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Public Submission to ACCC East Coast Gas Inquiry by Innovative Energy Consulting Pty Ltd ("IEC") on July 1, 2015

IEC welcomes the opportunity to provide comments pursuant to the East Coast Gas Inquiry Issues Paper dated June 4, 2015. IEC has provided commercial, strategic and regulatory consulting services to gas industry clients operating in North America and Australia since the mid 1990's. IEC's clients include various government agencies and departments, industry associations and large companies operating across the value chain in Australia's gas industry. IEC's Managing Director, Glen W. Gill, participated extensively in Canada's gas de-regulation process that commenced in the mid 1980's and in gas matters pertaining to Australia's economic reform process that commenced in the early 1990's. He has been an executive of numerous large corporations including one of Encana's predecessor Alberta Energy Company, Enron, BHP Billiton, Allgas/Energex and Emera Energy. He also serves as a Director and Public Officer for Encana International Australia Pty Ltd. Encana is one of the largest gas producers in North American and exclusively develops unconventional gas plays.

Among other things, IEC completed a comprehensive and publicly available report for the DomGas Alliance dated November 2012, the Australia Domestic Gas Policy Report, that benchmarks Australia's gas industry to other major OECD regions and countries that have surplus gas resources and are net exporters of gas to other countries and regions, as the case may be. The issues and challenges facing eastern Australia are many given how little has been accomplished since gas reform commenced in the early 1990's especially compared to the implementation of gas liberalisation (reform or de-regulation) initiatives in other OECD countries, particularly North America. Our comments in this submission will focus on a selection of key areas which we consider to be the underlying root cause of most issues and problems. In particular we will offer a reality check regarding some of the underlying assumptions implicit in the referenced paper. Most of the government led gas reform initiatives to date in eastern Australia have been mere ‘window dressing’ for they have not as yet resulted in the creation of a fair, competitive and open gas market as defined by any generally acceptable definition of such for a commodity. It is a stretch to refer to an ‘Australian wholesale gas market’ when the gas industry in Australia consists of long term contracts with onerous and restrictive clauses, joint venture marketing by gas producers continues to exist and numerous other barriers to competition continue to plaque the gas industry.

It is our view that the eastern Australian gas industry has major structural and regulatory issues that are becoming very problematic and will increasingly do so as LNG export options materialise. It is also our view that operators in the upstream and midstream sectors of Australia’s gas industry do so on terms that are unusual for a country with a developed economy and that these terms would not be acceptable in most, if any other, OECD countries. OECD countries tend to strongly discourage anti-competitive behaviour of gas suppliers. Alternatively, transactions related to gas trade and the pricing of, access to and services offered by monopoly infrastructure such as gas pipelines and gas storage facilities is considered to be of major concern to the economic health and security of energy supplies in those countries. Australia has, to date, been rather indifferent regarding these issues and the industry is somewhat confusing as the meaning of industry terms are more often than not completely different in Australia compared to the generally accepted definitions in Europe and North America.

East Coast Wholesale Gas Market Competitiveness & Structure General Comments

- Eastern Australia's gas industry is 40+ years old and yet it does not display many of the features that one would expect to find in an OECD country that has a world class endowment of gas resources, a vibrant gas consuming sector, an interconnected pipeline grid and 4 decades of development;
- Two decades after the initiation of gas reforms across Australia, there appears to be very little actual progress made in terms of creating meaningful gas to gas competition, greater efficiency and productivity in the gas value chain, a more resilient gas supply chain, gas penetration in the total primary energy supply (TPES) and low delivered prices to major end users of gas.
- The absence of abundant low cost gas supplies to the domestic gas market generally, i.e. engineered gas shortages and high gas pricing to the domestic users of gas, reflects a lack of resiliency to change, a poor industry structure in terms of gas trade, poor policies regarding the stewardship of government owned gas resources and very poor economic regulation of gas pipelines and other vital infrastructure. The result has been many unintended consequences and these consequences will only escalate with the introduction of LNG exports from Gladstone.
- The re-emergence of state parochialism is a major concern as Qld's primary objective appears to be the export of most, if not all, of their gas resources into the LNG export market with little to no concern on the impact of unconstrained exports on the remaining states and territories connected to the eastern Australia gas grid. This is clearly a return to pre-microeconomic reform behaviour where inter-state gas trade was prohibited. The risk of stranded gas related investment and other costs to Australia's economy generally due to such a parochial strategy have been ignored to date.
- The export of onshore gas supplies from eastern Australia is much different than the export of, otherwise stranded, giant offshore gas fields as is the case in Western Australia and the Timor Sea. The Commonwealth Government and the general public would be well served if these differences were addressed for they are many and they have profound implications on other issues including, but not limited to, the social license to operate, the economy and political goodwill and popularity.
- LNG exports offer gas explorers and producers several benefits including, but not limited to: access to a somewhat liquid world LNG market, gas market diversification and the ability to accelerate gas production and sales. The conversion of gas into LNG and the subsequent sale of this product should not dictate the domestic gas price any more than the conversion of gas into any of many other by-products for export. The vertical integration of the LNG export projects has resulted in a large shift in market power to the upstream sector which would not have occurred had a tolling model been applied or a

prohibition of vertical integration. It is unusual for gas exports to a higher priced gas market to set the domestic gas price in the region of abundant and surplus gas resources. Such a scenario is not governed by market forces but by market power as evidenced by other large gas exporting OECD regions such as Alaska and western Canada.

- Security, reliability and efficiency in the gas industry has been proven elsewhere to be obtained by economic regulation of those with excess market power (i.e. infrastructure owners/operators) and a transparent, fully competitive commodity market (gas) with multiple buyers and multiple sellers trading frequently in time and at frequent intervals along the value chain.
- Any benchmarking to other OECD countries in general and to those with abundant gas resources in particular, indicates that eastern Australia has historically been a very dysfunctional gas industry and it continues to fall far below world's best practice in terms of security, efficiency, reliability and pricing of pipeline gas supplies. This is not a very good report card and radical changes are required to correct the situation.
- Benchmarking also illustrates that Australia clearly lags other OECD countries that have abundant gas resources in terms of creating value from that resource and this gap is expected to increase under the scenario of increased LNG exports at the expense of the health of the domestic gas market. Gas share of TPES is low, gas consumption per capita is low and delivered gas prices to large gas users are relatively high.
- Gas is the only primary energy source that is not a globally traded commodity. The unique properties of gas that have resulted in many regional, national and continental gas markets invoke a requirement for unique policies and regulation of the gas industry, similar to what is required for the electricity industry. Australia has failed to properly address the gas industry in this regard.
- Access to readily available, low cost gas supplies has, and will increasingly constitute a large competitive advantage for developed and developing nations worldwide. As an energy form, gas is by far the cleanest burning fossil fuel and its value is increasing along with global carbon consciousness. The many non-energy uses for gas are also important components of most developed economies.
- History has proven that countries with large resource endowment do not automatically gain an economic competitive advantage over countries that do not have such surplus endowment of resources. Exporting countries have to take the necessary precautions to avoid what are known to economists as the Natural Resource Curse and Dutch Disease. Australia's large LNG export boom, that is well underway, has the capacity to trigger both of these symptoms and the subsequent regrets. Mere "hewers of wood and drawers of water" would remain forever poor if they

failed to industrialise. Furthermore sudden shocks to an economic system from export booms are not in a country's best interest.

- Gas resource rich countries rely on a comprehensive menu of interventions and gas regulations and policies in order to protect the national interest and the best interest of the general public regarding the use of indigenous gas production. Benchmarking illustrates that Australia does not manage its gas resources adequately to ensure that gas explorers and production companies operate in a manner that is consistent with a vibrant domestic gas market.

- Australia needs to have sufficiently comprehensive policies and regulations in place in order to control and manage the export of raw commodities. Simply relying on market forces without comprehensive guidelines and controls to mitigate inequitable market power is one extreme while nationalising all resources is the other extreme. Neither of these scenarios has proven to serve the public interest very well.

- Gas resource rich countries, regions and continents generally export gas only after they first develop their own domestic gas market into a vibrant one that has very high gas consumption rates per capita and a high gas penetration in the TPES. To do otherwise destroys value and effectively de-industrialises the exporting region. If and when indigenous gas production declines, exports are reduced to allow the domestic market to continue to access abundant low cost gas supplies.

- Gas exports and a vibrant domestic gas market are not mutually exclusive but it is common to have a rather large price differential between gas production serving the domestic gas market and gas production serving the export market in a net exporting region or country. This is consistent with the regions or nations best interest until free trade agreements are entered into between countries. The convergence of domestic gas prices to LNG export netbacks first in WA and now in Qld are clearly not in any party's best interest except the Australian gas producers and perhaps the royalty owners; although this is not clear given the people own the resource and the multiples of value associated with value adding activities utilising low cost gas. For example, the province of Alberta, Canada with a population of just over four million in 2013 has a gas demand that exceeds Australia's national gas demand. Alberta is a large exporter of gas to the rest of Canada and to many regions in the U.S. and yet it has always focussed on maintaining a low provincial price for gas and it has generated much provincial wealth and accumulated a C$17.2 billion heritage fund for future Albertans.

- Russia, Norway, the Netherlands and Canada are major gas exporting nations that are comparable to Australia in terms of economic and socio political factors and, with the exception of Norway, they all have comprehensive export and, domestic gas policies that ensure that a large price differential exists between gas export netback prices and domestic gas netback prices in order to stimulate and protect the extensive use of indigenous gas in each country. Norway's situation is justified due to the surplus hydro power generation capacity in Norway and the low cost green nature of this abundant energy source.

- Alaska, Texas, Louisiana and Alberta are examples of large gas supply regions within OECD countries that have gas policies and regulations that ensure low delivered gas prices regionally while embracing reliable gas exports from the producing region for surplus gas supplies. Louisiana and Alberta have embraced the gas hub concept where gas is traded on an hourly basis at the Henry and Alberta gas hubs respectively. Price transparency in a very liquid gas commodity market are hallmarks of a competitive gas market. There is no meaningful short term gas trading and gas hub trading activity across Australia. Consequently, reported prices in the STTM are but an attempt to falsify the status and maturity level of the gas market and gas trade in Australia. The AEMO is the prime promoter of this propaganda and that is a major concern.

- To the extent that Australian LNG exports result in domestic gas demand destruction and/or upward domestic gas price pressures then unlimited LNG exports and the associated sterilisation of gas reserves dedicated thereto have serious macroeconomic consequences. The recent demands by Qld CSG producers for export parity pricing will have significant economic and environmental consequences.

- The development of gas import dependence – whether the gas sector was developed on domestic gas or based on imported gas – typically plays the decisive role for differences in gas pricing mechanisms which have developed in different regions of the world. Countries whose gas consumption can predominantly be supplied by domestic gas production have regulatory control, should they wish to use it, of supply (upstream) and demand (downstream) and thus a major influence on the gas pricing mechanism that is employed in that country. Therefore, in reference to Australia's situation, Japan's gas supply costs to consumers (i.e. gas export prices received by Australian LNG sales) should have no bearing on Australia's gas supply costs to domestic consumers.

- North America, and increasingly Europe, relies on intense gas to gas competition whereby multiple sellers and multiple buyers trade for gas on a short term basis, a concept yet to be employed effectively in Australia. Gas pricing and other sale terms found in long term gas supply contracts to Australian large gas consumers reflect engineered gas supply shortages, market bearable pricing and other market control tools utilised by gas producers. This anti-competitive behaviour has escalated now that the world LNG market for Australian gas exports has improved in terms of pricing and demand. This is not in the national interest.

- Security of gas demand is as important as security of supply as the gas industry is capital intensive and the related infrastructure is specialised and exclusively used for gas. Domestic gas demand is a much more secure market than the export market and domestic gas demand with its vast network of infrastructure takes much longer to build than does an export industry, including long lead time LNG export facilities. Consequently, demand destruction in the domestic market due to high domestic gas prices, uncertainty over the availability of affordable gas supplies and declining trust in the gas industry and in government regulation and policies pertaining to the gas industry is to be avoided. While it may take a decade to build gas export facilities it takes multiple decades to build a vibrant domestic gas market.
- The unanticipated shale gas production boom in the U.S. has resulted in stranded LNG import terminals and re-gasification assets in the U.S. and on the east coast of Canada that were largely built less than 7 years ago to offset declining indigenous North American gas supplies. This is a clear example of how unreliable LNG trade can be in the long term and how security of gas demand is much higher in the domestic gas market than exists for LNG exports regardless of contracts. The domestic gas market in an OECD country will always be there to the extent that indigenous gas production is priced reasonably. Australia's domestic gas market should be valued by gas producers operating in Australia and the ultimate resource owner, the crown, for in the longer term indigenous gas always has a large transportation cost advantage over future gas imports to that market (i.e. PNG pipeline gas or LNG imports).
- Benchmarking to other OECD countries in general, and to those with abundant gas resources in particular, reveals that significant efficiency gains and other advantages to both gas consumers and gas producers could be achieved if policy and structural changes were introduced in Australia. Australia has recently attracted and continues to attract significant capital investment in its upstream sector of the gas industry and it needs to adopt policies that continue to support both this upstream investment and ensure that its domestic market has access to readily available low cost gas supplies. These activities are not mutually exclusive as demonstrated by many large gas producing regions overseas.
- The influence of increasing gas exports (pipeline gas or LNG) from most large gas exporting regions on domestic gas prices is usually the opposite

to what has happened in WA and is currently occurring in Qld and the east coast of Australia. Larger exports usually mean larger surpluses of indigenous gas resources and that normally translates into downward pressure on domestic gas prices. This is how market forces work in a functioning market. Export projects, whether they be via LNG or long distance gas pipelines, are very capital intensive and therefore export capacity typically lags the amount of surplus gas supply deliverability, reserves and production over the requirements of the local and domestic gas market.

- The many unchallenged claims by gas producers across Australia that the domestic market now must compete with exports with respect to the gas price reflect a new pinnacle of what has, for some time, been an escalation of market power and market manipulation. Most third party consultants in Australia echo the producer rhetoric which is another major concern. Quite the opposite to Australia, is the U.S., where proposed gas export projects are required to demonstrate how they will reduce prices and price volatility in the domestic U.S. gas market to the satisfaction of the U.S. Department of Energy (DOE). Furthermore, the DOE constantly monitors the situation and if necessary will revoke the export licence to the extent that it fails to demonstrate that it remains in the national interest. The DOE has stated in its conditional approval of the recent Sabine LNG export licence: "We intend to monitor those conditions in the future to ensure that the exports of LNG authorized herein and in any future authorizations of natural gas exports do not subsequently lead to a reduction in the supply of natural gas needed to meet essential domestic needs. The cumulative impact of these export authorizations could pose a threat to the public interest. DOE is authorized, after opportunity for a hearing and for good cause shown, to take action as is necessary or appropriate should circumstances warrant it. Furthermore, DOE/FE will evaluate the cumulative impact of the instant authorization and any future authorizations for export authority when considering any subsequent application for such authority." Even remote Alaska has to comply with these rules. The level of petroleum related activity (450,000 producing gas wells in the U.S.) indicates that investment is not discouraged by such policies. Canada has a very similar policy and monitoring procedure and Canada has in excess of 150,000 producing gas wells.

- Exports to a gas market where higher gas prices prevail may yield a price advantage to the exporter and to the Government in terms of its royalty revenue from gas production allocated to that export sale but there should be no linkage between higher international gas prices under export activity and the domestic gas market prices of the exporting country or region. To the extent that export prices are low, there is often an export floor price equal to the domestic gas market wellhead price prevailing in the exporting country to alleviate the ‘dumping of resources’ to competing economies. Domestic gas production for domestic gas consumption in a net gas exporting nation or region should be priced on the basis of the availability of supply to that market and, in turn, the marginal costs of indigenous gas production. Contrary to the allegations by Australian gas producers, the price received from exports is irrelevant. Any convergence of these two prices, unless under a floor pricing policy for exports to prevent resource dumping, is due to a free trade agreement or a symptom of market power abuse and market failure.

About IEC

IEC provides commercial, regulatory and strategic advice to large companies in the gas industries of North America and Australia. Prior to founding IEC, its Managing Director, Glen W. Gill, has held executive positions for over 2 decades with many of the largest gas companies operating in both Australia and North America and across the entire value chain. Most of his experience is with upstream petroleum exploration and production companies but his experience includes large vertically integrated gas and electricity companies that are involved in gas production, power generation, reticulation, trading, gas pipelines, and gas storage.

Mr. Gill was involved in the de-regulation of Canada's gas industry that commenced in 1985 and represented the interests of AEC Oil & Gas (predecessor to North America's largest unconventional gas producer and second largest gas producer, Encana), in that process. Mr. Gill was also involved in the micro-economic reforms that commenced in Australia in the early 1990's as they related to the gas industry and in that process he represented the interests of BHP Petroleum and its related companies, BHP Steel and BHP Minerals.

It is important to note that IEC is neither a gas producer nor a gas consumer and is not representing any client interest in this submission. IEC is therefore objective and unlike many of those submitting submissions, has no self-serving agenda. Mr. Gill has extensive experience in the regulatory and policy arena and has written comprehensive submissions to regulators and policy makers in both Canada and Australia over the past 3 decades.

The gas industry tends to be very fragmented and each sector tends to make self-serving arguments to the extent that it is sometimes difficult for policy makers and regulators to find a balanced solution to issues or to generate workable criteria for goals and objectives. This submission may be particularly helpful in that IEC is attempting to make observation and comments based on extensive experience working across the gas value chain in Australia and overseas in other advanced economies.

Answers to Submission Guideline Questions

Q.1

East coast gas buyers are facing an unprecedented level of competition for gas supplies. Now that a gas pipeline grid has evolved across the east coast, gas supplies will generally compete for the highest priced markets, particularly under a tight gas supply situation with respect to overall gas demand. Gas demand has tripled with the LNG facilities at Gladstone and the fact that these facilities are owned by upstream gas consortiums (i.e. vertically integrated projects) tilts the playing field in favour of LNG demand regardless of price differentials between the LNG export market and the domestic gas market. The value chain in SE Qld is owned or controlled by gas producers and they will ensure that their gas demand is met as a priority over any domestic gas market. The extremely inefficient gas pipeline grid and the extremely high tariffs associated with gas pipelines in the east coast of Australia compared to any other OECD country for similar aged and sized pipelines discourages the movement of gas over multiple states and territories. Since most of the new gas supplies appear to be located in SE Qld, this is a rather moot point at this time. It is rather ironic, however that the east coast is facing a very tight gas supply/demand situation and yet the prolific offshore Bass Strait gas fields will continue to idle away at an average annual production rate that is approximately 50% of its delivery capacity. This situation highlights how ineffective and inefficient the gas industry is across the east coast. Gas production facilities in North America consistently run at an average annual utilisation rate exceeding 90% of their capacity. Again, this reflects a high fixed cost business with low variable costs and how in a competitive gas market, gas producers find a way to keep their gas production facilities operating irrespective of gas demand conditions. Open access gas storage facilities and inter-regional gas pipeline capacity permit this to occur.

Q.2

Stock piling gas reserves to cover long term projects or long term gas sale or LNG sale agreements is a concept that is outdated and a hallmark of a very immature and commercially inefficient gas industry structure. It is very expensive to prove up gas reserves; therefore a vibrant, competitive upstream gas industry operates very efficiently on a minimum of reserve coverage. Replacing reserves and production declines from wells is done on a ‘just-in-time’ basis in North America. Australia would do well by looking at proven best in class practices such as this as opposed to insisting that Australia is different.

Q.3

IEC is not sure why gas producers would seek to prove up additional gas reserves when the country is awash in gas reserves compared to its annual gas production rate. Australia has more than replaced its gas production in terms of reserve additions since gas was first produced in this country. The problems in Australia's upstream sector are:

1. The very long time between gas discoveries and gas production (years and decades as opposed to months);
2. The long production life of gas fields as they idle along (Bass Strait is the extreme example of this problem);
3. The hoarding of leases and gas production facilities by incumbents; and
4. Withholding gas production from the market (ignoring variable costs and the creation of pricing cartels).

Small gas producers and new entrants from overseas find it very difficult to enter Australia's gas industry due to the many artificial, yet very effective, barriers to entry that exist. Incumbent gas producers do not like competition and they have manufactured a gas industry structure in Australia that serves that goal.

Q.4

One would have to be very naïve to believe that vertical integration does not impact markets generally and one would have to be extremely naïve to believe that the vertical integration by east coast gas producers into the demand side of the equation to the extent that has occurred with the LNG export projects does not materially impact gas supply availability and therefore gas supply prices to the domestic market. As mentioned earlier, LNG tolling facilities at Gladstone should have been built in a much more sensible manner and should not have impacted the domestic market to the degree that the current ones have and will continue to do so in the near future. Gas producers will always supply their own gas demand in preference to a gas demand associated with an asset owned by a third party and this is particularly the case for capital intensive LNG export facilities. This is further exacerbated by financial non-performance penalties that exist with their LNG offtake buyers. Consequently the LNG facilities at Gladstone will get whatever gas supply they need in preference to the domestic gas market irrespective of the prevailing price in the domestic gas market. This is precisely why gas exporting nations like Canada and the USA retain the right to stop gas exports, if and when, they interfere with the national interest (i.e. readily available low cost gas supplies to the domestic gas market in the exporting country). Australia apparently is of the opinion that gas producers interest are in alignment with those of government and the national interest – a rather interesting position that is not supported in other OECD countries.

Q.5

IEC respectfully hopes that this is a rhetorical question given the answer is obvious. Long term sales contracts in themselves contribute significantly to market power. In fact almost everything associated with the CSG to LNG export projects from pipelines that are exempt from third party access to the statements that the domestic gas market has to now meet the LNG netback price in order to have any hope of securing additional gas supplies is nothing but anti-competitive abuse that reflects market failure due to an unreasonable level of market power.

Q.6

Inter basin competition in the east coast of Australia has commenced but not in a very vibrant nor effective manner. There are many reasons for this not the least of which is the very inefficient pipeline routes and the extremely high tariffs associated with all gas transmission pipelines in Australia given their age, cost and historical use. Gas producers have been very reluctant to have any meaningful gas on gas competition as evidenced by the joint venture marketing arrangements, long term contracts for gas sales and non-cooperative behaviour by operators.

During the early 1990's I was a senior manager at BHP Petroleum and among other things was responsible for initiating and underpinning the commercial arrangements for the proposed Eastern Gas Pipeline which included all of the threshold gas sales arrangements in NSW. Of course, BHP Petroleum was the non-operator; 50% owner of Bass Strait gas production and drove this initiative without any co-operation from Esso Australia. In fact Esso Australia refused to sell any gas into NSW in principle because of its interest in the Cooper Basin gas unit via its ownership of Delhi Petroleum. This anti-competitive behaviour continued for a few years while BHP Petroleum continued to drive the project with 100% BHP Petroleum gas and was only resolved when Esso Australia decided to divest of its interest in Delhi. This was the first inter-state gas pipeline project in Australia promoted and built by the private sector and the first meaningful inter-basin competition in Australia and yet Esso Australia tried with all of its might to frustrate this initiative led by BHP. This anti-competitive behaviour and attitude still abounds in the east coast upstream and midstream sectors and one would have to be very naïve to suggest that it doesn't exist.

Q.7

One would have to question why Australia's gas industry is becoming more vertically integrated when that of Europe and North America is trending in exactly the opposite direction. Market forces are very alive in North America and Europe which leads to the pursuit of greater efficiency and lower costs while the pursuit of market power is very alive in Australia. Gas producers in North America now know how to survive and thrive in a very low price gas environment. Most of the offshore gas pipelines and most of the gas processing plants in North America are owned by midstream companies that have no exploration and gas well production activities. These companies create value for gas producers. Vertical integration does not create value but it does enhance market power and it does create major barriers to entry.

Q.8

It is rather academic to discuss fuel switching potential in Australia's east coast gas market. The gas market is not considered to be very elastic in Australia and so fuel switching will be very expensive and often irreversible. The elasticity of both supply and demand should be considered and discussed.

Perhaps a more important related topic is the lack of policy that would allow a country rich in gas, which is by far the cleanest and most efficient fossil fuel, to reduce it's already low gas penetration rate and abandon some or all of the gas related infrastructure and investment made since the 1960's building a domestic gas market. It most definitely appears as if the gas producers are writing the country's energy policy.

Q.9

Australia's exploration, retention and production licence regime for petroleum is unlike anything that I have experienced in North America. First, practically anyone can acquire exploration licences and then sit on them almost indefinitely without any real fear of relinquishment. Furthermore, the leases are very large and they cover all geological zones with no vertical segmentation. Retention and production licences are also generous with no 'produce it or lose it' terms or else if they exist, like the relinquishment terms they are not actually enforced. The Cooper Basin JV had to relinquish some land after a few decades in SA but other than that very little turn-over of leases occurs in Australia. The recent activity by several new entrants in the Cooper Basin illustrate how relinquishment of leases results in increased exploration and production activity. Australia is basically closed for business when it comes to its E&P sector. The relatively small number of companies that operate in Australia is evidence of this issue.

Q.10

Access to prospective geological horizons is but one of many criteria that new entrants analyse in their decision to enter countries or regions of countries. I am the Public Officer for Encana International Australia Pty and can assure you that access to drilling rigs and other services and gas pipelines, storage and markets are as important as access to exploration acreage. There basically is no meaningful access to gas pipelines nor gas storage in the east coast. There is no liquid gas market and consequently there is no access to a gas market. Drilling rigs and other oil field services are essentially contracted long term to incumbents. Encana is arguably the world's largest unconventional gas producer and yet it does not find Australia very attractive at this time for the aforementioned reasons. Encana is not interested in entering essentially a closed market where those with the most market power win. Encana prefers an open, transparent and very competitive environment where the low cost producer wins.

Q.11

Again we find this question somewhat irrelevant as we believe no one needs to assess whether or not new gas reserves are required; but gas producers need to embrace competition and the owners of the resource (the people of Australia via government agencies) need to implement some basic stewardship principles.

Q.12

Technical and financial requirements or conditions are ever changing. Unconventional gas is vastly different from conventional gas and offshore gas is vastly different from onshore gas. It is important to remember that unconventional gas and oil was pioneered in North America for decades by new entrants with no experience in conventional oil and gas. The majors and integrated petroleum companies have yet to make a profit with unconventional gas. The oil sands in Canada were developed initially by specialist companies with no conventional oil production experience. Woodside and BHP have until recently, stuck to offshore gas plays. Technology and commercial innovation has consistently lowered the cost of gas and increased the recoverable resource base in North America despite many decades of very high drilling activity. While Australia has embraced technology transfer it seems to avoid embracing the transfer of best practices on either a commercial and regulatory basis. This is very discouraging given the tremendous benefits to the gas industry from the latter two variables.

Q.13

There is a wide range of complexity to gas processing plants depending on the composition of the raw gas that enters the plant and the pipeline specifications for gas after processing. This is a very complex subject but suffice it to say for this investigation that dry gas production that does not require much processing to remove impurities or natural gas liquids (NGL's) and simply requires compression and dehydration is not typically a problem with respect to access to gas processing facilities as these facilities are low cost and modular in nature; thereby easily accommodating a variety of production rates and changes to those rates over time. Any gas that requires removal of NGL's, CO2, H2S or other impurities is problematic in that they require large capital and have economies of scale and therefore large barriers to entry.

Third party access to gas processing is relatively uncommon in Australia (Apache at Veranus Island in WA was the major exception). The upstream joint ventures are essentially unco-operative and they do not generally view their assets as business units open for business to third parties. This attitude is indicative of a very profitable upstream sector that focusses on barriers as opposed to marginal economics and asset utilisation rates. U.S. based Apache had a different corporate culture and sought out win/win business relationships.

Q.14

The joint ventures that own gas processing assets in the east coast tend to ignore any economic incentive to sell spare capacity even on an interruptible basis as their focus is on gaining a larger share of what has been historically a relatively small domestic gas demand or market. The Longford gas plant is a great example of this. This plant idles most of the year and there are numerous undeveloped gas fields in the offshore Gippsland Basin and yet I am not aware of Exxon soliciting third party business on any terms. This is typical of incumbent operators that use their asset position to essentially frustrate new entrant gas producers. Perhaps this attitude will change given the tripling of gas demand in the east coast but this remains to be seen.

Q.15

Gas producers in Australia are well aware of the reluctance by most gas plant operators to sell processing services at a reasonable charge; consequently they strive to accumulate sufficient proved reserves and gas sale contracts to justify the construction of a large vertically integrated gas project. Vertical integration in this manner - wells, gathering system and gas plant is also a barrier to entry and leads to anti-competitive behaviour. This model has been replaced in North America with gas producers finding and producing gas from wells with the remainder of the facilities required for gas production owned and operated by open access midstream operators.

Q.16

It is very important for gas producers to gain access to any and all unutilised capacity at all existing gas processing plants at reasonable terms and conditions. This is a tall order in a country plagued with market bearable pricing mentality and no discipline in the gas industry vis-à-vis lowering infrastructure related costs. IEC will expand on this topic in dealing with the gas pipeline questions.

The province of British Columbia, Canada is the owner of most of the gas resources in that province and it dictated in the early 1950's that gas explorers and producers were until recently prohibited from building gas plants in that province. This policy remained in effect for many decades as the pipeline company serving B.C. built and operated all gas plants and sold services on a non-discriminatory and cost of service basis. This model worked extremely well in B.C. and accelerated gas production from a very complex and deep basin containing gas with many impurities. The ultimate owner of the gas, the B.C. government elected to minimise barriers to entry and market power created from building and operating large complicated gas processing plants.

Q.17

Western Australia was the first region that I know of to have two distinct gas pipeline specifications and hence two pipeline systems that each contained different barriers to entry. This model is a very poor one since it increases the barrier to entry as evidenced by the numerous delays in commercialising BHP's Macedon gas field. This situation was driven by the large capex associated with the northwest shelf project and the liquids rich gas associated with that project and the lack of good forward thinking policy in WA at that time. This situation has now been replicated in S.E. Qld. The situation in SE Qld is such that methane is the feedstock for all three LNG facilities at Gladstone and their respective large gas pipelines. CSG which is essentially pure methane or a substitute gas supply of the same specification (which is rare to find) is the only feedstock supply that is suitable for the tight gas specifications associated with the LNG trains as they were designed. This is a rather unique and bizarre situation since it eliminates many gas supply options for these LNG trains in the future as most, if not all, conventional gas supplies would not be suitable unless most of the ethane and other NGL's were first removed from the gas. Removing most of the ethane is a very difficult and expensive proposition for it requires very large sophisticated gas processing plants like the straddle plants that Alberta has built on its provincial export points. Such plants are only economically viable if they process very large quantities of gas (in the order of numerous PJ's/d). When different gas pipeline specifications exist as they now do in the east coast, it is much more difficult for pipeline gas to be traded as a commodity. Commodities must be fungible and that is now not the case in the east coast for pipeline gas. This is another setback to the process of creating vibrant gas on gas competition and to the overall commercial maturity of the east coast gas industry in terms of buying and selling gas including the building of a liquid STTM.

Q.18

The east coast has never before experienced a shortage of gas supply in terms of deliverability from producing gas wells that is insufficient to meet all of the gas demand on a daily, weekly and monthly basis. This gap will become very evident later this year as all of the 6 LNG export trains are commissioned and placed into operation. Since gas will flow preferentially to the export market due to the structure of the gas industry in the east coast, domestic gas buyers are obviously struggling to secure gas supplies at any price and most certainly at a price that is reasonable given the abundant gas resources located in the east coast.

A joint study by the Harvard Business School and The Boston Consulting Group released in June 2015 states: **"The U.S. now has a global energy advantage, with wholesale natural gas prices averaging about one-third of those in most other industrial countries, and industrial electricity prices 30–50% lower than in other major export nations. That means major benefits for industry, households, governments, and communities, while reducing America's trade deficit and geopolitical risks."** Australia is racing along the opposite path; namely creating a global energy disadvantage with gas prices to its domestic market reaching levels that will most certainly result in demand erosion and the corresponding loss of jobs and value adding. Furthermore, the already very expensive gas related infrastructure serving the domestic market will become much more expensive for the rest of the domestic market since costs must be recovered at whatever throughput exists. This is often referred to overseas as the proverbial 'death spiral' and it appears to me that very little thought has gone into this scenario. The multiple millions of end users that comprise the residential and commercial sectors (the voters) will face unprecedented high commodity gas prices as well as unprecedented high gas transportation and distribution costs.

The end users of east coast gas are not nearly as sophisticated nor as organised as the gas producers and the infrastructure owners. Consequently, they tend to rely on various government bodies to look after their needs. This has turned out to be a very poor strategy since the aforementioned producer and infrastructure groups seem to have their way with most, if not all, government agencies in the east coast. This is a rather unfortunate situation and the window of opportunity for pro-active resolution has long faded. The next couple of years will be most interesting in the east coast as many major issues that have not been resolved will surface.

Q.19

All of the members of APPEA appear to be in alignment over how they generally sell gas in the east coast. BHP Petroleum broke away from the pack in the 1990's in order to supply gas to BHP Steel's NSW operations and to other large end users in NSW but that was largely indicative of my involvement and position at BHP as opposed to a new and improved business model that would be embraced by other gas supply participants. The solidarity among the gas producing community is very strong today as evidenced by the self-serving and very anti-competitive statements from APPEA that are echoed by most of the non-international based upstream gas companies. Most of APPEA's and APGA's public statements would not be made by similar associations in Europe or North America – mainly because they would be scrutinised for anti-competitive conduct which is taken very seriously and secondly, because they would be exposed quickly as self-serving rhetoric with little, if any, substance. Yet governments, consultants and industry in Australia seem to accept these statements and positions as fact.

Of course setting prices in the domestic market and threatening to withhold supply from the domestic gas market (the non LNG related demand) unless and until they meet the export netback equivalent price is about as anti-competitive as one can get. Conversely, in Canada, exporters of gas prior to the North American Free Trade Agreement had to demonstrate how the export of gas will benefit all gas end users in Canada prior to receiving the right to export. Furthermore, any unintended deviation from this objective could result in the revoking of one's gas export rights. It is poor energy policy to allow the domestic gas market in the east coast to be essentially held hostage by gas producers who have been granted gas exploration and production rights from the crown (i.e. the people of Australia).

Q.20

While I am not familiar with specific negotiations, I am familiar with gas trading in a mature and efficient market place. The outdated manner in which buyers insist on buying gas and the manner in which sellers insist on selling gas in the east coast lends itself to impasse and protracted negotiations. Long term contracts tend to develop into win/lose transactions over time. While all countries initially embraced this manner of gas trade, such transactions should be replaced by much more efficient market based commodity contracts for gas molecules. The east coast has yet to entertain this concept. The STTM as mentioned earlier is but a farce for it has no meaningful liquidity and therefore no meaningful pricing information contrary to what is being espoused by the AEMO.

Q.21

East coast gas prices in the wholesale market have yet to be established by market forces; that is by multiple buyers and multiple sellers transacting in a dynamic and competitive market place. Prices have historically been set by those with market power. The state of Victoria set the very low gas prices under the first long term sales contract from Bass Strait ($0.27/GJ unadjusted for inflation for 20 years). There is no gas market per se in the east coast, only long term contracts with long term pricing terms that rarely adjust to any market conditions. It is therefore very difficult to comment on key factors except to say that those with the market power in the east coast set the prices for both gas and pipeline tariffs. In an open and freely traded gas market gas producers are price takers not price setters and monopoly infrastructure owners are economically regulated in order to minimise the cost of such services and to ensure that all services are offered on a non-discriminatory basis. Australia has very few if any of the hallmarks of an open, freely traded and efficient gas industry. Perhaps a major structural change in this direction is pending as the east coast is quite accurately referred to as a slow train wreck by Credit Suisse n recent press.

Q.22

There is very little credible information available in the east coast with respect to the gas value chain and activity related thereto and all pricing information and terms and conditions of long term contracts are extremely confidential. It is very rare to find a gas industry that conducts its affairs with such secrecy! While the AEMO now reports some information pertaining to the industry, it is basic information and some of their reports are more opinion than fact and seem to simply reiterate what APPEA and APGA tell them.

State, commonwealth and territory governments, the ultimate owners of the in-situ resource, seem to be indifferent for they are not well staffed, have little focus on the gas industry and do not require much data reporting from industry participants. For example, it appears to be impossible to get any basic information regarding the injection, storage and withdrawal of gas in and out of underground gas storage facilities and what, if any, third party access is available. This is basic and prudent management information that would be readily available overseas as well as much more information related to such facilities.

The STTM reporting and statements related thereto are as mentioned earlier a farce. There are generally accepted ratings and levels of liquidity that must be met prior to any reliable and meaningful price reporting in a short term market and again, Australia ignores all such concepts and reports in detail the results of its STTM. This data is totally unreliable and confuses buyers and other market participants who trust the AEMO to have some minimum level of competence and integrity. A game of smoke and mirrors is not helpful and is a very poor substitute for facts and transparency.

In the past I have led teams of professionals in North America that traded very large quantities of physical gas on a daily basis and over longer terms. I have also worked in Australia on a contract basis for some of the largest buyers of gas in the east coast and a an executive for a gas retail company and I would say that it is almost impossible to get reliable information in the east coast in order to make good gas buying decisions. I would make the same comment with respect to access to gas pipelines and gas storage facilities. Buying gas in the east coast is problematic. I have also witnessed anti-competitive behaviour by gas producers and gas pipeline companies in the east coast that would not be tolerated overseas and some of that behaviour was so blatant that it would have most certainly led to not only investigation but serious fines and penalties. I have served as an executive for large gas producers and the largest gas pipeline company in North America and am well aware of the generally accepted rules of conduct in this regard.

Another complicating issue is the use of very outdated long term gas sale agreements (GSAs) in the east coast. Gas producers and large gas consumers, alike seem to believe that these are necessary and useful and yet Europe and North America have generally replaced such contracts for domestic gas supplies long ago with a portfolio of firm, interruptible, short term, medium term and long term contracts containing much more workable terms and conditions. In fact, today, essentially all of the gas produced in Alberta, Canada and all of the gas produced in the Gulf of Mexico region is sold under contracts that reference and float with a daily spot price. Whether one is a buyer of gas or a seller of gas in North America, all contracts used are a standard contract that reciprocates in a very balanced fashion. I have yet to experience any resemblance of a balanced long term GSA in Australia, which again reflects a take it or leave it attitude by the gas producing sector – more evidence of market power and abuse related to that power.

Q.23

There is no appropriate reference price for gas in the east coast at this time for reasons previously discussed in Q.22. A reliable and transparent STTM price is required in the east coast in order to set and frequently re-set gas prices to reflect the prevailing market conditions. Many large structural changes must occur in the east coast prior to achieving this objective. There are numerous conditions precedent that do not exist in the east coast and most of them are related to poor regulation and policies related to its gas industry. The 'laissez-faire' attitude of regulators and policy makers across the east coast has not resulted in an efficient gas industry and the situation is, in my view, getting worse as neglected problems and issues of the past continue to grow and their unintended impact on the industry grows as well.

The 'commoditisation' of any commodity requires a reliable posted reference price tied to a location and quality of the commodity. The transformation of gas and electricity industries into a commodity market for the gas molecule or electron, as the case may be, and infrastructure related services on monopolistic assets related to transmission, storage and distribution activities is particularly challenging compared to substances that are easily stored and transported. While Australia has worked diligently at transforming its electricity industry into such a structure, it has done very little in that regard with its gas industry. The pros and cons of commoditising any substance into a physical and financial market is well documented and I am not aware of any substance that has been commoditised by returning to a state of parochialism, lack of information, inflexibility, etc. and the inefficiencies associated with that former state of trade. The pros and cons and an explanation of how posted prices relate to each other is beyond the scope of this document.

<u>Q.24</u>

The statement 'oil linked' GSAs require a much more detailed definition before this question can be answered. The term 'oil linked' is a vague term that can have a variety of meanings. Delivered gas prices to many large end users, including most remote mining operations, in Australia were historically set at a 'market bearable' price that reflected the only other option available to these potential customers, namely oil or diesel. Delivered gas prices offered by gas producers were offered at a slight discount to the appropriate alternative fuel and then escalated according to a CPI related formula. These were oil linked and price re-openers were generally re-set to a relationship with alternative fuels. Gas on gas competition did not exist generally. Oil linked prices in this way waned as multiple gas supplies and choice slowly emerged with the formulation of the inter-state gas pipeline grid in the east coast and the emergence of new gas supplies with new operators.

A return to oil linked GSAs has occurred recently as LNG export project JV owners have been acquiring supplemental feedstock gas supplies related to their oil linked LNG offtake contracts. Furthermore, the immediate shortage of gas production and deliverability has resulted in withholding gas from the domestic gas market until and unless they agree to a similar oil linked pricing formula. The degree of oil linking in terms of the initial starting price and the annual price adjustment formula is not known due to the confidential nature of these agreements.

It is most difficult to therefore comment on the degree that buyers or sellers can effectively hedge their exposure to oil price volatility. A short answer is that any degree of exposure to any liquid underlying commodity with an associated futures market can be hedged to some degree. This includes foreign exchange rates, oil price and interest rates. Many financial products exist and can be acquired to assist in volatility risk management by buyers and sellers alike, but independent of each other's risk profile and risk tolerance. Gas producers, gas buyers and gas storage customers regularly use financial products in North America and Europe that are derived from the underlying short term physical gas market. Calgary, Alberta based Encana Corporation, Canada's largest gas producer, reported in their June 2015 corporate presentation that they realised approximately $9 billion in hedging gains from 2003 to 2014. Gas producers who do not hedge essentially enjoy risk and volatility and therefore cannot complain when markets go against their favour. Financial products exist whenever a product becomes a true commodity and these tools are an important dimension to any producer and consumer of that product.

Q.25

First, it is important to understand that each of the terms and conditions in any GSA can and should be priced separately and independent of the price associated with the gas molecules. This is much easier to do in a more mature and sophisticated gas industry such as that which exists in North America and increasingly so in Europe.

Second, it is important to appreciate that many of the onerous terms and conditions such as take-or-pay, min day, max day, reserve dedication, delivery point, etc. contained in most, if not every, long term GSA in the east coast are outdated and inefficient commercial terms that have not been used in North America since the early 1980's.

While I cannot comment on details of negotiations today between gas producers and buyers, I do know that there is a large resistance to replace these historical non-pricing terms and conditions with much more workable and balanced concepts. There is a lot of commercial ignorance and rigid thinking in this regard.

Q.26

Gas producers in the east coast have historically tried, via GSAs, to control the destination of their gas production and prohibit any secondary gas market – all very anti-competitive behaviour camouflaged as a need to have revenue security and certainty of customer - prior to a commitment to develop and produce their gas reserves. It is most interesting that these same producers don't sell oil under long term contracts let alone long term contracts with such restrictive and onerous conditions. Furthermore, gas producers in North America don't need such assurances and they spend much more on gas supply development and production each year than occurs in Australia.

Q.27

I have witnessed numerous long term GSAs in the east coast over the past 25 years and it is most difficult to determine the price of the gas molecule in such GSA's because of all of the other 'non-pricing' terms and conditions that have different values to the buyer and the seller. I submit that all terms should and do affect the overall price under the GSA. Unless and until GSA are standardised and the value of various terms can be quantified, then it is impossible to compare prices under long term GSAs on an equivalent basis. All so called 'non-pricing' terms should have some effect on price negotiations; to state otherwise is simply foolish.

As gas industries mature into a commodity market it becomes very easy to quantify most terms in any GSA. Again, Australia has seemingly made little effort to move in that direction.

Q.28

I believe that many of the so called non-price terms and conditions contained in GSAs found on the east coast contain anti-competitive concepts that are not enforceable in any democratic and free society. There is no real commercial reason for many of these clauses and they become exposed for what they truly are when challenged. I have represented several large gas end users in the east coast in this regard and when challenged, gas producers generally withdraw their notices or complaints. Unfortunately many buyers of gas do not get good advice in this regard or consider such advice a waste of funds. I am not at liberty to discuss the details of such matters due to client confidentiality commitments. I would rate this commonly found style of conduct by some large gas producers in the east coast as corporate "bullying".

Q.29

Since by definition long term GSA's contain many terms and conditions that may be reflect the status of market conditions or gas industry maturity levels at the time of their negotiation but that do not reflect conditions or maturity levels throughout the term of these GSA's, they are problematic in this regard. Furthermore, most of the GSA's that I have witnessed in the east coast discourage re-openers of any kind including related to pricing terms. Onerous and unnecessarily restrictive terms and conditions also exist in these GSA's with respect to any desire by the buyer to re-visit or re-negotiate any of the terms and conditions contained therein. These GSA's are not market sensitive in any way and simply reflect the status of the gas industry and the respective market power of the seller and buyer at one point in time.

Q.30 to Q.33

IEC has no response or comment at this time.

Q.34

As mentioned in my earlier comments, it has been proven overseas that a large and vibrant short term gas trading market does provide a sufficient level of flexibility to all market participants. Australia does not have any resemblance to such a short term trading market for gas and it would be best served by not trying to pretend that it does and get on with creating one. There are many structural issues that prohibit this from occurring and there are many market power issues to first resolve. Unless a major correction occurs in the east coast and it changes its path to a much better destination, I hold little hope of a bona fide trading market developing in the future.

Q.35

If, and when, the east coast gas industry ever develops a bona fide STTM in terms of liquidity, transparency and reliability for price discovery that reflects the supply and demand conditions for gas in the east coast, then the reference price from that STTM would be relevant as an index and reference point for all future GSAs as evidenced in other jurisdictions overseas. That reference prices is based on a geographic location but there are well documented and proven methods of adjusting that prevailing market price to other geographic locations. In North America this adjustment is referred to as geographic basis. Linkages from one gas trading hub to another tends to be very strong with a sensible correlation over time. Then and only then does a geographic basis become reliable to market participants. Inter-hub linkages are very strong now in North America, improving across Europe and do not exist in the east coast.

Q.36

No valid STTM which implies tremendous market power is present and that the industry structure is not conducive to gas on gas competition. The playing field is not level nor even available to many with respect to pipeline access and tariffs.

Q.37

All overseas experience is relevant; it is simply a matter of degree. The experience of undeveloped economies seems to be the most relevant at this time given how neglected the east coast of Australia's gas industry has been to date regarding the creation of an industry structure that is appropriate for an advanced economy. One can only hope that this will change and that the east coast will seek to mimic the experience and results demonstrated by advanced economies in general and those with abundant indigenous gas resources in particular.

It is most interesting that the ACCC does not mention anywhere in its issues paper, Canada even though Canada resembles Australia in many ways and in fact I would submit that Canada's gas industry had many more obstacles to overcome than does Australia in terms of the creation of an open and freely traded gas commodity market.

Despite those obstacles, the AECO or Alberta hub is actually much larger than the Henry Hub in terms of physical gas trades per day and there are a wide range of financial services related to gas available in Canada including a very liquid futures market.

The path or journey from an immature gas industry to a mature, competitive, and very efficient gas industry that has occurred in the EU, Canada and the U.S. is relevant to Australia in that there exists nothing but excuses to prevent Australia from experiencing the same results. To suggest otherwise displays an attitude of inferiority or victim status. The U.S., Canada and the EU have all taken very different paths to get to the same destination. Every country, and in fact different regions within countries, all struggle with different challenges and issues. Australia is no different and, in my view, the east coast of Australia has many advantages over other jurisdictions in terms of creating a vibrant, deep and transparent short term gas trading market and low cost pipeline and gas storage tariffs. The fact that a huge gap exists between countries such as Canada and Australia in this regard reflects, in my view, an overwhelming attitude of indifference in Australia and unchallenged market power and abuse related thereto. Competitive gas markets don't just happen, they have to be created. It takes a fair bit of expertise, effort and resolve to create such a gas market given the complexities of the gas industry.

Q.38

The following statement contained in paragraph 73 of the issues paper: "Gippsland Basin joint venture gas producers have argued that joint marketing arrangements are necessary for practical reasons … and thereby reducing the end cost to gas users" is rather interesting given my earlier statements about how Esso Australia did not participate in the initial Eastern Gas Pipeline project and related long term GSAs for a number of years in the mid 1990's because they did not wish to compete with their Cooper Basin interests. The whole subject of joint venture marketing and its apparent necessity is another farce that for some reason has been supported historically by the ACCC. Most of my 35+ years of gas industry experience has been working with major gas producers both in Canada and Australia and it is my opinion that the ACCC has been totally incompetent in the promotion of joint marketing. Of course, the gas producers will make argument in an attempt to justify joint marketing, but it is the ACCC's role to differentiate fact from self-serving fiction and they have yet to do that regarding this and many other issues. Esso Australia was quite prepared in the 1990's to not supply gas into NSW but rather bank its 50% gas interest in the reservoirs for future 100% sales into Victoria gas markets. The first two long term GSAs into NSW that underpinned the construction of the Eastern Gas Pipeline were made solely and exclusively by BHP Petroleum with its share of new gas supplies from the Gippsland Basin.

It is also very difficult to imagine that gas producers in the east coast are concerned in any way with the delivered cost of gas to end users given their behaviour over the past 40 years in the east coast. Market bearable pricing has been the flavour of the past in Australia's gas industry by gas producers and gas producers appear to be indifferent to the extremely high pipeline tariffs in place in the east coast and the re-capitalisation of assets to above replacement values when various governments have privatised gas pipeline assets.

As a former manager of gas marketing for both large and small gas producers, I can confirm that separate marketing of gas by producers is not difficult in the east coast and in fact, was done in the mid 1990's by me while employed as a senior manager with BHP Petroleum. Like so many issues confronting the east coast gas industry, this is another one that is plagued with theoretical excuses about why it cannot be done as opposed to finding ways to accomplish the objective or task.

I am sure that all members of cartels such as OPEC are convinced that they need to jointly market their oil production. What else would one expect to hear from operators such as Woodside, Santos and Exxon Australia, historically the three largest gas production operators in Australia?

What we discovered in Canada is that gas producers generally are not in alignment with respect to how they wish to sell gas from any joint venture and therefore taking their gas in kind becomes the standard practice. Operators in Canada may market their joint venture gas on behalf of their partners but only after charging those joint venture partners a rather large marketing and administration fee. Those operators do not want to market their joint ventures gas and therefore have a deterrent in the standard joint operating agreements to that effect. Consequently seldom do joint venture partners not take and market their gas in kind each day. Balancing different sale quantities is not particularly difficult, particularly when a bona fide STTM exists and/or good access to pipelines and gas storage.

In a very shallow upstream segment such as exists on the east coast of Australia, it is vital that gas producers are encouraged to take and market their gas in kind in order to accelerate the rate of change to a more dynamic gas on gas competition business environment. Once sufficient liquidity is created (i.e. multiple sellers numbers improve) then joint marketing by some members of any JV ceases to be a big issue from a competition or lack thereof concern.

Essentially all gas production has been 'taken in kind' and marketed in kind by gas producers in Alberta, Canada since the late 1980's. Gas producers operating in an open and liquid gas market actually prefer to take their gas in kind and diversify their gas sales portfolio as they see fit for each producer has different expectations vis-a-vis gas price, cash flow, margins and other business variables. This model also results in a generally more educated and sophisticated gas industry overall as more companies get involved in gas issues and the resolution of these issues.

Selling gas collectively has proven to be a very inefficient model, but it does allow gas producers to gain significant market power in a shallow gas market where the number of joint ventures operating in the upstream sector of the gas industry is relatively few. That appears to be a strong objective across Australia.

The history of Australia is that the ACCC has, and continues to, support such anti-competitive behaviour as joint venture marketing arrangements including the right of the upstream joint venture operator to include rights of first refusal on any and all gas sales agreements that a non-operator joint venture partner might wish to enter into with a third party. Does the ACCC truly believe that it is appropriate, for example, that Santos needs to approve a potential gas sale between Beach and Origin from Beach's proprietary gas production in the Cooper Basin gas unit that is operated by Santos?

Q.39

I cannot imagine any significant regulatory cost or saving associated with joint versus severally marketing gas in the east coast and questioning the benefits to the gas industry generally of having more sellers or suppliers of gas with more variety in how they sell that gas is flawed thinking. If one was to apply rigorous logic to the gas producer's arguments regarding joint marketing one would find little substance.

Q.40

The gas pipeline sector in the east coast has historically charged very high tariffs and offered very poor service levels as benchmarked to gas pipelines economically regulated in either Europe or North America. The tariffs and rates are so poor from a capacity user's perspective that they do not even resemble the pipeline sector overseas. I have done extensive benchmarking in this regard and the findings, again reflect an apparent indifference in Australia regarding pipeline cost on a per GJ/100km haul basis, on the level of services offered and on the access terms for contracted but otherwise unused capacity on a daily basis.

For some unknown reason, the east coast has privatised pipelines at above their replacement cost and/or allowed new pipelines to be constructed with widespread exemptions from any meaningful economic regulation nor third party access terms. This is unexpected and counter to any growth and value generation from this industry given the relatively large distances separating gas supplies and gas markets compared to Europe. Compared to North America generally and Canada specifically, the distances between gas supply and gas demand in the east coast is relatively short. For example, the average GJ of gas produced in Canada in 2000 travelled on average over 3,000 km on a gas pipeline (excluding reticulation) prior to its consumption. The average tariff paid for this pipeline haul in Canada would be similar or less than that paid in Australia for a fraction of the distance travelled by an average GJ of gas production. Once normalised for the age of gas pipelines, their size and historical throughput, properly regulated gas pipelines tend to have a fairly common firm forward haul tariff on a $/GJ/100 km basis. Australia's pipelines vary widely in this regard and are orders of magnitude higher than those found in North America. While I have heard many excuses from the APGA association (formerly APIA) regarding why tariffs and services in Australia are different, I have yet to understand why this has to be the case.

Increased concentration of pipeline ownership is not necessarily a problem in itself, but coupled with a lack of strict economic regulation to minimise or eliminate market power, becomes very problematic. Gas pipelines are natural monopolies and must be treated as such by regulators or else the domestic market will suffer as it has in the east coast. Gas penetrations are embarrassing low for an OECD country with abundant gas resources. Market power remains relatively unchecked in this sector of the gas industry and among other things, there is no level playing field as services and tariffs are discriminatory. This fundamental structural defect prohibits the development of a vibrant underground gas storage sector and prohibits the creation of a hub around which a vibrant STTM can grow.

Q.41

There is no real threat of meaningful and effective economic regulation in the gas pipeline sector of the east coast at this time and the gas pipeline operators are behaving accordingly. The economic regulation of gas infrastructure in the east coast is virtually non-existent and the industry suffers as a result.

Q.42

The fact that gas pipelines in the east coast can and do respond to the opportunity to make windfall profits should not be confused with a timely response to meet shipper needs for all market participants whether a producer, trader, storage customer, retailer, or end user. Most gas pipelines in the east coast are essentially controlled by the foundation shippers who are almost exclusively made up of a few among the gas producing community. Unlike in Europe or in North America, these holders of long term firm service contracts on various pipelines control the capacity whether or not they intend to use it during any given pipeline nomination period. This is about as anti-competitive as one can get given the fact that access to gas pipelines is essential for the movement of gas in the domestic market.

The gas pipeline sector in the east coast is so bad at providing value propositions and services that the three Gladstone LNG projects built their own large diameter gas pipelines to supply feedstock gas even though this was clearly a non-core business activity requiring the importation of expertise in this regard from overseas. This is a clear sign of a complete lack of confidence in Australia's pipeline sector. LNG export projects proposed in Canada and the US would not entertain such a model as was embraced in SE Qld.

Q.43

Pipeline services and hub related services have not evolved in the east coast and the lack market participants in any of the so-called hubs reflects this gap. I was involved in the establishment of the AECO gas hub in Alberta in the mid 1980's – the first gas hub established in Canada. This hub was affiliated with a gas storage facility and it grew to match the famous Henry Hub in terms of physical trading. None of the so called gas hubs in Australia would be recognised in either the North America nor

Europe as a bona fide gas hub due to the lack of open access gas storage directly connected to the hub, the lack of sufficient interconnecting gas pipelines with a common gas quality and the lack of acceptable access principles and a common non-discriminatory tariff on what little connecting pipelines exist at these hubs. Gas hubs don't suddenly appear because someone calls a geographic point on a map a gas hub. Gas hubs are functional and provide tremendous liquidity and eventually financial services associated with the underlying highly liquid physical market. Market makers and traders congregate at gas hubs as do gas storage operators. None of these players exist in the east coast.

While Wallumbilla has the potential to be a gas hub and the primary price discovery point in the east coast, it is far from that at the moment. The volume of STTM conducted at Wallumbilla remains very small and insignificant in terms of price discovery. One of the problems that I see in the east coast is the attempt by the AEMO to force gas hubs and the STTM to exist – fighting all market participants along the way and charging large margins to cover their inefficiencies and AEMO's overhead costs. The gas hubs in North America were created by market participants in order to fulfil a recognised need; namely increased efficiency and transparency in the gas market. Market participants in the east coast view the STTM as simply another bureaucratic venture by the AEMO with no useful benefit to them.

Q.44

Gas pipeline services, or the lack thereof, and a basic unwillingness to be open for business beyond the foundation customers is a real problem in the east coast. Market participants cannot access idle pipeline capacity without making a deal with the holders of firm transportation capacity. This is a ludicrous business model for the concept of common facilities is lost and replaced by the concept of market power skewed to the foundation customers as they essentially control who uses the pipeline capacity that they don't wish to use on any given day.

Backhaul rates often equal or exceed forward haul tariffs in Australia – another of many business practices that do not reflect the cost of providing the service as backhauls actually create more capacity for forward haul service. This essentially makes the pipeline capacity on a commercial basis exceed that of its physical capacity. The list of bewildering practices in the east coast pipeline sector is very long and cannot be dealt with in this submission.

Gas pipelines serving the east coast have extremely low average capacity factors or utilisation rates compared to gas pipelines in Canada. Typically, downstream gas storage capacity is used to increase the utilisation rates of inter-regional and inter-state gas pipelines but this is not done to any material degree in the east coast.

Q.45

There is a need for much better information flow across the entire gas value chain in the east coast. Such information should not be kept confidential for sharing it on a timely basis would lead to greater innovation by market participants as they seek to increase asset utilisation rates and provide better value propositions to their customers. This is how capitalism works and it is especially important for gas since gas is captive to monopoly infrastructure.

The hoarding of leases, gas plant facilities, gas storage facilities and of contracted pipeline capacity whether used or not are all examples of anti-competitive behaviour and the ACCC should recognise this. The east coast gas industry has catered to those companies who were the original pioneers and new entrants are typically either excluded from participating or are marginalised. This phenomena was particularly evident in the early days of the CSG industry in the east coast. None of the original players in that subset of the upstream sector, namely AMOCO, Enron, ConocoPhillips, Tristar, Tipperary, First SouceEnergy and Forcenergy made any progress in actually commercialising CSG. The incumbent gas producers made great efforts to oppose and discredit this new gas resource and then bought out most of these assets at fire sale prices when the CSG pioneers decided to pull out of Australia. The Qld government contributed to the failure of these players by not resolving in a timely and pro-active manner the ownership of CSG (coal or petroleum leases) and they did not support the initial efforts in any manner in terms of dealing with the many barriers to entry that they faced.

Q.46

The so-called Greenfields Incentive is not necessary for pipeline investment and is a by-product of acquiescing to the self-serving rhetoric of APGA members and that association. Much larger and much more capital intensive gas pipelines have been and continue to be built overseas without such an incentive. It is not consistent with the best interests of the gas industry in general as it results in windfall profits to gas pipeline owners and in very poor services and high tariffs to all of the customers who follow the foundation customers. Again this is unique to Australia and it has resulted in many negative unintended consequences and the benefits are very questionable.

Canada is a global leader in the pipeline sector for oil, gas and NGL's related infrastructure and it has never required such an incentive program in order to attract the necessary capital required for green field pipelines. In 2002, Canada's pipelines moved 6,300 PJ's of gas and 860 million bbls of oil, of which 60% was exporter to the USA via long distance pipelines. As of 2008 there was in excess of 100,000 km of large diameter high pressure transmission pipelines in Canada serving the petroleum industry. The province of Alberta has over 400,000 km of energy related pipeline (i.e. pipelines used to gather, transmit and distribute oil, gas and NGL's) and the cost to use this system is but a fraction of the cost to use a short inter-state gas pipeline in Australia.

Q.47

Currently, the secondary market cannot function properly with respect to either gas trading nor gas pipeline capacity. Gas trading in the secondary market is extremely difficult because one cannot easily re-route gas in the east coast on gas pipelines due to the rigid non-customer focus of those pipelines and because there is very little flexibility and liquidity in the system. Access to an effective STTM and/or access to gas storage facilities is required in order to have an efficient and vibrant secondary gas trading market.

The secondary market for gas pipeline capacity is essentially non-existent in the east coast due to the onerous manner in which one has to access unused contracted capacity. Unlike North America and Europe the gas pipeline owner/operator in Australia does not have the right to sell contracted but otherwise unused pipeline capacity during a nominating period. The pipeline company in Australia has essentially sold that capacity to one party and cannot sell it to another, even on an interruptible basis that would be subject to the right of first refusal from the party that has contracted the capacity. The right of first refusal is typically exercised by a firm capacity customer during the nomination process of scheduling throughput for the next period (as short as 4 hours in North America and typically a day ahead in Australia). Should that party elect to not utilise all of its contracted capacity, the pipeline operator in Europe and North America has the right to sell that capacity on an interruptible basis to all interested parties and the funds from that sale would be used to reduce the tariffs to all firm customers. In Australia, any interested parties must negotiate with the firm foundation customer – good luck with that one!

In Europe and North America all gas pipeline customers utilising the same type of service over the same distance on the pipeline would all pay exactly the same tariff – a principle referred to as non-discriminatory access and services. Non-discriminatory tariffs and services is a key to the creation of gas trading hubs and a vibrant STTM. Competition should revolve around the GJ of gas and not the pipeline tariffs along a similar pipeline route.

Delivery and receipt point restrictions are common due to the fact that gas pipelines do not have unrestricted flexibility in their operations. However, requests for changes in either a delivery or receipt point over a stipulated period of time should be respected and accommodated by the gas pipeline operator on a reasonable efforts basis and subject to the operational integrity of the pipeline. To simply refuse to entertain and accommodate such requests reflects a very poor attitude and a very poor customer service culture.

Q.48 to Q.54

IE has no response; have no recent experience in these matters.

Q.55

Industry participants generally do not have the ability to use gas storage to the degree that they should in the east coast. First, there are a number of very different gas storage facilities and they are used for completely different purposes. LNG peak shaving facilities exist at Newcastle and Dandenong and these facilities are typically used by gas reticulation or network operators to charge up the back end of a reticulation system for infrequent and short periods of time. There are hundreds of these facilities across the U.S. and there are also propane/air systems that accomplish much the same purpose. LNG peak shaving facilities trickle gas into storage over a long period of time and provide a very short term burst of gas.

Underground gas storage (UGS) typically plays a much larger and dynamic role in a gas industry. UGS facilities involve injecting, storage and withdrawal of pipeline spec gas utilising underground, special purpose depleted reservoirs, aquifers and solution mined caverns in salt deposits. UGS commenced in Canada in 1915 and the use of distributed UGS facilities across Europe, North America and Russia has become a key and integral part of the gas value chain. The development and use of UGS in the east coast has seriously lagged the aforementioned regions. The first UGS facilities in the east coast were associated with the Cooper Basin gas centre and were used to optimise the operations of the gas processing trains at Moomba. Another UGS facility was developed at the Ballera gas plant for the same purpose. These facilities are integrated into the respective JV's (both operated by Santos) and they have to date been used exclusively for the gas produced by the associated JV. These two UGS facilities are upstream facilities in that they are used to accommodate the gas storage requirements of gas production operations.

The Iona UGS facility is the only open access UGS facility in the east coast and it is very small relative to the domestic gas market size. This facility is classified as a downstream or market area UGS facility in that it serves primarily retail agents and large end users of gas. When benchmarking to other countries, this is the only facility that should be used as all UGS data from Europe and North America include only open access UGS facilities.

More recently AGL and the GLNG JV have built UGS facilities near Wallumbilla as they seek to provide additional services to the CSG to LNG projects. While gas production facilities in general can benefit from access to UGS, unconventional gas production is a prime candidate for large UGS facilities due to the production characteristics of this gas. Gas storage facilities in SE Qld will also assist in optimising the economic performance of the entire value chain associated with CSG to LNG projects.

The use of UGS in the east coast is expected to change rather dramatically for a number of reasons. First gas demand volatility in the domestic gas market has been historically met by swing gas supplies from the Moomba gas plant (supplemented by Moomba UGS) and by the Longford gas plant (large variations in operating throughput with gas demand fluctuations in Victoria). The decline of the Moomba conventional gas fields has significantly reduced this swing gas role and the Gippsland Basin gas production operations is finally realising that it has been providing essentially free gas storage services to Victoria for the past 4 decades and is seeking to eliminate that gift. Much greater gas storage capacity would be required to substitute for the historical swing gas role that Longford has played in the past.

The east coast is for the first time in its history facing a very tight gas supply/demand scenario. While this scenario is challenging it also presents the opportunity to transform the upstream sector into a much more efficient one. An efficient model would produce wells at high rates, replace well deliverability declines on a just-in-time basis and also replace produced reserves on a just-in-time basis. Large surplus well deliverability capacity and reserve coverage for more than 8 years has been proven to significantly increase upstream costs. The much more commercially efficient model used extensively in North America relies on gas storage to smooth out temporary fluctuations between gas supply and gas demand and the capacity to drill, complete and produce sufficient incremental wells each year in order to maintain a reliable low cost gas supply. The east coast gas producers cannot continue to ignore costs or expect to simply recover higher costs from the market. Operators in other countries have learned how to consistently reduce costs and that is what commodity supplier's worldwide do consistently in order to compete. The lack of competition and focus on efficiency is one of the major problems in the east coast upstream gas sector. Gas storage has played a vital role overseas in assisting gas producers to minimise the cost of gas while maintaining a very reliable gas supply to the market. That is why Western Canada has more UGS capacity than does the large market region in Ontario and Quebec, the large gas producing regions in the U.S. have 1/3 of the overall UGS capacity of that country and Russia has more UGS capacity than does Europe.

Another major foreseen change is the large requirement for quick cycling, high rate UGS services to optimise the feedstock gas supplies and the operation of the 6 LNG export trains at Gladstone. This is analogous to the large gas storage facilities used by gas producers in Alberta, Canada. As of 2010 Canada's dominant gas producing region, Alberta, had 360 PJ's of working gas and 7 PJ/d of maximum deliverability capacity from UGS. This storage capacity has been growing exponentially since the mid 1980's and it serves the provincial upstream industry that operates 140,000 gas wells and gas production that peaked in 2002 at 14 PJ/d. Most of the gas produced is exported to either the U.S. or to eastern Canada and the export pipelines have an annual capacity factor that exceed 90% and therefore are very similar to LNG export facilities in that regard. The requirement for UGS increases as unconventional gas increasingly displaces conventional gas production.

Canada's largest gas producer, Encana produces exclusively unconventional gas and in 2002 it owned 150 PJ's of underground gas storage working gas capacity with 3.0 PJ/d and 3.8 PJ/d of maximum injection and deliverability capacity respectively.

SE Qld requires multiple cycles per year of high deliverability and high injection rate gas storage facilities in order to accommodate the requirements of the three vertically integrated CSG to LNG projects. Extremely high quality depleted reservoirs or better yet, salt caverns, are required to meet this growing need. As usual, geological limitations will rule and the only know solution at the moment would be the Boree Salt deposit located in the Adavale Basin.

The main driver for greater UGS use in the east coast is the need to lower the cost of gas supplies and to increase the utilisation level of assets and thereby increase asset returns.

A third possible driver for additional UGS is gas trading hub storage to provide additional liquidity and hub services to the STTM should that market ever develop in the east coast. Wallumbilla is the obvious site for that type of storage at the moment.

Storage in gas pipelines is touted in Australia as a credible form of gas storage and yet gas pipelines are not that suitable for large pressure variations. While line pack can offer some flexibility it is not generally considered to be a material contribution to the gas storage requirements. Australia is rather unique in this regard. I am not aware of any pipeline storage services sold by pipeline operators in North America or Europe.

Q.56

Existing levels of UGS in the east coast fall far short of that which will be required by the overall gas industry in the future. Benchmarking to world's best practice suggests that 130 PJ's of maximum working gas capacity and 2.9 PJ/d of maximum deliverability capacity is required for SE Qld alone. Should Bass Strait eliminate its swing role, then another 600 TJ/d of deliverability capacity is required in Victoria as well as an additional 60 PJ's of working gas capacity. This would permit the Longford gas plant to operate at a very high capacity factor and the peak gas demands in Victoria would be served from gas storage.

The east coast market does not supply adequate price signals for the development of additional gas storage at this time. Gas storage typically responds to gas price volatility and seasonal price swings. There is no seasonal gas price differential in either Victoria or S.A. at this time for the gas supplies that serve those two seasonal gas demand markets. Furthermore, the lack of a credible STTM and associated gas pricing volatility hinders the development of UGS facilities that essentially monetise gas price volatility. The other missing price signal is a futures market for gas whereby volatility and pricing spreads can be monetised utilising gas storage.

In North America, gas storage services are priced as a long term option in a commodity market. Australia does not even have variable pricing in its GSAs to reflect the optionality granted in those contracts during times of high gas demand. Price signals are not required for vertically integrated projects such as the CSG to LNG projects because the owners can perform economic analysis of these projects with and without gas storage to derive the cost/benefit relationship of additional gas storage facilities or long term gas storage service contracts with a tariff structure.

Therefore it will be easier and quicker to justify additional UGS facilities located in SE Qld than elsewhere in the east coast. These internal pricing signals is what drove the GLNG joint venture to pursue the development of new UGS facilities slightly north of Roma. The problem with that initiative was the lack of high quality depleted reservoirs in the Surat and Bowen Basins that are both suitable and cost effective for conversion into gas storage.

Q.57

Third parties to date can only access the very small Iona UGS facility. This facility has a maximum working gas capacity of 23.5 PJ's and 500 TJ/d and 170 TJ/d of maximum deliverability and injection capacity respectively. This facility has undergone several expansions over its 14 years of operation. It is very difficult to determine under what terms and conditions storage customers use this facility and the storage services offered and charges related thereto are equally as difficult to determine. This is in contrast to UGS facilities in North America who generally post their storage services and contracts on their website. They also post commodity charges and demand charges for various storage services and many other services such as park and loan and gas swaps to other storage facilities located in other regions of the country. I have tried to understand what value propositions and services are offered by EnergyAustralia at Iona and have yet to be successful. They have recently entered a divestment process so perhaps the level of transparency and disclosure will increase under a new owner.

Q.58

The barriers to the development of additional gas storage facilities are numerous. IEC has extensive experience in the gas storage sector of North America and has been involved in numerous gas storage development schemes in the east coast of Australia. IEC has the development rights to a very large salt cavern gas storage field south of Blackall, Qld and has been promoting this project for the past seven years to primarily the CSG to LNG projects. IEC also held a sale process on behalf of Adelaide Energy with respect to the gas storage potential of the depleted Katnook gas fields located in the southeast corner of SA. Additionally IEC explored the acquisition of the Silver Springs depleted reservoir located in the Surat Basin when owned by Mosaic. IEC was involved in the construction of the Iona facility by TXU Australia and has extensively searched for suitable underground salt deposits across the east coast. IEC also provided extensive consulting to both QGC and the GLNG CSG to LNG projects regarding gas storage development prospects and the commercial value of UGS to their operations – both during the ramp gas period and on an ongoing basis. All of these initiatives and projects faced numerous barriers to the extent that very little additional storage capacity was added to the east coast as a result. Silver Springs and RUGS were the only development projects to materialise and the performance of these two new facilities is relatively unknown due to the lack of information about gas storage facility operations and capacity in the east coast.

Regulatory uncertainty is one of the primary barriers to the development of UGS in the east coast. This is particularly the case for salt cavern storage which has yet to be developed in Australia but it is also true for depleted reservoir storage. Gas storage is very complicated and requires comprehensive regulations and policies related to its development and operation. Most states and territories in the east coast have yet to address this requirement.

Another material barrier is the lack of access to interruptible gas pipeline services and if access is granted than reasonable interruptible tariffs must be available. Gas storage facilities are typically built in uncongested locations along gas pipelines since storage customers must be able to access on a reasonable basis interruptible pipeline capacity on both a forward haul and back haul basis for gas injection and withdrawals from storage. While most of the gas pipelines in the east coast qualify from an uncongested criteria, access to spare capacity on a timely basis at a reasonable tariff seldom exists. For some reason gas pipeline operators would rather have low throughputs than offer pipeline services to gas storage customers.

The lack of pricing signals has already been discussed and is a commercial barrier.

Geological constraints are a barrier. Most depleted reservoirs do not make good gas storage candidates due to a variety of reservoir engineering, wellbore integrity and geological reasons. Consequently, high quality reservoirs and/or thick pure salt deposits are typically well sought after in most OECD countries.

Acquiring 100% of a petroleum production lease over depleted reservoirs or of a mineral lease over a quality salt deposit can be problematic. Producers tend to hang onto depleted reservoirs particularly when they are part of a larger gas field and mining companies tend to hold onto mining leases for mineral prospects other than salt. The lack of vertical segregation of geological horizons for either petroleum or mining tenements in most of Australia is another large barrier.

Technically, gas storage facilities require unique special purpose wells, dual flow meter stations and more complex gas plants than are generally seen in normal gas production operations. The equipment and skills required are generally not available in the east coast which results in high costs and project delays. The existing UGS facilities in the east coast would be rated as very unsophisticated and bottom performers when compared to state of the art, high performance, and quick cycling UGS facilities found overseas.

To summarise, the barriers to the development of new underground gas storage facilities are commercial, technical and regulatory in nature and are many.

Q.59

This question is somewhat unclear to me, but if it is in regard to the nominating and scheduling of gas flows through the activity or value chain then I would say that the east coast is very slack with respect to the process of nominating, scheduling, allocating and the reporting of gas flows on a real time basis with commensurate penalties for non-performance. This reflects the historically unsophisticated value chain with few operators involved in the process in the east coast. As more asset operators and market participants become involved in this activity, a much more robust system and procedures will be required. The east coast gas supply chain from wellhead to burner tip has, to date, involved only a relatively few operators and market participants (i.e. shippers or users of capacity throughout the supply chain.

In contrast the NGTL high pressure pipeline system located in Alberta, Canada is operated by TransCanada Pipelines Limited and handles 10 PJ/d of gas and is 24,373 km in total length. It gathers gas from 1,000 different receipt points (interconnections with gas plants, gas storage facilities and other gas pipeline systems and delivers gas to over 200 delivery points (downstream export pipelines, gas storage facilities, reticulation systems and large end users facilities). The NGTL system interfaces with 100's of different operators and handles gas for 100s of shippers. Gas trades within the NGTL system, which operates as a virtual gas hub for the STTM, exceed six times the physical flow (i.e. daily trades are in excess of 60 PJ/d). Ten very large gas storage facilities are embedded within the NGTL system and they can all turn from injection to withdrawal within a 4 hour period. These gas storage facilities have a combined capacity that exceeds 7 PJ/d. Gas is nominated and scheduled on a 4 hour basis on the entire NGTL system and there are very large penalties for any material deviation of actual scheduled gas from nominated volumes for any NGTL customer over each 4 hour nominating and dispatching period.

Again the east coast has a long way to go in terms of scheduling and nominating gas in a reliable and accurate manner along a complicated and sophisticated chain comprising different operators and a large number of customers in each segment of the value chain.

Further to my earlier response to Q.40 the following illustrates the tremendous gap in service and tariffs across the east coast gas pipeline grid compared to North America and Europe.

The cost to use the entire NGTL system is $0.20/GJ to get on the system at one of the 1,000 receipt points and there is no cost to go to a UGS facility located in Alberta and to get back onto the NGTL system from storage and there is no additional cost to ultimately deliver the gas to any deliver point in Alberta. Should one wish to export gas out of the province instead of selling into the provincial market, then there is an additional charge incurred when leaving the province at the borders of $015/GJ to 0.18/GJ depending on the border point. There is no infrastructure in Australia that remotely resembles the value for money that one gets in, not only Alberta, but in any province or state in Canada and the U.S. This is not because of volume as many Australian operators argue, but because of the cost of service model that Australia rejected for pricing its gas infrastructure services.

D.60

It is important to first understand that the definition of ‘Contract carriage model’ in Australia is markedly different than the generally accepted definition of that term as it is defined in Europe and North America. As is the case so often found in Australia’s gas industry, Australia elected to redefine a term commonly used overseas which leads to much confusion and misunderstanding. I am very familiar with the meaning of contract carriage model and I can assure you that this model has been materially modified in Australia and as a result it is not very effective. The model adopted for Australia is plagued with market power abuse and has discouraged gas on gas competition, commercial innovation and new gas supplies from new entrants. It has also discouraged the creation of a secondary market for pipeline and storage services and the formulation of meaningful workable gas hubs and the STTM. Large users of gas have generally not bought gas delivered to upstream delivery points and gas traders in the wholesale market are virtually non-existent.

The fact that the east coast has two distinctly different models for gas pipelines and gas scheduling on those pipeline systems and the fact that it now has two distinctly different gas specifications on large gas pipelines that inter-connect in SE Qld says much about the lack of policy and indifference to efficiency and ease of operations in the east coast gas industry. Continents such as Europe and North America have made great strides in standardising the gas industry so that trade and operations between countries can be more efficient and yet the small east coast region of Australia has the exact opposite approach.

Q.61

In this matter and many others, there is a need in the east coast to choose between continuing to act in an extremely inefficient manner and changing this course to create a gas industry that is efficient, reliable and low cost. While many espouse this goal there have been very few steps taken toward it and many taken in exactly the opposite direction.

Comments on East Coast Gas Market Reform Agenda

It is, I suggest, time to admit that the experiment to reform eastern Australia's gas industry utilising an unproven Australian made model that commenced in the mid 1990's has not delivered adequate results. Any post mortem analysis would conclude that not much was accomplished toward the objective of creating an open and competitive market for gas. Two decades after the commencement of major gas reform initiatives the gas industry remains plagued by gross inefficiencies and unchecked market power.

By comparison, Canada created a competitive gas market commencing in October 1985 via a land mark de-regulation agreement of the gas commodity while maintaining the economic regulation of gas pipelines. The following is an excerpt from a report by the National Energy Board of Canada called Natural Gas Market Assessment – 10 years after Deregulation published in September, 1996:

> The main story in the natural gas producing sector in the last decade was the 40 percent fall in wellhead prices that occurred from 1985 to 1987 and the subsequent actions by the sector to survive in the lower price environment that has persisted since then. The gas producing sector has responded by aggressively cutting costs and rapidly expanding export sales. Cost reductions have come from corporate downsizing, applications of new technology such as "3-D" seismic, improved drilling practices, improved inventory management, and increased attention to costs in each step of the exploration and production process. As a result of all these actions, gas replacement costs in Alberta have been reduced in real terms by about 50 percent since 1985.

The concluding remarks of the report state:

> Overall, our report finds that the natural gas industry is efficient and responsive to the demands of the marketplace. The pipeline sector has developed a new range of services which, along with improved storage capability, has greatly enhanced the flexibility and reliability of the delivery system. The gas producing sector has cut costs sharply and has increased production dramatically, despite persistently low wellhead prices. While production has increased, the pace of technological change and improved knowledge of the producing basin in western Canada indicates that supply can be expected to meet Canadian and export demand for the foreseeable future. Current estimates of the ultimate potential of the Western Canada Sedimentary Basin are about 50 percent greater than those of ten years ago.

The key performance indicators of a functioning eastern gas market should include the following:

1. Multiple sellers of gas competing for markets on a daily and monthly basis;
2. The cost of gas supply should decrease as competition increases due to an emphasis on cost cutting and greater efficiency of operations and capital employed;
3. Gas prices would be volatile and thereby send price signals regarding the value of such services as gas storage;
4. A gas futures market is a hallmark feature of a working commodity market and it replaces gas price forecasting or guessing what the future value of gas is;
5. Gas pipeline tariffs should be the same for everyone utilising the same type of service on any given day. Pipeline tariffs should represent the age and the history of depreciation of the pipeline. Economies of scale associated with low cost expansions would be enjoyed by all users of a pipeline;
6. A range of gas prices would exist depending on the term of a sale, the flexibility of the transaction and many other features. The commodity price would be distinct and separate from all other aspects such as transportation and storage costs;
7. A vibrant and large open access gas storage sector would exist and all market participants would be encouraged to utilise the services which would be offered on a non-discriminatory basis;
8. A large price differential would exist between the domestic gas market in eastern Australia and the netback price received from the LNG export market. The LNG export market must clear the market (landed LNG price) in the destination market while the domestic market price of gas would be determined by the supply and demand dynamics associated with all of the gas that remains trapped in eastern Australia. Withholding gas from the market would be prohibited by the resource owners (various governments) as it is not in the best interest of the nation for gas producers to manipulate the market for their commercial advantage;
9. The utilisation rates of flowing gas wells and gas plants should be very high as the marginal cost to produce gas is very small relative to the prevailing gas price in a liquid gas market. The cash cost to produce is equal to the royalty payment and the operating cost;
10. The gas production and gas reserve replacement rates would be 'just in time' to offset well declines and R/P declines. Excess inventory of either 2P reserves (i.e. beyond 8 years of annual production) or producing wells is an inefficient use of capital and increases gas costs unnecessarily. Australia typically has a large inventory of excess gas reserves and gas well production capacity;

11. The gas supply chain would be very resilient to change, that is, it would have the capacity to cope with large changes without compromising reliability and security of supply and do so in a very cost effective manner.

There are many examples overseas of functioning gas markets. The North American gas market has long been considered to be the most sophisticated and mature gas market and it does not resemble what exists today in eastern Australia. The reasons given for why Australia is different are, in my view, nothing but excuses.

<u>Promote Gas Supply Competition</u>

The initiation of gas supply competition would be a great start, followed by the promotion of gas supply competition over the long term. As I mentioned earlier, there has yet to be true gas to gas competition in eastern Australia and the gas producing sector has, and continues to, adamantly resist this. The gas producers prefer to bring on gas reserves whenever they see fit and that translates into market manipulation and other anti-competitive behaviour. This attitude originated during the era when the eastern Australia gas demand was carved up by state and served by essentially one of two gas plants that did not compete for market share. While there no longer exists a monopoly gas supplier to each state gas demand, this attitude of avoiding competition remains.

There are many different ways to force intense gas to gas competition and the following is a partial list of driving factors:

1. 'Use it or lose it' gas reserves associated with PL's. For example in Alberta a gas producer must quickly produce from all gas reservoirs under a PL, including up-hole gas or else the Alberta government will revoke the rights to any un-producing gas reserves and sell those rights to another interested party. The use it or lose it policies in Australia are very lenient compared to most jurisdictions overseas.

2. To the extent that gas prices are not cost based but rather market based (determined by true market forces) then the gas producer is wise to sell into today's gas market for tomorrow prices may collapse.

3. The low cost producer wins. To the extent that gas producers are truly price takers as are all primary producers in an open market, they take whatever revenue they can get and focus on driving down costs as they strive to be in the bottom quartile of the industry in terms of gas supply cost. Such a focus has been in existence for decades in North America and yet there is little, if any, evidence of its existence in eastern Australia to date.

4. The ultimate threat is the nationalisation of gas exploration and production activities to the extent that gas producers do not wish to offer fair and reasonable prices to consumers and to focus on costs and capital and operational efficiencies. National petroleum companies are popular and

growing at alarming rates as nations seek to better control the cost of energy supplies and the exploitation of their natural resources.

Improve commercial and regulatory environment for infrastructure

Gas infrastructure, namely pipelines and reticulation systems, are natural monopolies and therefore must be controlled by competent regulation and regulators. Australia has very little experience in this regard due to the fact that this infrastructure was largely government owned across eastern Australia until the mid to late 1990's. The privatisation and subsequent regulation of this infrastructure was done in such a manner as to ignore all of the lessons and policies in this regard overseas.

The economic regulation of gas pipelines is a surrogate to competition and therefore is a prerequisite to the development of a functioning gas market. This has yet to be achieved in eastern Australia. While North American has evolved to the extent that offshore gas pipelines, offshore production platforms and most gas processing plants are no longer owned by gas producers but by specialised low cost of capital, value creating midstream companies, Australia has reversed that trend and gas producers prefer to build, operate and own their own onshore gas transmission pipelines as is the case with all three LNG export projects at Gladstone. Furthermore, gas is often converted to electricity near the supply and the electricity transmitted long distances as opposed to the normally accepted, preferred solution of pipelining the gas to electricity demand sinks and then converting it to electricity. This behaviour is indicative of market failure in terms of eastern Australia's gas pipeline sector.

The situation must be improved for the benefit of those who wish to move gas as opposed to the benefit of the pipeline owners. Any benchmarking to world best in class practices would indicate that there is a huge problem in eastern Australia in the gas pipeline sector.

Eastern Australia Gas Policy – General Policy Comments

The Domestic Gas Market Role

Once considered a waste by-product of petroleum activity and production, gas has evolved over the past 5 decades into the most desirable fossil fuel from an environmental and efficiency perspective. Additionally gas has very important non-energy uses for modern society. Globally, gas share of the total primary energy supply (TPES) is increasing and international gas trade is also increasing as many nations have inadequate indigenous gas resources or inadequate production rates from those resources to meet their growing domestic gas requirements. Australia is gas resource rich and yet lags the OECD average and significantly lags the average of OECD gas exporting nations in terms of gas penetration in its TPES. Australia's current gas and energy policy supports unlimited gas exports from Australia regardless of the impact on its already stunted domestic gas industry and the corresponding negative impact to its economy and environment.

Australia's domestic gas market has provided the necessary impetus for Australia's gas production and supply chain development from the discovery of gas in Roma in the early 1960's until oil linked LNG prices became profitable in 1999. It is entirely inaccurate and inappropriate for Australian gas producers to make claims today about how they have historically been disadvantaged by supplying Australia's domestic gas market and to make threats to not supply this market in the future unless and until it delivers the same netbacks to them as does LNG exports (i.e. parity pricing between LNG exports and the domestic gas market).

While Australia's domestic gas market has grown substantially since the late 1960's, it does not reflect the abundant low cost gas resources that exist across Australia. For example, Australia lags other major gas supply regions such as Western Canada, Russia and the south west U.S. in every benchmarking category that examines efficiency, gas penetration and low gas supply cost to consumers. There is little value adding to gas in Australia in terms of converting gas feedstock into various goods for both the domestic market and for export including: fertilizers, methanol and gas to liquid products. Australia also lags many OECD countries in terms of the use of gas for electric power generation.

The export of gas from Australia in the form of LNG commenced in 1989, lagging the introduction of pipeline gas supplies into Australia's domestic market by more than two decades and into Western Australia's domestic market by five years. There is little doubt that the sale of gas into the domestic market long before LNG was exported from Australia's first LNG export project, the Northwest Shelf project, was the catalyst for attracting petroleum exploration and gas production development across Australia. LNG sales from Australia were only contemplated when gas discoveries were sufficiently large that they could not, in a reasonable time frame, be absorbed in Australia's relatively small domestic gas market. The lack of a continental Australia gas market has further exacerbated this issue.

Australia's R/P ratio of 90 years can be compared to 12.4 years for Canada, 13 years for the U.S., and 4.5 years for the U.K. The global R/P ratio was approximately 64 years as of 2011 and the OECD average was 16 years. Australia's R/P ratio is comparable to the non OECD country. Australia's R/P ratio is indicative of an undeveloped economy in a resource rich country. Resource rich developed economies tend to generate large domestic gas demand (i.e. Alberta, Canada) and convert gas resources into value adding exportable goods thereby creating jobs and multiplying the benefits from its gas resources. There is always a limit to how large a domestic gas market can become given the population, etc of the resource rich country but Australia's domestic gas market is currently smaller than that of the province of Alberta, Canada. There has been very little effort in Australia to grow its domestic gas demand commensurate with its gas resource endowment.

Australia's use of gas as a feedstock is also extremely low compared to other gas resource rich countries. It is rather unusual for a large commodity producer (agriculture and mining) such as Australia to forfeit the many benefits to the economy and security of supply from manufacturing at least all of its own demand for such gas intensive input products as fertiliser and explosives. The replacement of imports is not only attractive economically but also from a supply risk mitigation perspective. Canada is a great example of intense gas usage based on a similar resource rich perspective as Australia. Canada consumes nearly 300% more gas on a per capita basis than does Australia and this gas consumption is driven not by the home heating demand related to the cold climate as many uninformed people believe, but by the industrial, mining and petrochemical sectors of the market. Canada utilises very little gas for power generation due to its abundance of hydro generated electricity (>50% of generation).

Absent a major policy shift, the path forward for Australia appears to be contrary to what most developed nations who have abundant gas resources would be. Australia's domestic gas market has been stunted for some time now and significant demand destruction is the outlook given the lack of a gas policy that protects the domestic gas market. It is obvious that Australia will soon be suffering from both the resource curse and the 'Dutch Disease' regarding its gas resources. Australia's use of gas in its primary energy consumption is at the world average; this is a very poor reflection of gas policy given Australia is about to become one of the world's top gas exporters, given that it has embraced a carbon constrained future and given it is an economically developed nation. Very few comparable nations have neglected their domestic gas market to the extent that Australia has. For example, gas consumption as a percentage of the total primary energy consumption for Russia, the Middle East and the Netherlands is twice that of Australia.

Reliance on Market Power Legacy in Australia

Australia's upstream sector of its gas industry has been plagued with anti-competitive behaviour since the genesis of the country's pipeline gas industry commencing in the 1960's. While it is not unusual for start-up regional pipeline gas markets to have such growing pains, it is unusual for an economically developed country to continue to tolerate, and in some cases even embrace such behaviour for multiple decades.

Originally the buyers of gas were dominated by government owned companies and they demanded fairly harsh terms from petroleum producers that had no alternative gas market. The vintage GSAs between gas producers and the gas reticulation companies reflected this skewing of market power. Various governments also owned essentially all the gas pipeline infrastructure from the 1960's until the privatisation of these pipelines in the mid 1990's. The charges were high and the services poor associated with those pipelines compared to world's best practice, essentially reflecting another tax on the gas industry. The prohibition of interstate gas trade was another of many encumbrances to the struggling gas industry. Not surprisingly gas producers responded by developing anti-competitive patterns of behaviour in the manner in which they developed gas production leases and sold gas production across Australia.

Post the mid 1990 gas reform initiatives, gas producers continued with their anti-competitive behaviour for it was entrenched in the system by now. They were joined by the new pipeline sector owners who took advantage of the recently formed and inexperienced pipeline regulatory bodies charged with ensuring that gas pipeline access and tariffs, were in the public interest. The pipeline owner's accomplishments were many; to the extent that most gas pipelines in Australia are not economically regulated tariffs are generally discriminatory and the cost of services are not reflective of actual costs. The term 'service providers' for this sector has become rather ironic compared to the standards set in most other OECD countries.

The large end users of gas have essentially been victims of the many unintended consequences that resulted from the first 50 years of Australia's gas industry. Unlike other OECD countries that faced gas de-regulation and gas liberalisation, the large gas users across Australia did not, until recently, form a coalition to influence the evolution of Australia's gas industry. Gas users groups have been relatively fragmented compared to the gas producer association but this is changing. The EUAA was mostly pre-occupied with matters and issues relating to the electricity industry but is now expanding its focus to domestic gas supply. The WA based DomGas Alliance has been engaged in public and industry debate for some time. Manufacturing Australia and the Australia Industry Group are also now engaging in the issue given the potential impact on Australia's manufacturing sector.

Domestic gas market policy must address, among other things, market power and anti-competitive behaviour. To not address these important issues makes a farce out of the entire process. To date Australia has done very little in this regard on the basis that intervention done in most other gas resource rich countries is not appropriate or required in Australia. Nothing could be further from the truth as evidenced by the current state of Australia's gas industry.

To avoid abuse of market power (pushing gas prices up), competitiveness is assured in efficient gas markets overseas by ensuring access to many players on both the demand and supply side of the equation. In such gas markets, security of supply is guaranteed by transparent, efficient and liquid markets and not by political protection. Infrastructure owners who have market power are economically regulated as a surrogate for competition but gas trade acts like a commodity.

Alternatively, other nations nationalise their gas industries and/or control the pricing of gas in order to mitigate market power. This is a popular model in less democratic nations and less developed economies. The European and North American gas industries had major intervention by governments including price controls until the mid 1980's. Australia partially embraced this model through government ownership in gas pipelines and gas reticulation assets from the 1960's until the late 1990's. The privatisation of these assets above their replacement cost was a tax to the gas industry since infrastructure serving the common good of the industry is typically depreciated and not permitted to appreciate in value.

A description of the many ways in which Australian gas producers have and continue to manipulate Australia's gas market and its regulators is beyond the scope of this submission. Suffice it to say that across Australia the pattern is similar and while the tactics often differ the result is the same. The result is high delivered gas prices to large gas consumers and onerous GSAs that contain anti-competitive restrictions and obligations that discourage the use of gas in Australia.

Oil is a transportable, global commodity. Gas is generally consumed on the continent where it's produced – and the relatively low price of gas in North America and most other gas producing regions compared to oil reflects that. The gas producers in Australia want to change this concept by their assertions that there is an emerging global gas market and that Australians have to pay global gas prices (i.e. match the netback price received from LNG exports to the highest priced gas markets in the world). Such a notion is contrary to what is the reality in the largest continental gas markets, namely North America and Europe where price differentials have and continue to exist between exports and indigenous gas production that serves the domestic market of exporting regions/countries.

Exports to a gas market where higher gas prices prevail may yield a price advantage to the exporter and to the Government in terms of its royalty revenue from gas production allocated to that export sale but there should be no linkage between higher international gas prices under export activity and the domestic gas market prices of the exporting country or region. To the extent that export prices are low, there is often an export floor price equal to the domestic gas market wellhead price prevailing in the exporting country to alleviate the 'dumping of resources' to competing economies. Domestic gas production for domestic gas consumption in a net gas exporting nation or region should be priced on the basis of the availability of supply to that market and, in turn, the marginal costs of indigenous gas production. Contrary to the allegations by Australian gas producers, the price received from exports is irrelevant. Any convergence of these two prices, unless under a floor pricing policy for exports, is a symptom of market power abuse and market failure.

It is most convenient for gas producers to now take this position given the netback from LNG sales from the northwest shelf project was for the first two decades of that projects life much lower than the netback from sales to the domestic market in WA. It is not unusual for gas prices serving the domestic markets to be much lower than those received from export sales but the reverse is usually discouraged or prohibited since one is essentially providing lower cost energy to a competition nation or region.

The engineering of perceived gas supply shortages when the country is awash with gas resources is one of the main devices used by Australia gas producers to effectively prop up gas prices in the domestic gas market. The notion that a producer's ability to deliver gas under a long term sale contract must be underwritten by demonstrated 2P gas reserves upfront serves the producers in this regard. This is a very antiquated practice and an inefficient manner in which to conduct gas sale and purchase agreements and to underpin export projects. Similar reserve dedicated long term GSAs existed at one time in North America but were replaced in the 1980's with long term GSAs that were much more flexible and among other things did not contain dedicated gas reserves. The flexibility of these GSAs enabled the gas industry to become much more efficient. Long term contracting essentially disappeared in the 1990's as the market evolved to essentially all short term sales.

Finding and proving 2P gas reserves is a capital intensive business and producers should rely on their exploration track record and failing that, their ability to acquire gas supply either in-situ or gas production as required from third parties to supply any and all future gas supply commitments. The concept of dedicated gas reserves and stockpiling gas upfront prior to entering into long term sale contracts disappeared long ago in overseas markets that lead the way in efficiency benchmarking studies.

For example, the U.S. has relied on an R/P ratio of less than 10 years for decades and Canada has followed in this regard. This transition occurred in both of those countries well before the conversion of the gas market to predominantly short term or spot transactions. The practice of reserve dedication has proven to be a very inefficient method in which to sell gas and was replaced by corporate performance guarantees with liquidated damage provisions for non-performance. The only reason that this gas contracting structure still exists in Australia is for the gas producers to effectively engineer a gas supply shortage. The sterilisation of sufficient proven producing gas reserves to underpin the first 15 or 20 years of sales from new LNG export projects only exacerbates this problem. It should be adequate for the proponents of these projects to have sufficient confidence in the ultimate gas resource base within economic reach of supplying those projects and their ability to continue to find and develop those resources at a profit. To rely on upfront dedication of proven gas reserves is a very conservative approach that does not exist in other industries, including the oil industry. Again there is much rhetoric in Australia regarding this subject as this concept is used to convince gas buyers to comply with the gas producer's agenda of controlling and manipulating the domestic gas market.

In addition to this are the claims by gas producers that the industry would not exist without long term sale contracts containing long term pricing formulas and infrequent and onerous price renewal provisions. These claims are not supported by fact. It has not been a barrier to investment in North America's gas industry and the worldwide oil industry as both are based on short term supply contracts and short term variable pricing formulas; usually based on a daily price index.

One of many examples that expose this rhetoric is the fact that, in Canada, large petroleum producers have spent C$ 50 billion on oil sands mega mining projects in Canada. This expenditure is expected to grow by another C$ 100 billion over the next few years if the oil price outlook improves. All of this expenditure is underpinned by volatile, short term world oil prices and a 3 to 5 year oil futures market. To suggest that upstream gas production facilities would not exist in Australia without certainty of market and revenue to the producers is inconsistent with how the oil and gas industry operates in other OECD countries.

Free & Fair Gas Markets

The evidence in a gas market of the elimination of market power is when the following criteria have been met:

1. A **Fungible Commodity** downstream of the gas processing plants – gas molecules should be a homogenous, fungible commodity to enable the free trade and movement of gas throughout the connected gas grid and into and out of any gas storage facilities. A common gas specification must exist across all gas pipelines for gas to be a fungible commodity. Long term contracts that tend to de-commoditise gas should be discouraged.

2. **Access to Low Cost Infrastructure** – transportation and reticulation services should be provided at the lowest cost consistent with the adequacy of service, safety, and a return to the investor commensurate with risk. The recovery of capital costs should be on a depreciating asset with no recapitalisation of the asset regardless of who owns the assets. Furthermore, tariffs should be non-discriminatory and cost based with no cross subsidisation among the various users or across various services. For example, a back haul transportation charge should be minimal since this service actually creates more forward haul capacity in a gas pipeline as the gas will move by displacement as opposed to actual physical movement. This transaction also reduces compressor fuel and other variable costs to the pipeline.

3. **Multiple Sellers** – this means that gas faces competition in the domestic market from not only other sources of energy or feedstock, but also from gas from many other sources. One would expect that intense gas to gas competition would be

the primary source of market forces in Australia's domestic gas market as opposed to alternative fuels and/or gas export prices.

4. **Multiple Buyers** – this means that transactions or gas trading takes place at each level of transaction from producer to consumer. While this may appear to be counterintuitive, gas should be traded many times prior to consumption in order for inefficiencies to be worked out of the value chain. Marketing and trading companies greatly assist in the driving out of inefficiencies along the value chain and also increase the churn levels at gas trading hubs.

These conditions will generate an environment that attracts investment to all sectors of the gas industry and results in potential short term gas price volatility but long term health and stability in the industry.

An efficient gas industry is the product of market forces working diligently in the gas commodity market (i.e. gas trading and services) and strict economic regulation of any and all market participants who hold excess market power such as the owners/operators of midstream and downstream gas pipeline infrastructure and any other segment of the value chain that is not subject to market forces. This does not occur unless good policy and practices exist at the Government level and proper market power tests and solutions to mitigate such market power exist and are applied in a non-discriminatory manner. The proverbial 'level playing field' must be diligently and ruthlessly sought after.

Another indicator of market maturity involves the role of underground gas storage (UGS) facilities in a gas market. In Russia, Western Canada and the Gulf of Mexico region UGS facilities are used to promote gas exports to other regions and countries and to ensure that intense gas on gas competition occurs in setting domestic gas prices In excess of 50 UGS facilities exist in Canada and Russia and an UGS working gas capacity in each country in excess of 10% of the annual gas production is used effectively to lower delivered prices and to ensure reliability of gas supply on a daily basis. Gas storage has been a tool used for decades to enable gas exporting regions to achieve the necessary efficiencies and security of supply in order to accommodate the demands and expectations of both the domestic and export markets. These regions and countries over the past 40 years have developed their gas resources, export and domestic markets, and related infrastructure in such a way that the domestic market enjoys abundant, low cost, reliable gas. High valued export markets were served on a secondary priority but with a very high level of reliability. For example, Western Canada has exported over half of its gas production to the U.S. markets over the past 25 years while serving Canada's national domestic market on a first priority basis and yet has never defaulted on deliveries to its U.S. gas customers. An extensive network of underground gas storage and other facilities are used to ensure that gas supplies are abundant and to reduce price spikes in the prevailing gas market.

An efficient gas market has many characteristics that are not as yet present in Australia's gas industry. Some of the features of an efficient gas market are as follows:

1. Multiple gas transactions (buyers and sellers) at every stage in the value chain;

2. Proliferation of services such as underground gas storage, hub services, and financial services;

3. A vibrant primary market and a vibrant secondary market. The short term trading of gas as a commodity and access to unused or surplus pipeline capacity is a pre-requisite for the secondary market as is sufficient depth in the market;

4. Inefficiencies are minimised and/or eliminated very quickly by market forces and the innovation and creativity of market participants. Market participants include a variety of service providers and are not limited to pipeline operators, retailers, gas producers and gas consumers as is the case in Australia at present;

5. Gas flows hourly and daily to those willing to pay the prevailing market price somewhat like what occurs in the electricity market in Australia. Gas trade is not hoarded or encumbered by long term contracts with very restrictive terms and conditions but is swapped and exchanged freely throughout the gas value chain in order to meet all gas demand at the lowest possible price. Gas deliveries and withdrawals from underground gas storage facilities occurs continuously as the role of balancing the physical volatility of demand and supply is absorbed easily by gas storage facilities. Salt cavern gas storage is the most efficient type of gas storage for short term balancing and depleted reservoir gas storage is the most efficient type of gas storage for longer term and seasonal balancing;

6. Real time gas price signals indicate the physical balancing of the system and gas price volatility and the level of gas prices sends signals to various market participants that more or less facilities are required at various points along the value chain. For example, large gas price volatility will encourage gas storage developers and owners to expand existing facilities and or develop new ones. This is how market forces look after the needs of a gas industry in a competitive environment.

Since gas pipelines and reticulation facilities are seldom, if ever, subject to competitive forces their tariffs, services and policies must be scrutinised and regulated by a regulatory body in order to ensure that barriers to competition are minimised and ideally eliminated. The regulation of gas pipelines across Australia has been at best dismally managed to date. The light handed regulation policies adopted in Australia for gas pipelines has not resulted in a level playing field nor open access to low cost infrastructure. Benchmarking to world's best practice regarding this sector of the gas industry confirms these allegations but this is not the principle topic of this report and therefore will not be addressed in detail.

A Vibrant & Competitive Gas Market

The liberalisation and de-regulation of gas markets and gas industries has occurred in North America and Europe to various degrees commencing in the 1980's. Reports written ten years after the de-regulation of Canada's gas industry have showed tremendous benefits to all of the stakeholders (upstream, midstream and downstream participants alike) as inefficiencies were driven out of the gas industry and exports grew at unprecedented rates.

The same cannot be said of the Australian experiment that commenced in the early 1990's as part of the micro-economic reform process. Australia stubbornly ignored all of the lessons from Europe and North America and insisted on a new and untested model. This model involved recapitalising the nation's entire gas pipeline infrastructure at or above replacement cost as Governments grabbed essentially another industry tax as they exited the ownership of infrastructure.

Australia then decided to not economically regulate infrastructure and the services that they offered but relied on "light handed regulation", whatever that is. It is the task of regulators to generate a surrogate for competition in the event that market power exists and it most certainly exists for all gas transmission pipeline owners. Permitting the charging of market based tariffs for gas transmission services is consistent with permitting the joint venture marketing of gas by upstream JV's but neither will result in the development of an efficient domestic gas market. As a result the gas industry (both producers and large consumers) proceeded to basically bypass the gas pipeline industry via gas field located power generation, or building their own gas transmission pipelines or relying on LNG exports for most of their markets. To make matters even worse, the ACCC renewed all joint venture marketing arrangements and/or granted new ones to new projects.

It takes considerable effort in the gas industry to accomplish a 'marketplace' where gas is freely traded as a commodity. Only Canada, the U.S. and the U.K. have successfully created such a marketplace. Gas producers supplying into those markets and increasingly so across Europe are price takers. Their gas supply costs and their price expectations are irrelevant except to the degree that they may wish to shut-in gas production when the prevailing price for gas is less than their cash costs (i.e. royalty payments and operating costs). In such a market gas producers focus on becoming a low cost producer vis-a-vis their competitors for they know that market forces will reward low cost efficient gas producers and punish inefficient high cost gas producers. This is how capitalism works.

In contrast, Australia's gas supply chain is plagued with significant market power and this market power has not been effectively addressed by gas policy across Australia to date. Gas producers both individually and collectively hold substantial market power in Australia and in essence set gas prices as opposed to being price takers. As mentioned above, in a free market structure a gas producer is a price taker in that it would receive whatever the prevailing wholesale price is as established by true gas on gas competition dynamics. This prevailing gas price would be volatile and its level would not reflect the cost of gas supply nor export parity but the laws of supply and demand from time to time that exist in a dynamic market of willing sellers and willing buyers.

Since gas is held captive to the gas infrastructure network and is not a fungible commodity until it is pipeline gas or LNG, as the case may be, the creation of a level playing field across such a complex industry takes considerable effort and influence by Government and regulatory bodies. Failing the creation of such a marketplace where multiple buyers and multiple sellers frequently trade gas in meaningful quantities, gas prices tend to be monitored very closely for anti-competitive behaviour and often become economically regulated by Government.

To be successful, gas industry liberalisation entails four preconditions:

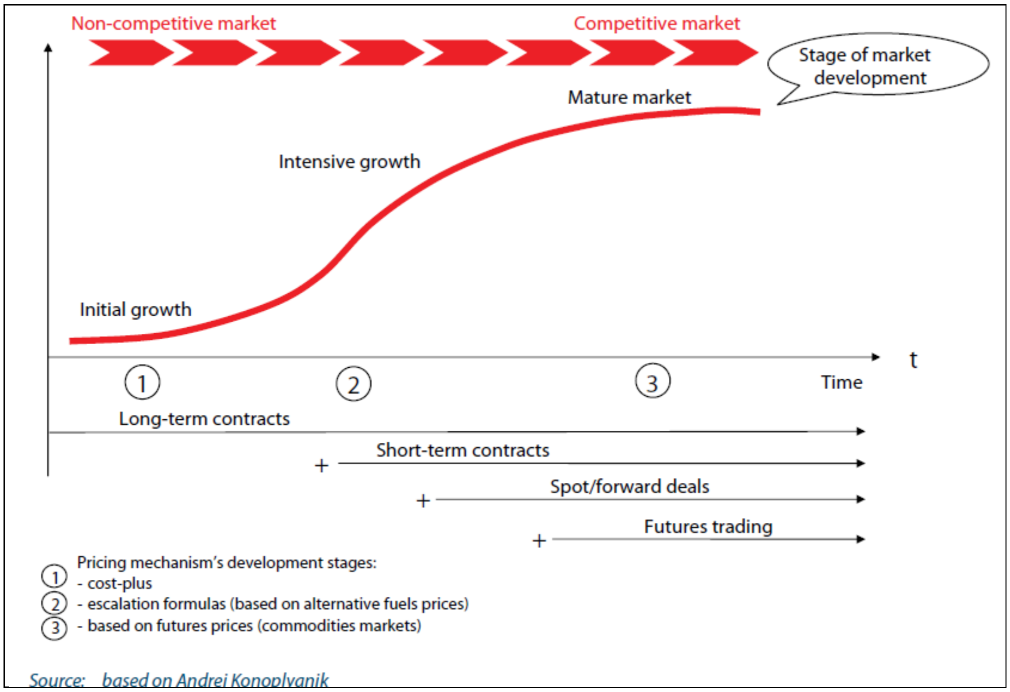
1. There must be competitive gas available to the market;
2. Customers must be free to choose among suppliers;
3. The transmission system must be open to shipment by competitive suppliers (“open” or “third party access”);
4. Pipeline access must also be non-discriminatory in their charges for the same service.

All four steps have been successfully achieved in the U.S., Canada and the U.K.. Short term commodity trading has now largely replaced long term contracting in those markets, and those remaining long term contracts – mostly for cross border trade – are pegged to indictors reflecting gas to gas competition. This success is in contrast to import dependent regions for, despite efforts of the European Community to liberalise its gas industry, the progress there is far from complete. There has also been comparatively little effort to liberalise gas markets in Northeast Asia.

While gas to gas competition is the hallmark of efficient gas market structures, it is important to differentiate between contract gas to gas competition and commodity gas to gas competition. Commodity gas to gas competition involves real time price discovery in a liquid market and today this only occurs in Canada, the U.S., the U.K. and perhaps soon in the Netherlands and Germany. In commodity gas to gas competition markets the market place determines the clearing price for gas.

Contract gas to gas competition occurs in countries and regions such as Australia where long term GSAs dominate the domestic gas market and the short term gas market is illiquid. The absence of a liquid transaction market discourages price discovery and transparency. Both sellers and buyers can be frustrated because of restrictive contractual terms and very little commercial flexibility. Gas prices reflect contract terms and market conditions at the time the contract was negotiated as opposed to current market conditions. This explains the large price differentials that exist across Australia and from one vintage GSA to another.

Figure 1. Gas Market Maturation Path



Australia's domestic gas market characteristics remain at the initial growth stage shown in Figure 1. While AEMO and the Victoria Government have tried to introduce and promote short term contracts and day trading in the wholesale east coast Australia gas market, these initiatives have not as yet resulted in any meaningful liquidity and/or market price derivation.

Exports, Imports & Domestic Gas Pricing Relationship

Experience in many large gas markets has demonstrated that long-term contracts for imported gas and/or long term contracts for exported gas and liquid national or regional domestic gas markets can co-exist. Most OECD countries have indigenous gas supplies that tend to be priced much differently in terms of both the pricing mechanism (liquid or long term contracts, short term hub pricing or escalated pricing formulas, etc.) and the level of pricing compared to gas exports from that country or gas imports to that country, as the case may be.

For example, major gas exporting countries typically have pipeline gas supplies to their domestic gas markets priced much lower at the wellhead than gas that is permitted to be exported, either by pipeline or by LNG ships. Alberta, Canada provides an excellent example over the period between gas de-regulation in 1985 and the North American Free Trade Agreement in 1994. The wellhead price differential between gas production destined to the Alberta domestic market and gas production destined to the U.S. export market was greater than the wellhead price to the domestic market (i.e. export prices were more than double domestic gas prices at a common point of reference). The Netherlands, Russia and Alaska have similar relationships between export gas prices and domestic gas prices.

The converse is typically the case for major gas importing countries around the world. The imported gas delivered to the city gate within such countries typically far exceeds the cost of indigenous gas supplies delivered to that same city gate. For example, in contrast to the situation in North America and the U.K., gas markets in the rest of the European Union (excluding the Netherlands), and in Japan and Korea have developed based on imported gas. These markets have been shaped by the desire of exporting countries to maximise the rent received for gas exports as a compensation for the depletion of their finite resources. The EU depends on three large gas-exporting countries: Algeria, Norway and Russia for 50% of its consumption. All three of these gas exporting countries have demanded oil linked pricing in the past. Russia has only recently acquiesced to the notion that gas pipeline supplies from Russia to Europe may have attracted an unnecessary price premium and that future supplies will be more competitively priced.

The wellhead price received in Russia from gas exports to Europe far exceeds the wellhead gas price received from sales to the Russian domestic gas market and was reported to be 500% of the domestic gas price in 2000. The Russian domestic gas market prices are among the lowest in the world; reflecting the abundance of gas resources in Russia. Conversely, pipeline gas exports to Europe command much higher prices for they are priced on a delivered basis to compete with LNG imports into Europe and are typically oil linked and under long term sales arrangements. This substantial pricing differential between gas used for the domestic gas market and exported gas is typical of exporting countries and regions. Prior to the free trade agreement with, first the U.S. and then Mexico, Canada's produced gas also constituted a low priced gas supply to Canada's domestic gas market and a much higher priced gas supply for all gas exports to the U.S. This dual pricing relationship reflected the abundant gas resources in Canada and the dependency of the Lower 48 U.S. on gas imports from Canada for up to 20% of gas consumption.

The development of gas import dependence – whether the gas sector was developed on domestic gas or based on imported gas – typically plays the decisive role for differences in pricing mechanisms which developed in different regions of the world. Countries whose gas consumption can predominantly be supplied by domestic gas production have regulatory control, should they wish to use it, of supply (upstream) and demand (downstream) and thus a major influence on the gas pricing mechanism that is employed in that country. Import-dependent countries have little influence on the regulation of the gas supply side and therefore cannot control whether gas prices are oil linked, regulated, or subject to gas to gas competition. This should not be the case in Australia where governments have full control over gas resources and can implement policies to ensure energy security, i.e. availability of supply and affordability of pricing. There is no reason why Australia needs to link domestic gas prices to the world's highest priced gas import markets, such as Japan. Such a decision would reflect a poor energy policy and would be inconsistent with other OECD gas exporting regions and nations.

The U.K. transitioned from a net exporter of gas to a net importer of gas in the winter of 2005/06 with a corresponding major impact on gas pricing at the U.K.'s NBP gas hub. As a net exporter of gas, the U.K. had, by definition, surplus gas and therefore aggressive gas to gas competition in its domestic gas market. The volatility of gas prices at NBP has significantly increased since the U.K. has become a net importer of gas reflecting the lack of excess domestic gas production and of course the average price of gas in the U.K. has increased due to the much higher price of import gas supplies compared to the price of indigenous gas production. As mentioned previously, large price differentials between domestic gas production and imported gas supplies are common for net importing countries and regions. This price differential reflects the following market forces:

- The number of import gas choices in the past has not been large as international gas pipelines were rare but becoming more common and global LNG trade was relatively small and very restrictive;

- Gas exporting countries typically seek a premium for gas exports over their pipeline gas supplies to their domestic market because there are security of export demand, security of domestic supply and public benefit concerns;

- The additional freight to transport gas long distances between countries and in the case of LNG, between continents.

Not only did the North Sea gas production decline sufficiently to require gas imports but the deliverability swing historically provided by the North Sea gas fields also declined, thereby placing a much larger requirement for gas storage capacity. This is analogous to the current decline of Bass Strait and Cooper Basin conventional gas production in east coast Australia – the historical suppliers of "as required" swing gas supplies (gas deliverability from excess upstream production capacity). This transition in the U.K. has raised major security of gas supply issues and has caused gas prices in the U.K. to become influenced by gas import prices into continental Europe. The upward pressure on domestic gas prices due to a reliance on imports into the U.K. is an ongoing area of concern for that nation.

Local gas consumption located in prolific onshore gas supply basins worldwide has not exhibited a phenomenon of price convergence with exports on a netback comparison basis unless and until gas supplies decline significantly from the stage where exports facilities were justified. For example, gas prices to Alberta consumers were a fraction of the netback price received from U.S. exports for Alberta gas for two decades and only converged when there were insufficient gas supplies to meet both local gas consumption and exporting pipelines. The same phenomena of local depressed prices existed in the Gulf Coast states of America as it served New England, the Midwest U.S. and the south eastern seaboard of the U.S.

Russia, which has the second-largest gas market in the world, has subsidised domestic gas prices from revenues received from exports for some time. Alberta, Canada has also done this for decades in that it costs less to pipeline Alberta gas production to provincial end users than to provincial export border points, essentially thereby subsidising the freight associated with serving Alberta gas consumers.

Prior to the commoditisation of gas in Canada, Canadian pipeline gas exports to the U.S. were typically done under long term contracts with delivered prices that met the competition (U.S. pipeline gas and other hydrocarbon fuels) at various city gates located in the U.S. Consequently, the wellhead price of Canadian gas exports to the U.S. were usually much higher than the wellhead price of U.S. domestic gas supplies consumed in the U.S. since Canadians only targeted the high priced U.S. gas markets in regions that were remote from U.S. domestic gas supplies. Netback prices in Canada from such export sales reflected the cost of incremental gas supplies into major U.S. gas markets less transportation costs or freight costs from Canada to those U.S. markets.

Gas exporters are typically price takers as opposed to prices setters. LNG or pipeline gas exports, as the case may be, are typically priced to compete with alternatives upon delivery to the importing country. Countries reliant on gas imports tend to pay higher gas prices than are generally available to gas producers selling gas into the domestic market of gas resource rich regions or countries.

Market Power Test

Most OECD countries, including Canada and the U.S. and most, if not all, countries in the EU, have very strict guidelines and rules regarding competition policy and introduce onerous market power tests regarding market behaviour with respect to price setting. The enforcement of these guidelines is an ongoing process and outcomes have serious implications to the extent that companies or individuals are deemed to have sufficient market power to materially influence the price of indigenous gas supplies into the domestic market of that country. The Canadian competition analysis methodology is similar to that used by U.S. antitrust authorities and by U.S. regulators in evaluating the state of competition in natural gas storage markets in that country. The market structure in a gas market region, i.e. Western Australia or the east coast Australia gas market would be examined and scrutinized in order to determine whether the geographic gas market region raises competition policy concerns or not. Specifically, moderate levels of seller concentration and potential market entry suggest a competitive structure and the absence of market power. The prevailing market price for gas and related gas contracts and selling mechanisms would also be examined to determine whether or not competition policy concerns exist in that regard. It is difficult to imagine how either of the Australian gas markets would pass any kind of market power test or any type of test to determine the essence of an open and competitive gas market.

Canadian competition policy authorities routinely evaluate the state of competition in specific markets, including its gas industry. In effect, the existence of market power reflects the absence of competition in that the firm or firms exerting the market power can profitably influence prices (i.e. raise and maintain prices above competitive levels), quality, variety, service, advertising, innovation or any other dimension of competition. A review of the structural characteristics of the market with particular emphasis on seller concentration and barriers to market entry and exit generally occurs. In addition, other factors such as the rate of innovation, market transparency, and the value and frequency of transactions are considered when relevant. The FERC defines market power as the ability to profitably maintain prices above competitive levels for a significant period of time. This principle has been interpreted by the FERC in more detail as follows:

1. If a company can sustain an increase in its rates in the order of 10% or more without losing significant market share, the company is in a position to exercise market power to the detriment of the public interest; and

2. A significant period of time is typically considered to be one year or more.

A seller could exercise market power by acting alone (unilateral market power) or acting together with other sellers (interdependent market power). If the market was characterized by a Herfindahl-Hirshman Index (HHI) value (a measure of concentration) below 0.18 the applicant for market-based rates would be subject to less scrutiny than if the index was above this level.

These conditions will generate an environment that attracts investment to all sectors of the gas industry and results in potential short term gas price volatility but long term health and stability in the industry. What is perhaps surprising and counter intuitive is that while deregulating or liberalising a regional or national gas market, federal and state regulatory agencies typically become more intrusive in the individual transactions among producer, pipeline, distributor, retailer and consumer. The alternative is to nationalise resources and infrastructure and that is the course taken by some countries.

The HHI serves as a first screen to measure market power. If the HHI indicates market power, then a second screen is applied to see if the market participant is in a position to exercise market power. The market power framework employed by the FERC and often adopted by the NEB in Canada consists of the following five steps:

1) product market definition;
2) geographic market definition;
   a. identify facilities and services;
   b. identify the geographic market;
   c. identify good alternatives;
3) market concentration analysis;
4) identify potential competition ; and

5) identify other factors.

The first and second steps lay the foundation for the market concentration analysis by defining what the product is and who is in the market. The third step examines measures of the market participant's market power. The fourth and fifth steps examine factors that might alter interpretation of the concentration measures.

Economic Regulation of Common Carriage Infrastructure Policy

Since all gas is held hostage to infrastructure unless and until it is converted into LNG, most national gas policies focus on the intrinsic market power of all midstream and downstream asset owners. These assets include underground gas storage, gas transmission pipelines, gas reticulation pipelines, gas hubs, and some gas processing plants.

Australia lags every OECD country in this regard. 'Gas de-regulation' or 'gas liberalisation', whichever term you prefer, is something of a misnomer given that in a deregulated market, items such as transmission tariffs, reticulation tariffs, storage fees and access terms to both firm and interruptible capacity remain regulated or controlled by state, provincial and national regulators, as the case may be. What has really been de-regulated or liberalised is the market price of gas molecules along the value chain, often referred to as the wholesale gas market.

An efficient gas industry is the product of market forces working diligently in the gas commodity market (i.e. gas trading and services) and strict economic regulation of any and all market participants who hold excess market power such as the owners/operators of midstream and downstream gas pipeline infrastructure and any other segment of the value chain that is not subject to market forces. This does not occur unless good policy and practices exist at the Government level and proper market power tests and solutions to mitigate such market power exist and are applied in a non-discriminatory manner.

This is one of the basic ingredients or prerequisites to establish an open and competitive gas market that can be relied upon to generate the lowest cost and most reliable gas supply chain. Australia currently appears to have none of these four preconditions. The last two apply to the midstream sector (APGA members) and it is important to note that these two preconditions were the focus of gas de-regulation in North America for without them a gas commodity market cannot exist.

The FERC applies a market power test to assets such as gas pipelines and gas storage facilities to determine if they can be permitted to charge market based rates for services as opposed to being subject to regulated prices under the cost of service regulation mechanism. Most facilities, even in the very facility intense North American gas market, are deemed to have market power. It is most certain that no gas pipeline, gas reticulation nor gas storage facility in Australia would qualify for exemption under these market power tests and yet most of them have been excused from economic regulatory scrutiny.

Concluding Comments – Urgency Required

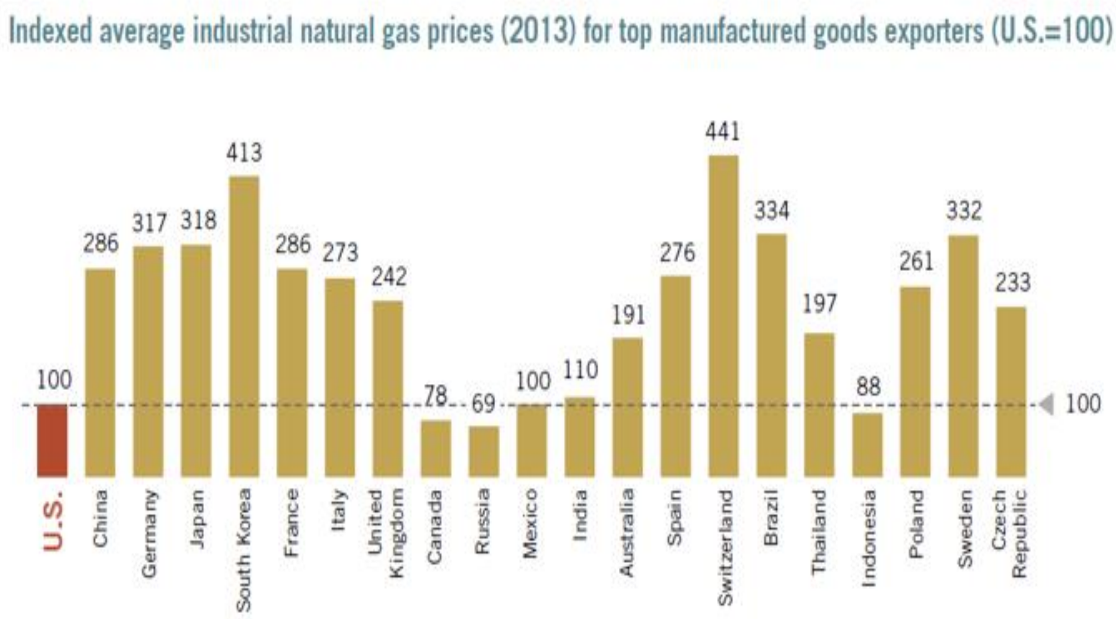
In conclusion, it is IEC's view that the wholesale gas prices in the east coast do not reflect gas on gas competition generally and they most certainly do not reflect gas on gas competition on a frequent ongoing basis between multiple sellers and multiple buyers. Gas producers are not price takers in the east coast but tend to be price setters and they tend to lock in those gas prices for a long period of time with no or very little adjustment to changing gas supply/demand dynamics.

This phenomena is not cyclical and does not reflect a temporary seller's market environment but is structural in nature. The east coast should capitalise on its abundant gas resource advantage that it has over most other countries and regions with advanced economies. The availability of reliable low cost gas supplies is considered to be a large advantage today and into the future as gas is considered to be the bridging fuel to a low carbon future. Low energy costs in general and low delivered gas costs in particular are a competitive advantage to advanced economies. Australia has one of the most widely distributed and relatively large gas resource base compared to domestic gas demand among OECD countries and yet it continues to struggle with the development, production and distribution of this resource. Figure 2.0 illustrates how disadvantaged Australia was in 2013 compared to other net exporting gas countries (Canada, Russia, Mexico and Indonesia) on a delivered gas price to domestic industrial gas users:

The U.S. is transitioning to a net exporter from many years of being a net importer of gas and delivered gas prices to the industrial sector in 2013 was almost twice as high in Australia than in the U.S. The rhetoric about historically low gas prices in Australia is not supported by fact for on a delivered basis customers in Australia have historically paid much higher gas prices than in any other net exporting country with an advanced economy. Benchmarking Australia's gas prices to countries or regions within countries that do not have sufficient indigenous gas resources to meet their gas demand and are therefore net importers of gas is rather meaningless since gas, like electricity, increase in cost with distances from major supply centres.

This situation of high delivered gas prices to consumers is going to get much worse in the next few years as domestic gas prices are expected to triple from those in effect in 2013 in the east coast under the status quo structure and levels of competition and economic regulation of pipelines. The east coast will resort to being a 'hewer of wood and hauler of water' as it destroys and discourages industrial activity and favours LNG exports. While the impact of developing unconventional gas resources has transformed the economies of Canada and the U.S. through the lowering of delivered domestic gas prices, the impact on the east coast is shaping up to be a transformation of the economy with an unknown outcome. It is not obvious that the national interest is best served by relying on export revenue at the expense of domestic demand destruction and associated stranded gas pipeline and gas reticulation assets. One would hope that much more thought and analysis has gone into this evaluation and decision than went into the domestic gas reform process that commenced in the early 1990's.

Figure 2.0



Source: Harold L. Sirkin, Michael Zinser, and Justin Rose, "The U.S. as One of the Developed World's Lowest-Cost Manufacturers: Behind the American Export Surge," The Boston Consulting Group, August 20, 2013, p. 6, https://www.bcgperspectives.com/content/articles/lean_manufacturing_sourcing_procurement_behind_american_export_surge, accessed May 2015.

The challenge is a large one given the lack of resiliency in the east coast gas supply chain and the fact that gas demand is going to triple over the next year. This scale of growth is unprecedented in an OECD country and gas supplies (deliverability of pipeline gas supplies) on the east coast will be extremely tight and possibly very short for some time. Referring to the current situation in the east coast as a seller's market is a misnomer for all of the new gas demand is in fact owned by the gas producers or traditional sellers into the domestic market. The sellers now own most of the gas demand in the east coast and they will most certainly cater to that demand over the remainder of the east coast gas market.

Australia industry lacks competitiveness generally due to many factors but primarily due to high labour costs, low productivity and high taxes. The east coast is on a path that will most certainly deteriorate this current competitive disadvantage. Without a competitive gas supply (both low commodity prices and infrastructure related charges) the east coast economy will transition to one that is more dependent on export revenue at the expense of its industrial base. 'More of the same' is not the answer. The elimination of market power and abuse related thereto in both the gas producer sector and the gas transportation, storage and distribution infrastructure sector is the answer for that will lead to more gas availability at much lower delivered prices to consumers in the east coast. The east coast does not need more gas resources or gas reserves contrary to what many proclaim. It does need much more resilience and greater efficiency in its production and midstream sectors of the gas industry.

A report called **America's Unconventional Energy Opportunity** released in June 2015 jointly by the Boston Consulting Group and the Harvard Business School states: "Natural gas exports would create new markets for U.S. production without affecting the U.S. cost advantage or raising U.S. prices". This is how freely traded competitive markets work in the gas industry since LNG is actually a derivative of gas and it's netback price from LNG importing countries is irrelevant to the prevailing domestic price in the exporting countries STTM. The supply/demand balance in the exporting country is relevant but access to the LNG export market is congested by capacity constraints and long lead times for capacity expansions. Gas supplies to the domestic component of gas demand in the east coast would be readily available should the east coast reform the structure of its gas supply and infrastructure service providers.

In order to proceed on a better path, it is important that companies and industry organisations take steps to changer their tone, moderate rhetoric and temper disrespectful and combative behaviour. Benchmarking in an attempt to discover facts and a 'facts are friendly' approach would be a welcome change. Governments must exhibit a basic level of knowledge and expertise in energy matters. The stewardship of resources owned by the citizens of Australia must be improved as must the competitiveness of Australia's economy. A healthy and vibrant gas industry has never been more important to advanced economies than it is today. The ACCC task with respect to this subject is therefore very important and the level of change required, while daunting, is very achievable. Policy makers and regulators are obligated to balance the various stakeholder interest and to put the Australian public first and they need to do much more in the east coast to make this a reality. We need less actors and more passionate doers with integrity.

IEC appreciates the opportunity to offer these comments and offers them in the spirit of assisting the ACCC in its evaluation of the east coast wholesale gas market and related infrastructure and structure that supports that market. We hope that our views as expressed in this submission will be helpful toward that end.

Regards

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