ECONOMICS AND INDUSTRY STANDING COMMITTEE

INQUIRY INTO DOMESTIC GAS PRICES

TRANSCRIPT OF EVIDENCE
TAKEN AT PERTH
MONDAY, 11 OCTOBER 2010

SESSION ONE

Members

Dr M.D. Nahan (Chairman)
Mr W.J. Johnston (Deputy Chairman)
Mr M.P. Murray
Mrs L.M. Harvey
Mr J.E. McGrath

Hearing commenced at 12.33 pm

BOARDMAN, MR JOHN STUART
Independent Consultant, RISC Pty Ltd, examined:

The CHAIRMAN: Thanks, John, for coming, particularly at short notice. I will read a brief opening statement for the record. Welcome and thanks for your attendance. This committee hearing is a proceeding of Parliament and warrants the same respect that proceedings in the house itself demand. Even though you are not required to give evidence on oath, any deliberate misleading of the committee may be regarded as a contempt of Parliament. Before we commence, there are a few procedural questions I need to ask. Have you completed the "Details of Witness" form?

Mr Boardman: I have.

The CHAIRMAN: Do you understand the notes at the bottom of the form?

Mr Boardman: I do.

The CHAIRMAN: Did you receive and read the information for witnesses briefing sheet regarding giving evidence before a parliamentary committee?

Mr Boardman: I did.

The CHAIRMAN: Do you have any questions relating to your appearance before the committee today?

Mr Boardman: I do not.

The CHAIRMAN: Again, the committee would like to thank you for your appearance. Before we ask any questions, do you wish to make any opening statement?

Mr Boardman: Chairman, if I may just put my position into context. I have 40 years in the upstream oil and gas industry, the last 28 of which have been in Western Australia. During the last 28 years I have been involved to a greater or lesser extent in the Western Australian domestic gas market since I joined Woodside in 1982. I set up Resource Investment Strategy Consultants, which is a specialist independent company to advise people primarily in the upstream oil and gas industry; that is, E and P companies, banks and investors. I have been an expert witness in gas contract price arbitrations in both Western Australia and in the eastern states during the last 16 years, and RISC has established a reputation for being fiercely independent, giving critical objective advice, even when it is not what the client wants to hear. The views that I am going to express to you today are my own although they have been supported by extensive analysis of the domestic market and LNG projects by RISC over the last 16 years and, of course, prior experience to that.

The CHAIRMAN: What is your technical background—engineer, geologist?

Mr Boardman: Petroleum engineer.

The CHAIRMAN: Just to go through a few questions, particularly with your background, we might urge you to be a bit expansive in the sense that if you think we need to know something particularly of background and details, please explore it. As you know, the major reason for this inquiry is that in the north at least we have a large amount of gas and growing volumes of gas coming on stream, but there is a perception that there is an inadequate supply to the domestic market, and that we could see a situation where we have huge amounts of gas going offshore in LNG but inadequate supplies of gas onshore, which would mean higher priced gas. So it is concerned with both supply and a price issue domestically. That is the essence of this inquiry. We have taken a tour of eastern states, particularly Queensland, which was very interesting, and also saw over the past 10 years the growth and competitiveness of the structure of the eastern states market and the interconnectiveness. I understand some of the weaknesses here. Particularly with your background, our interest is to explore the manner of these contracts, particularly the interface between offshore LNG contracts and domestic. One issue that has come up to us is that there is a perception that offshore, for a variety of reasons, reserves of gas are being pooled into LNG projects to get them up to scale, and that will lead to at least a temporary, but also may be a permanent, quarantine of gas to the export market as opposed to the domestic market. The argument is that the developers need scale and scope and a strong support of reserves and that LNG is the best way to monetarise those reserves in a quick manner. So do you see in terms of structure a problem with accessing gas for domestic use because of the nature of the LNG industry?

Mr Boardman: Let me give you a simple answer first and then let me expand on it. I think the way in which you have articulated it is exactly the way in which the market is working. The gas resources that have been discovered off the Western Australian coast are substantial; however, supply and demand are always a function of price. You have got to look no further than the US market since 2007 to see a classic example of supply–demand balance, where with the pressures on demand Henry Hub prices went up to $7 or $8. As a result of that, the whole shale gas industry in the US took off. The US now moves from being potentially the world's largest LNG importer by 2020 to, just a few weeks ago, the first export licence for the lower 48 states being granted, so it is going to start exporting LNG.

The CHAIRMAN: They are going to export LNG?

Mr Boardman: The first export licence has been granted for the export of LNG from the lower 48. Alaska has been exporting LNG for 30 years or something. It is simply a function of the fact that the amount of shale gas, which is now being developed on the back of a $7 or $8 Henry Hub, is now too great for the domestic market. Domestic prices have now been forced down to sub-$4–$3.50, and shale gas producers say, "We are hurting. We need to get this into some other source." Therefore, the LNG export market is opening up.

If I look at the situation here in Western Australia, and I have to qualify what I am saying, if large consumers of natural gas were prepared to pay, for example, $8—not too literally, but that sort of price—you would have seen several years ago the development of some of these resources, but they have to be large consumers. The Western Australian gas market, as I am sure you are aware, is a project market; there is no liquidity in the market. Some 90 per cent of the gas is sold to four consumers. The amount of gas consumed in the residential and commercial sector is something like four per cent. So there is just no liquidity in the market; therefore, you should never compare WA with a totally liquid market, like the US or Europe. In my opinion it is very misleading to compare WA with the eastern states. The Victorian market is quite different. There is a lot more liquidity and more spot sales. Contracts are struck on quite different terms and conditions. Even in Queensland, Queensland's market has changed dramatically over the last, I guess for five years—that is all. It is a combination of things: the Queensland government's 13 per cent gas-fired generation policy; the demise of the PNG–Queensland pipeline; innovative technical techniques being used by the CSG producers to be able to get better performance out of their wells; economics—so a combination—and then lastly, of course, the prospect of CSG to LNG. That has changed that market dramatically.

The CHAIRMAN: Also, the pipeline interconnection with the southern states.

Mr Boardman: Absolutely; it is an interconnected market there. It has nothing like the same amount of liquidity Europe or the States has, but it has substantially more than WA.

The CHAIRMAN: Do you think, as just a small side issue, that as a policy or as a practical outcome we could get in this state something similar to what exists over in the eastern states or is it a just a matter of the structure of our economy and the demand?

Mr Boardman: I think it is the latter. I, certainly like most people, have no preordained right to be able to predict the future. I probably would not be sitting here if I did. But back in the mid-90s I predicted that there would be a lot more liquidity in the Western Australian market.

[12.45 pm]

I thought that as aggregators started to come over here, I thought a spot market would develop and that you would start to see not a paradigm shift, but a gradual shift away from the very clunky, project-driven market; it has not happened, and, today, I have to say that I just cannot see it happening in my lifetime.

The CHAIRMAN: The aggregators started coming in the '90s; they are not here now though.

Mr Boardman: No, it did not work; it was not a viable business model.

The CHAIRMAN: Okay. Could Alinta not do that? I mean, they are a commercial firm; they might have gotten waylaid by ownership structures for a while.

Mr Boardman: I think that if it was a viable business model, certainly AGL would have made it work. They have the experience and the expertise, but the market's just too thin.

The CHAIRMAN: Too thin and too lumpy.

Mr Boardman: Too lumpy; yes.

The CHAIRMAN: In your view, we are, kind of, stuck with this almost semi-managed structure where you have lumpiness, you have no liquidity, you have single options—one pipeline, maybe two—and all fully regulated pipelines, which makes it difficult.

Mr Boardman: Yes.

The CHAIRMAN: We have a limited amount of supply and only four major consumers, so we are almost stuck with, kind of, a market that needs oversight, rather than market driven, to some extent.

Mr Boardman: Yes, I certainly believe it does need oversight. My views, when it comes to either the sellers or the buyers are totally non-partisan; my views when it comes to taxpayers—both WA and Australian—is somewhat partisan.

The CHAIRMAN: On the LNG contracts, one of our issues is that we are trying to get some kind of a handle on price.

Mr Boardman: Yes.

The CHAIRMAN: The one thing that everyone tells us is that there is no single price; it is all contracts. Is it possible to get pretty good indicative indications of, one, the LNG price, and maybe the LNG net back price for many of these contracts?

Mr Boardman: Yes, as you have just identified, most LNG is sold under long-term contracts. The terms and conditions of those contracts are confidential; however, through one source or another, there is a lot of information in the public domain on those contract prices. In all LNG contracts that I am aware of—so certainly all of the LNG contracts in this region and out of the Middle East; probably 90 per cent of the LNG trade—the pricing is based on an LNG price formula that the LNG price equals a slope factor times a crude price, and that might be a crude cocktail price plus a factor. It is a "Y=MX+C" type of a formula. The factor is a negotiated factor and is dependant on a whole host of things, primarily distance. The slope is determined, basically, on the circumstances of the buyer and seller at the time. If you look at, for example, the LNG comp sales contract between North West Shelf and CNOOC, the slope on that sort of sets the bottom end of the scale; if you look at the Qatargas II contract into Korea, that sets the upper end of the scale. That was a slope of 0.18, I think, from memory; a slope of about 0.175 will give you crude oil parity.

The CHAIRMAN: Okay.

Mr Boardman: So slightly above crude oil parity.

The CHAIRMAN: When was that signed; the Korean one? Was it 2007-08?

Mr Boardman: Yes; 2007.

The CHAIRMAN: So when prices were when crude prices were pretty high; above $100?

Mr Boardman: Yes. There was a combination of circumstances; Exxon are good negotiators and the Koreans were in a tight spot for the short to medium-term gas supply into Korea. Everyone was thinking, “Oil prices are going to continue going up forever; jump in.” That still is the highest. We are seeing, now, slopes settle around about the 0.15. There is commentary in the market at the moment—or has been for a while—that there is oversupply and demand is softening, and therefore there is pressure on prices; that is not our observation. We are seeing prices holding up, probably, to some extent, due to producers not being prepared to enter into the sort of pricing structure that North West Shelf entered into. A slope of around 0.15 is, sort of, our benchmark at the moment.

The CHAIRMAN: We have heard evidence generally about the potential softening, and that if all of the LNG projects that are mooted came on the market there would be a significant softening in the demand for LNG, particularly since there will be some ripple effect—it could be large—from the US growth. Also, there is some issue about the potential for LNG to move away from oil parity pricing relative to crude. Do you have any comments on, both, your outlook and —

Mr Boardman: Yes, and I repeat that I do not have a crystal ball that has been, sort of, divinely blessed or anything. My view is that, for a number of reasons, the underlying demand for LNG will remain strong. I think that the probability of all of the LNG projects that are in the planning phase at the moment coming on stream when the project proponents say they are going to come on stream—at least say and state in the public domain when they are going to come on stream—is so close to zip, you can forget about it. Because of the combination of the slippage of the projects, underlying strong demand, and, provided price suppliers are prepared to negotiate around that 0.15—they do not want to push prices up higher—I think underlying demand will stay strong. But, as always, demand is a function of price, and there is a very graphic chart that FACTS produced two years ago now, I think, or maybe last year—2009—which shows the demand into China as a function of different LNG prices at around about $6 per million BTU; by 2020 there is another 20 million-odd tonnes of demand. At $12 per million BTU, the demand of 2020 it just about satiated by current contract levels.

The CHAIRMAN: What do you think are the current net back prices for LNG in Western Australia for the projects up there? What is the ballpark? Can you give us an indication of what you think the net back is to, I suppose, the beginning of the train—wherever you net back to; maybe you can describe that? One of the issues we have to look at is, one, what would be the LNG net back prices in the projects up north; two, what are its components; and, three, is it relevant for public policy purposes for pricing of domestic gas?

Mr Boardman: If I can paraphrase your question: what is likely to be the agreed PRRT transfer price for gas into the LNG facilities?

The CHAIRMAN: Exactly, yes.

Mr Boardman: Obviously, it will vary from project to project, but I would have thought somewhere in the range of, sort of, $2 to $3 per million BTU—a mean somewhere around $2.50. That would be my estimate at the moment. On top of that, there is another—I was about to say $3.50 per gigajoule LNG processing cost, but provided today’s exchange rate continues to prevail, sort of, for the next few years while Gorgon is being built, that $3.50 could be a bit on the low side, but $3.50 to $4. You are looking at $6 as a break-even price for LNG FOB for a project like Gorgon.

The CHAIRMAN: So the administered price into the processing unit is about $2.50 to $3; somewhere around there?

Mr Boardman: Yes, I would have thought that. As I say, it varies from project to project.

The CHAIRMAN: Of course. With some of these projects you would have a hard time determining until they get more expenditure under the belt, I would imagine.

Mr Boardman: Absolutely.

The CHAIRMAN: Is the net back price for that price of $2.50 to $3 relevant? Is that the benchmark that proponents would use to decide whether to sell gas to the domestic market; or if they were to demand a higher price for the domestic market, why? Are they acting in a non-commercial manner, or are there some strategic or business impediments or issues that induce them to give priority to LNG for export?

Mr Boardman: That is, of course, the $64 000 question. Can I answer the question in two parts?

The CHAIRMAN: Sure.

Mr Boardman: I see two quite distinct classes of gas in the future, one is which is that class of gas that is not covered by the domestic gas reservation policy and, therefore, is totally at the producers' discretion within the requirements of the PSLA retention lease, production licence et cetera as to whether they develop that gas and the price at which they make that development decision. Let us just put that on one side for a moment, because I think your question was really directed at the other class of gas, which is that gas which is covered by the WA domestic gas reservation policy—that is, the 2 000 petajoules for Gorgon. If you take my first figure as being a reasonable estimate for Gorgon, but probably Gorgon might be a bit higher—let us just settle on $3 as that PRRT transfer price. The Gorgon joint venture will then, of course, have additional investment to be able to put any gas into the DBNG.

The CHAIRMAN: Yes.

Mr Boardman: Fairly modest; I would not have thought that it would add more than $1 per gigajoule—sorry; am I using interchangeable units here?

The CHAIRMAN: Gigajoule is one I am comfortable with.

Mr Boardman: Okay. We are talking about domestic gas, let me talk in gigajoules. We have $3 per gigajoule as the PRRT transfer price. Let us say we have another $1 per gigajoule for the cost of putting that gas into the DBNG, so $4 per gigajoule is the minimum price that the Gorgon joint venture should accept for that gas and get their hurdle rate of return.

Of course, they cannot do anything else with that gas. It is basically in escrow, so it either goes into the domestic market at that price or it just sits there and has no value.

[1.00 pm]

My expectation would be that the Gorgon joint venture, the domestic gas sellers of the venture, will act in a commercial manner and that they will look at the market and at the individual players in the market, they will try to work out what those players can pay, and they will negotiate the best price that they can get north of $4. That would be my expectation.

The CHAIRMAN: What about the first type of gas, the one that is not impacted by the reservation policy? If they can get $6 or $5—$1 above their costs—why would they prefer domestic gas as opposed to LNG?

Mr Boardman: Again, I think Reindeer falls into this category, Macedon falls into this category; they are differentiated from the Gorgon Wheatstone–type gas because they do not have sufficient volume to go into the LNG market. Sure, I guess they could sell that gas as third-party gas and have it tolled through a Pluto plant or any other LNG plant, or they could develop it as domestic gas and, again, I think that is just a straight commercial decision. As far as I know, it is not public domain, the price that Apache and its joint-venture partners have achieved for Reindeer, but I would be very surprised if it was south of $5; my expectation would be more like $6. At that point both the ability to be able to get it into the market early and that sales price, I would say, that that is probably their best commercial decision.

The CHAIRMAN: The reservation policy is one of the issues that we are going to explore. Do you think it is a necessary and appropriate policy to get adequate supply of gas onto the domestic market?

Mr Boardman: I do not think it is a bad policy. I think it is a bit of a blunt instrument. I think that there is much more that could have been done—that could and can still be done—in a proactive way to stimulate domestic gas coming into the market, to stimulate greater value-add on our other natural resources, through government initiatives. I am certainly not advocating that the government starts interfering in commercial decision-making, but I think that the government can play a much more proactive role in facilitating discussions and, certainly, the consideration towards ensuring capital efficiency —

The CHAIRMAN: Those are unique suggestions so let us explore those.

Mr Boardman: May I provide a little diagram to help my explanation?

The CHAIRMAN: Sure.

I take it these are not kites!

Mr Boardman: No; they are purely schematic representations of two gas fields, which I called A and B. This is an extract from a presentation which I gave at the LNG conference in Perth last year. My thesis is very simple: if there are two offshore gas fields, A and B, and the title to those fields is held under different names, and those gas fields are developed as standalone LNG projects, then based on the economics—on our cost database and our economic assumptions—the combined NPV of those two projects in money of the day, zero discount is $91 billion, and at 10 per cent discount, it is $14 billion. If those two fields were held under common title, either a single joint venture or a single company, how would that single titleholder develop those fields? If the answer is as in scenario 1, then the conversation ends. However, if the answer is what they would most likely do is develop field A first into an onshore facility, then build a second train and develop field B tied back through existing infrastructure—maximise the use of that infrastructure—then we need to have more of a conversation, because scenario 2 provides an undiscounted NPV of $107 billion and an NPV10 of $18 billion; that is, a difference of $16 billion and $4 billion. The problem with this is, from my perspective, I think that it is entirely the prerogative of companies to determine themselves whether their shareholders are getting good value, but it is not only the prerogative, it is the obligation of government to ensure that the nation is getting the best value. In scenario 1, basically, the Australian taxpayers end up subsidising that proliferation development, that independence, to the tune of $9.3 billion—a combination of corporation tax and PRRT. So, simply, if the government had said—you could imagine the sort of projects that I am talking about—"Look, we don't mind what you do, so long as it complies with the PSLA, commercial decision-making is your prerogative. However, taxpayers are not going to subsidise this capital inefficiency, so if you want to go ahead and do your own thing, then you make sure that we're kept whole. We want another $9.3 billion over and above the PRRT and corporation tax that we are going to receive from this proliferation development, because, in our view, if there was common title, then this is the way it would be developed." That proposition then leads to the development of common infrastructure, which leads to a combination of both higher profits and lower prices—a more competitive situation—which I think is the outcome that the state should be looking for.

The CHAIRMAN: The argument is understood, our taxation system and our whole thesis is based on the idea that businesses have an incentive; they get NPV improvement of $16 billion. The tax office really relies on them to maximise the value for them and for the tax office and is reluctant to get into ex-ante optimisation development and then tax on the basis of ex-ante optimisation versus reality, if you understand what I mean.

Mr Boardman: I understand exactly what you mean.

The CHAIRMAN: Therefore, why would they not do this themselves? Is it because of the oligopolist nature of the industry? Is it because of the complicated nature of these joint-venture arrangements? We both know they are cumbersome and complex, and maybe the industry itself—these are generally either giant corporations who are often state-controlled entities that are into this game. In other words, is there a market imperfection, a market failure, to stop them from optimising going from scenario 1 to 2?

Mr Boardman: I do not think it is a failure of the market, unless one defines “market failure” as being a lack of legislation which requires them to optimise their developments. But I think there is a combination of all those things that you just said. The Pluto development—it is public domain information that Woodside tried to engage with the North West Shelf and were unsuccessful. Again, it is public domain information that Woodside and Chevron attempted to engage on Wheatstone going through Pluto. At the end of the day, they made decisions which they obviously felt were in the best interests of their shareholders, but I question whether those decisions are in the best interests of Australian taxpayers.

The CHAIRMAN: In Indonesia and I understand in the Middle East, the government has leaned on developers to toll or to share infrastructure. I think in Indonesia most of the gas is tolled through that, as I understand it.

Mr Boardman: They are two quite different situations. In Indonesia, of course, the Bontang project is now being handed over; it is the end of the lease period that Total had, so it is now owned and operated by Pertamina. You are almost right; that is the principle which is to be applied, although no-one has actually agreed terms and conditions, as far as I know, for the tolling through Bontang—what happens to third-party gas and how that happens. But that is another story; the principle is the fact that that is what will happen.

In Qatar a different approach was taken; the Qatari government made a decision, basically, that they were going to pre-invest in a bunch of infrastructure and basically told the LNG project proponents, “Yes, that’s where your train will go; you build it there, and these are the terms and conditions.”

The CHAIRMAN: In there, who supplies the gas—the government? Who owns the gas and brings it into —

Mr Boardman: The gas is provided by the offshore operators and there is a transfer price hike into the LNG plant. It can be the same proponents in both upstream and downstream, but there is a transfer price. That is a different model again.

The CHAIRMAN: In the other options besides this one on capital efficiency—we started this one by saying are there other policy instruments that government can use to, let us say, ensure not only primarily efficiency and gains from the ventures, but also a greater consideration of domestic gas market.

Mr Boardman: Again, the flow-on from my proliferation–collaboration thesis is one of infrastructure; that there is a common infrastructure which is facilitated, provided by the state. When I say “provided by the state”, I am not suggesting that it is gifted, but at least that there is a mechanism put in place in a similar way to which the original SECWA pipeline was established, and, indeed, those contracts, probably today under more commercial conditions than was established in 1982, but a similar sort of principle.

[1.15 pm]

The CHAIRMAN: Is this tolling essentially what Pluto is doing? They are going out and building two trains with inadequate gas. They are going to have to go out and find gas somehow to —

Mr Boardman: I was overseas last week, so I did not know that Pluto has announced a second train.

The CHAIRMAN: It has been rumoured they are going to build two.

Mr Boardman: The original plan was to build two. Indeed —

The CHAIRMAN: I thought there was a public announcement that they are going to commit to a second one.

Mr Boardman: I was away last week, so I do not know what happened last week, but before I went away the decision on the second train had been deferred until the end of the year.

The CHAIRMAN: Do they have enough gas for the single train? What are the issues? You look at Pluto and North West Shelf and the North West Shelf project is going towards the end of its life.

Mr Boardman: Yes.

The CHAIRMAN: It has five trains sitting there and—not right away—in five or six years they will need gas to potentially replace that. Is that your assessment? In other words —

Mr Boardman: If it is seven or eight years' time, then we can agree.

The CHAIRMAN: It is yet to be determined.

Mr Boardman: In seven or eight years' time, the North West Shelf will need additional gas to keep those facilities full at capacity.

The CHAIRMAN: North West Shelf could be out there acquiring; they could be in the need because they have this sum capital in terms of the trains and they have to go out there and acquire more gas.

Mr Boardman: Absolutely.

The CHAIRMAN: Six or eight years is not a long way away in the LNG world, is it?

Mr Boardman: Very short period of time.

The CHAIRMAN: What you have painted here, particularly in "scenario 2", as one of our concerns is that the projects—let us say Gorgon or any of them—go out and get a reserve and it is usually beneficial for them to acquire adjacent reserves and pull them into the project. The concern is not so much that they do it and it is a benefit for them, but it takes away from the state the Macedon-type projects that could otherwise be targeted for the domestic market.

Mr Boardman: Absolutely.

The CHAIRMAN: North West Shelf are looking to fill five trains, and maybe Pluto, and the benefits from this collaboration or aggregation are that you are going to get a large amount of the gas fields found off the north west pulled into the LNG sector; there are more and more pressures to do that. Would you agree with that?

Mr Boardman: Yes, I would agree with that.

The CHAIRMAN: That means that the 15 per cent reservation takes on some importance.

Mr Boardman: Gorgon is 2 000 petajoules. There is another over 1 000 petajoules from Wheatstone. I mean, that is a lot of gas. At the sort of prices that I foresee it coming into the domestic market, \$5 or \$6 per gigajoule, I think that will satiate demand for quite a long time—a very long time.

The CHAIRMAN: Okay. Maybe I better start back almost to the beginning of this. With the reserve gas from projects, Wheatstone and Gorgon—I am not sure anything is discussed of the Browse issue yet. I cannot remember—do you think we have adequate aggregate available gas for the domestic market for a good period of time?

Mr Boardman: I think we have adequate gas for the market under the way in which it is working at the moment. I think that if the state agreements to add value to some of our other resources were to be enacted, there is probably some more gas required, not a lot, but more for the longer term.

The CHAIRMAN: You were at that department of energy—in fact, I heard your debate with Tom and others and you obviously saw a concern, particularly with the DomGas Alliance with whom you were debating at that time amongst others, about the imminent shortage, physical and price, of gas. Would you disagree with their diagnoses?

Mr Boardman: Yes, I would. First of all, if I look at the figures from the department of mines over the past 10 years—in fact, probably longer; since 1990—it is quite clear that in 2009–10 the price per gigajoule was $3.71. This is obviously an annual average price. That is the first observation. Sure, there would have been short-term contracts struck for $8. I think there is even one up around $16. That happens where there are particular circumstances of buyer and seller—same in Victoria. Victoria uses LNG for short-term peak shaving. That does not come at $3 per gigajoule, no way.

The other factor which everyone just sort of glosses over is that the price of gas is made up of probably four elements. One is the intrinsic energy value of the gas to a buyer, and that includes the equivalent costs with another fossil fuel. It also includes the difference in capital costs for building whatever facility it is to use those different fuels, and the difference in operating costs. It is not just an energy equivalent of a tonne of coal versus, you know, a few gigajoules of gas. That is fairly straight forward and that is the sort of headline number that everyone focuses on.

There are a couple of other elements, which are much more difficult to quantify. One is the environmental element, which, because of the lack of any clear carbon tax or carbon pricing at the moment—people are aware of, but, as far as I am aware, no-one is saying, "We are prepared to pay this much extra for gas or discount this for coal or whatever". So that is not transparently coming into the pricing. Then there is the delivery charge, which is absolutely transparent, which is the difference between what you pay at the plant gate and what you pay for it to come into your facility. The last element, which is probably the biggest element of all of pricing, is what is called the service element price. Again, I have an example here if it will help. I have used this example because it goes a long way to explain not just some differences that are perceived between Victoria and Western Australia, but actual differences within pricing within contracts in any jurisdiction.

If I look first of all at a plain, vanilla gas contract based on 2P reserves and I have said the plateau period—a 20-year contract of 100 terajoules a day requires 730 petajoules of gas and then there is another 30 per cent that is required for the tail gas; that is the energy at the end. There is a load factor of one—in other words there is no swing, no date of variation—and a take-or-pay obligation of 100 per cent. In other words, whether you take the gas or not, you are paying for 100 terajoules a day, day in, day out.

The CHAIRMAN: Was the North West Shelf, or the domgas contract, something similar to this?

Mr Boardman: No, not at all. We will come on to the domgas contract. The domgas contract is more analogous to the example I am using below. Let us just say there is a debt to equity for the project of 70–30, which is pretty typical, and that the project proponents can make their hurdle rate of return by selling that gas at $3 per gigajoule. The buyer then says, "Hold on, I am not happy with 2P reserves. I want 1P." So on the basis of a typically appraised field that is ready for development, but also based on the Department of Mines and Petroleum, 1P versus 2P for the whole of the Carnarvon Basin is 70 per cent—actually 70.5 for the whole of the Carnarvon Basin and that includes a bunch of North West Shelf gas which is more mature. So, my contractible gas goes from 730 down to 511. For a 20-year contract, my DCQ now comes down to 70. The buyer says, "I want a load factor of 0.8." In other words, "I want to be able to adjust my base level up by 125 per cent during the day, from day to day and week to week." That means that I have to allow 25 per cent of the capacity in my facilities just for that swing. So the maximum that I can put through the facility now, which has been built for 70, is 56. The rest of that capacity is totally at the buyer's discretion as to whether they want that extra capacity or not, but it has to be available.

The next thing that happens is that the buyer says, "Look, I am exposed to the vagaries of the aluminium market and if prices are soft, if demand is low, I want the ability to take less than my

DCQ, less than my annual contract quantity, so that I can turn things down and reduce the amount of energy that I consume and the amount of alumina that I produce. I want a take-or-pay factor of 0.8, meaning that I only actually have an obligation to pay for 44.8 terajoules per day.” The significance of that factor is not so much that that is what will be produced, it is that that is the factor that will be used, particularly by banks, to decide how much cash flow is guaranteed from the project and therefore how much money they will provide.

It will probably also have a significant influence on the equity decision. Certainly as a function of that, the debt to equity of 70–30 now drops to 56–44. Therefore, the cost of my WACC goes up from 8.5 to 9.2. That is an eight per cent increase. Arithmetically adding each of those components of the contract, you have moved a gas price from $3 to $10.59. That delta is $7.59. That is on top of the original $3. So you are paying more. Look, straight away I can see it is an extreme example because what will happen immediately is that the parties start negotiating and there is a compromise reached in terms of the contractible reserves levels, the load factors and take or pay; it is a compromise. Those are just those headline contract elements.

I have an actual example, an actual expert witness case that I had in the eastern states two years ago. The range of value that I ascribed to the service elements that were in the particular contract, relative to a plain, vanilla contract, was between $2.37 and $4.79.

[1.30 pm]

Sure, not the $7 that I used in my illustration here, but, nevertheless, this was a real contract and this was an analysis that looked at the interruptibility provisions, the seller’s facilities, the gas specification load factor, take-or-pay term, delivery point, reserves cover warranties, price escalation, price review provisions, force majeure. So, the message that I would just like to summarise with is that there is an enormous difference that a buyer will pay for gas under a plain, vanilla type of contract and under an all-singing, all-dancing, bells-and-whistles type of contract.

The CHAIRMAN: So, just to summarise a very important point, and the point is well taken: prices vary immensely for good reasons out there. It is not just a single quantity, take or pay; you get various attributes to that supply of gas that people have to pay a lot for. And, of course, you see quoted in the media huge variations. There are also other factors, as you indicated earlier, about time and urgency, and duration of the contract. But your central point is a very important one: under the known projects that are going ahead that are committed to—Gorgon, Wheatstone, Pluto and whatnot and the reservation—you think there should be adequate supplies of gas for the known demand forecast available now.

Mr Boardman: Yes.

The CHAIRMAN: The Department of Mines and Petroleum has a graph that you have seen.

Mr Boardman: Yes.

The CHAIRMAN: We discussed that at the Office of Energy public meeting. You would disagree with their forecast. You will remember their forecasts show that when their demand goes up, their supply is contingent upon their assumptions about whether or not the domgas contract on the North West Shelf is renewed and to what extent it is renewed. Do you disagree with their forecasts?

Mr Boardman: Yes, I think that—and I think that I made the comment actually at the conference —

The CHAIRMAN: Yes, you did.

Mr Boardman: — to have any credibility on forecasting future demand, you have to differentiate aspiration—appetite—from true demand. I mean, we have been modelling the WA gas market since—well, I started modelling the WA gas market in Woodside, so I have probably been modelling the WA gas market since the mid-1980s. But I have certainly been modelling it in RISC since 1994. I mean, the biggest challenge that you face in forecasting is that there are projects which are apparently just coming up to approval, and these projects—we have had all of the iron ore projects, the midstream steel projects, the BHP —

The CHAIRMAN: Briquette iron.

Mr Boardman: Briquette iron projects, Worsley with additional trains, Alcoa with additional trains, Wesfarmers with petrochemicals. The Canadian fertiliser manufacturer project is going ahead on the Burrup—Agrium. I mean, from memory, there was something like an additional 1 000 terajoules per day that was projected to be in the market, additional demand in the market, by now, 2010. I have not looked at the exact figure, but I would think relative to 1995, say, that the additional demand in the market is less than 200 terajoules—definitely less than 200 terajoules. So that 800 terajoules just never materialised, and for various reasons. But certainly I do not pretend that one of those reasons would undoubtedly be a jump in price. If the producers were prepared to sell at $1 per gigajoule, then probably some of those projects would have proceeded. I certainly think the fertilisers models would have proceeded.

The CHAIRMAN: And on the other side, of course, we have the expansion of iron ore was not predicted 10 years ago to the extent that it has happened and, of course, the Indian Burrup Fertilisers came out.

Mr Boardman: Burrup Fertilisers, yes.

The CHAIRMAN: Your point is that this is a project-driven demand.

Mr Boardman: Very much so.

The CHAIRMAN: It is highly uncertain and it ain't happening until it happens.

Mr Boardman: And both buyers and sellers in this state have one thing in common. They probably have many things in common, but they have one very important thing in common: they both want the certainty of making that investment. The producer wants the certainty that they are going to get revenues for the next at least 10, preferably 20, years to cover their major capital investment, and the buyer wants the certainty that they are going to get a continuous supply of gas at a particular price for the next 20 years to justify their capital investment. And that differentiates this market completely from a liquid market, a commodity market, such as you have in Europe and the US, and to a lesser extent in the eastern states and Victoria.

The CHAIRMAN: We hear that the North West Shelf is a costly place to build and that the cost offshore, because most of this is getting deeper and deeper, is going up. Is that a factor in driving up the underlying price of gas, either to the LNG and therefore perhaps to the domestic market?

Mr Boardman: Absolutely; yes, no question. I cannot remember what the break-even price would have been for the North West Shelf when that was approved, but in US-dollar terms, I would have thought somewhere around $1.50—somewhere around there—which would have been low twos, which is about what the second contract price was, was it not—somewhere around $2?

The CHAIRMAN: Yes, it was. Are there any issues of technological change? I know you are more the contract person, but a couple of issues that have been floating around there are floating platforms, and that has the potential to bring on a tap for LNG in the smaller fields. Any other issues that could affect the cost or bringing fields like Macedon, which would otherwise be domgas, into the LNG market?

Mr Boardman: The technology changes. I mean, FLNG is going to bring its own specific challenges to Western Australia, specific to the Western Australian gas reservation policy.

The CHAIRMAN: Yes, it is.

Mr Boardman: Yes; I am sure you have worked that one out. So, what are the obligations of Shell to bring gas into the domestic market and how are they expected to do it, and all the rest of it? I do not see it personally as a show stopper. I think the probability of a proliferation of LNG vessels is zip. Despite things that are in the media almost on a weekly basis, I think that that technology is going to remain the domain of the Shells of the world for some time. And the second point is that I believe that a company like Shell will be extremely conscious of its public image, extremely conscious of sort of the spirit of the obligations under the WA domestic gas reservation policy, and will seek to provide that gas from its other resources. And as far as I can see, there is no difficulty in any producer, in supplying that, that their actual gas reservation volumes from any source. It does not have to be from the source which has been developed for LNG.

The CHAIRMAN: One of the issues that comes up—you mentioned the US is now on conventional gas, and I note your organisation has released a report on conventional gas in Australia in 2010. It is a report that you are selling, so I will not ask you for too much detail on that. Is there very much scope, do you believe, in Western Australia for either shale or tight gas?

Mr Boardman: Again, the answer comes back to price. In terms of resource potential, yes, considerable resource potential for shale gas. However, the price that that gas is going to require to come into the market in any significant volume, based on our work, it is going to make it quite difficult. It is not going to be any cheaper than the gas which is going to come from Gorgon or from Wheatstone or Pluto or anywhere else; that is for sure.

The CHAIRMAN: Okay. And there are capacity problems with drills and technology and teams to get out there and access that stuff, too.

Mr Boardman: There are enormous challenges. Just like the CSG–CBM industry in Queensland, you know, sort of the initial proponents of that industry, Conoco, one of the biggest producers of coal-bed methane in the USA, right, a huge program in Queensland—total failure. They spent $280 million, $300 million, and sold out to Oil Company of Australia for $3.5 million; and that was all of their interests, all of Conoco’s interests.

The CHAIRMAN: That is ConocoPhillips?

Mr Boardman: Well, it is now; it was only Conoco at that time.

The CHAIRMAN: Okay. When did this happen—1990s?

Mr Boardman: Yes, mid-90s. I struggle with dates, so, mid-90s. Origin then bought out Oil Company of Australia—corporate, right—for about $400 million, and then ConocoPhillips came back in and picked up 50 per cent of the acreage that they had sold to Oil Company of Australia for $6.5 billion, which is about the best return that I know of.

I am sorry, the point of that was that in between the US expert, Conoco, leaving and then coming back, the upstream CSG producers in Queensland had learnt how to handle the specific coals in Queensland. I do not think that anyone is going to be able to just do a straight transfer of technology from the Barnett shales in the US to the Canning basin shales. That is where they will start, and then there will be failures and there will be a huge learning curve. But before they can even start, they have got to get sort of enormous quantities of equipment in to be able to do the fracture stimulations that make these things viable in the US. And I do not know who is going to do the first one, because none of the players at the moment has deep enough pockets to even think about the mobilisation costs, let alone the actual operating costs. So, shale gas is sort of good for getting share prices up for the juniors at the moment, but it has got a long way to go.

The CHAIRMAN: Thank you very much. I will read this out just in closing. Thanks for your evidence. A transcript of this hearing will be forwarded to you for correction of minor errors. Please make these corrections, if there are any, and return the transcript within 10 days of the date of the covering letter. If the transcript is not returned within this period, it will be deemed to be correct. New material cannot be added by these corrections and the sense of your evidence cannot be altered. Should you wish to provide additional information or elaborate on a particular point, please provide a supplementary submission with your corrections. You have provided us with a couple of pieces of data. How do we treat this? Can we accept them as a submission?

Mr Boardman: Sure.

The CHAIRMAN: We might need to make sure we have the right citations. Tim will get in touch with you about that. Thank you; you have been very helpful and useful.

Hearing concluded at 1.45 pm