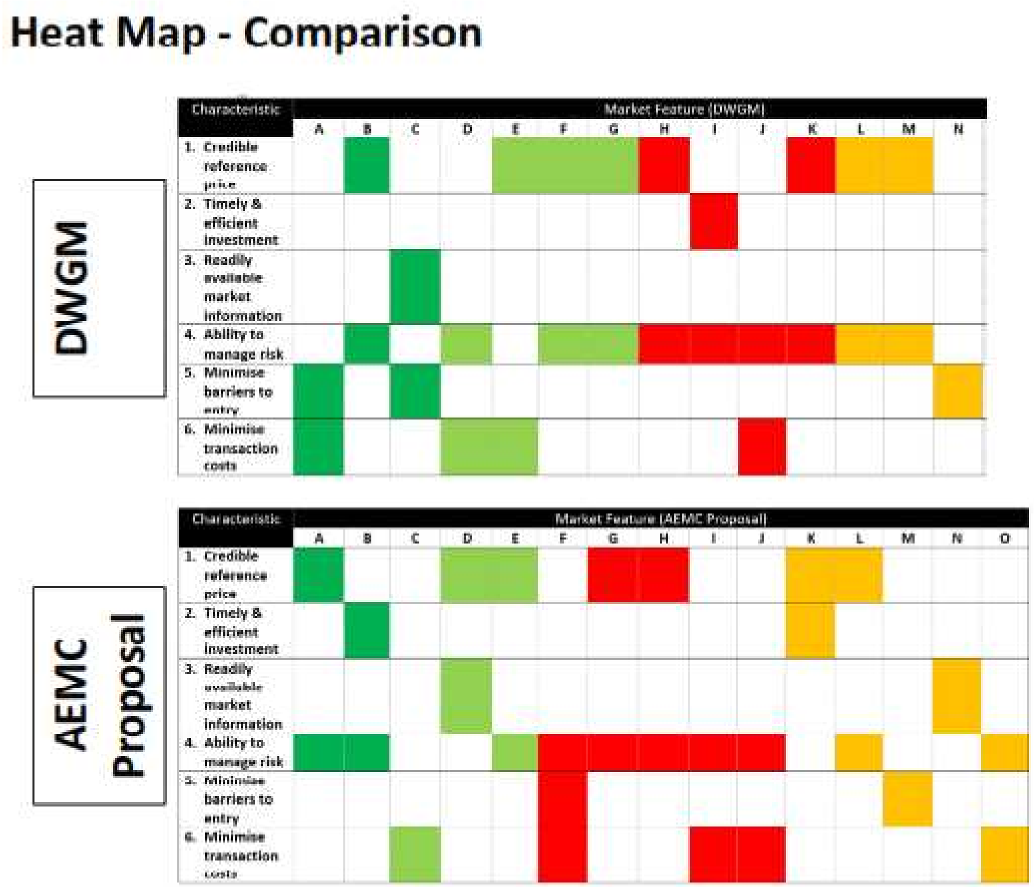
the same time the AEMC has not addressed many of the very real concerns raised by stakeholders during the workshops about the AEMC proposal.

What is even more concerning is that during the AEMC workshops, stakeholders representing producers, pipeline owner, retailers, shippers and consumers all expressed considerable concern about the benefits expressed about the AEMC model and were unconvinced about the extent of the detriments of the DWGM expressed by the AEMC or its ability to incorporate elements of the AEMC model.

3.1 Strengths and weaknesses of both models

At the AEMC forum, the Seed Advisory presentation highlighted that there were as many risks (if not more) to participants from the AEMC model as there were from a model based on the DWGM. Despite these being raised during the AEMC workshops, the concerns appear to have been ignored.

Seed Advisory provided a pictorial representation of the issues in the form of heat maps which highlight the strengths and weaknesses of the AEMC model and the DWGM.



Source: Seed Advisory presentation AEMC forum 14 November 2016

While the MEU does not necessarily agree with all of the Seed Advisory assessments of strengths and weaknesses (eg the MEU does not consider that the DWGM does not deliver timely and efficient investment) what is concerning is that the heat maps imply that AEMC proposal does not deliver outcomes that are clearly superior to the DWGM. Specifically, while there are acknowledged weaknesses of the DWGM, the AEMC model also has some serious weaknesses that have been "glossed over" even though they were raised during the workshops.

AEMC Proposal - Major Strengths and Weaknesses

	Market element / feature	Relevant characteristic(s)
Strengths	Platform for forward exchange	• manage risks • credible price
Strengths	Firm entry / exit rights	• investment • manage risks
Weaknesses	Voluntary nature of exchange	• manage risks • credible price
Weaknesses	Constraint cost allocation	• manage risks • credible price
Weaknesses	Auction for entry / exit rights	• manage risks • minimise transaction costs
Weaknesses	Separation of commodity / balancing	• manage risks • minimise transaction costs

Source: Seed Advisory presentation AEMC forum 14 November 2016

The MEU understands that Seed Advisory will be providing a more detailed assessment of the strengths and weaknesses of the DWGM, but particularly of the AEMC model that were raised in discussions held during the workshops.

3.2 What could be added to the DWGM to improve the it?

3.2.1 Forward trading

One of the aspects of the AEMC proposal that provides considerable benefit is an ability to carry out forward trading between participants. The import of the AEMC assessment is that this option is only available with its model yet there is no reason why this feature could not be added to the DWGM.

The addition of forward trading for a fixed product on an intra-day, day ahead, week ahead, month ahead to the DWGM is not only feasible but would be beneficial.

As a minimum, the AEMC should have modelled this feature as part of the DWGM when comparing its model to the base case.

3.2.2 Improved constraint management

As with the AEMC model, there is a residual risk associated with managing constraints. The AEMC assessment of its model downplays the impact of constraints within its proposal, yet there are still risks that have to be managed.

The MEU is convinced that there are better options for managing constraints, whether by reducing the risk (eg by more frequent settlement) by assessing the issue in more detail and identifying other options.

What has not been carried out is any process to identify whether the DWGM could be enhanced by detailed investigation of the various options proposed by stakeholders.

3.3 Conclusions

There are significant concerns about the outcomes from the assessment of the benefits of the PwC modelling and these are detailed in the following section 4.

What is very concerning is that there has been no further effort to assess whether the DWGM could be enhanced with features such as are included in the AEMC model and if these could deliver similar benefits but at a lower cost.

The fact that the AEMC model is identified as having a significant number of major weaknesses (which will reduce the benefits claimed) makes it all the more important that alternatives should be examined in as much detail as the AEMC model.

4. The Cost Benefit Assessment

The reason to carry out cost benefit analyses is to identify what changes between one option and another will deliver a better net benefit.

The AEMC has made assertions that the change to its preferred market structure will reduce risk and costs for participants and generate a net benefit. In contrast, many stakeholders, including those involved with assisting the AEMC in its workshops to identify issues with the AEMC proposed structure, have consistently maintained that the changes will not deliver the benefits identified by the AEMC and that the change will introduce new risks and costs that are not present in the current DWGM.

Further, many stakeholders have provided a view that a number of the supposed shortcomings of the DWGM are a result of a lack of upstream competition rather than of the market structure.

What is concerning is that the only aspect of the current market where there is an interface between the Victorian market and interstate users, is the connection at Culcairn. This connection only provides about 15% of the total rated capacity of gas transport between Victoria and other states and about 10% of the rated capacity of the DWGM. With this in mind, it becomes quite concerning that such a small interface is seen as providing such large benefits as are identified in the cost benefit analysis report provided by PwC.

There is further concern that the benefits allocated to Victorian consumers of the total benefits identified are such a large proportion of the total benefits. Equally of concern is the relatively small costs allocated for implementing the change. Stakeholders involved in the AEMC workshops have advised that they see significant increased costs in not only managing within the new structure but also in the managing the increased risks that the new structure introduces compared to the costs and risks inherent in the DWGM.

In a gas market where it is seen that gas demand is more likely to fall[19] than increase in both the medium and long term, consumers are very concerned that there is a better outcome where the detriments of the existing market are identified and addressed rather than implementation of an entirely new market structure.

It is of major concern whether changes based on the existing DWGM would overcome the known detriments at considerably less cost and much greater certainty of outcome than an entire restructure of the market, especially where it is known that consumption is falling.

[19] See for example the AEMO Gas Statements of Opportunity and Eastern Australian Domestic gas market Study 2014 prepared by DoI and BREE figure 3.4 showing declining growth in industrial use of gas, figure 3.5 showing declining use for electricity generation

That the AEMC has not investigated such an alternative scenario in much greater depth and assessed the likely benefits from such a change raises a real concern that consumers are going to be handed an outcome that has significant shortcomings.

4.1 Overview

The MEU has consistently expressed its concern with the costs of implementing the AEMC's proposed Southern Hub model that is intended to replace the current market arrangements in Victoria, the Declared Wholesale Gas Market (DWGM). Many other stakeholders in the Victorian market have expressed similar concerns with the AEMC's preferred model, in that the AEMC model exhibits a significant number of shortcomings and increases risks.

The MEU, along with other stakeholders, recognised that the DWGM has some limitations. However, it was also recognised that a number of reforms to the DWGM have been successfully introduced over the years to address issues as they arise.

Most particularly, the introduction of intra-day trading has markedly reduced the quantity of ancillary payments imposed while the extension of the Authorised MDQ (AMDQ) program to included AMDQ credits (AMDQcc) for new system expansion has provided a new market mechanism to allocate new capacity and underpin market investment in the expansion of capacity (the expansion of the Culcairn interconnect is a case in point).

As a result of the DWGM design and subsequent enhancements, the DWGM framework had ensured a high level of security of supply of gas to Victorian consumers, supported efficient regulated and market based investment in network capacity and had successfully underpinned a growing level of gas retail competition.

From the perspective of Victorian consumers, therefore, a strong case has to be made for any radical changes to the Victorian gas market. Moreover, it is essential that the case for radical changes to the DWGM model be made not only against the option of retaining the 'status quo', but also against the more realistic option – and the one sought by most stakeholders including the MEU – of enhancements of the DWGM.

For this reason, the MEU (and other stakeholders) have urged the AEMC to undertake an objective assessment of the costs and benefits for the alternative of a DWGM incorporating some key elements of the AEMC model. More specifically, the MEU seeks a cost benefit review of the two main alternatives, namely the incremental/hybrid reform of the DWGM and the AEMC's preferred option of radical change, i.e. of moving to an entry-exit continuous trading model based (in the first instance) on gas market models operating in the UK and Europe.

Indeed, the Victorian government in its initial response to the AEMC's review of the DWGM highlighted the need for a robust cost-benefit analysis. For example, noting both the existing benefits of the DWGM to Victorian gas consumers and the challenges facing the Victorian gas market in the future, the Victorian Government stated that:[20]

> "Recommendations will need to be based on rigorous analysis of the costs and benefits of different options"

In its Draft Final Report on the DWGM review, the AEMC acknowledges the concerns expressed by stakeholders that the Southern Hub model "may be unduly costly", that "the amount of change might be unnecessary" and that "incremental changes may be more appropriate".[21] However, the AEMC concluded that its own proposed "package of incremental reforms" would:[22]

> "…significantly increase the complexity of the current market arrangements, while delivering only modest improvements in participant's ability to manage risk and investment incentives."

What the AEMC, however, has **not done** in proceeding with the development of the Southern Hub framework is to conduct a 'rigorous analysis of the costs and benefits of different options' as specified by the Victorian Government (above).

Instead, the AEMC has focused the cost benefit analysis only on its preferred option and has failed to provide an independent cost benefit comparison of the 'incremental/hybrid reform of the DWGM' option (preferred by most stakeholders) against the 'entry-exit continuous trading' option preferred by the AEMC.

To wit, the AEMC has initiated two cost benefit studies conducted by PwC and published in May 2016 and October 2016 to assess only the AEMC's preferred option. The two studies were:

- PwC, *Cost benefit analysis of gas market reforms*, Final Report, May 2016 [PwC Gas Market report] and
- PwC, *Cost benefit analysis of the Victorian Declared Wholesale Gas Market reforms*, Final report, October 2016 [PwC DWGM report].

PwC's Gas Market report (May 2016) focussed on an assessment of the costs and benefits of the whole package of reforms to the East Coast Gas Market. However, it was noted in the May report that the majority of the costs and of the

---

[20] Department of Economic Development, Jobs, Transport and Resources, *Submission to the Australian Energy Market Commission Review of the Victorian Declared Wholesale Gas Market – Discussion Paper.* p. 2

[21] Cited in AEMC, *Review of the Victorian Declared Wholesale Gas Market,* Draft Final report, 14 October 2016, p. 47. The comments, which were expressed in the course of the AEMC's more recent Working Group meetings are similar to comments expressed in multiple submissions to the AEMC.

[22] Ibid.

benefits of the East Coast Gas reform were assigned to the Victorian gas market changes. PwC's DWGM report (October 2016) provided a more detailed assessment of the costs and benefits to Victorian consumers.

Notably, the PwC reports have been published after the AEMC published its Draft Reports on the East Coast Gas Market and the DWGM Review. Therefore, consumers in general have not had the opportunity to comment in detail on the cost benefit studies, albeit they are important to whether the proposed changes are to the benefit of Victorian consumers. [23]

In this response, the MEU will focus on the outcomes of PwC's cost benefit analysis as set out in their October Report. In addition, the comments will be focussed on the analysis of costs and benefits to Victorian consumers in line with the Victorian's Government's emphasis that the AEMC should focus its review of the DWGM, and options for reform, in terms of their impact on the Victorian consumer and economy.[24]

In other words:

A significant proportion of the costs of the east coast gas reforms proposed by the AEMC will fall on Victorian gas consumers. More specifically, the proposed changes to the wholesale gas market design from the existing DWGM to an entry-exit market model will pose significant and, in many cases, unknown costs on Victorian customers, particularly over the next 5 years. These costs will occur at a time when there are pressures on Victorian consumers from increases in both gas prices and (most likely) increases in electricity prices.[25]

It is essential therefore that the AEMC demonstrate that there is a significant and realistic benefit to Victorian consumers over the next 10-15 years as a direct result of their proposed changes to the current functioning DWGM.

The MEU also expects the Victorian government to use its understanding of the Victorian economy and the challenges facing the economy to very carefully evaluate the benefits claimed by the AEMC on the basis of the PwC report.

[23] Since the publication of the AEMC's original draft reports for the East Coast Gas Market and, more specifically, the DWGM review, the AEMC initiated an industry based working group and public forums. However, there has been no formal opportunity for stakeholders outside the working group to respond in detail to the PwC cost benefit assessments and the working group was not tasked to assess the benefits.

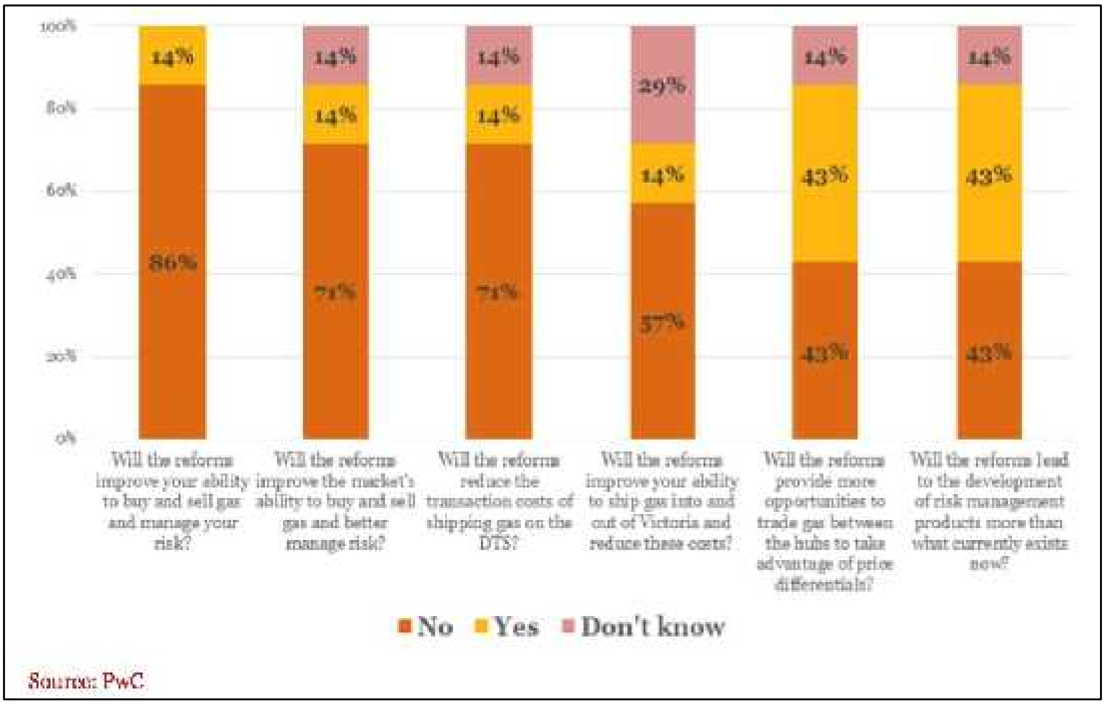
[24] See for instance, Department of Economic Development, Jobs, Transport and Resources, *Submission to the Australian Energy Market Commission Review of the Victorian Declared Wholesale Gas Market – Discussion Paper.* p. 2

[25] The closure of Hazelwood power station in early 2017 is predicted to increase Victorian consumers electricity bills by more than 6% while similar increases are expected in gas prices. See for instance: Age, "Gas and electricity prices to surge after Hazelwood closure", 2 December 2016. http://www.theage.com.au/victoria/gas-and-electricity-prices-to-surge-after-hazelwood-closure-20161201-gt238c.html

The MEU also expects the Victorian government to take careful note of the findings of PwC's survey of stakeholders in August 2016.

As illustrated in Figure 1, stakeholder responses to questions on whether they agreed with the AEMC's stated benefits of reform were "largely negative". The survey included multiple parties with different interests in the Victorian gas market such as AEMO, APA, large and small retailers (including retailers with substantial upstream gas holdings), generators and the MEU.[26]. Their concerns should not be readily dismissed as PwC does in its comments.

Figure 1: Summary of survey response to the benefits of the DWGM reforms



Source: PwC, *Cost benefit analysis of the Victorian Declared Wholesale Gas Market reforms,* Final report, October, 2016, Figure 10, p. 23.

For example, in response to the stakeholders' comments PwC notes the following:[27]

> "Reconciling the results of this survey with the expected returns from our modelling may be seen best in the context of the incidence (or burden) of reform; namely that our modelling shows the benefits are spread across many areas of the economy, but costs are largely concentrated on market participants which may explain the survey results."

---

[26] See: PwC, *Cost benefit analysis of the Victorian Declared Wholesale Gas Market reforms,* Final report, October, 2016, p. 22, footnote 40.
[27] PwC, *Cost benefit analysis of the Victorian Declared Wholesale Gas Market reforms,* Final report, October, 2016, p. 22.

PwC then goes on to state:

> "The stakeholders' comments in the survey suggest the greatest area of concern is costs rather than the likely achievement of benefits. Perhaps more bluntly, they may be considering their costs and whether they will benefit from a more efficient market."

The MEU as a participant in this stakeholder survey is concerned that PwC may not have fully considered the additional factors that might influence the response of stakeholders, noting that they were responding to the general benefit claims of the AEMC rather than the specific cost benefit analysis of PwC (which sought to 'quantify' the benefits and costs). Further, respondents were also aware that the AEMC model has a number of elements about which there are some very real concerns as to which benefits will be delivered and to what extent. So to assert that respondents focused on costs rather than benefits is not an observation that is supported.

Certainly the analysis of the PwC report gives the MEU concern that a major change with significant cost implications to Victorian gas users is being supported by an analysis where both the benefits and the costs are highly uncertain.

As explained later in this section, there are a wide range of feasible costs and many questions about the quantum of the benefits, particularly relative to the alternative, the progressive changes to the DWGM model.

The MEU does understand that further assessment of the costs may be undertaken as part of the regulatory impact statement (RIS) process (as recommended by PwC). However, we urge the Victorian government to take a cautious approach to committing to the changes in the gas market prior to this more detailed assessment.

The remaining sections examine a number of conceptual issues and underpinning assumptions in the PwC cost benefit analysis.

In making these criticisms, the MEU recognises that PwC has also identified that the cost benefit analysis provides 'indicative' information only (albeit on best endeavours basis), and that critical cost information has not always been available to PwC. However, this is a further reason for caution by the Victorian Government, particularly as PwC does not assess the benefits of the AEMC's proposal against the appropriate alternative, namely the progressive improvement of the DWGM (discussed further below).

The MEU also recognises that some of our concerns with the assumptions in the PwC modelling may be addressed as part of the ongoing work of the AEMC and the Gas Reform Group and its subsidiary working groups.

Again, however, the MEU highlights that as the AEMC working group progressed its analysis of the AEMC model, concerns were raised about many elements. It is expected that similar issues will face the proposed Gas Reform Group (along with its working groups) as they carry out their work, because the complexities of addressing these issues are becoming increasingly clear. The challenges of "importing" a model of a gas wholesale market from Europe or the UK, both of which have greater producer competition, much larger gas flows, and very different physical characteristics to the DTS. It is important to note that as stakeholders worked with the AEMC examining the AEMC model, as work progressed through the process, the issues became clearer and they became less supportive of the change proposed by the AEMC.

4.2 Conceptual Issues

The MEU has a number of basic conceptual issues with the PwC analysis.

4.2.1 Only one option examined

> **The PwC cost benefit analysis only looks at one option for reform of the Victorian market**, namely the AEMC's preferred entry-exit continuous trading model. PwC's assessment is based on benefits and costs of its preferred model **relative to a 'base case'** that:
>
> > "…includes assumptions about structural changes in the gas market" [28]
>
> across the east coast that includes overall changes in east coast supply and demand, moratoria on onshore gas exploration, price changes and that the **reforms other than the change to the DWGM will be implemented.**
>
> However, what stakeholders (including presumably the Victorian Government) were seeking from the AEMC was an independent assessment of the **costs and benefits of the option for incremental reform of the DWGM as well as for the entry-exit model.**[29]

[28] PwC, *Cost benefit analysis of the Victorian Declared Wholesale Gas Market reforms*, Final report, October 2016, p. v.

[29] As discussed later in this section, the AEMC's Final Draft Report appears to imply that this is a task for consumers and other stakeholders to undertake the detail design and costing of incremental or hybrid reform. The MEU considers this is not appropriate. The AEMC, not the market participants, has been assigned the role of providing "rigorous analysis of the costs and benefits of different options".

4.2.2 Limitations of the studies

PwC has highlighted the limitations of its two cost benefit studies. For example, PwC has stated at the outset of their October 2016 report that:[30]

> "Our report has been limited to estimating the economic impacts of the policy reforms proposed by the AEMC … The broad nature of the modelling is such that the results are **intended to be indicative only**".[emphasis added]

However, the MEU considers that the AEMC has not adequately discussed the limitations of the PwC study in its response to stakeholder concerns with the costs to implement the change. Instead, the AEMC responds to stakeholder concerns with costs of its preferred entry-exit model by asserting without adequate qualification that[31]:

> "...the cost benefit analysis undertaken by PwC indicates that the costs would be significantly outweighed by the likely benefits".

4.2.3 Theoretical and high level modelling

Consistent with the disclaimer by PwC, the MEU stresses that PwC's assessment of the benefits of the AEMC's proposed model are theoretical based on very high level economic modelling of the impacts over 10 and 20 years (from 2020-21) on Gross Domestic Product (GDP) and Victorian Gross State Product (GSP). PwC uses a 'computable general equilibrium' (CGE) type model that provides a specific time path of the economy following a change in policy or the introduction of a new 'project'. While CGE models have the benefit of flexibility and can consider outcomes by region and consumer type, significant variation in estimates can be produced using the same CGE model depending on the assumptions on the economic environment and specific policy or project specifications.[32]

4.2.4 The basis of the modelling

The assumptions made regarding the benefit that the change to the DWGM will achieve are conceptually predicated on two major elements

1. That interstate trade in gas will be enhanced providing benefits to all consumers and

---

[30] PwC, *Cost benefit analysis of the Victorian Declared Wholesale Gas Market reforms*, Final report, October 2016, p. i.

[31] AEMC, *Review of the Victorian Declared Wholesale Gas Market,* Draft Final report, 14 October 2016, p. 48.

[32] For example, see review by the Queensland Government, "Overview of some alternative methodologies for economic impact analysis".

2. There will be benefits to Victorian consumers through an improved market structure

Regarding the first point, it needs to be recognised (as discussed in section 1.3.4) that at most about 15% of the gas capacity that moves interstate from Victoria transits the DTS with the large majority leaving Victoria via SEAGas and Eastern Gas Pipelines. In the event that there are significant flows towards Victoria, then the benefit of these will be primarily observed in the exports on SEAGas and EGP allowing Otway and Longford to inject more gas into the DWGM, rather than the small amount that might enter via Culcairn.

The assumption that changing the DWGM to enable such a small volume of gas transiting Culcairn will provide significant benefits in other states as well as Victoria is of concern and raises the question as to why so much benefit is provided by such a relatively small amount of gas that can leave or enter the DTS from interstate.

The DWGM already provides considerable benefit to Victorian consumers, so considering the small (if any) benefit from interstate trade, the MEU questions how changing the DWGM can generate such a massive benefit for Victorian consumers.

Secondly, the basis of the modelling uses benefits generated from markets developed overseas yet the Victorian DWGM is recognised internationally as an appropriate market for the needs.

4.3 'Assumptions' in the PwC model

The MEU has concerns with a number of the explicit and the more implicit assumptions[33] underpinning the CGE economic model, assumptions that generated a positive net benefit to Victorian consumers. Specific areas of concern are:

4.3.1 Benefits drawn from overseas experiences

In assessing the benefits of the change to the DWGM, PwC has drawn significantly on benefits that are observed in other markets following reforms to the market.

[33] A number of the implicit assumptions rely on a particular perspective of the relationships and second order effects flow through in the Australian economy. It is not clear whether this adequately accounts for the extent of foreign ownership of energy assets in Australia.

However, there are important limitations to this assessment. PwC acknowledges this to some extent when it concludes as follows:[34]

> "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."

The MEU considers that reliance on other markets to define key benefits of reform to the DWGM must be more strongly qualified. For example, Victoria has already progressed many important reforms to its gas market – it is not starting from a base of a vertically integrated utility with little market maturity. As CEPA/TPA stated in their recent presentation to the Review Working Group:[35]

> "…the Victorian market is starting the reform process from a much stronger position than many other countries in Europe which had vertically integrated monopoly suppliers."

The MEU considers that there would be many other factors in addition to the relative maturity of the Victorian market and that these factors would in effect modify the marginal benefits to Victoria of a step change in the Victorian gas market.

4.3.2 Liquidity will increase

There is a basic assumption that liquidity in the market will increase as a result of the redesign of the Victorian DWGM. This assumption has been made despite the recognition that there is low competition and increasing consolidation in the upstream producer market. Economic and financial drivers that go way beyond the structure of the Victorian wholesale gas market drive this trend. To put it another way, it is very unlikely that a change to the DWGM, per se, will encourage new producers into the market or breakdown the joint marketing of gas by producers. For example, in its Inquiry into the east coast gas market the ACCC stated: [36]

> "There is a need for more sources of gas supply particularly the southern states. The gas users in these states are becoming overly dependent on the jointly marketed GBJV gas …Increasing the level and diversity of supply, located close to southern demand centres,

---

[34] PwC, *Cost benefit analysis of the Victorian Declared Wholesale Gas Market reforms*, Final report, October 2016, p. 35.
[35] CEPA/TPA Presentation to Working Group 4, 31 August 2016
[36] ACCC, "*East Coast Gas Inquiry key findings*", April 2016. See finding 5 and finding 14. https://www.accc.gov.au/system/files/East%20Coast%20Gas%20Inquiry%20key%20findings_0.pdf

> will improve competitive dynamics in the south and is likely to lead to better pricing outcomes for domestic users."

And

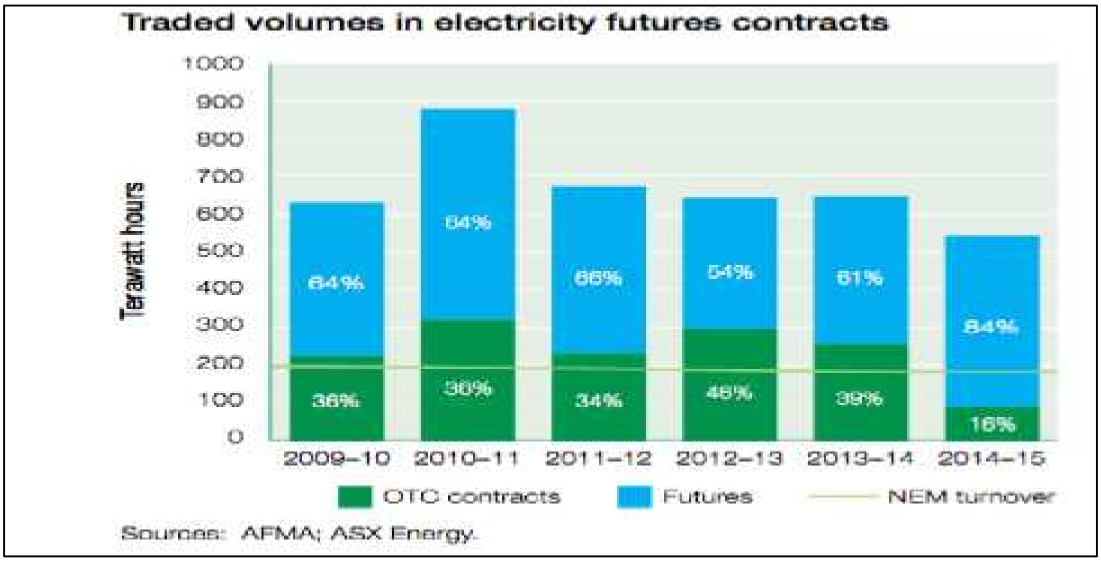
> "The liquidity of gas trading mechanisms is currently limited. In the long-run, liquidity will be best supported by an increase in the diversity of gas market participants and the volume of gas supply in the market overall."

Logic and experience would suggest that without such increase in diversity of supply in Victoria, the proposed market changes will make little difference to gas costs or to the transparency of gas prices. Without adequate liquidity in the aspect of gas supply it is unlikely that a strong secondary financial market will emerge.

The possibility of improved liquidity in the wholesale gas market is also constrained by the extent to which large gas retailers have established long-term contracts and/or interests in upstream production assets. This parallels the drive by electricity retailers to build or acquire their own generation assets as, inter alia, a physical risk management tool and this continues, although as noted in South Australia, increased control of generation assets by retailers and a lack of competition in that generation market, the liquidity in the SA regional market has fallen dramatically.

The reduction in both OTC and Futures electricity contracts is further evidence that financial liquidity is linked to broader market structure developments such as the consolidation of the market and vertical integration ('gentailers'). Figure 2 illustrates this decline through to June 2015 and it is likely to have declined further over the following year.

Figure 2: Traded volumes in electricity futures contracts



Source: AER, *State of the Energy Market 2015*, February 2016, Figure 1.25, p. 54.

4.3.3 Market competition will increase

There is an assumption by the AEMC and PwC that the revised market structure will increase competition. However, there is no convincing substantiation of this claim.

Indeed the assumption overlooks the strongly expressed concerns by current smaller gas retailers with the potential costs of the changes and the challenges of accessing matching capacity rights a small retailer or a new entrant might face. In these conditions, there is a strong possibility that there will be further consolidation of gas retailers in Victoria and that large retailers (with more diverse and flexible portfolios) and gas fired generators will capture any benefits of lower gas prices in Victoria (should they emerge) rather than Victorian consumers. Given complex ownership of these entities, it is also not apparent how such additional profits would benefit overall Victorian GSP as they would be effectively "a transfer of wealth".

4.3.4 Gas demand in Victoria is not highly elastic

There is an assumption that gas demand in Victoria has a relatively high elasticity and, more specifically, that shippers, retailers and direct industrial customers can

(a) respond quickly to gas price reductions and

(b) any savings will be passed through to consumers in their costs of gas.

This assumption is significant and is of particular concern given that the principal benefits stated in the PwC report as flowing to the Victorian GSP will flow largely through to claimed improvements in the productivity and output of the large industrial sector in Victoria, a sector where there is seen a declining demand (see section 2.3.4).

The experience of MEU members and other industrial gas users is that industry does not, and largely cannot, respond to the occasional (and often unanticipated) low prices for gas, such as might occasionally arise from Queensland[37] and referred to in the draft report. Further, residential demand is primarily an outcome of weather and also is not elastic in that demand will vary with prices.

It is far more likely that, should additional low cost gas reach the Victorian market at net costs lower than current contract prices (i.e. after

[37] Such as might occur if an LNG plant is off-line and there is surplus gas from the Queensland CSG production fields. Even if this event reduced the price of gas entering Victoria it is not clear if and how industrial users could effectively ramp up production, particularly if they are already limited by their capacity rights.

taking account of interstate transport and alternative gas uses in Queensland, NSW and Cooper Basin storage), the gas will be taken up by generators or by retailers seeking low cost gas for storage[38] which are all dependent on the timing of when the low prices occur and the prevailing swap market conditions.

However, it is not clear how, in practice, the growth of industrial and large commercial demand anticipated in the CGE modelling will be eventuate, particularly in the face a number of related factors such as:

- low liquidity upstream of the wholesale/producer gas market;
- the additional requirement for direct customers to acquire and manage separate capacity rights on the DTS;
- the complexity of continuous balancing (and risks associated with imbalance penalties).

4.3.5 Limited capacity to manage price volatility

There is an assumption in the cost benefit analysis that gas retailers have very limited capacity to manage the risk of price volatility in the DWGM in the absence of a financial derivative market, and that this outlook will improve under the entry-exit model. As noted above, there is an assumption that under the proposed model a financial market will emerge although it is not clear this will happen given the upstream supply constraints.

In addition, the assumption ignores the extent to which retailers (and some direct customers) can already manage their risk under the current arrangements through taking upstream positions, matching GSA rights with demand, contracting with existing retailers with long gas positions and undertaking 'second order' hedging. Second tier retailers report that they manage market risk through 'hedging contracts' with other participants in the gas market and/or taking out oil price linked hedges to reflect gas contracts linked to Brent oil.[39]

4.3.6 All gas does not flow through the Victorian hub

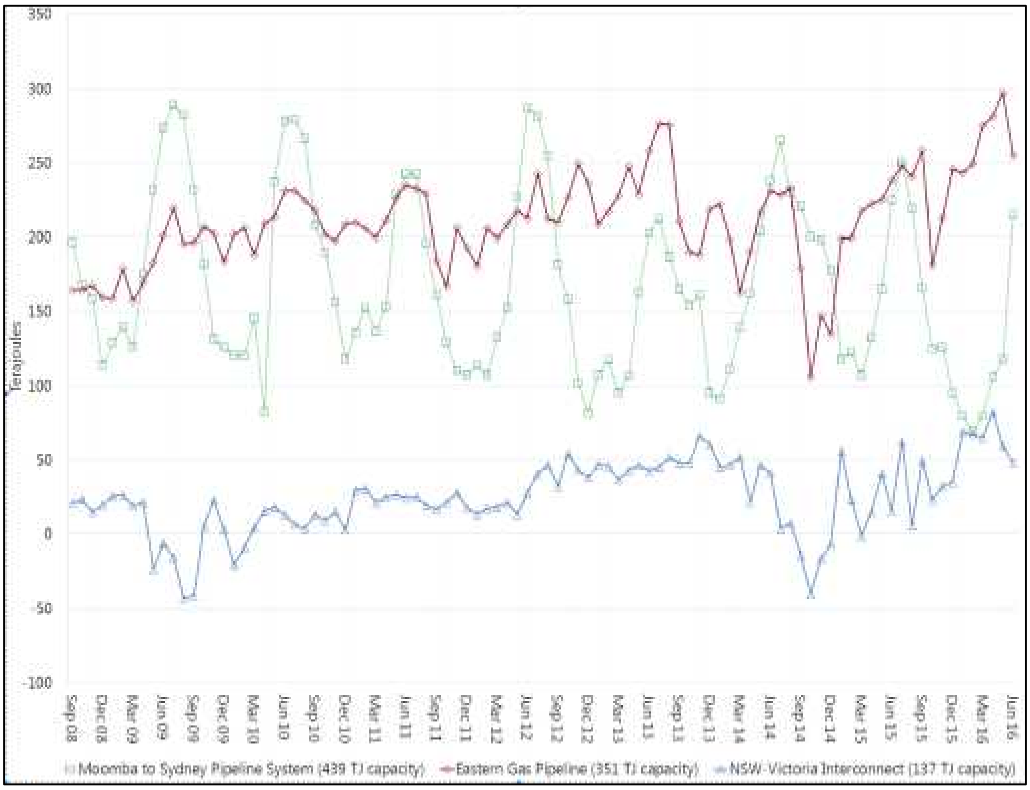
Currently, the majority of interstate gas flows from Victoria sit outside the DWGM/DTS (see section 2.3.3), and are subject to contract carriage

[38] For example, there is some evidence that retailers took advantage of low cost ramp gas to accelerate the fill storage in Victoria.

[39] For instance, Snowy Hydro reports that it manages the risks of its gas supply contracts (which it states are in the main indexed to oil prices) by taking out oil price and currency hedges. See Snowy Hydro annual report for 15/16: "The Groups policy is to hedge up to 100% of its oil linked gas purchases by way of Australian dollar denominated oil contracts for a period of up to 3 years" (p 51). Snowy Hydro also states that it manages gas price risk through "hedging contracts with participants in the gas market (p. 24). Snowy Hydro gas retailing includes the portfolio of Red Energy and Lumo Energy, collectively representing the largest 2nd tier gas retailer in Victoria.

arrangements rather than the market carriage arrangements under the DWGM. These include flows on the Eastern Gas Pipeline (EGP) to NSW and the SEA Gas Pipeline to SA (and beyond). Figure 3 below, for instance, illustrates the dominance of the EGP in terms of supply from Victoria to NSW compared to the flows via the DTS and Culcairn.

Figure 3: Average daily gas flows from Victoria to NSW/ACT (to June 16)



Source: AER, Wholesale Market Statistics (accessed 30 Nov 2016) http://www.aer.gov.au/wholesale-markets/wholesale-statistics/average-daily-flows-nsw-act-demand-region-monthly

While APA has progressively expanded the NSW-Victoria (Culcairn) interconnect, it is also worth noting that Jemena is expanding capacity on the EGP. In addition the SEAGas to Moomba to Adelaide pipelines (MAPS) were interconnected in 2015 and the MAPS pipeline reinforced to allow bidirectional flows, together allowing Victorian gas to be shipped north via South Australia.[40] In other words, the flows of Victorian gas northward for LNG have only limited reliance on the flows through the DTS/DWGM to Culcairn.

It is not clear how the reality of these flows have been taken into account in the assessment of the benefits to Victoria gas consumers and

[40] See AER, *State of the Energy Market 2015*, 4 February 2016, p. 103.

Victorian GSP of changing the current DWGM arrangements.[41] Certainly there are no obvious reasons why those flows interstate through pipelines that are not part of the DTS will influence prices within the Victorian hub at all, or at least in any way different to the way they influence prices in the current market – *unless of course any new entry-exit capacity charges at Longford, Iona and Culcairn drive gas flows further away from the DTS network.* If such a redirection occurred, it is not clear how this would be a benefit to Victorian given that DTS network revenue must recover the regulated revenue allowance for APA's network.

The MEU would expect the Victorian Government to make its final decision based on more information than is currently available about these relative prices for DTS access under the current and proposed design.

4.4 PwC Assessments of the Costs of Implementing the Entry-exit continuous trading model

As noted previously, PwC have appropriately qualified their analysis of the costs of implementing the AEMC proposed model. It is recognised that accurate cost estimates are difficult when so much of the detail of the proposal is unknown – not only is the 'devil in the detail' but the range of potential costs including IT and ongoing operational costs is very closely related to this detail.[42]

Therefore, the MEU's comments on costs are necessarily very high level, although we must highlight that already there is a very significant burden of costs identified in the PwC study for direct customers. Given this, MEU summarises some of the issues below. However, the MEU also notes that this is by no means a comprehensive analysis of the issues around PwC's cost benefit analysis. The MEU would expect the Victorian Government to undertake a more thorough and critical assessment of these costs particularly as the details become clearer through the Gas Reform Group.

It is important, for instance, that **independent analysis of the proposed costs, the possible range of costs and the implementation risks and that this analysis is provided to the Victorian Government prior to the development of a RIS.** A summary of the MEU's 'first cut' analysis of possible issues with the costs is set out below.

[41] For instance, if there is a shortage of gas in Sydney as a result of Cooper Basin gas being directed to Queensland LNG, then a good portion of Victorian gas is likely to flow via the Eastern Gas Pipeline rather than the Culcairn interconnect. This is not likely to have a direct impact on the DWGM prices but can potentially provide a reference point for gas contracts in Victoria.

[42] For example, the balancing rules, capacity auction and release rules, and pricing rules to ensure (a) system security given the particular nature of the Victorian transmission system and demand profile, (b) access for new entrants, (c) protection of existing capacity and GSA rights, can have significant effects on costs and (of course) on competition and security.

- PwC has relied on various sources for its costs some of which have limited relevance to current costs. For example, PwC has relied on costs identified in by MMA in the "Gas Market Options Cost Benefit Analysis" of 2006. While these costs have been indexed, there is concern as to their relevance in the current situation. Large market participants in the August survey indicated considerably higher costs than the figures derived from the MMA's cost estimates for the STTM and GBB report.[43]

- Where PwC has not been given specific updated costs in the August 2016 survey from relevant stakeholders, it has (at least sometimes) relied on costs applied in the PwC May 2016 report. In the important instance of costs associated with APA (who will be taking on new roles under the proposed market arrangements), PwC reports that APA indicated in August that costs would be significantly higher than they suggested in May, but, in the absence of detail, PwC appears to have continued to rely on APA's estimate in their April survey.[44]

- AEMO has significantly updated its costs estimates in the August survey and provided an updated range for implementation costs of $30m to $80m to PwC[45] (depending on the functions it will be required to undertake). PwC has used a figure of $55m (in $2015-16) for implementation costs. However, to the extent that AEMO's stated cost range depends on the allocation of tasks to AEMO, some of these costs may well need to be reassigned to other parties (e.g. to APA). It is not clear how PwC has addressed this issue.

- The PwC analysis assigns only a small amount to "Planning costs" namely a total of $8m ($2015-16) or $7m discounted,[46] for all the relevant market participants. This seems to be a relatively small amount for a project that is also recognised as significantly more difficult than the establishment if the STTM/GBB for instance. Moreover, it is not clear, however, how overall reform project costs are going to be allocated.

  For instance, Figure 4 below sets out an implementation map prepared by the AEMC. There are clearly many additional costs associated with the overall governance of the gas market reform. PwC has not specified how these costs will be allocated including the costs of the chair and project management advisors and communication specialists.

---

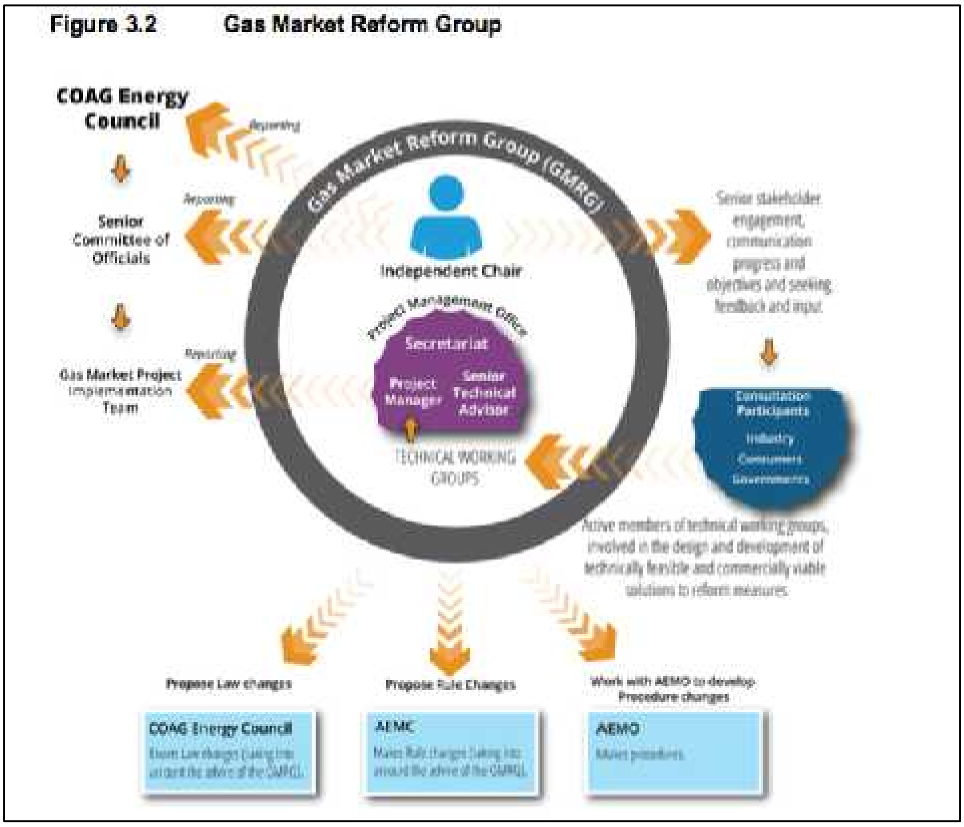
[43] See: PwC, *Cost benefit analysis of the Victorian Declared Wholesale Gas Market reforms*, Final report, October 2016, Table 13, p 46. For implementation costs large market participants indicated a range of $4.5 - $10m, MMA/literature review indicated a cost of $1.6m. PwC has used an 'average estimate of $4.4m from a stated range of $1.6m to $10.0m.

[44] Ibid, Table 17, p. 46. PwC assigns a value of $875,000 to $1.75m to pipeline operator implementation costs along with $0 ongoing costs.

[45] Ibid, Table 16, p. 46.

[46] Ibid, Table 7, p. 34.

Figure 4: Gas Market Reform Group Governance Framework



Source: AEMC, *Review of the Victorian Declared Wholesale Gas Market*, Draft Final Report, 14 October 2016, Figure 3.2, p. 51

- The scenario analysis prepared by PwC in the DWGM report is inadequate in terms of Victorian gas users understanding the full trade off of costs and benefits for Victorian consumers and, more particularly, the risks around this figure.

  For example, PwC summarises its overall cost benefit of the changes to the Victorian market as follows:[47]

  > "The analysis in the central scenario indicates that, for an implementation cost of approximately $100 million and ongoing costs of approximately $7 million, the proposed reforms could lead to greater productivity growth, consumption, exports and investment, resulting in GDP that in net terms is $0.9 billion higher than it would otherwise be in 2040."

  The MEU concludes that the benefits of the Victorian market changes are expressed in terms of **total GDP**, not in terms of benefits to Victorian gas consumers or **Victorian GSP. In contrast, the stated**

[47] Ibid, p. 35.

costs are expressed in terms of costs (direct or indirect) to Victorian market participants.

It would have been more useful for Victorian gas consumers (who are likely to have to fund the changes as noted above) for PwC to summarise both the benefits and costs in terms of their impact on Victoria.

Moreover, it is important for Victorians to understand the risks associated with implementation by presenting the high, low and central scenarios in Section 5.2 Tables 9 - 10 in terms of the range of net benefits taking into account the range of benefit assumptions and DWGM costs in terms of Victorian GSP. For example, the MEU would look to see an assessment of the low scenario for Victorian GSP against the high scenario of costs to the Victorian consumers.

In its assessment, PwC does not appear to have considered the significant risks around future demand for gas in Victoria. AEMO is forecasting a decline in Victorian gas industrial use due to gas price pressures and structural changes in the Victorian economy. Even if there is a long-term net benefit to Victoria of the changes proposed from the DWGM (and the MEU does not accept that the cost benefit analysis is sufficiently robust in terms of data to support that assumption), a large part of these claimed benefits are occurring beyond 2030. However, the large components of the costs will be incurred by market participants in the nearer term and will be passed through to customers in that near term.

It is essential therefore, that analysis is made on the impacts in the near term as well as the longer term on gas prices. Large customers will make their decisions on location of plant based on 'current' gas prices on offer (including the new transportation costs) rather than promises of some future decline in delivered gas prices.

Moreover, these higher costs will need to be recovered over a declining demand, exacerbated by the near term higher prices.

4.5 Conclusions on the cost benefit analysis

An overarching theme from the review of the PwC cost benefit analysis is that the benefits have been overstated significantly because much of the benefit that is derived from overseas experience reflects a move from a vertically integrated system to a market based system. Essentially, what PwC and the AEMC have overlooked is that the DWGM already provides many of the benefits that have been generated in overseas markets, so to all intents, the PwC report has effectively excluded the benefits that have already been realised in the DWGM and so has double counted the benefits.

There are significant flaws in the assumptions that are used by PwC and these also lead to an overstatement of the benefits that will accrue to the market.

But an underlying and very important aspect of the cost benefit study is that there are essential flaws in the conceptual basis in that PwC admits there are limitations of their modelling and because of the high level nature of the modelling the outcome is very dependent on the assumptions made; the MEU analysis of the these assumptions shows that there is very likely a much lower benefit that might be delivered than that implied by PwC.

The MEU also notes that PwC has only modelled one scenario – that of the AEMC model. The benefits identified from the modelling are predicated on an assumption that the current DWGM will not and cannot be enhanced in any way. As a result there has been no attempt to model the benefits that might come from the hybrid model proposed by Seed Advisory at the AEMC forum or from approaches to refine the current DWGM.

The MEU considers that not only is the modelling provided seriously flawed, but by not examining options, the modelling has resulted in a biased view of what might be better in the long term interests of Victorian consumers.

5. Summary of conclusions

The AEMC has drawn a conclusion that the DWGM is not fit for purpose and needs to be replaced with an entirely new market structure.

What was not investigated by the AEMC is the extent to which the lack of upstream competition has prevented the DWGM from reaching its full potential and whether more modest changes to the DWGM could deliver the needed upside at a much lower cost and risk to consumers.

The AEMC has made many observations that its proposed model is superior to the DWGM even if it were to undergo further refinements. The MEU considers that many of the detriments of the DWGM cited by AEMC are not as significant as is imputed by the AEMC. What is concerning is that the AEMC has elected not to carry out any assessments of an upgraded DWGM (or a hybrid as suggested by Seed Advisory) to assess whether such an option could deliver better outcomes for Victorian consumers without the costs and risks of a major change

In particular the MEU considers that the benefits thought to be delivered through easier interstate trading are significantly overstated as the bulk of the gas traded north from Victoria never transits the DWGM or the AEMC proposed option.

The MEU is also very concerned that the risks inherent in the new model have been downplayed despite the advice delivered to the AEMC during the workshops by practitioners operating in the gas markets, that the new model will introduce different but still significant risks that are not seen in the DWGM.

For example, aspects raised address:

- The AEMC model is more complex in that there are three separate markets for balancing, commodity and capacity. Each of these additional markets will provide some benefit but they also introduce risk
- It is unknown what the impacts on the current GSAs will be
- Will security of supply reduce as a result of less involvement by AEMO?
- Will liquidity actually increase despite the highly concentrated upstream market?
- Will there be liquidity in the voluntary exchange?
- Will as available gas really be available as and when needed?
- Will the negative impacts of a transition be greater than expected?

It is concerning that these issues have been minimalised in the assessments of the benefits of the AEMC model

There are significant concerns about the outcomes from the assessment of the benefits of the PwC modelling and what is also concerning is that there has been no further effort to assess whether the DWGM could be enhanced with features such as those are included in the AEMC model (eg forward trading) and if these could deliver similar benefits but at a lower cost.

The fact that the AEMC model is identified as having a significant number of major weaknesses (which will reduce the benefits claimed) makes it all the more important that alternatives should be examined in as much detail as the AEMC model.

An overarching theme from the review of the PwC cost benefit analysis is that the benefits have been overstated significantly because much of the benefit that is derived from overseas experience reflects a move from a vertically integrated system to a market based system. Essentially, what PwC and the AEMC have overlooked is that the DWGM already provides many of the benefits that have been generated in overseas markets, so to all intents, the PwC report has effectively excluded the benefits that have already been realised in the DWGM and so has double counted the benefits.

There are significant flaws in the assumptions that are used by PwC and these also lead to an overstatement of the benefits that will accrue to the market.

But an underlying and very important aspect of the cost benefit study is that there are essential flaws in the conceptual basis in that PwC admits there are limitations of their modelling and because of the high level nature of the modelling the outcome is very dependent on the assumptions made; the MEU analysis of the these assumptions shows that there is very likely a much lower benefit that might be delivered than that implied by PwC.

The MEU also notes that PwC has only modelled one scenario – that of the AEMC model. The benefits identified from the modelling are predicated on an assumption that the current DWGM will not and cannot be enhanced in any way. As a result there has been no attempt to model the benefits that might come from the hybrid model proposed by Seed Advisory at the AEMC forum or from approaches to refine the current DWGM.

The MEU considers that not only is the modelling provided seriously flawed, but by not examining options, the modelling has resulted in a biased view of what might be better in the long term interests of Victorian consumers.

Appendix A

The AGE

November 28 2016 - 7:15PM

Fossil fuel giants using questionable deductions to shrink tax bills: Auditor-General

Heath Aston

A damning investigation has found multinational companies are claiming billions of dollars in questionable deductions while exploiting the nation's natural riches, using accounting tricks allowed to flourish under a hands-off government approach that is dudding Australian taxpayers of royalties.

And in a stunning disclosure, the probe by Auditor-General Grant Hehir found nearly two decades had passed since a federal government audited the self-assessed royalty payments from the North West Shelf, a giant project located in the lucrative oil and gas region off the West Australian coast and jointly owned by Woodside, Shell, Chevron and BHP Billiton.

Underlining rising concerns over whether the $200 billion liquefied natural gas industry is paying its fair share of tax, Mr Hehir's report discovered a $5 billion bonanza of deductions claimed by the project in just one 18-month period.

Some of the Auditor-General's most damning criticism was reserved for a single $705 million cost deduction that helped reduce royalties owed to the taxpayer by $88 million. Mr Hehir argued the $705 million deduction may not have been technically valid.

The multibillion-dollar deductions - which are still being taken despite the project being fully mature after 25 years in operation - dwarf the $1.9 billion in royalties it paid in the same 18-month period.

Mr Hehir warned his review may only scratch the surface.

"There has been limited scrutiny of the claimed deductions...the available evidence indicates that the problems are much greater than has yet been quantified," he found.

Among the most concerning findings were:

- It has been 17 years since the government audited the self-assessed royalty payments from North West Shelf;

- One of the meters relied on to measure gas output, and therefore royalties due, was broken for five years;
- The Royalty Schedule which governs payment calculations has not been updated in 10 years, and;
- The West Australian government engaged audit firm Ernst & Young to conduct a 2014 "external review" of deductions even though the firm is also the long-time auditor of the North West Shelf's financial accounts.

Mr Hehir found deductible costs, which include operating and capital expenditure, depreciation and crude oil excise, can represent up to 90 per cent of the gross value of the gas produced.

"There are some significant shortcomings in the framework for calculating North West Shelf royalties," he found.

North West Shelf has already paid $8.6 million in underpaid royalties as a result of the Auditor-General's investigation.

Mr Hehir also made a withering assessment of the hands-off approach of bureaucrats in the federal Department of Industry, Innovation and Science and the state Department of Mines and Petroleum, which oversees the royalty system.

"Given the actual and potential size of allowable deductions being claimed by NWS producers on a monthly basis, it would be reasonable to expect [the departments] to have developed and implemented a robust compliance strategy and included strong controls around verifying the validity of deductions being claimed," he wrote.

He said there were no agreed procedures and no assurances sought that deductions are being claimed correctly.

Mr Hehir recommended the state and federal governments work together to ensure deductions claimed by the North West Shelf producers in 2015 are valid, as well as work to "verify the validity" of deductions claimed prior to 2014.

A Woodside spokeswoman said the company had "robust compliance processes with regard to royalty obligations" and had assisted audits in an "open, transparent and cooperative manner".

Woodside pointed to a reference in Mr Hehir's report about underpaid royalties totalling "$11.6 million" but that total was in direct relation to a 2014 external audit, which the Auditor-General described as "limited in scope".

Resource tax expert Diane Kraal, a lecturer from Monash University, said it was hard to know just how much has been lost from the North West Shelf without a forecast for how much royalty revenue had been expected.

In its response to the Auditor-General's report, the federal department agreed the system could be 'improved" but argued it was nonetheless "robust".

For historical reasons, the North West Shelf pays royalties but also comes under the petroleum resource rent tax (PRRT).

Newer LNG export projects like Chevron's massive Gorgon and Wheatstone ventures are not required to pay royalties at all but are only assessed for the profits-based PRRT.

Fairfax Media has revealed over recent months that just 5 per cent of 150 oil and gas ventures are paying any PRRT, despite Australia being poised to eclipse Qatar as the world's single biggest exporter of LNG by 2020.

The industry has built up a mountainous $187 billion in exploration and development tax credits, which continue to rise sharply and will be used to insulate companies from paying PRRT for years to come.

Last week, Craig Emerson, one of the architects of the PRRT in the Hawke government backed calls for a parliamentary inquiry into why the boom in LNG exports shows no sign of delivering any meaningful contribution to the wealth of Australia.

Appendix B

Australian Financial Review
Nov 27 2016 at 11:00 PM

Exploration drought stokes gas shortage fears

Angela Macdonald-Smith

Western Australia is likely to see no onshore exploration wells drilled this year, while offshore drilling also has slumped, fuelling fears of gas shortages on the west as well as the east coast

The problem appears most severe in WA, but applies nationwide as some states become off-limits due to drilling bans and weak commodity prices, regulatory hurdles and stretched balance sheets crimp exploration, said Bill Tinapple, a former top oil and gas bureaucrat in WA.

"Across Australia – Western Australia is just symptomatic – exploration is sliding," said Mr Tinapple, the former petroleum executive director at WA's Department of Mines and Petroleum, who fears the onshore industry will be set back for at least 10 years.

"Without exploration to cover future growth and to replace gas that is utilised, shortages may be severe."

Wood Mackenzie analyst Saul Kavonic said the exploration outlook in WA had become bleaker as many companies slash exploration spending amid low oil prices.

"Exploration budgets have really felt the brunt of industry cost-cutting," Mr Kavonic said. "Exploration drilling offshore WA has dropped since 2011 as many projects moved from exploration into the development phase, and then fallen further still as oil prices collapsed."

Wood Mackenzie is forecasting a shortfall in WA domestic gas supplies from the mid 2020s unless prices rise to levels high enough to justify developing new fields, many of which are far away from existing infrastructure or relatively small, making them more costly.

Spending on both onshore and offshore exploration has fallen by almost two thirds over the past two years, according to the Australian Petroleum Production and Exploration Association, which says exploration drilling offshore is at its lowest in almost 20 years, while onshore drilling is at its lowest for 15 years.

Within the last two years Hess Corporation, Apache Corporation, ConocoPhillips, Chevron and PetroChina are among majors that have exited onshore exploration in individual states.

APPEA head Malcolm Roberts said the association didn't see a risk of gas shortages in WA but he said a shortfall is expected to emerge on the east coast from 2019 and progressively worsen.

"There's every good reason to be concerned, given you can count the number of offshore wells on one hand," Dr Roberts said. "It's not a sustainable position for the industry."

In WA, Mr Tinapple, who is now a consultant, primarily blames burdensome regulations on stakeholder consultation and approvals that have been beefed up to the extent that they are killing off activity.

"It's a shift in approach that I was part of getting started, but now seeing what impact it has on companies, how companies are leaving WA, I am concerned that the pendulum has swung too far," he said.

But Jeff Haworth, now the executive director of petroleum at the DMP, defended WA's regulatory regime, pointing out that, while there will be no exploration wells spudded in the state this year, 2015 saw the number of wells more than double from four to nine.

"Stakeholder engagement is a necessary part of company business and the need for community acceptance has always been there for projects," he said.

"Nowadays, the issue has been made difficult by the amount of anti-fossil fuels activity in Australia and globally, and the result has been seen in other jurisdictions."

Mr Haworth said that, with the industry entering its third year of lower oil prices, exploration funding was drying up and programs around the world had been delayed or curtailed.

"This does have a short-term delay in finding new gas fields, but with the Waitsia discovery along with the Red Gully North discovery immediate concerns with gas supply are certainly not alarming," he said.

"Once the oil price recovers exploration will pick up."

In the east drilling moratoria have brought onshore work to a standstill in Victoria, while the new Northern Territory government has introduced a ban on drilling for unconventional oil and gas.

The Queensland government earlier this month suggested possible measures to encourage long-term supplies of gas to help meet a seven-fold increase in the state's demand between 2013-14 and 2017-18.

"With exploration declining and NSW and Victoria prohibiting exploration, where will the gas come from?" Mr Tinapple asked.

Appendix C

World's Priciest Gas Is Bound for One U.S. Region This Winter

Bloomberg

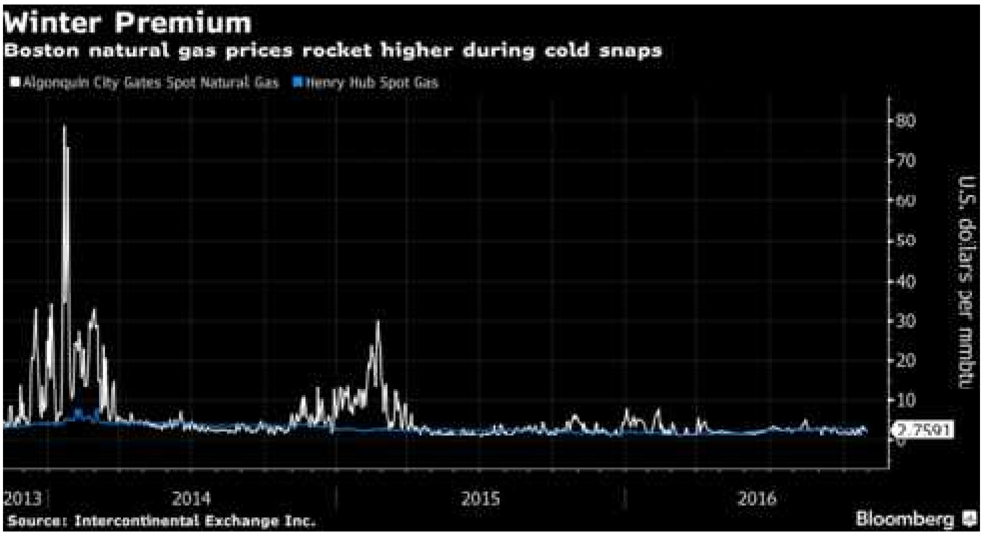
Naureen Malik November 2, 2016 — 5:04 AM AEDT

The global glut of natural gas still hasn't reached one corner of the U.S.

The heating fuel may surge to $20 to $25 per million British thermal units in New England this winter, the highest in the world, as pipeline bottlenecks limit supplies during frigid weather, traders including Consolidated Edison Inc.'s ConEdison Energy said. Prices have collapsed across the rest of the globe amid tepid demand growth, rising exports and a plunge in crude oil prices earlier this year.

Competition for pipeline access into New England is poised to intensify as the power grid, already getting more than half of its supply from gas, becomes even more reliant on the fuel as coal-fired plants shut. Opposition from environmental and consumer groups threatens to delay and derail new lines, including a $3 billion Spectra Energy Corp. project.

"New England remains pipeline constrained, so if bouts of very cold weather move in this winter, you could certainly see prices spike," Alex Tertzakian, an analyst with Energy Aspects Ltd. in London, said in an e-mail Oct. 28. "This would likely make New England briefly the world's premium market."



Gas deliveries on Spectra's Algonquin line to Boston and other New England cities for January and February were valued at more than $7.60 per million British thermal units

Tuesday, according to Bloomberg Fair Value prices. In spot trading Monday, Algonquin settled at $2.76, a 3-cent discount to the benchmark Henry Hub in Louisiana.

“There is going to be a lot of volatility and it’s going to be driven by the weather,” John Borruso, ConEdison Energy’s manager of natural gas trading, said in an Oct. 20 telephone interview. “The number of days you see more than $20 is under three or five days. If it’s super cold for a number of days you might start to stress the infrastructure.”

Globally, prices aren’t expected to approach those levels in major markets. Spot liquefied natural gas for Japan traded below $6 per million Btu as of Sept. 30 and the U.K. NBP benchmark is trading at about $6. Neither region has seen $20 LNG prices in the last decade, according to Bloomberg Intelligence data.

Operating conditions on the six-state grid managed by ISO New England Inc. are already “precarious” during winter periods and beyond 2019 “may become unsustainable” in extreme cold conditions, Chief Executive Officer Gordon van Welie said in late September. The grid started a winter reliability program compensating generators for stockpiling fuel oil and LNG.

Borruso and Michael Harris, chief executive officer of Unified Energy Services, see the potential for New England gas prices to spike even as Spectra prepares to put its Algonquin Incremental Project into service in November. The project would boost Algonquin’s capacity by 342 million cubic feet, or 12 percent.

LNG Imports

The new gas flows “should help mitigate the worst price spikes” in winter and may reduce prices by $4 to $5 per million Btu, the Federal Energy Regulatory Commission’s staff said in presentation last week.

New England will also need to keep importing liquefied natural gas this winter to meet demand. About three to four tankers per month will dock at Engie SA’s Everett terminal near Boston, Madeline Jowdy, senior director of global gas and LNG at Pira Energy Group in New York, said Oct. 28.

Boston Harbor is already seeing the most LNG tanker traffic in four years. Everett terminal has received 26 cargoes so far this year with 66 billion cubic feet of gas, Carol Churchill, a spokeswoman at the facility, said in an Oct. 25 e-mail. Another tanker, the Gaselys, is heading for Boston, according to vessel tracking data compiled by Bloomberg.

“The New England market -- weather permitting -- has been and will continue to be a premium world LNG market during certain times of the year,” Jowdy said. The pipeline constraints mean “LNG is required for meeting peak gas demand.”

There Is But One True Hub, and His Name Is Henry

Jeff D. Makholm

The world is full of gas trading "hubs." Some are shown in **Exhibit 1.**

Indeed, there are many more gas hubs than these. The US Energy Information Administration (EIA) lists about 30 "Market Center Hubs" (from Sumas at the Canadian/US border in the Pacific Northwest to the Waha Hub in West Texas to the Algonquin City Gate Hub near Boston).[1] Europe also has many hubs, with EU sources listing two as "mature," two more merely as "active," four as "poor," and eight as "inactive."[2]

What are these gas hubs? What do they do? Answering either question is not easy. The question of hubs for natural gas represents the intersection of commodities markets, financial derivative markets, pipeline markets, and regulatory policy. It is virtually impossible to find people who are authoritative sources in all four areas. It is hard enough to find anyone who can describe what their own particular hub does in plain language (without resorting to the nomenclature I call "hedge-speak" or references to obscure regulations).

Part of the problem is the use of one term for different things—the term "hub" itself. The term "commodity trading hubs" to most people dealing with commodities markets means cities like Singapore, London, and Rotterdam—where the major commodities dealers have their headquarters. Identifying "gas trading hubs" may produce the list above and many more, but a closer look reveals that one hub is not like another. Some hubs are places on a map; others are "notional" (hypothetical) places within a region's pipeline system. Some hubs are places where the title to gas changes from seller to buyer as the gas passes a particular meter; others are not only that but specific locations against which financial speculators can trade in derivative contracts for future delivery—either in the gas itself or in the cost of getting it from one spot to another on time. As with many issues in the international market for gas, the term "hub" does not translate well from one place to another.

The garbled meaning of "hub" is unique to gas—other commodities do not have such problems defining what a hub means. Why is this so? The answer is that natural gas is a uniquely inconvenient commodity.

What goes on at gas hubs reveals less about gas commodity trading than about the way governments regulate.

Alone among either "soft commodities" in agricultural products (such as wheat, coffee, cocoa, and sugar) or "hard commodities" in mined minerals and hydrocarbons, gas needs pipelines to reach even the smallest consumers. Other soft and hard commodities can use roads, rivers, railroads, and airplanes to reach inland destinations, but gas cannot. How governments regulate the gas industry's pipeline infrastruc-

Dr. **Jeff D. Makholm** (Jeff.Makholm@NERA.com), senior vice president of NERA Economic Consulting, specializes in the economics of regulated infrastructure industries in the energy (electricity, gas, and petroleum products), transportation (pipelines, railroads, and airports), water, and telecommunications sectors. He has directed projects on competition, pricing, financing, privatization, and industrial development for many utilities and other infrastructure businesses in the United States and more than 20 other countries.

 DOI 10.1002/gas.21912 /

Exhibit 1. Hubs

	Hub Name	Hub Creator	Date Created
North American Gas Hubs	Henry Hub	NYMEX	1990
	Dominion South	Dominion Transmission	2012
	NOVA	Nova Gas Pipeline	1993
European Gas Hubs	UK NBP	British Gas	1996
	TTF	Gasunie	2002
	NCG	Net Connect Germany	2013
Other Gas Hubs	Wallumbilla (Australia)	ASX	2015
	Chinese Hub	Xinhua News and NDRC	2015

ture determines how "hubs" operate and whether gas markets work like hubs in other modern commodity markets—like crude oil or corn. Indeed, what goes on at gas hubs reveals less about gas commodity trading than about the way governments regulate the pipelines that gas markets cannot do without.

I sort gas hubs into three categories:

1. *Physical hubs,* where gas passes a meter station on defined pipeline facilities
2. *Notional hubs* that refer only to a hypothetical point within a particular pipeline system
3. *Fictional hubs,* created mostly for show—the *sound* of a competitive gas market where the political or *pipeline structure* in place does not exist to support one

PHYSICAL HUBS

The oldest gas hub is the Henry Hub, created by the New York Mercantile Exchange (NYMEX) to begin trading in 1990. At that time, the United States was moving away from a tortured history of field gas-price regulation—an era of problems stretching back to the early 1950s and the infamous *Phillips* decision of the Supreme Court.[3] The financial industry wanted to participate in trading gas-price risk in the new, structurally competitive gas market.

For its role in supporting a highly successful futures market, the Henry Hub stands alone.

NYMEX needed a registered location at which to settle the ultimate delivery of gas futures contracts—as is the case for other commodities such a crude oil[4] or corn.[5] The Henry Hub chosen by NYMEX was both convenient and capable of dealing with gas arriving from many locations—the facilities, owned by Sabine Pipe Line LLC, connect to nine interstate and four intrastate gas pipelines.[6] For its role in supporting a highly successful futures market (the full "financialization" of gas), the Henry Hub stands alone. It is the only place in the world where financial markets trade in the price risk of gas for future delivery as it trades in future in other bulk commodities—buying and selling standard gas lots many times before the final buyer takes delivery at the specified delivery location (about 26 sales before delivery for gas at the Henry Hub, compared to about 31 times for US corn at exchange-registered warehouses).[7]

There are many other physical hubs in North America where the financial markets trade in locational delivery derivatives (called "basis swaps," tied to differential spot prices between Henry Hub and some other hub). However, the financial markets tie those swap settlement prices back to the Henry Hub. With the great growth in unconventional gas production in Pennsylvania's Marcellus Basin and the northward shift in the center of US gas production, another hub—Dominion South in southwest Pennsylvania—has attracted interest as its short-term traded volumes surpass those at the Henry Hub.

But while Dominion South's volumes are huge and growing, the Henry Hub is still the benchmark for US gas futures settlements. If gas traders want to buy or sell long-term futures at Dominion South, they use the Henry Hub as the benchmark and simply transfer those prices to Dominion South through basis swaps. The Henry Hub, with its well-defined and multipipelined location, remains the single fulcrum for futures trading in the North American gas market.

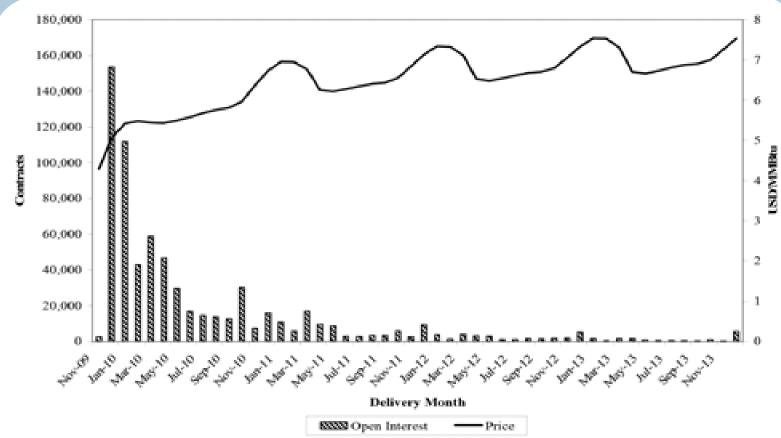
Most organized futures markets extend only a relatively short period ahead (from one to two years). Thereafter, while price discovery may extend further, the number of trades and contracts outstanding (known as "open interest"), and, hence, the liquidity of the market for those trades, drop sharply. The same is true for the Henry Hub, as shown in **Exhibit 2** for a representative period in 2009 (before the shale boom drove all gas prices down).[8]

NOTIONAL HUBS

I referred to notional gas trading hubs as "gas islands" in a previous column in this publication.[9] Two of those notional hubs are Alberta's Nova Inventory Transfer (NIT) hub and the United Kingdom's National Balancing Point (NBP).[10] Both notional hubs see a lot of gas trading—but almost no futures market activity compared to the Henry Hub.

The Nova gas pipeline system, unique in North America, provides transport services without pipe-

Exhibit 2. Henry Hub Natural Gas Futures Prices and Open Interest



Source: Data obtained from NYMEX and as of October 28, 2009.

line-specific contract paths within its network—reflecting a complicated commercial history rooted in its original taxpayer funding through the province. Shippers pay a fee to enter the network and another to exit—as if the system were a large tank. Gas trades happen somewhere between those locations, with the logistics handled by Nova. NIT gas trading is somewhat vigorous—with gas trading, on average, six times before physical delivery (the "churn ratio").[11] But it is spot—i.e., next-day—trading only. There is no futures market like the Henry Hub.

The NBP also operates like a large tank, with gas entering at particular places and exiting at others. The NBP's churn ratio is around 17.[12] But futures trading at the NBP, while offered, is virtually nonexistent by reference to the Henry Hub.[13]

Futures markets fail at the NIT and NBP because the pipeline regulatory systems constructed for the Nova and privatized British Gas systems (the latter now owned by National Grid Gas) expressly obscure their physical operation. Both notional systems came about as a result of pressures to open up third-party gas trading on pipeline systems that had not grown up around licensed, contract-based services on specific facilities (like those in the United States).

Bowing to pressure to provide a vehicle for third-party gas trades in an era before contract-based open access, both Nova and British Gas offered location-free trading—a regulatory shortcut to quick gas trading. Such "notional" trading opened the door usefully to gas trading. But the regulatory shortcut had two unfortunate consequences: (1) the notional system barred competitive entry for gas transport within the reach of the Nova and British Gas systems, for as a practical matter it is impossible to compete with any transport provider that does not charge for the use of specific facilities that a competitor may bypass; and (2) without specific facilities (and reliable means to get to those facilities), financial markets had no tangible delivery point against which to reliably deliver futures contract volumes.

FICTIONAL HUBS

What I label "fictional hubs" are those points created by regulators and other governmental bodies (or even exchanges) around the world under the hopeful belief that simply naming a point will attract competitive activity.[14]

"Fictional hubs" are those points created by regulators and other governmental bodies . . . around the world under the hopeful belief that simply naming a point will attract competitive activity.

The many EU continental gas hubs, the Wallumbilla hub in Australia, and the Chinese hub are all fictional hubs in this way. Gas may trade at these hubs between those Europeans, Australians, or Chinese who own the gas in the pipelines in those regions, but the structural conditions for competitive transport do not exist in any of those places: the European Union's is a collection of UK-style entry/exit regions with notional hubs; the Australian pipeline system is largely unregulated without the necessary transparency for competitive pipeline access; and the Chinese system is

 DOI 10.1002/gas / © 2016 Wiley Periodicals, Inc.

itself effectively closed to competitive gas production or pipeline access. Thus, there is no practical means for competitive access to those hubs or for those hubs to satisfy the needs of the financial market against which to define futures contract deliveries.

They are hubs in name only with no useful role and nothing to do—or "inactive" as the European Union labels most of its.

CONCLUSION

Liquefied natural gas tanker prices on the high seas, unconventional gas production from the Marcellus field, complex price-setting arbitrations in Europe and Australia, and Russian studies of the value of East Siberian gas—still in the ground and someday destined for Beijing and Shanghai—all eventually reference the Henry Hub, even if it may be half a world away. The world knows that there is something special about the Henry Hub. But given the proliferation of other "gas hubs," the world seems to be a bit vague on why.

The Henry Hub is unique for key reasons. It sits at a unique junction of independent pipelines within a genuinely competitive continental pipeline transport system (representing three-quarters of all the world's gas pipelines). That competitive transport system itself came about through path-breaking regulatory reforms that had developed fully enough by 1990 for NYMEX to seek the best place to "financialize" gas—permitting gas to join the other hard and soft commodities where price risk is traded in financial markets.

The Henry Hub's role in futures markets has resisted duplication even within North America. There is no possibility to duplicate its role anywhere else in the world until and unless other regions' pipeline systems also provide competitive transport—to and from the kind of physical delivery locations required by organized commodities futures exchanges. Notional hubs cannot substitute. Such hubs, designed to obscure physical operations, may facilitate gas trading within pipeline systems. But as *ad hoc* regulatory constructions separated from any particular location, notional hubs are no substitute in the eyes of financial markets for the known location and quantity of exchange-authorized delivery facilities.

Ultimately, genuine commodity hubs that can support futures markets *follow* competitive commodity markets—which depend on the ability of competitors reliably to ship commodities to those points for future delivery—which depends on competitive access to transport. Given the unique nature of gas as a commodity, the demands of a genuine gas futures trading hub are severe.

Genuine commodity hubs that can support futures markets *follow* competitive commodity markets

Considering what drives the financial industry's participation in commodities futures markets, it is no surprise that the Henry Hub is the only one.

NOTES

1. EIA. (2009). *Natural gas market centers and hubs in relation to major natural gas transportation corridors, 2009*. Retrieved from https://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/MarketCenterHubsMap.html.
2. Oxford Institute for Energy Studies. (2016, March). JOGMEC seminar presentation.
3. In *Phillips Petroleum Co. v. Wisconsin*, the Supreme Court in 1954 upheld a lower court ruling that federal regulators must set the price of gas. See Sanders, M. E. (1981). *The regulation of natural gas: Policy and politics.* Philadelphia, PA: Temple University Press; p. 95.
4. For example, the delivery point for West Texas Intermediate crude oil futures is "any pipeline or storage facility in Cushing, Oklahoma with pipeline access to Enterprise, Cushing storage or Enbridge, Cushing storage." CME Group. (2009). *NYMEX rulebook.* Retrieved from https://www.cmegroup.com/rulebook/NYMEX/2/200.pdf.
5. Delivery of corn "shall be made by the delivery of registered warehouse receipts issued by warehousemen against stocks in warehouses which have been declared regular by the Exchange." Ibid.
6. Makholm, J. D. (2012). *The political economy of pipelines*. Chicago: The University of Chicago Press; p. 118.
7. Sources for these ratios: US Energy Information Administration, US Department of Agriculture, and Bloomberg.
8. See NV Energy, 2010–2029 Integrated Resource Plan, Docket No. 09–07003, Pre-filed direct testimony of Jeff D. Makholm.
9. Makholm, J. (2015, October). "Entry/exit" pipeline pricing in gas "island" enables EU to resist competition. *Natural Gas and Electricity*, *32*(3), 27–29.
10. The NIT is also commonly referred to as "AECO" after the Alberta Energy Company that developed storage in southern Alberta. That is because title transfers were first provided as a "hub" service at the first AECO facility (Suffield) in the early 1990s,
11. The churn ratio is the measure of the number of times a parcel of a commodity is traded and retraded between its initial sale by the producer and final purchase by the consumer (http://www.albertaoilmagazine.com/2009/10/energy-shopping-center/).
12. See: Heather, P. (2010, August). *The evolution and functioning of the traded gas market in Britain*. Oxford Institute for Energy Studies, NG 44.
13. The NYMEX US gas futures were 333,000 times the level of such trades on the Intercontinental Exchange for Europe, including the NBP in 2013. See Makholm, J. (2015, Winter). Regulation of natural gas in the United States, Canada, and Europe: Prospects for a low carbon fuel. *Review of Environmental Economics and Policy*, 9(1), 107–127.
14. This is reminiscent of the line in the 1989 movie *Field of Dreams*: "If you build it, he will come."

