Economic Regulation Authority
WESTERN AUSTRALIA

Gas Issues in Western Australia

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A. Introduction

Thank you for the opportunity to speak with you today.

Late last year the Authority decided it would be a good time to seek the views of our stakeholders about the benefits or otherwise of the Gas Access Regime. We wanted a frank assessment about whether we as regulators were a) making a difference and b) whether it was a positive contribution. Regulation is not costless and unless it is leading to outcomes that are better (which I would describe as more economically efficient) than would occur in the absence of regulation then there are better things that we could be doing.

The Authority adheres to the view that there should be regular reviews of regulation – whether it continues to be relevant; whether the costs exceed the benefits; whether the form of regulation needs to change; and how it can be improved to achieve more quality outcomes.

So the brief to the ERA Secretariat was quite simple – is the existence of the legislation and therefore also the ERA justified – at least with respect to gas access matters?

Today, I am pleased to be able to release the results of that survey of stakeholders – copies of the discussion paper will be available as you leave today and also will be available on our website.

I would like to express my appreciation to those stakeholders who took part in the survey. The willingness to make significant time available to meet with the Secretariat and the frankness and openness with which you took part meant the Authority has benefited greatly from the information made available. The discussions were confidential and I believe we have respected that confidentiality in the paper we are releasing. We have hopefully successfully, accurately reflected the views of those participating without individual attribution. Where companies are mentioned, it is because the information is already in the public domain, or, in one case – the North West Shelf Venture – approval has been obtained to make the information public.

This leads me to a couple of qualifications I need to make. First, the views expressed in the Discussion Paper are an accurate reflection of the views of the stakeholders and do not necessarily reflect either my personal views or the views of the Authority. Second, in commenting on the Discussion Paper, I will editorialise and draw out what I see as any lessons or implications that can be drawn from the views expressed in the Paper in an attempt to make a contribution to a very important debate for all West Australians. However, these are my personal views and do not necessarily reflect any formal position of the Authority.

B. Outline of Talk

Today, I want to divide my presentation into two parts.

First, I will outline the results of the survey of stakeholders including adding my own perspective on the various views expressed. I should point out that the Discussion Paper itself focuses only on the views of the stakeholders. I will look at pipeline issues, the Authority's administration of the Code and upstream issues including the availability and price of gas.

In the second part, I will venture some views on the current situation with respect to the price and availability of gas – what is the current situation, how did we get here and what, if anything can we do to improve the situation?

C. Results of the Stakeholder Survey

Introduction

Let me again express my appreciation to those who participated – including gas users, shippers, producers, pipeline owners and relevant government agencies. Can I also publicly acknowledge the good work by Russell Dumas and Peter Rixson of the ERA's Secretariat. They presented a very full and frank confidential report for the Authority's consideration and the Discussion Paper being released today is a summary of the full Report.

Pipeline Issues

The main pipelines regulated by the Authority are the Dampier to Bunbury Pipeline (DBNGP), the Goldfields Gas Pipeline (GGP) and the Mid-West and South-West Gas Distribution System. I will discuss each of these in turn.

DBNGP:

There were a number of concerns expressed about the DBNGP. Again, I need to stress that these are concerns expressed to the Authority by stakeholders and do not necessarily reflect the views of the Authority. I also need to add that not every issue raised has been included in the Discussion paper – only those where there was a consistent message emerging from the stakeholders.

One consistent concern expressed – by a number of shippers and potential shippers – related to the relationship between DBNGP (WA) Transmission Pty Ltd (DBP) and Alinta. They expressed the view that Alinta's position as a part owner of the DBNGP would enable it, in conjunction with DBP, to inhibit competition in the downstream energy market in order to protect its position as a major energy retailer. While it was a consistent view expressed, no specific examples were provided to support this concern and I am therefore unable to comment on the validity of the concerns expressed.

Perceptions however, rightly or wrongly held, can be important. I am reminded of past debates (when I was in another role) around the problems of the vertical integration of Western Power and the frequent concerns expressed by generators and potential generators about whether they were getting a "fair go" with respect to access to the network. That particular issue has now been addressed with the first access arrangement under the Electricity Network Access Code for a separate Western Power networks to come into effect next month.

The Gas Code requires ringfencing arrangements to be in place between DBP and Alinta and the Authority recently exercised its discretion under the Code to require DBP to provide an annual report, from an independent auditor, outlining its compliance with the Code's ringfencing provisions. The Authority approved DBP's 2006 report and is due to receive DBP's next report in October this year.

However, shippers and potential shippers expressed the view that the Code's ringfencing arrangements may not be adequate to prevent Alinta influencing the operation of the DBNGP if it wished to do so.

A significant degree of concern was also expressed by shippers and potential shippers over the Standard Shipper Contract (SSC) under which all shippers on the DBNGP operate. The main concerns were that:

- the minimum 15 year contract period under the SSC constrained the ability for energy sellers to buy gas and on-sell energy when energy sale contracts were generally only up to five years;

- the financial hurdles (such as bank guarantees and credit rating) set by the DBP to obtain an SSC were difficult for small to medium sized companies to meet;
- administration of the SSC was complex and difficult to manage; and
- DBP could be difficult to deal with in relation to SSC issues, there was little give and take in negotiations and DBP appeared to be under-resourced which made negotiations protracted.

Now, of course, there are always two sides to any argument. I am again not in a position to comment on the validity of the concerns expressed, however, these concerns were consistently raised, particularly when compared with the other regulated pipelines, and I think this may reflect on the commercial relationships between the parties. I will comment on this further when making some overall observations regarding gas pipeline regulation.

A number of shippers and potential shippers also commented on the absence of a significant gas aggregator to allow small to medium energy retailers or users to obtain a gas supply. It was suggested that, in the current market, such firms have difficulty in both obtaining a gas supply contract from producers and a gas transportation contract from DBP and so they would be assisted by an aggregator able to purchase and transport gas for on-sale to small energy retailers or users.

However, it was also evident from stakeholder comments that those parties which had undertaken some aggregation activities in the past were reducing or discontinuing such activities (with suggestions that, for a variety of reasons including dealing with the SSC, it was getting all too difficult to justify the effort).

A final concern outlined by shippers and potential shippers was the lack of spare capacity on the DBP. The suggestion was that this lack of spare capacity forced new shippers onto the SSC, made administration of the SSC more difficult and prevented shippers from readily obtaining additional firm capacity, forcing an up to 30 month wait for such capacity under the terms of the SSC.

It is pertinent to note that all the issues raised with respect to the DBP (with the exception of ringfencing) are commercial matters on which the Authority has no role or influence. In regard to the SSC, the Authority will not have any direct role until 2016 when the SSC tariffs reduce to the access arrangement tariffs and then later in 2019 when the SSC terms and conditions revert to the access arrangement terms and conditions.

From the Authority's point of view, the question is: Is the Authority making a difference? If these concerns expressed in relation to the DBNGP are valid, it would appear that the Authority is making little difference so far as the operation of this pipeline is concerned at this point in time.

GGP

Shippers and potential shippers were generally satisfied with the operation of the GGP. All shippers on the GGP have commercially negotiated individual shipper contracts. A number of shippers commented that GGT displayed flexibility and "give-and-take" in negotiations on these contracts.

Is the Authority making a difference? As for the DBNGP, the Authority has no role in relation to the commercially negotiated shipper contracts. However, a number of shippers on the GGP commented that they had been able to renegotiate or were currently renegotiating their tariffs downwards in light of the access arrangement tariffs put in place by the Authority in 2005. On this basis, it could be said that the Authority has had an impact.

Mid-West and South-West Gas Distribution System

Shippers and potential shippers were generally satisfied with the operation of the Mid-West and South-West Gas Distribution System. All shippers using the System have shipper contracts based on the access arrangement and the view was that the Code was working for this pipeline system.

Is the Authority making a difference? In this case, the Authority is playing a direct role in ensuring the pipeline operates in accordance with the Code objectives through the access arrangement.

Transmission Pipeline Owners

An issue of concern expressed by pipeline owners was the lack of certainty under the Code in the recovery of capital invested in expanding a pipeline. The issue relates to the new facilities investment test under the Code. They considered that the Code failed to facilitate investment in pipeline expansions as there was no certainty that all the capital invested in the expansion could be rolled into the pipeline's capital base.

The Authority is currently preparing a paper on the new facilities investment section of the Code which will in turn be considered by the AER and other regulators. Eventually it is likely to be released as a discussion paper, probably by the Utility Regulators' Forum.

While the interpretation of the new facilities investment section of the Code could be improved by having regulators agree on a consistent approach to its application, I have to say that the Authority sees merit in the economic principles underlying the current new facilities investment tests.

Without the new facilities investment tests there is a potential for economically inefficient investment to be made as it would allow the cost of expansions to be spread across all users not just those benefiting from the expansion – a "socialization" of the costs or, to put it another way, a subsidy of new users by existing users in those cases where the new facilities investment tests would not have been met.

A particular problem in respect of new facilities investment arises with respect to the DBNGP. As the former Managing Director of Alinta, Bob Browning, explained, when the DBNGP was purchased most recently, there were a number of unique aspects to that purchase. In order to arrive at a price which would "get the banks to take their collective feet off the hose" (or words to that effect), it was necessary to agree tariffs with shippers that were in excess of regulated tariffs until 2016. The resulting SSCs contain "most favoured nation" clauses which means that, in the event that there was spare capacity on the pipeline, it would be open to someone to claim that capacity under regulated tariffs, with the result that regulated tariffs would flow through to the SSCs undermining the financial basis of the purchase. In short, the DBP cannot afford to have spare capacity on the pipeline until 2016.

The impact of this is that if capacity can only be expanded in line with contracted demand, i.e. new demand fully underwritten by firm contracts, it may be that a particular expansion is technically inefficient compared to a larger expansion and therefore particularly expensive (although subsequent expansions may be less expensive). In this case, the capital investment involved may not pass the new facilities investment tests. That part of the investment that does not meet the tests could be placed in a Speculative Investment Fund and could be considered for rolling into the capital base at future expansions providing that such future expansions occur.

In more normal situations you would expect the expansions to be done in a way which is technically efficient which may result in some spare capacity, but which is more likely on some reasonable basis for forecasting future demand, to satisfy the new facilities investment test.

In summary, I have difficulty arguing against tests that put the focus on economically efficient investment. Further, I am not sure that a national Code should be changed because of the particular circumstances of one pipeline particularly noting the Code was in place at the time of the purchase of the DBNGP and given the potential use of the Speculative Investment Fund. Finally, I note that in any case, two of the three principle pipelines regulated by the Authority, have commercial tariffs in excess of the regulated tariffs.

Some Observations – Commercial Negotiation

There are some general observations I would like to make prompted by the feedback we have received.

The first goes to the role of economic regulation. Economic Regulation of monopoly infrastructure seeks to prevent the abuse of monopoly power – either by ensuring that access is not restricted and/or ensuring pricing power is not exploited. This role does not prevent commercial negotiation or outcomes – indeed I would hope it encourages it – but it does provide a constraint on the exercise of monopoly power in the event that commercial agreements cannot be made. The Authority has no desire to be in the forefront of gas market deliberations but rather sees itself more in the role of a safety net when all else fails.

It appears to me, that at least in one case, the parties are having some difficulty in arriving at commercial solutions. In part, this appears to be because of a lack of trust between the various parties. This comes through in the feedback we have received.

I would respectfully suggest that this is an issue that all parties might wish to give some considered and mature thought to and that perhaps in doing so they might prefer to put more emphasis on resolving issues through commercial discussions. A lasting solution that is mutually beneficial is more likely to come from an agreement between the parties themselves than one that is imposed by any external party.

Authority's Administration of the Code

Stakeholders were generally satisfied with the Authority's administration of the Code noting that they appreciated the accessibility of the Authority and the level of consultation and discussion during access arrangement processes.

A number of stakeholders also expressed support for a front-end consultative approach to future access arrangements with early (pre-lodgement) consideration of the information requirements for access arrangements. Given the time lines proposed in the new draft national gas legislation this will become even more imperative and the Authority will be developing, in conjunction with the AER, an early consultation program involving all stakeholders prior to the next round of gas and electricity access arrangements particularly focusing on the information requirements when submitting access arrangements.

Interestingly, but not surprisingly, some stakeholders thought the Authority both required and provided too much information in its assessment of access arrangements, while others suggested not enough.

Finally, the Authority received some useful suggestions about how we can improve, particularly about how we could further improve our consultation and communication, and we will (and have) taken those suggestions into account.

Upstream Issues

Gas Supply

Many stakeholders expressed concern that the gas supply market is very tight, that gas supply contracts are difficult to secure and that long term contracts are no longer available.

In some cases, companies noted that they have been unable to obtain gas supply contracts because the producers are not interested in small contracts.

The feedback indicates a considerable change in the gas supply situation here in Western Australia since around mid-2006. Prior to this time, long term contracts (20-25 years) were available. It is understood that currently, the maximum term available in the market is generally about 5 years and that currently it is not possible to obtain contracts under about 10 TJ/day.

Gas producers commented that they were no longer offering long term contracts due to uncertainty about future gas field development costs in light of the large cost increases currently being experienced. Some of the producers also mentioned that uncertainties in relation to future gas prices and the Government's domestic gas reservation policy were additional considerations.

Some of the stakeholders mentioned that the declaration of force majeure on 28/12/06 by the Harriet Joint Venture partners in relation to their 20 year, 66TJ/day gas supply contract with Burrup Fertilisers, was a significant factor in the tightening of the market.

It is also understood that the Varanus Island gas supply capacity is now close to being fully committed. In these circumstances, it appears that the supply of gas to WA is likely to depend largely on NWSG for the next few years.

NWSG recently advised the Authority that the upgrading program currently being undertaken on its two Domgas plants had run into technical difficulties. Given the technical problems further work on the upgrading has been halted until a detailed diagnostic and technical evaluation of the problem is undertaken. If this issue can be resolved, NWSG will again engage with potential gas buyers. However, the upgrading is unlikely to be completed until late 2008.

The upgrade was to increase the capacity of the plants by around 100TJ/day to accommodate growing demand and align with pipeline expansions. It is estimated that any additional capacity from the upgrade will have been taken up by mid-2009. NWSG advise that there is restricted capability for further upgrades – an additional Domgas plant would be needed to meet further demand – and presumably such a new train would not be producing for up to five years, taking into account the need to identify sufficient demand to justify the investment and time for the construction of the plant.

There are three known potential new sources of gas which may come into the WA market at some stage in the future – but there is no definitive Domgas development timetable for these projects – Macedon, Gorgon and Pluto.

For a variety of reasons none of them will come on stream soon in any case. In Macedon's case, the earliest date is probably 4-5 years (assuming agreement can be reached with DBP on gas quality issues – I will come back to this later); for Gorgon, probably at least 7 years; and for Pluto perhaps at least 12 years. In all cases, a decision on commercial viability is required as a precursor to the development of Domgas facilities.

It is likely therefore, there could be potential problems looming in the supply of gas at various periods over the next 5-7 years.

Beyond 2014, it is probable that the NWSV would have built a new Domgas plant (up to 300TJ/day) and/or Macedon would have been developed (150 TJ/day) and/or Gorgon would have developed a Domgas plant (up to 300TJ/day). Companies have recently started exploration work to investigate areas prospective for CSM (presumably in response to higher domestic gas prices) and it is possible that CSM fields could be productive in WA in five years time.

Prior to 2014, there are likely to be gas difficulties from now until late 2008 (assuming the NWSV upgrades proceed successfully), and from around mid 2009 until sometime in late 2010 (when the Varanus Island producers bring on stream their known undeveloped gas fields such as the Reindeer gas field owned by Santos). It is not known whether the undeveloped gas fields around Varanus will be sufficient to provide the domestic gas market over the period 2010-14.

It is also possible that sizable new gas fields could be found onshore or close offshore in the Perth Basin. Such fields could be developed relatively quickly. Alternatively, 'greenfield' areas such as the onshore Canning Basin (in the Kimberley) might yield new large gas fields. However, it would take considerable time to develop the infrastructure (incl. pipelines) to support the development of such fields.

Gas Prices

Associated with concerns about the gas supply, stakeholders expressed considerable concern about the steep rise in the gas price for new contracts over the period since mid-2006.

Information from stakeholders indicates that domestic gas prices have more than doubled in the 12 month period since early 2006 to a current level of around $5.50 to $6/GJ. This compares with $2 to $2.50/GJ in early 2006. By contrast, on the East Coast the availability of CSM and new supplies from alternative producers has driven prices down from around $3.50/GJ to about $3/GJ in 2006 in Victoria and NSW and about $2.50/GJ in Queensland.

One of the stakeholders consulted estimated that the netback price of domestic gas, based on LNG prices at that time, was about $5.80/GJ. The netback price represents the price at which LNG producers would be getting a similar return on domestic gas as compared with LNG taking into account the relevant infrastructure required to produce these two products.

This ends my description of the survey of stakeholders. I would now like to put my own perspective on the current situation with respect to the price and availability of gas.

4. Some Perspectives on the Price and Availability of Gas

What is the current situation?

Based on the information from participants in the survey, it appears that the current situation with respect to gas supply is as follows:

- currently, there appears to be little spare gas available for new contracts for the domestic market;
- provided the NWSV can overcome their technical problems with the upgrade of the Domgas plants, this situation should be eased by the end of 2008, however it is likely that the additional capacity will be taken up in new contracts by the end of 2009;
- there is then likely to be little gas available for new contracts until late 2010 or 2011 when supply will hopefully be available from the currently undeveloped fields in the Varanus Island hub;
- unless there are new discoveries either onshore or close offshore in the Perth Basin within the next two years that can be developed relatively quickly or there is continued growth from the Varanus Island hub or the Macedon field is in production, then supply could become increasingly tight from 2012 to 2014; and
- subject to gas prices, the situation for potential gas users should be more encouraging after 2014 either as a result of new discoveries or because it is worthwhile for NWSV to build a new domestic gas train and/or Gorgon to start domestic supplies and /or Macedon will be in production.

The position with respect to gas prices is that there has been a large increase in gas prices in the last 12 months – from $2 to $2.50 to somewhere between $5.50 to $6/GJ and perhaps higher. For reasons discussed later, the LNG netback price should act (at least over the medium to long term) as a domestic gas price ceiling.

At the same time it also needs to be recognized that commodity prices generally have increased. The major energy users in Western Australia will have benefited from this commodity price boom.

How did we get here?

Given that WA is the most reliant on gas of all the States – over 40% of WA's total energy needs are met by gas, and given there is no shortage of gas reserves, it is a fair question to ask how did we get to the situation where the supply of gas to the domestic market is so tight and we have had such an increase in prices – more than doubling – in less than twelve months?

There are probably a variety of reasons but, in my view, a significant contributor is that price signals were suppressed leading to a lack of targeted exploration for potential gas fields that would supply the domestic market.

The nature of the domestic gas market in WA with its long term physical contracts and the relative absence of financial trading tends to result in price signals being "lumpy" and to follow rather than anticipate any underlying change in the supply/demand situation.

The 20 year take or pay contract that was an integral part of the development of the NWS project has also played a part. At the beginning of the contract it had a price at that time comparable to the expected LNG netback price but with different escalation factors going forward. This was considered a high domestic price at the time particularly in comparison to eastern states gas prices. (In 1985 this contract was renegotiated providing some relief to SECWA as the commitments to take gas were well in excess of the State's requirements.)

By contrast, in 1998 the average LNG netback was around 60% greater than the domestic price and by 2005 the LNG netback price was three times the domestic price and the gap was widening. (This has led some to say that the take or pay contract gave us cheap domestic gas in recent years but that ignores the fact that for many years we had paid for gas that was not needed.)

The end result was that the domestic gas price was relatively low until the price spikes of the last 12 months both in comparison to gas prices in the east and certainly in comparison to LNG netback prices.

The incentive provided by such a price differential leads to a focus on large offshore fields suitable for LNG export (particularly given the WA offshore success rate and discovery size is relatively high compared to the Australian average). Similarly the domestic gas price, at least until recently has not provided the incentive for exploration for potential domestic gas fields or for coal seam methane (particular when the onshore success rate is lower – and therefore the risk higher – in WA than in the east).

However in the last five years or so, the growth in demand for domestic gas, the run down in inventories from the take or pay contract, the nearing of capacity from the NWS Domgas plants and most recently the increase in domestic gas prices has changed the outlook. For example, exploration, appraisal and development drilling in the Perth basin has increased significantly in the last five years and can be expected to continue. As a further example, Santos, in its 2006 annual report, mentioned that sharply higher prices in WA will support further gas developments in that State.

Finally, as the gas price gets closer to the LNG netback price there is a greater incentive for large offshore fields to consider domestic gas plants as part of their overall project.

What, if anything, can we do?

Let the Price Signals Work

Whatever else we do, it seems to me that we must allow the price signals to work to both encourage exploration for new fields and encourage the development of existing reserves for the domestic market. Were we to try and suppress the current increase in price then there is a risk that the existing capacity constraint would last even longer and the size of the problem would become even greater.

While it is difficult to see how we can avoid the potential capacity constraint on new contracts from mid 2009 to the end of 2010 or 2011, there will be an even greater problem after 2012 if there are no new discoveries or new developments of existing reserves suitable to supply the domestic market, and there is a potentially even bigger problem after 2014 if there is no incentive for producers with large offshore fields to consider the domestic market.

It might also mean that prices would ultimately have to go higher than is the case if we allow the price signal to do its job by bringing on new sources of supply.

This does mean that at least in the short to medium term, higher gas prices are going to be a feature of the WA gas market. In the medium to longer term the LNG netback price should act as a ceiling on the domestic gas price given the large offshore reserves that are available.

However, this does not mean that domestic gas prices should equate to the LNG netback price. There are now, and there will be in the future, gas fields, which for a variety of reasons will not be suited to the LNG market and therefore will be seeking to compete for domestic sales. The more such fields that are developed, the lower the domestic price will be as they compete to supply the domestic market. As I commented earlier this has been the experience in the eastern states where discovery and development of CSM fields and new supplies from alternative producers has kept average prices in the eastern states to around $3/GJ while WA prices have been increasing.

What can we do while we wait for prices to work?

Apart from waiting for the market to work, is there anything else we can do to minimize the impact of tight domestic supply constraining economic growth in WA either because of the lack of availability of gas for new projects or because very high prices will send investment elsewhere?

In the short term, we have to hope that the NWSV can overcome the current technical problems delaying the upgrades of their existing Domgas plants.

In the medium term we need to see the development of new fields such as the Reindeer field in the Varanus island hub and the Macedon gas field.

One of the issues mentioned earlier and which has been the subject of recent press comment is the ability of the gas from BHPBilliton's Macedon field to meet the gas quality requirements of the DBNGP. This is worth focusing on briefly.

The gas from the Macedon field would not meet either the quality specification of the DBNGP SSC or the broader quality specification set by the Authority in the DBNGP's access arrangement. This is because the Macedon gas has too low a Higher Heating Value (HHV). The Federal Minister has recently pointed that Macedon gas would satisfy the broader Australian gas specification. I am not sure if this is totally correct but it would come very close.

The Authority in setting the gas specification for the DBNGP was limited by safety regulations which set a HHV higher than it would otherwise have been. I am unsure whether there is still a safety issue (although I am told that it may no longer be an issue). Subject to the safety issue, it would be possible for the State Government to amend this regulation so that the Macedon gas would meet, or come very close to meeting, the specification.

However, there is still the requirement of the SSC, and any change here would require agreement from the owners of the DBNGP who in turn would be potentially faced with some reductions in capacity (and higher cost for future expansions) as there would be less energy transported by the DBNGP.

It would also be possible for BHPBilliton to spike the gas so that it meets the requirements of the SSC. This would be an additional cost, but it is fair to say that with the recent increases in the price of gas, the relative size of that cost has decreased. There are likely other commercial options involving NWSV, BHPBilliton and the DBP. However, it is not known if these technical solutions are commercially viable.

As an aside, it is worth mentioning that there are problems with applying the broader Australian specification in total to the DBNGP. This has to do with the moisture content allowable under the broader Australian Specification which given the pressure and length of the DBNGP could raise technical concerns for the DBNGP.

However, the point is that there should be a commercial solution of one kind or another to this problem and given the scenarios outlined earlier it is in everyone's interest that a solution is found as soon as possible so that Macedon gas is made available to the domestic market.

Are there other actions that could be taken to encourage the early development of existing fields or exploration for new fields which will add capacity to the domestic gas market? At least three have been mentioned – project approval processes, a flow through share scheme and a "use it or lose it" approach to retention leases. I will briefly comment on each of these in turn.

The issue of project approvals has been high on the agenda in recent years and action has been taken following the Keating Review. The development of an efficient and timely approval process which gives appropriate consideration to all aspects, including native title and environmental issues, should be on ongoing task and one of continuous improvement. It is too important an issue to assume that we have got it right and no more needs to be done. It is particularly important in the current climate that approvals processes do not delay the delivery of new gas supplies to the domestic market.

A flow-through share scheme would remove the tax asymmetries that deny companies with insufficient taxable income the full benefit of immediate deductibility of exploration expenses. It would allow shareholders the capacity to claim those expenses as they are incurred. Industry has argued that such a scheme would lead to more investment in exploration.

They have been tried twice in Australia in the past and have been abandoned – either because they were seen as a tax avoidance vehicle and/or they were seen as too expensive from a government point of view compared to any growth in exploration expenditure. On the other hand proponents point to the success of such a scheme in Canada.

It would seem this idea is worthy of consideration if a case can be made that it will lead to a genuine increase in exploration expenditure (that is, it is additional expenditure beyond what would have otherwise occurred).

Concern has been expressed by some, including the DomGas Alliance, about the operation of retention leases with suggestions that existing producers may be "hoarding" or "sitting on" reserves for commercial advantage and that to counter this there should be a "use it or lose it" policy.

Since 2003 there has been a significant change in the way retention leases are dealt with. There is now an aggregate lease period (exploration plus retention) of 15 years made up of an exploration lease of 5 years with two possible extensions of 5 years each if the reserves discovered are not commercial. There is a trade off here between the aggregate length of the lease and the incentive to undertake exploration. It would appear that there is little support for reducing the 15 years although some argue that there could be a more rigorous assessment of the commerciality of reserves when granting lease extensions.

It should be noted that any incentive to “hoard” would be reduced the higher the gas price (in the case of reserves limited to the domestic market) and the closer the gas price is to the LNG netback price (in the case of reserves that are capable of supplying LNG and/or the domestic market). Perhaps this issue had a greater currency in the recent past because gas prices were seen as being unsustainably low.

Conclusion

On this analysis it appears that WA will be faced with gas prices significantly higher than in the recent past at least in the short and medium term. Further there may well be difficulty in signing new gas supply contacts during various periods over the next 5-7 years. Beyond this, it could be expected that the incentive provided by higher prices will have led to greater supplies of domestic gas and given the overall reserves available that should be sufficient to satisfy reasonable levels of demand.

Further, in my view, there is not any magic answer to the short to medium term problem. Apart from allowing the market to work there are a limited range of actions that could be undertaken to positively assist the problem. In this environment we need to be careful that we don’t take actions that would be counterproductive, for example, by artificially suppressing prices.

All parties will need to look for commercial solutions to ease our way through the adjustment process caused by higher prices and while we wait for additional supplies to come on-line. Can I conclude this talk by making a similar point to the one I made earlier?

It was apparent from the stakeholder survey and from other observations that there is some lack of trust among the parties in the gas market. The current challenges being faced by all participants can be alleviated by constructive commercial negotiations between the parties. But that process will require goodwill to be shown by all the parties and will require all parties to bring a mature approach to those commercial negotiations.

Thank You.