Centrica

Energy Management and Storage Presentation

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Opening Remarks

Phil Bentley

Group Finance Director

I. Welcome

Welcome to this palatial Cazenove conference centre. Now I know where all our brokers' fees go! Good to see so many of you here. Clearly, EMG is a key part of our strategy and a part of our earnings growth and earnings delivery. Whilst we always look at the customer as being the heart of the business, we can only offer value to customers if we have advantaged cost of goods. Today, rather than hearing about the customer end of the value chain, as it were, we are going to be talking about the cost of goods side of the value chain.

I know it's an area where there will hopefully be a lot of insight we can bring. No doubt a lot of questions as well. We've scheduled quite a lot of time for Q&As. In the meantime, let me hand over to my friend and colleague, Jake Ulrich. I hope most of you know Jake already. I put you in his hands.

Opening Remarks

Jake Ulrich

Managing Director, CEMG

I. Overview

Thanks, Phil. I will get into introductions of the team a little bit later. We have divided this into two parts. What will be discussed first is the Centrica Storage Limited; the Rough field primarily.

Bruce Walker is here. Bruce used to work in the CEMG, but has just been named head of Centrica Storage. He can give you an update and tell you pretty much things that are pretty much out in the public domain. We have a restraining order, basically, within CEMG. We are not allowed within two kilometres of the facility. We are not allowed to talk to Bruce except in public functions like this. Therefore, without any further ado, Bruce will talk about Centrica Storage, we will have a Q&A period, and then we will move on to the CEMG business.

One Year On

Bruce Walker

Managing Director, Centrica Storage

I. Centrica Storage

Good afternoon, everyone. As Jake says, as a result of the Competition Commission's inquiry, and the recommendations, Centrica Storage is now a separate business unit within Centrica, and is no longer part of the Energy Management Group. This part of the presentation has therefore been prepared separately by Centrica Storage. However, I think we've not been apart for long enough for our view of the world to have diverged too much.

In this brief presentation I want to do four things. I want to remind you of what we bought. It's almost exactly a year since the acquisition. We bought the asset on 14 November 2002. I'm going to say a bit about what we've done since then.

I will summarise the outcome of the Competition Commission's inquiry.

Lastly, I will say a bit about what has happened in our view to the storage market since we acquired the asset, and the implications of that for the value of Rough.

1. Centrica Storage Assets – The Rough and Easington Assets

Briefly, what did we buy? The assets acquired from Dynegy comprised the Rough gas storage field which lies about 25 miles off the Yorkshire coast, and the associated onshore gas receiving and processing terminal. The Easington Terminal processes Rough gas, but also receives and processes gas from the BP-operated Amethyst field, and will also shortly also be processing gas from the new fields of Helvellyn and Rose. Those all provide a tariff income to Centrica Storage.

The package we bought also included a minority interest in a nearby undeveloped gas field: York. But, we attributed no value to that part of the package in the purchase price. The bulk of the value, and most of what I am going to talk about, is the Rough storage asset itself.

a. Rough

Rough's basic role is to enable storage users – our customers, including from now on the Energy Management Group within Centrica – to meet seasonal swing in gas demand. They do this by injecting gas into store in summer when demand and prices are low, and taking gas out of store in winter when demand and prices are high.

The constraints of maximum injection and withdrawal rates mean that the total storage capacity can be filled over about 180 days in the summer, and can be emptied over about 70 days in the winter.

Physically offshore there are two platform complexes. The larger is shown here: 47/3B which has 24 wells which are capable of both production and withdrawal of gas from the store, and injection of gas into the store. 3B was built in 1983 when Rough was converted to a store. The other platform is 8 Alpha. It is the original production platform, dating back to 1977, which has six production wells.

Rough is by far the largest storage asset in the UK. It comprises about 75% of total UK storage by volume. It is capable of meeting over 7% of total UK peak gas demand.

2. Asset Integrity and Performance

That is what we've bought. I'll just say a bit about what we have done since we bought it. We have in fact made enormous progress in addressing a number of issues which we recognised at the time of acquisition.

a. Health & Safety Executive issues

When we acquired it, the asset was the subject of a Health & Safety Executive deferred prohibition order. That is a sort of yellow card which says if you don't take certain actions to rectify issues then the facility can be shut down.

Our first task was to address those issues, to improve the permit to work scheme offshore and onshore, to install a radar system to address ship collision risk, staff training, and dealing with the very large maintenance backlog, which, as you see, we inherited at that acquisition. We succeeded in getting that prohibition notice lifted in February – within three months or so of acquisition. Since then we have continued to work hard, to develop and maintain the key relationship with the HSE to demonstrate that we are committing the right resources, and putting in place the right business controls and risk assurance processes on the asset.

b. Efficiency and reliability

We also have an active, ongoing programme to improve efficiency and reliability of operations. Apart from addressing the maintenance backlog, this has included changing of 36-inch valves offshore, a major sub-sea inspection programme to assess the integrity of the asset, a major topside paint programme, and refurbishment of three compressors.

Compressor failures were the main reason for our disappointing performance over part of the summer in injection mode. But within the next few weeks, we will have completed overhaul of the fourth compressor, therefore having completed overhaul of all four compressors on the facility since acquisition. We have identified the cause of the major problem in the summer which related to the wrong specification material in the tie rods in the compressor unit.

It is a cliché, but true to say, that people are the most important part of the asset. That is particularly true of an asset like this. We have implemented personal performance contracts for managers, performance bonus schemes for technicians and operators. Already, I think, we are seeing substantial improvements in morale as we demonstrate our commitment to investing in the facility and the asset, physically and in the development of training of people.

c. Value-adding opportunities

We are also actively pursuing value-adding opportunities to improve efficiency and reduce operating costs. We developed, as the first step, a new model of the ways of our operations which will allow us to evaluate these opportunities. They include:

- The re-wheeling of compressors to reduce fuel costs and increase efficiency.
- Better control of sand production to improve well deliverability.
- A re-perforation programme, again to improve deliverability and injection.

3. Outlook

We are also seeking to maximise opportunities to secure third party tariff income. Two new fields – Helvellyn and Rose – will be processed at Easington from early next year. In fact I think one of them is now expected to be in later this month.

Of course Centrica, and to be more precise, the Energy Management Group within Centrica, was also successful this year in securing contracts to manage the design, the construction, and the commissioning of the major new gas reception facility which will receive Norwegian Gas from 2006. Centrica Storage will take over the operation of that asset after commissioning, bringing both a new income stream to Centrica Storage, and also, we think, potential operational synergies going forward.

4. Competition Commission Outcome

It's been a busy year. We have also, of course, had the slight distraction of a Competition Commission inquiry. As we said in August when the Competition Commission reported, we welcome the outcome. The Commission agreed that the potential adverse effects, as they saw it, of the merger, could be addressed by undertakings relating specifically to the Rough storage operation – relating to the way Rough capacity is sold, separation of the storage business unit, rules for the protection of commercially-sensitive information, and of course compliance reporting and monitoring.

Importantly, the Commission agreed with our case that divestment or undertakings with more general application to Centrica's flexibility of portfolio were not required. Therefore, our operations of flexibility, and our supply portfolio, particularly in Morecambe and the long-term interruptible contracts are unaffected.

In all, the outcome was well within the range of our expectations at the time of the acquisition.

5. The Key Undertakings

I wanted to say a little bit more about two aspects of the recommended undertakings. The discussions with the OFT and Ofgem have now concluded. We have signed undertakings reflecting these. They are now with the Secretary of State for her approval. We expect to hear the outcome within the next few days.

a. Separation and information barriers

The two issues I want to say a little bit more about are Separation – as I said at the beginning, Centrica Storage is now a separate storage unit, reporting into the executive through the Company Secretary, and no longer through Jake as MD of CEMG.

'Chinese Walls' were already in place to protect the commercially-sensitive information. Of course, they will remain in place. However, it is important that Centrica Storage unit will still call on the corporate resource shared services. The particularly point I wanted to emphasise: Centrica Storage will still have access to the reservoir development and asset management skills within the Energy Management Group.

We will continue to draw on a common pool of expertise on reservoir and process modelling, major projects, specialist HR expertise, especially in relation to offshore asset operations, policies on Health & Safety environment and quality in relation to offshore operations and emergency response. In all of these areas, we will continue to be able to draw on the EMG resource.

We recognised, at the time of the acquisition, the synergies in this area, particularly in relation to the Morecambe operation. We are very pleased that the Commission both recognised those synergies, and accepted that they should be retained.

b. Capacity sales

The second aspect that I want to dwell a bit more on is the important one of the way in which we sell capacity. We are required, under the undertakings, to offer capacity on a range of contract durations and price indexation mechanisms. We were in fact already doing so, and were very keen to pursue a range of pricing mechanisms and durations.

The important outcome of the inquiry is that the recommendations do not impose constraints on how much capacity we sell, over what durations, and over what price index terms. We argued strongly with the Commission that both we and our customers wanted the commercial freedom to be able to negotiate terms for storage services. We were very pleased that the Competition Commission has accepted that the market should be allowed to operate freely in this area.

As far as other parts of the Centrica Group are concerned, as you are probably aware, we can reserve up to 20% of the capacity for other parts of the group, declining over five years to 15%. It is important to know that that restriction applies only to the primary market in capacity sales, EMG and Accord are free without restriction to participate in the secondary market for capacity.

Finally, the existing standard contract terms, which have worked well over the last few years, will remain in place, largely unchanged.

In summary, the undertakings are very much in line with our expectations at the time of acquisition.

That is what we've bought, what we've done with it, and the impact of the Competition Commission inquiry. I now just want, in this last part of the presentation, to say a bit about how the market in storage services has moved since we bought the asset and some of the value drivers for the Rough asset.

6. Value Drivers

I am not going to attempt to give a detailed analysis of supply and demand, though I think some of the EMG material later does touch on it. The fundamentals are widely recognised. The UK is quickly moving into import dependency. Indeed at peak winter periods it is already import dependent. UKCS supplies – United Kingdom offshore supplies – traditional high swing fields are in rapid decline. In some cases, they're being converted to higher load factor, lower swing terms.

New UKCS production and new import sources for the pipeline oil LNG are being developed as high load factor, low swing supplies. A number of new storage projects are being progressed, but so far on a fairly modest scale and at generally relatively low volume short duration facilities compared to Rough. As an illustration, even if the two existing firm projects – Aldborough and Byley – when those are commissioned, Rough will remain in the order of 66% of total UK storage by volume.

We also estimate that storage prices will have to increase by something of the order of 25% from current levels, before the conversion of depleted offshore fields, such as Rough, to provide large volume storage would become economically attractive.

On the demand side, particularly residential demand, remains highly seasonal. We are bullish about storage values, storage prices, but coming from Centrica Storage that is hardly headline-grabbing news. I wanted to therefore go on to try to be a bit more explicit about what drives the value of Rough and what has happened to that driver since acquisition.

In this busy and full slide, it attempts to do that. I'm not going to go through it line by line. The bullets down the left-hand side summarise how we sell Rough for capacity in the form of standard bundle units, or SBUs. They are really a function of the physical nature of the asset reflecting the fact that, as I said earlier, you basically can withdraw gas three times as fast as you can inject it. A standard bundle unit comprises one unit of deliverability, 67 units of space, and about one-third of a unit of injection.

As mentioned, the revenue from the sales of SBUs is the main driver of Rough value. As I mentioned earlier, Rough is essentially a simple operation. It takes customers' gas in the summer, when prices are low, and redelivers it in winter when prices are high. The prices can be high in summer. You could also use it for that purpose as well.

The value of Rough is therefore largely driven – as the bullet points to the left say – by the price spread between the summer price, the Q2 and Q3 prices, April to September, and the first quarter winter price, the January to March price. This basic, or intrinsic, value of Rough, can be shown of an SBU to be about 2.4 times this Q1 versus summer price spread. The spread here is expressed in pence per therm. The 2.4 multiplier takes care of the conversion in units from therms to SBUs.

It's not quite as simple as that as the final bullet point on the left-hand side says. Rough also gives customers options through short-term flexibility, variation in both injection and withdrawal. We believe this optional insurance value is currently undervalued by the market. We believe that this 2.4-times formula represents a conservative valuation of the Rough SBU.

One important point which doesn't appear in this slide: storage years – as ever, there are complications – run from May to April. We have sold all SBUs for the current storage years, of 2003-2004, at an average SBU price of about 16.7p per standard bundle unit, per SBU. We have not sold any SBUs from 1 May onwards, therefore all storage prices from that period on will be at new price levels. We have no legacy commitment beyond 1 May 2004.

7. 2002 Profit and Loss

The right hand side of the slide is a summary of the 2002 profit and loss account for Centrica Storage, derived from the statutory accounts of the various companies that form the Centrica Storage Group. The top line is the revenue from the sales of SBUs, at an average price of 13p per SBU for the financial year of 2002. The other revenue comes from commodity charges. Those are the unit charges for injection and withdrawal. Those are cost-related – we don't make money, we don't particularly want to make money out of those. We want customers to extract the maximum value by maximising injection and withdrawal in the facility.

The other capacity line comes from the sale of additional space and interruptible services. This will vary form year to year depending on essentially how the reservoir is depleted during the winter, and how much space or additional interruptible services we can sell, which varies from year to year. 2002 was actually rather a good year for this revenue line, for the additional space and interruptible service line. But, as discussed earlier, we do all have hopes of growing those incremental capacity sales through further investment in the facility.

Other revenues, mainly third party tariff revenues, these actually fall off a bit in 2003 as Amethyst declines. But that decline is more than compensated for by Rose and Helvellyn coming on stream next year. We see that as increasing over the next few years. Thereafter it will depend on our success in attracting further third party gas.

On the cost side, we are looking at ways of reducing operating costs. I would not pretend that there is enormous scope to eat into that cost figure, though we will work at it.

What I really want to draw from this slide is that, apart from that top line, although the other lines will vary, there is enormous scope for variation. Movements in the SBU sales revenue will largely flow through to the bottom line in terms of profit before interest and tax, re-emphasising that the major driver of Rough value is the revenue we secure from sales of SBUs.

8. Summer/Winter Gas Price Differential

As we showed earlier, the value of the SBU is driven very much by the Q1 winter versus Q2-Q3 summer price spread. This slide shows how that spread has moved between the dates of acquisition – 14 November 2002 – and the first anniversary of that date.

Customers who are buying SBUs are very much looking at the difference between the average forward spot price in the two summer quarters and the first quarter of the following year. The price we paid for the asset was broadly consistent with the historic spread of around 6-6.5p. The lower light blue bars on this chart. Storage prices consistent with the new spread of over 10p were secured for the last units of capacity sold for the 2003/4 storage year.

As we said earlier, our view of market fundamentals suggest to us that there is room for further growth in that spread and in Rough values.

9. Summary

To summarise:

- We have made significant progress in addressing issues we inherited at the time of acquisition – HSE issues and plant maintenance backlogs.
- We have identified and are evaluating value-adding opportunities.
- New Norwegian Gas will be landed at Easington at a new terminal operated by us.
- Undertakings, following the Competition Commission reference, are in line with our expectations at the time of acquisition.
- Movement in the forward curve for the Q1 summer price spread indicates an increase in value of at least 50% since acquisition.
- Market fundamentals suggest to us continued growth in the future value of Rough storage services.

Questions and Answers – Centrica Storage

Jason Goddard, CSFB

Can you give us a sense of the capex annually at Rough? I guess maybe a bit higher this year than years going forward. If you could give us a sense of that. Secondly, in terms of the capacity that you can use in the primary market for Rough – there seems to be a condition here to ratchet that down – where would you have been before if you had not bought Rough, if that had not been made a condition? And why is that not value loss to you?

Bruce Walker

Taking the first question first. I think it is fair to say that the asset has suffered from a little bit of neglect in the final years of its ownership by BG Storage and subsequently for various reasons during its one year in the hands of Dynegy. We recognised that we would have to do things to put that right. We have spent something like £9 million in special capital and revenue projects this year. Split roughly, it's £2 million capital, £6-£7 million revenue. I would expect that capital spend – without distinguishing capital revenue – the sort of special capital/revenue spend over the next few years to perhaps run at around the £10 million mark, but thereafter fall back to something nearer £5 million, once the asset is in a steady, ongoing condition.

As for your second question, in a way it's more of a question for Jake and his team, but my understanding is that traditionally Centrica has used something of the order of 20-25% of Rough capacity. I guess we emphasise two things: CEMG is still free to acquire Rough capacity in the secondary market. We have the right to retain any capacity from incremental investment for the Group. As I mentioned in the presentation, there are a number of projects we are looking at, including the re-wheeling and reconfiguration of compression which have the potential to increase usable capacity in the facility by perhaps 3-4%. A number of projects are contributing to that 3-4% figure. The purpose of the declining percentage was very much to give us the incentive to go after those incremental projects, and we will do so.

Simon Flowers, Merrill Lynch

Two questions please: one, a technical one. Is there any finite life of the reservoir, in terms of injecting storage? Is that something that could go on indefinitely? Do you have a view on that? And the second question – I'm interested on the winter/summer spread. Why has it moved up so much in such a short time? I would have thought that with the mild weather that we had in October and November, you might have thought the opposite, in a way.

Bruce Walker

In terms of asset life, in a sense the asset will live as long as it is economic to spend money maintaining it. It is not like a depleting field or asset. Our current expectation is that the field will be abandoned in 2029. We reckon there are something like 25-26 years of life remaining in the asset.

It's a combination of licence expiry, and a view of when it will no longer be economic to maintain and sustain the asset long term. It's not a fixed licence. Licences can be extended and the views of the economics may change, but that is our current expectation. Your second question?

Simon Flowers, Merrill Lynch

Why do you think the spread has moved up so much?

Bruce Walker

I think it is driven basically by the fundamentals: UKCS, beach… It is more important to say that storage provides something in the order of 25% of the total summer/winter seasonality in the UK market. Most of the rest of that is provided by beach swing, by other offshore fields swinging between summer and winter production. As both fields deplete and as contacts are renegotiated to move the higher load factors and lower swings, a little bit of that can have quite an impact on the supply/demand for storage. I think that is what has been happening over the last two or three years.

Robert Marshall-Lee, Newton Investment Management

A couple of questions please. On that last point, I was wondering why, given that swing outlook, the forward curve drops away from the 15 down to 10 and stays so flat moving forward, rather than increasing over time.

Bruce Walker

I'm glad you mentioned that. The first of these bar charts is a bit of an anomaly. People generally book storage in the spring and are looking at the forward curve for summer and for winter prices. From 2004/5 onwards, the bars show that spread in the forward curve between winter and summer prices. For 2003/4, the spread just reflects the spot spread, as at 14 November 2003 versus the actual summer price in 2003, the average historic price over the two summer quarters. It's not comparable with the other lines. But it does illustrate that if you can get the timing of your realisation of the value of storage, there is potentially a large upside. If someone had bought storage and was in a position to trade out of that storage position on 14 November 2003, that person would have made a killing. It's an illustration of some of the option value that exists within storage, over and above the simple summer/winter spread.

Robert Marshall-Lee, Newton Investment Management

My second part was just in terms of what response you are expecting from the industry with the decline of the field swing we are seeing. Are you expecting changes to the nature of the LNG response, interconnection, etc?

Bruce Walker

In a word, yes. The storage contributes about 25% to matching UK summer/winter supply variation. As traditional UKCS beach swing declines, there will be room for pipeline reversal, or modulation of pipeline import supplies to contribute to matching that seasonal requirement. There will be the potential for LNG to also contribute.

But it is worth saying that building in spare capacity to long pipelines from Russia or Norway, or building spare capacity into LNG projects, is not cheap. Although they will contribute, I don't think it affects our view that there is a continuing tightness of that winter peak supply/demand, and storage is a major contribution to make to balancing that supply/demand position.

Phil Bentley

I think we might if we may move on. If there are more questions specifically for Bruce, we have a tea break at half time. We scheduled 25 minutes for this session. We are quite a bit over already. We will answer all the questions we want, but if we can perhaps move on now. Collar Bruce. If there are any other questions, we can wrap it up in the Q&A

session at the end, if there are some burning questions still on storage. Thank you for that, Bruce.

Centrica Energy Management Group

Jake Ulrich

Managing Director, CEMG

I. Introductions

We are going to move on to the CEMG part of the presentation. I just want to point out a few people so that when we get to the break in about 45 minutes you can corner them and push them on some of these issues.

Sarwjit Sambhi is our CFO, Director of Strategy, and he is the point man on the emissions issues, renewables specifically. Alan Bennett next to him. Alan runs the asset portfolio, both generation and the upstream reserves. John Bradley is our optimisation linear programming guru. We will have him answer all the tough questions later. Gearóid Lane many of you have met and argued with in the past. He is head of electricity supply for us. Ian Wood, who will speak next, is running our business development and the gas supply book, as well as the electricity supply book. We have a few other people. Everyone knows Phil, the CFO. I like to think of him as the soft side of Centrica! The guy out front with the investment community. Anyway, you can corner him too. We have Kath Kyle with us. Kath is in the back and her team will be circulating.

II. Centrica Energy Management Group

1. Why We Exist

Centrica Energy Management Group – why are we here today, why does Centrica Energy Management Group exist? It's pretty simple. There are two things. We can argue about the semantics and really get into the meaning of this, but it is simple. I am not trying to make it complicated.

We want to optimise the energy cost for the downstream business, i.e., Mark Clare's group at British Gas. Centrica Business Services, and the folks in Europe who Ian is responsible for supplying. It is the same thing in North America. I'm not going to belabour North America today. That is part of another presentation. We will use it sometimes as an example, to differentiate different things that we're doing worldwide.

The other thing is reducing earnings volatility. In my mind, reducing earnings volatility is a hedging function. We may be very heavy on the assets, fixed price types of things, where we can lock in a spread. Of course, you might lock in a negative spread, but at least you reduce volatility.

The energy costs, on the other hand, we want to be as low as possible every year. We do not want to have a lot of disruptions within a year depending upon the market. I look at this: there is a hedge function and there is an optimisation function. We could buy all spot product. Obviously then we would have a very volatile supply portfolio. We would not tie up much capital. We could hedge up everything. It would not be possible for us to 100% hedge gas with assets, or electricity with assets. So it's a combination of the assets and the contracts. We will get into more detail on that as we go along.

2. Tools Utilisation

These are the tools that we use.

a. Gas and power asset portfolio

The first thing: we do have a gas and power asset portfolio. We have about 2.2 gigawatts of generation capacity that we own. We also have about 2.3 trillion cubic feet of gas, the basic part of the portfolio. We also have a number of bilateral and trading functions in contracts within the Group. As far as the bilateral contracts, you have heard about three in the past year, fairly big ones. We have done a deal with the Norwegians for about 5 billion cubic metres per year of gas. We have done a deal with the Dutch – it could be the Dutch, it could be the Russians, it's not important at this point – but it is for 8 billion cubic metres of gas. We have also done a fairly chunky power deal with a large British nuclear company.

b. Energy procurement through traded market and bilateral contracts

That is the other part of the Group. We are looking at what we can do as far as contractual arrangements. Ideally, and everyone knows this, in a very liquid-efficient market we could do a lot of that with contracts, and we would not need to own that many assets.

On the other hand, when prices are going up, maybe you might want to have a little bit of asset cover, and when prices are going down, it doesn't look as attractive. What I am trying to say is, it depends on the market you are in, what the customers want – there are a whole slew of factors that we have to take into account when we come up with this asset/contract mix.

c. Wholesale and industrial customer base

The other thing we have is a wholesale and industrial customer base. We do have the opportunity to move gas into the wholesale markets or into the industrial markets when the weather is maybe a little bit warmer than the retail groups can use. On the other hand, in extremely cold weather, we have used the interruptability with our industrial customers to shift that gas into the residential markets. It is a matter of looking at what is the best bottom line decision at any given point.

John is not going to talk about this today, but the basic sequence is that we have a year-long linear programme where we look at how we're going to schedule all the power plants and how we're going to pull all the gas out. This takes into account all the contractual commitments we have, as well as our best view on current pricing. We do have a number of limitations as to how much we can run. We have to put time in for maintenance, we have to have some down time and some flexibility. John's group does that.

Then they re-look at it on the shorter-term basis: quarterly, for the next month, finally down to the week. How are we going to run things and withdraw this week? If it is a very, very warm period, maybe we will shut Morecambe in, maybe we'll buy some spot gas. Or, it's very cold, maybe we need to accelerate the production at Morecambe, or take on some of our higher priced contracts. We are looking at that within the week.

Finally it gets down to the day. On the given day, we don't have a programme that can run quickly enough. That's when it is up to John and the team to basically make the right decision as to what is best for the Group.

d. Asset and contract optimisation

Asset and contract optimisation: I cannot say enough about it and how important it is. A lot people think we make money around trading, and around Accord. Accord is actually a small part of the book.

In a good year, and I caveat this – if Enron hadn't happened maybe it would have made 30 million that year. A not so good year might be in the 15-20 million range. There are a number of things that can influence that. What John's group is looking at is how the position that Accord takes, and how our physical contract position interact. A good example of that would be when the interconnector goes down. If the interconnector goes down, Accord is long on that, so they are losing money because they have to buy gas from the continent to cover the disruption. So gas is backing up into the UK and, guess what, prices go down. That's when we use the contract flexibility to buy cheap gas and run it into the retail markets.

On the outside it looks like Accord has lost money. But what people don't see is that we've been able to take advantage of that situation through the Group.

e. Flexibility and shape

These different tools, different ways of looking at it, provide two things: flexibility and shape. What I mean by shape is a structural issue. The UK power market is balanced half-hourly. We use the most electricity around 5pm in the afternoon. That is structural. It is endemic. We have to account for that.

The other thing in gas markets is that there is a seasonal spread. Bruce has given you some idea of the value of that spread. But we know today that our residential load is going to be about six times as high in the winter months as it is during the summer months. Those two we know we have to take into account when we schedule things and when we buy things.

The second is flexibility. What happens when it is much colder than normal? What happens when it is much warmer than normal? What happens when a competitor goes off line? What happens when a casing cracks in a nuclear plant? You can come up with a dozen different scenarios that we can't plan for, but we need to have the flexibility within the portfolios to manoeuvre around that and mitigate any damage. Actually, we have done an okay job at that.

3. UK Energy Business Performance in Volatile Markets

What I want to show you here is – and you've all seen these charts – price volatility, absolute price levels in both electricity and in natural gas since 1998. Also, to basically look at what the earnings have been of the core energy business within Centrica.

In 1998 it was £165 million. Last year it was £829 million. These are the power plants. These are the upstream gas assets. There is some storage component, a tiny one, in 02. It is the retail business and it is Centrica Business Services. It is everything from upstream to downstream in the UK.

You can see that back in 1988, power prices were fairly healthy: up over £24 per megawatt hour baseload. Prices came down substantially because of NETA. Not a good time to own a power plant. We looked at most of the plants that were for sale during this period. Gearóid Lane will give you the details.

But it didn't make sense to buy. Clearly the site was heading south. We had a bounce in late '99 early 2000, and a further drop to last spring when prices were down around 15, 16. Now they're moving up. Is this sustainable? It's going to last. Gearóid is going to address why some of these changes are occurring. Is it a good time to buy assets now? Yeah, it probably is. We bought a number of them over the low part of this cycle. Did we want to buy 100% during that part of the cycle? I would say that no, we didn't. We will get into some of these details.

Gas: a similar situation. We were in a fairly low gas price environment during that period. We've come up well over 22p per therm here. A good thing with Morecambe and some of these assets. Would we have bought 100% cover, would we have owned 100% equity assets? I don't think BP and Shell would have let us, to be honest. We could not physically buy enough gas to do that. It's a mix of getting the right contracts with the majors, owning some, and managing that.

4. Procurement

a. Tailored to customer propositions

This is an important slide here. This is our approach to procurement. I know that everyone has heard this many, many times, from Phil and the investment relations team. It is tailored to the customer proposition, but this is really critical in how we operate. I will give you some examples on the next slide, but if you can bear with me. It is probably on the same page, so don't bother not looking.

The customer proposition changes geographically. It changes by market and it changes by product. It is very different selling electricity in Texas, selling electricity or gas in Ontario, selling gas in Alberta, selling gas in Belgium, power and gas here. All different markets, all driven by somewhat different dynamics and the different points in the commodity price group.

We do look at what the customer needs. Is the customer going to sign up for five years? That is what we have in Ontario. We have a five-year fixed price product. That requires a completely different level of hedge cover than in an area like western Canada where it is a price pass-through, and you can change the price on a very frequent basis.

We come over here, and we have basically a one-year rolling price. We can pass that cost on to a large extent the following year, if the whole curve moves up. But what we need to guard against is a sudden blip, a sudden increase in prices halfway through the year or towards the end of the year. That is very difficult to hedge. That is when the asset stability does help out a bit.

b. Asset hedge based on long-term risk reduction

The asset hedge is based on what we think the long-term volatility is, and how liquid is the market. Do we have a lot of traders in? Do we have a lot of people who don't own assets, willing to make the market? Or are we basically being forced to buy from our competitors, where we need to own assets ourselves? We will get into more detail with that.

c. Dynamic over time

The other thing is in our approach. It is dynamic over time. What worked last year is not necessarily going to work next year. What worked pre-Enron is definitely not going to work post-Enron. Obviously, liquidity has changed. We have lost nine or 10 American companies who are market-makers and asset-owners, and willing to provide coverage and flexibility. We lost the two biggest players at the time: Enron and Dynegy's long-dated deals, 5-10-year deals. Very tough to find now. Most of the suppliers of gas, for instance, are majors. The majors don't have the same cash needs as the Enrons and Dynegys – they're not working a mark to market. You know the whole story. There are a number of reasons why it has changed. The liquidity is there in the short term, but there is not a long term trade in market in the same sense that there was three years ago.

d. Asset "right" strategy reflecting liquidity, credit risks (post Enron) and competitor positions

We talk about this asset right strategy. Let's counter-reflect it. If you can't buy the product long term, nobody is going to give you a fixed price, and you need a little bit more asset cover. If all your counter parties are below investment grade, obviously you need a little bit more asset cover. If your competitors are the only people who can supply you with the product, then you need some more asset cover. If we reverse those situations, obviously you pay a lot of short-term liquidity in gas. It is not quite as pressing a need.

e. Trade-off between cost of capital versus volatility reduction benefits

What we have is a trade-off between how much money we want to spend on these various projects, and how much volatility we are going to reduce, how much we can cover in the contracted market. I would take the position that you get a lot of bang for your buck for the first 10, 15, 20%, and you get a little bit less for that last 10, 15, 20%. We've never believed in 100% hedge. We've never believed in 0% hedge. There is some optimal range in there, and I'm not going to say we have pinpointed it. I can't say that it's 62.5%, I can't say it's within 5%. But I know a range and our model gives us a fairly good feel for what we want to do to minimise earnings volatility. We do the basic Monte Carlo analysis, we do scenario planning, to see what makes the most sense. A lot of it your gut-check will tell you is probably the right thing. Again, we'll get into it a little bit more with Ian and Gearóid.

5. Determinants of the Asset Hedge

I just put these three up because the model chews up the data and spits out a little bit different outcome for each of these, as to how much asset cover we want. When I talk about asset-hedging, we can hedge with assets, we can hedge with contracts, but it is all part of the procurement model. Here I am talking about how much of that procurement has to be hard asset.

In the UK Gas market, the risk factors are fairly low. It is an issue of how much volatility we are going to have in the coming year. But there are a lot of big players out there. BP and Shell have pretty good credit. Phil likes them. There is a lot of liquidity, a lot of market-makers, a lot of churn. It's very easy to come up with supply. The balancing is done daily. That is not technically too difficult. We have a lot of flexibility within the portfolio. We can manage that without too much risk. We may have to interrupt a few people, but the customers aren't going to freeze.

Texas Power is a little bit different. There is not as much liquidity there. There are a large number of merchant-generators. They're willing to provide power, but the credit ratings there are a bit dicier. The balancing risk: it is not a spread like it is here. It's one cash out or one cash in, depending where you are in the system. You don't tend to pay a large financial penalty if there is overcapacity. Those things work in your favour. The fact is though that you can't buy quarter-hourly blocks, which is what the balancing is done on, every 15 minutes. You have to buy four-hour blocks, so that is a little bit more cumbersome. So, all in all, you would want more asset coverage in Texas. You still have a shape issue - and there is a huge summer peak there.

Then UK Power: we have half-hour balancing. It is a little bit more onerous if you get it wrong. If you are short when the system is short you'll pay a fairly steep price. Or if you are long when the system is long, it is fairly painful. Our counter parties are the people we are competing against for these markets. There aren't many market-makers out there. So, in this case, we like having the power. The UK flexibility is in the coal plants. We don't have a lot of access to that. We do have some. We are trying to work on some deals that would give us more coverage coal-wise in the portfolio. But, all in all, these basic factors tend to push us towards a higher asset coverage in UK Power, for instance.

6. Short-Term Risks with Long-Term Optionality

We have talked a little bit about the procurement strategy. This goes back to the short term/long term. If you want to reduce volatility in earnings, you fix prices. If you want to fix prices, you can do it through the assets, or you can do it through a contract hedge. We have found, in the UK – and this is gas/power, indicative ranges for the UK – if you look on the left, and bear in mind that the right scale is a little bit different because you are doing two parts within a year, but you can see that there is a lot of concern for us about fixing prices in the current year. Again, we do not want to have a lot of volatility, a lot of risk, when we enter the customers' price in the beginning of the year. We are not going to have two or three chances to change prices during the year. We are going to get basically one shot at it. The closer we are to having our portfolio fixed, the less risk we run.

As we move out over time, we still have a fixed price risk because we still want to have some dampening of that price volatility going forward. The other thing, again, because we are 35% of the UK market, when we go out into the spot market to try to make either a big buy or a big sell, it tends to move the market some. Therefore, we want to phase things in and keep it nice and steady.

Power is a little bit different. We are more concerned about covering the shoulders, covering the peaks. We have also been in an environment where we thought power prices were pretty cheap, so it made a lot of sense for us to contractually commit to a lot of baseload and as much flexibility as we could, buy the assets that we can, so that we have a much higher target range for fixing prices in the electricity market. Gearóid will talk a little bit about that later.

7. Closing Comments

That is sort of an overview of it. We will come back to questions later. I will not specifically answer some now. I'm going to bring Ian Wood up to talk about the gas side of the business. When Ian has finished, we will have a Q&A period. Then we'll have a break. Ian.

Gas Position

Ian Wood

Director, Sales & Marketing, CEMG

I. Introduction

Thanks, Jake. Good afternoon, ladies and gentlemen. I appreciate the fact that we are already running a little bit behind schedule and that I am now all that stands between you and your coffee. If I can have your attention for the next 20 minutes or so, I will give you some useful insight into Centrica's gas position.

II. Centrica's Gas Position

1. CEMG the Fifth Largest Producer in the UK

Let us start with our existing equity production. As you can see from this slide, we are the fifth largest producer in the UK, producing some 10% of total UK supply. You are aware, of course, that Centrica inhertited the north and south Morecambe fields at the time of the demerger, together with the gas treatment terminals at Barrow, and the associated support base at Heysham. In case any of you has forgotten your geography lessons at school, the Morecambe fields sit in the east Irish Sea, where we have also recently developed the Bains field. Centrica owns 52% of Bains. We acted as the lead equity owner on behalf of GDF and First Oil in that process.

That 52% will help us realise a further 25bcf of recoverable reserves, which we will access by the Morecambe platform. Together with the reserves from Morecambe, our east Irish Sea assets will produce around 80% of our total equity reserves.

We have also been active in the northern and southern North Sea. The blue box here gives you an insight into what fields we have specific interest in. Worthy of specific mention is the recent development of the Rose field, in which we are 100% equity owner and operator, and the York field, which we acquired from Dynegy, as part of our purchase of the Rose storage facilities. We are looking to develop that field in the near future.

2. Asset Values

Any asset portfolio needs to be managed by a team possessing the correct technical competence in capability, particularly so if you want to maximise the value from that asset portfolio. We in CEMG believe that we have that technical capability in abundance.

This chart shows the deliverability curve for South Morecambe since first gas in 1985. As you will notice, South Morecambe was originally developed with a delivery rate of 1,200 million cubic feet per day. That was subsequently increased to 1,800 million cubic feet per day in 1992 with the installation of offshore compression. No further development really took place until after demerger when we saw the need and the opportunity to develop the asset to meet the expected decline in deliverability as a result of the field coming off plateau.

This chart shows the key projects we've been progressing to date. As well as the periodic and almost routine activities of compression re-wheeling, de-bottlenecking, and, of course, well reperforations to enhance deliverability, we have also drilled three further wells, two of which have been technically very stretching indeed. The first well, the extended reach well, involved a 5km horizontal well which was drilled to drain trapped reserves in the north of the field. And the Cross Flow Well, which was a UK-first for this particularly technique, was used to access trapped gas in the lower sections of the reservoir.

Overall this technical capability has added up to 350 million cubic feet a day of extra deliverability, and has increased the recoverable reserves, if we include Bains, by more than 175bcf in total. It's worth also saying that all of this was delivered safely, on schedule, and within budget.

3. Portfolio of Flexible Assets and Contracts

Well not only do we own and operate a powerful set of assets, but we also possess a significant and long-term contractual position. It is the combination of this asset base, and the contractual position in gas, which actually provides us with the high degree of flexibility within our portfolio which we need to meet customer demands.

The chart shows the multiplicity of supplies available to us. We have actually highlighted some of the more significant contracts and assets available. One of the first observations is that we are not all about Morecambe. The right-hand side of the chart, of this particular stack anyway, is somewhat indicative of our customer demand profile. Each bar represents the maximum daily take under each supply source, up to the minimum contracted take level. In most cases, we have the flexibility to reduce the daily take. That effectively means that we could compress that bar. Or we could increase the take duration, ie, we could stretch or elongate that bar, in order to balance customer demand. That would also help us optimise the market value from this portfolio.

We believe this capability is a key strength to Centrica in the gas market.

4. Meeting Customer Demand

As Jake mentioned, Centrica provides more than one-third of end-user demand in the UK. We are well positioned to meet this requirement, largely as a result of that profile of flexibile assets and contracts. This chart demonstrates the sheer size of our position, relative to our competitors, both in terms of the ratio of equity production in long-term contracts, to the actual demand line.

Clearly, our absolute customer volume needs would be far too great to be sourced via the wholesale, as Jake pointed out, and that would have an impact on pricing. We therefore need to maintain a large portfolio of long-term contracts and equity gas. Just to summarise this chart, for 2005, you can see that we have already met 93% of our demand.

5. Volume Terms to 2009

Looking further ahead, for Centrica specifically, as this chart demonstrates, we can see that at the bulk of our supply requirements in volume terms have already been covered through to 2009. We at Centrica recognised very early that our equity gas and long-term contract position was declining over time. We have set about to address that imbalance. How have we done that? Well the decline of contracted gas has largely been met by the signing of two new long-term contracts with Gasunie and Statoil. Between them, they will count for some 33% of our total supply requirements by 2008.

We believe these contracts were the first long-term contracts to be signed linked specifically to the UK gas market price, for delivery at the UK national balancing point. Effectively, the risk sitting with the producer.

Also on this chart, we notice that our appetite for New Equity gas is still there to meet the decline in existing reserves. The profile is shown: the green bar at the top. This represents our proposed investment plans in this area. We also recognise, of course, that to date it has been very difficult to acquire producing assets in the UKCS. We may well need to actually widen our horizons in the future if we are to fulfil this objective.

6. Imported Gas to Fill the Supply Gap

Let’s talk about the UK annual supply gap a little further. This is a picture which has been presented and commented on by almost every industry analyst recently. Yet, it is a very simple message. UKCS production is in decline and new sorts of imported gas will be required to fill the gap. There is nothing difficult about that.

In this chart we have actually netted off the effect of the existing UK interconnector, assuming it will be largely exporting during the summer months and importing during the winter months. However, allowing for that, we still estimate that by the end of this decade alone, the UK will require some 35BCM of imported gas.

As I said earlier, Centrica has been active as an industry leader, if you like, in supporting imported gas via the contracts with Statoil and Gasunie. Of course these were not just significant contracts in the impact they had on our own portfolio, but they have made a major contribution to underpinning the necessary investment infrastructure required to bring this gas to the UK. That is clearly an enhancement in terms of security supply, not only for our customers, but for the UK as well.

Let us not forget LNG in this context, because LNG will also play a role in filling the supply gap. We have already seen new reclassification facilities being developed and proposed for Milford Haven and Isle of Grain. In fact, if you actually look at this chart, you will notice there is a potential for a slight oversupply in the middle of the decade. This of course is based on the assumption that all of these projects will all come to fruition, on stream, at the same time. I guess we all agree that this is probably an unlikely scenario.

7. Diverse New Supplies for the UK

We have a supply demand gap, so where will the gas come from, and, more importantly, at what price will it arrive? The potential for diversity in new gas is immense. Without any doubt we will see gas arrive via new pipelines, we will see it arrive via ships. We will see it arrive directly from the Norwegian sector, the new infrastructure in the form of Britpipe. And we will see it arrive through the existing interconnectors and the new Dutch-Anglo interconnector, from, more likely, Russian sources.

LNG will be delivered, extensively in the early days I would guess from the Middle East and from North Africa. What I have also tried to show in this chart is to pictorially represent what the likely volume implications would be for each supply source, again on the assumption that all the proposed projects were to be delivered.

Only this week, I was surprised to hear that one so-called industry expert suggested that because of the UKCS's move towards import dependency, there was potential for a triple in the wholesale gas price. I find that quite an alarming statement, and clearly misinformed.

If we look at these potential resources, and we look at these new sources of supply to the UK, and we look at the resource cost, you can see that they range between that 15-18p range. We will come back to how those actually fit, and what implications they may have for long-term gas prices in a short while.

8. Peak Supply Remains Tight in the Near-Term

Before talking about that just a little further, I just wanted to consider the peak supply position. Having considered the annual UK supply/demand gap, we should of course look at the effect on peak. This chart shows a one in 20 typical winter profile. As the annual supplies from the UKCS decline, so does the available peak supply. As we can see, certainly in the first five years or so, we would expect that to be a somewhat tight situation for now.

Whilst new imported supplies will actually deliver baseload, they will actually lift up the curve, but it will be delivered on a flat basis, they will not provide a great deal of flexibility. Only very limited seasonal flexibility will be provided via these sources. To that extent, to manage fluctuations in gas supply and demand, it will have to be met via existing storage, potentially new storage developments, or greater use of the existing interconnector.

9. Implications for Future UK Prices

I mentioned price. Let us just discuss that a little further, as it is interesting: the implications for the future UK gas prices. On this chart, I've tried to hypothesise as to what the pricing effect would be if the UK moved towards that import-dependent mode.

If we start by examining the NBP curve, you can see how that curve is rapidly increased over the current year. That has been largely fed from a high oil price. The oil price has been in the $30 per range. We have seen a number of supply outages. And we've seen concerns in the marketplace expressed about the tightness of supply and demand in the current winter, and of course in the future. That is reflected in that particular curve.

If we compare that with the continental gas price curve, which is essentially the troll curve, largely oil-derived. We have tried to predict what that curve looks like, going forward. We have used two scenarios there. We have compared it with a $24 per barrel long-term oil price, and a $22 per barrel long-term oil price. They are the two dotted lines moving forward.

Looking at that curve, relative to the NBP curve, suggests that there would be a tendency for that NBP curve to trend towards that continental gas price curve over a period of time. Obviously probably starting in around the middle of 2004.

But the other important aspect of this chart is the actual resource cost curve. That resource cost curve is built up from the new supplies, which the UK requires as part of its import-dependent mode to actually fill that gap. We've considered short-distance LNG, we've considered some supplies from Russia, and we've considered the longer distance LNG also. We've considered that in the context of the cost of the marginal firm at that moment in time, on a sort of nominal basis. But that implies that there is a resource cost curve in that range of 18-20p.

So what does all that mean? From that we can assume that we are probably in that high price scenario for gas, but the high price scenario suggests that the long-term price for gas is going to trend out to round about that 20p per therm range going forward. Again, it is a hypothesis, but it is one well worth discussing.

10. Management of Weather Risk

Before we move on, let us just consider the situation regarding the weather. As we know, the management of weather risk is absolutely critical to our business. The chart on the slide shows the variation of heating degree days for 2003 versus the 10-year average.

As you can see, it has been a pretty warm experience this year. I'm sure you don't need a chart to know that it's been pretty warm this year.

But, as you would expect, the retail gas demand is strongly correlated to temperature. The use of weather hedging has delivered reduced earnings volatility to the Group over the past three warm winters.

However, we must recognise a number of points:

That intra-day basis risk cannot be hedged within the weather market as is. In other words, we use our contract portfolio to manage supply and demand requirements from customers. But of course a warm evening and a cold day: those kinds of scenarios are not ones we can manage through hedge products in the weather market.

Summer weather exposure, of course, remains an issue, particularly so where the unit margins are high. Our ability to hedge the summer and shoulder months is limited because of the liquidity of that particular aspect of the market.

On a more positive note, of course, let us not forget that Centrica is the largest UK player on the European weather derivatives market. We actively trade in both the primary and the secondary market, and have done so since its inception in 1998.

The weather market continues to grow. The number of European weather contracts transacted has increased by more than 400% since 2001. Our weather trading has been a key factor in supporting and promoting this growth. A substantial amount of Centrica's risk is now placed in this market each year.

11. Relative Cost Advantage

Overall, we firmly believe that our strategy in gas has given us a relative cost advantage over our competitors. That is what this chart shows. These, of course, are internal estimates. But we believe that in our assessment of our competitors' WACOG relative to our own, we are well positioned. This also refers to the residential WACOG and obviously Centrica is at the 100% baseline.

12. Summary

To summarise:

- We're the fifth-largest producer in the UK. We produce 10% of total UK supplies.
- We have a strong technical team who can maximise asset value. Of course, we have already demonstrated that with the advancement of South Morecambe since demerger.
- Our portfolio mix of equity and contracts gives us the flexibility to best serve & meet downstream demand. This has been built up over many years and we intend to maintain it.

- The bulk of our gas requirements are covered in volume terms to 2009. In the longer-term, we will secure new supplies from a diverse range of options, both contractually and in the form of equity.
- We do believe that our gas strategy provides us with a relative cost advantage over our competitors, and will continue to do so in the future.

Thank you.

Questions and Answers

Andrew Wright, UBS

When you look at the various sources you have for your gas supply over the next five or six years, although you have pretty good coverage in volume terms, it seems that the fixed price component of that is declining significantly, as Morecambe goes down, and some of your long-term fixed price contracts decline and are replaced by gas market price contracts. Is that a deliberate policy on your behalf, to reduce the fixed component of your price variability? Or is it something that you are seeking to address at some stage in the future?

Jake Ulrich

John, you can comment after I'm done on that. It is not a deliberate part of the strategy. We do have a range, and we are drifting into the bottom part of that range. We don't want to deal below that. We will be looking to obviously add some more equity gas, going forward. Ian's group is doing a number of things with some of our suppliers to change the way that these deals are priced, i.e., with more fixed price coverage. We are addressing that.

Phil Bentley

We have been moving from a lot of oil-linked prices that perhaps were different to what our competitors were paying for their gas to ones that give us a more comparable picture in terms of the exposure. We were locked in, fixed, to where we were seven or eight years ago on fixed price deals when the price had plummeted, then back to the analogy of cost of goods, we are out of the money on those cost of goods. We have to look at where our competitors are pitching it. Strategically and directionally, we are happier not have lots and lots of fixed price deals there but, as Jake said, within the range we are looking just to up that a little bit more as Morecambe falls.

But clearly, you have to be looking at where the competitors are coming from, as well as where the suppliers are coming from. BP, as Jake says, is not selling out a lot of fixed price deals these days long term.

Ian Wood

That's absolutely right. If they were, of course, they would be offering it out at a price way above what our expectation is of the market going forward. In that sense, it makes more sense to actually buy your gas linked to the market price. It also helps you with your supply and demand matching of course. If you do find that if you carry any length in the portfolio, then you can sell it out at a market price without any cost implications around that. We've already experienced the pain of being in long-term fixed price contractual positions in trying to meet the loss of demand or the fall in price as a result of that.

Jason Goddard, CSFB

What did you mean when you were talking about potentially getting hold of new equity gas when you said that you might have to widen your horizons in order to achieve that? Secondly, in the deals that we have seen recently, what do you think is the implied forward price of gas in the transaction costs?

Jake Ulrich

The second one first: obviously it has been too high for us. There have been two or three transactions done in the last year and we were obviously in the process… They were priced higher than we believe that the long-term curve, up around the 20p range. We do not think that in real terms we are going to stay this high. We think the market is a little overcooked right now. We will continue to try to buy things, but we are not going to be paying.

We want to buy equity. We do want to replace Morecambe production, but we are not going to overpay for it. It is a question of – do we get beaten up worse for paying too much or for not buying it? We will try to walk that balance for the next year or two.

There just hasn't been a lot coming out on the market. It goes back to your first question. If you look at the UKCS, the major seven with a tremendous amount of cash available – you can see them spending it far to the east of here – there just aren't that many prospects. Nobody wants to get rid of their production portfolio. They are willing to do some swaps. On the other hand, we really don't have much to swap out at this stage. We have to look beyond the UKCS. So does that mean Norway? Does that mean LNG involvement on the equity side? Yes, we will have to look beyond the UKCS.

Peter Atherton, Citigroup

Can you tell us your view on how linked the oil and gas price is going to be as the decade moves on? Is that still going to be the key driver? The link between them.

Ian Wood

The issue is one of infrastructure and development, and to some extent, the liberalisation within the rest of continental Europe. We expect to see that there will remain a long-term or medium-term correlation with oil looking ahead. But of course we see that dislocation happening certainly on a seasonal, monthly basis... In other words, short-term dislocations between the two commodities. But what we've historically observed is that there has been a longer-term correlation as the physical infrastructure links what is predominantly an oil-driven market with effectively the UK gas market.

Looking further ahead again, as we see more liberalisation come in, more and more free gas, more and more supply side competition on continental Europe, and more and more reference points in terms of transparency and liquidity of traded gas markets, then you could see that dislocation from oil and gas widen significantly. We expect to see that in the long term. In answer to your question: in the short - medium term, we see an annual correlation with the short-terms spreads, or dislocations between the two commodities, but the longer term, as a result of the liberalisation process, we would expect to see a dislocation between gas and oil.

Jake Ulrich

Not necessarily in either direction. We look at what is happening in the US and North America right now. We see gas is trading above its historic oil correlation. We could see the same thing here. We see a lot of LNG capacity, potentially, in Europe and the UK. If we do start to see some gas competition, that may speed up the de-linkage.

Ian Wood

To a certain extent we see that reflected in our contracts with Gasunie and Statoil. That is almost significant of a slight dislocation between oil and gas. With the first time being willing to sell long-term contracts linked to a gas index, as opposed to the traditional long-term oil-escalated type.

Jake Ulrich

One of the banks here did a study, and the Dutch have seen it, which basically says that UK prices are oil-linked right now because there's such a strong correlation through the interconnector, that this is not a true independent spot market. There clearly is some impact.

Andrew Wright - UBS

With carbon dioxide emission trading on the way in Europe, most people expect gas demand to rise as gas for coal substation is needed to reduce CO_2 emissions. Have you factored that into your view of the market going forward, or do you think the supply side is deep enough that there won't be a great deal of price disruption?

Ian Wood

First of all, you have answered your question at the end. The supply side is very, very deep. There is no shortage of gas in continental Europe. The issue you have is geographical shortages. The UK is a good example of that. But fundamentally, the fundamentals are that there are a significant amount of reserves, particularly from Russian reserves. It's all a question of price. It is when the economic price signals are sent to allow those reserves to be recovered and developed. There is no fundamental shortage of gas.

Jake Ulrich

If you look at the upstream consultants in the studies: at below 20p there is a tremendous amount of resource available. I don't see it necessarily pushing things.

Gearóid Lane

A specific answer to whether we've factored that into our view: yes, we have factored in a reduction in production from coal stations and significant increase from CCGTs, both as a result of Emissions Trading and the Large Combustion Plant directives.

Iain Turner, Deutsche Bank

You showed a graph of energy business operating profit going forward with profits going up year on year. Are you now in a situation where you are replacing Morecambe with market price gas? Does that mean that your best years, in terms of profitability, are behind you?

Sarwjit Sambhi

I'm going to show, at the end, what the profile of gas production is. But I think what you'll see at the end is a profile which shows declining profits from Morecambe, but new equity replacing those profits probably better than we expected. Are we going to be able to repeat the steady earnings profile that Jake showed earlier? It is possible, but it depends on how successful we are in terms of the investment programme.

Phil Bentley

There are two aspects to that question. It is not just the upstream business that was shown there, it was the downstream together. That is the whole point there. If you think about what we said before about the British Gas transformation, the opportunity to grow margin there, that significantly enhances that total pot. As we've said before, a 10% decline in Morecambe on Group EBIT is 3.5%. And so, that's what you're talking about. When you talk about the decline of Morecambe, you're talking about a 3.5% EBIT decline.

With the growth in our asset portfolio, and the growth in our downstream energy business margin together, it leaves, certainly, the view that we are not past our best. We have a long way to go yet.

Jake Ulrich

The mix will change.

Andrew Mead, Goldman Sachs

You talked about looking beyond the UK/Continental shelf. Would you also consider looking at large international pipeline investments to secure delivery, and how that investment economics works against getting guaranteed delivery in your longer-term contracts.

Jake Ulrich

No. We are still not into the pipes or wires game. I think, given the amount of capital involved, we are not the right player for that. There are enough interested players, producers especially. We are going to be in a minority position in larger projects. If we have to book capacity, fine, but not equity ownership.

Simon Flowers, Merrill Lynch

I think that was the answer to my question. When you look at these new projects, you are going to be transferring from having 100% at Morecambe, and complete control and the huge optionality that gives you. Are you just seeking to replace reserves at the right price? Because you will have a minority position, that will mean that the equity gas is different for you in the future.

Jake Ulrich

Let us be realistic. We are not going to be the lead on a big project outside the UKCS. We don't have the risk appetite for that either. We will be a smaller player. Yes, we will not have the flexibility either. But if you look at the curve that Ian showed earlier, the flexibility isn't so much in Morecambe, the flexibility is in the contracts. That's what we have to work on: recreating that flexibility along with the producer.

We are running Morecambe at a fairly high level now. Given the current gas prices, it doesn't make much sense to… We certainly don't shut it in during the winter period. We'll back it off in the summer. I'm not so concerned about us not being owner-operator.

Bobby Chada, Morgan Stanley

Just a follow-up on that question. You talked about the suite of contracts giving you as much flexibility, perhaps even more than Morecambe. We sort of overestimate where your flexibility comes from. Is that replicable going forward, or are those contracts legacy contracts that you don't think you can negotiate or renegotiate going forward?

Jake Ulrich

We won't have the same flexibility. There is no question, we are moving into a more baseload world. You are not going to develop a large LNG capacity here in the UK on winter prices alone. It's about more flexibility. A lot of that flexibility is through new storage. I am pretty bullish about storage prices going forward. I think we have a tremendous amount of input capacity, gas, coming into the UK, and available to the UK year round. But it is that flexibility that we need to recreate.

The other point that a lot of people overlook is the IUK operation. We will have a backlog capacity of 20bcm a year. It is a tremendous amount of flexibility if you get the right price signals.

Ian Wood

That is what we are seeing. Obviously, as beach supplies decline, with that decline is obviously the amount of flexibility that those beach contracts would have historically provided. We also see a shift in the mindset of the producer. It is not cheap to provide flexibility offshore and deliver that onshore. The producers are now saying, yes we will produce gas, but we are going to produce it baseload because that's the cheapest way of doing it. The market will seek out and find innovative solutions of creating and meeting that flexibility, because it is not going to go away. That demand side flexibility is always going to be required. We will see new structures, contract structures, and ways of meeting that. It will be on both a seasonal basis and on a daily basis.

LNG is a good example. You could imagine a scenario where you actually create some seasonal flexibility by buying from a producer baseload; baseload cargoes of LNG. Effectively having those cargoes delivered into the UK in the winter, and those same cargoes delivered into the US during the summer, the producer gets the benefit of high winter prices and high US oil prices on condition of demand, but we get, effectively, a seasonal or a flexible supply of winter gas. The market is going to have to think creatively around how it resolves these issues.

Gearóid Lane

In our own portfolios as well, we have also created an interesting new source of flexibility that John can exploit in the interplay between the gas portfolio and the CCGTs.

Jake Ulrich

That will increase going forward. We will see more CCGTs in the UK.

Electricity Position

Gearóid Lane

Head of Electricity Supplies, CEMG

I. Introduction

Thanks, Jake. Good afternoon, everybody. This afternoon I would like to talk about two main areas within the electricity world of Centrica. One is to give you some insight into how we procure electricity to risk manage our retail businesses, or growing retail businesses I should say. I have been working on that right since de-merger, in fact prior to that. I am an old hand on this stuff. Secondly, I want to touch on some of the challenges facing us going forward, in particularly, I want to touch on the Renewables obligation which is already upon us. It is in its second year now. Also, the EU Emissions Trading Directive, which will be upon us from 1 January 2005.

II. Power Station Portfolio

Jake eluded earlier to our building of a portfolio of power stations to help provide a base underneath the risk management of our power situation. That has all been developed over the last two and a half years. We have completed the acquisition of six gas-fired power stations with a total capacity of 2.2 gigawatts. What many of you may not have picked up on is that in terms of the number of gas turbines that we now operate, that makes us actually the largest operator of CCGT gas turbines within the UK. In terms of the number of megawatts of capacity that we own into our portfolio, it makes us the second biggest owner of CCGT capacity.

I'll be coming back again and again to the issue of flexibility, as Jake did, and Ian also. One significant feature of this portfolio that we have built up is that it includes plants of various vintages, right from the very first CCGT to have been commissioned in the UK, up to Humber Power which is a very modern gas-fired plant.

That flexibility and diversity gives it a lot of swing, to shifting capability, flexibility, which in turn enables us to risk manage our downstream businesses very effectively.

1. Spalding

I will say a few words about Spalding, up in the top left-hand side there. That was originally a 50-50 joint venture between ourselves and InterGen. We sat down with InterGen and then restructured that as a tolling contract whereby we were the off-taker of the power from the plant, and InterGen was the owner and developer of the plant. That plant is under construction. Surprisingly for a power plant, it is ahead of schedule in its construction. It is using proven 9FA-plus GE turbines. It is actually going to do its first firing in February. It will start commissioning in August. That gives us some slack within the timetable for that to be in place to be providing power into our portfolio by winter 2004. So far it is a real success story - touch wood.

2. Acquiring Power Stations at Low Cost

This is a graph that many of you will be familiar with. In fact I'm sure some of you have even drawn graphs like this in your own analysts' reports and are remarkable similar. Not that we lifted this from any of you, this is all our own wonderful work!

This shows two things. The left-hand axis shows the UK power price. That's this red line here. And the commodities cycle, which Jake has talked about. We have been interested in procuring some power plants to help risk manage our business right from these early days, 1998, 1999. We looked at many of these plants that were sold around that time, and took the decision that the prices were far too rich for us. The prices of those plants – the individual points on the line here – are actually against the right-hand axis which is pounds per kilowatt of capacity paid. Our acquisitions are all these ones down here, shown in dark blue on the text. We believe that we have acquired our fleet of power stations at the right time in the commodities cycle.

3. Managing the Portfolio of Assets and Contracts to Match Downstream Demand

I mentioned earlier the flexibility inherent within our portfolio of power stations. This graph demonstrates that quite strongly. This is a typical winter's day. It is a real winter's day, as to the way in which we would schedule our fleet.

The swing within our portfolio of power stations looks like a factor of four between minimum production and maximum production, all over a period of a few hours. This is 5pm on a winter's afternoon. You can see that the flexibility and shape within our portfolio means that we can largely eliminate our peak risk within the winter. The power stations tend to run much higher load factors during the summer when this peaking isn't required.

The dark blue block at the bottom is the power that we source from the market under a whole range of different arrangements. Jake mentioned the British Energy contract. That is a Shaped power purchase contract. We have a number of other structured contracts which feed into our portfolio. We have a significant portfolio of over-the-counter purchases, just through the trading market, where you pick up power on the phone. We'll see how those run out over the next few years.

The little blue bit on the top of the graph is worth pausing on for one moment. It is balancing mechanism volumes. This is both power which is in some cases bought and in some cases sold to the balancing mechanism.

One thing we wanted to pick up on with that is that people think of the UK balancing arrangements and the UK balancing mechanism as a particularly scary and volatile place that you don't want to be exposing yourself too. However, we have found that prudent use of the balancing mechanism is a very effective and very cost-effective part of a procurement strategy. For example, picking up significant volumes of power in the middle of the night, or selling very significant volumes of power in the middle of the day, at prices which you can be pretty convinced won't leave you exposed.

III. Power Prices

Picking up then for a moment on what has been happening to prices over the last few months. This is something that won't be a surprise to many of you, I'm sure. Way back in those heady days of the early part of this summer, prices were as flat as a pancake. £18 a megawatt hour. Annual power running out over the next three or four years. Very little contango in the curve, and a small amount of upward movement year on year.

If you compare that to where we are now, it is a completely different world. That is driven by two things, and we'll come back to them in a moment. On the one hand, there is a general upward movement in the level of power prices driven by an increased perception of tightness, due to mothballing and increased fuel prices. Beyond this part here, of summer 2005, emissions trading is also producing significant price premium within the curve.

Again, we will demonstrate this in a moment, but we would say that our exposure to this upward movement in power prices has been limited. It has been very effectively risk managed, both by the power station fleet, and having secured significant volumes of power during the lower part of the cycle.

IV. Fuel Prices

I wanted to pick up on fuel prices for a moment. Clearly everybody knows that gas prices have firmed up very significantly over the last few months. That has certainly been contributory to the movement in power prices. What probably isn't quite so publicised is just how much coal prices have changed over the last few months, in particular since this summer when coal prices have effectively doubled.

The driver on coal prices has primarily been increases in the cost of freight. Freight prices – from Richard's Bay, South Africa and from Newcastle, Australia, to the European markets – have trebled in cost over that period. It was largely driven by very intense competition for freight, and a lot of coal moving into China and other eastern markets. That has really got quite important implications for the marketplace. There is a damper between the spot coal prices – we see it here – and the effect of coal price to a power station, driven partly by coal stocks – stockpiles that are held by the individual power stations – and also driven by contractual arrangements between UK coal producers and the power stations themselves. Although those contractual positions are far, far lower than they were way back then when pretty much all UK coal had a long-term home in UK power stations.

But if this coal price increase stays with us for a significant period of time, that will have two implications for the marketplace. One is that the coal-fired plant will start to become a marginal price-setter far more than it has been for the last year or two, where gas has been setting prices for maybe 80% of the time plus. Coal could start to set prices up to 40-45-50% of the time, particularly during the summer months. That will have implications in itself.

More importantly, from our viewpoint as a competitor with a number of other producer-suppliers within the retail market, this will have a significant impact on the input power costs of the people who have a significant amount of coal within their production fleet.

V. Cover in the Near-Term

I mentioned earlier that we have secured a significant degree of cover against the forward movements in power prices. This graph is an attempt to demonstrate that. The dark blue part of the graph shows the percentage of our forecast future needs for electricity, that we have already covered, in a combination of our power stations, the structured contract portfolio, and the over-the-counter procurement activities.

The first thing to note is that we are covered for 2004 and 2005. Sarwjit will pick up some numbers on that in a little while. But our exposure to movements in power prices in 2004 and 2005 are strictly limited.

The second thing to note is the light blue bar on top of the dark one. It is showing the extra cover that we could secure from our own gas-fired power stations should we wish to run those stations at a higher load factor than we currently do. Why would we want to do that? Well, if power prices rise, in relation to gas prices, it will naturally be the case that we will risk manage that by running our gas fleet harder.

At the bottom of the graph, we have the numbers showing what we have assumed about the running patterns of our power stations over those years. The light blue part is basically showing what would happen if we ran them at an 85% load factor.

A final point to pick up on that graph: the period from 2005 to 2007. Our average level of cover over that period, or forward cover, is of the order of 75% right now. If we choose to run our power stations harder that will rise to almost 85%. The reason I pick up on the 2005 to 2007 period is because I'll be mentioning it again in a moment when we talk about the Emissions Trading Scheme because that is the first phase of the Emissions Trading Scheme.

VI. Assets Covering Demand

I also wanted to just give you a view as to our internal estimates of our cover position vis a vis our competitor's cover position. This graph shows our estimate of the total retail sales of each one of our major supply competitors for 2005. Those retail sales include all market sectors, from domestic all the way up to large industry.

The blue bar underneath, the dark blue bar, is the equity production levels – so the output from power stations that are owned by that company themselves. The light blue bar on top is long-term contractual power, by that I mean, not a one or two-year contractual commitments, but very long-term power purchase arrangements. In Centrica's case, that is the Spalding contract that I alluded to earlier. In our other competitor's cases, that is the long-term PPAs with the IPPs that were entered into in the early to mid 1990s, largely.

A point that would really show is that although there is a perception in the marketplace that our levels of cover are significantly lower than those of our competitors, this graph I believe will dispel this. That may be counter-intuitive to some of you, but in order to verify that, think of this: these companies down here control almost all power sold in the UK. Almost all; the lion's share of all power that is sold in the UK is sold by these seven companies.

But by comparison, the amount of power that is produced by people who are not affiliated to our selling power to these people – if take, for example, the non-vertically-integrated British Energy Power, Drax, Fiddlers Ferry/Ferrybridge, Mag nox, International Power, the Interconnector, I could go on - we're talking about significantly more than half of all the power that is produced in the UK is not under contract to these people. We're all in the same game.

This is also important when we talk about the Emissions Trading Scheme.

VII. Electricity Strategy for a Relative Cost Advantage

You've seen a graph like this from Ian's slides. Again it is the same format here. The 100% line across here is our cost of electricity. The blue and the orange lines are our estimates of our competitors' cost of electricity, where the blue line is the relative cost to our 100% of our most expensive competitor. The orange line is the relative cost of our cheapest competitor.

This graph shows that we believe that we have an advantage *vis-à-vis* our competitors, in terms of our weighted average cost of electricity for our residential customer base. Why is that? It is because we have acquired our assets at competitive prices and are therefore passing through power from our asset book at low prices. It is because we have purchased very significant volumes of forward cover at the bottom of the market, or at a bottom of the market. It is also because several of our competitors have material, very highly priced, power purchase agreements from the IPPs. You will be aware that the deals that were struck in the early to mid 1990s, which justified the building of a lot of these gas-fired power stations, had contract prices of £30 a megawatt hour or more. Even by the new high level of prices that we see now, those are very high.

I would also point out that we believe that a number of our competitors have very significant peak exposures – exposures to the peakiness of prices. I also mentioned the coal exposure that some of our competitors have. This is really just to show you why we believe we have a cost advantage.

What it does show is that, as we move through time, based on the existing portfolio of deals that we have in place right now, that competitive advantage will remain, but will diminish very significantly. Of course, that is based on what has been done to date, but we believe, at CEMG, that we will continue be able to provide innovative and competitively priced deals to secure power for our customers right into the future. This is a snapshot in time. It would have looked the same last year, coming down in 2006 rather than 2007.

VIII. The Renewables Obligation and the Emissions Trading Scheme

That is really all I wanted to say in respect of the procurement of electricity for our residential and business customer base. I now want to move on to discuss two of the burning issues. Burning issues for both us and for you in being holders of ours shares. That is, the Renewables obligation and the Emissions Trading Scheme.

1. Renewables Obligation

On the Renewables obligation, I want to start by putting up this graphic here. Just by way of some background to this: we went through a very detailed and strategy development process which was led by Sarwjit and involved myself over a period of pretty much a year. That culminated in the announcement by Sir Roy Gardner of our Renewables strategy at our interim results presentation at the end of June. At that time he announced that we would be spending up to £500 million of equity over the next five years in Renewable assets.

Those assets will be principally wind power. We also announced at that time that we would be centring our strategy around strategic partnerships. With a view to that, we have already announced our first significant deal, which is a 100-megawatt offshore wind farm in Morecambe Bay – a place that we know quite well. It is a joint venture between ourselves, Danish Oil and Natural Gas, and Stratkraft of Norway.

These two partners are significant in that they are bringing in new equity into the marketplace from outside, from well-credit-rated organisations. In fact, both of them are owned by their governments. Also, particularly in the case of Danish Oil and Natural Gas, significant expertise in both wind and offshore wind. We are very happy with that relationship. There is more in the pipeline. We can't say more now. Watch this space, is all we can say, but you should expect to see a flow of deals from us on Renewables, delivering this strategy in the coming months and years. Also, we would mention that we are involved in prospecting for new wind sites in the round two kroner states process to secure some acreage for potential future developments.

One final thing that I'll pick up on this graph: this dark blue line here is obviously our equity investments starting to feed renewable electricity in. The light blue part is our expectation of how much we will secure from the trading markets. Two more things – one is, the green bars on the left hand side. For the first period – as it is known in the market CP1 2002/3 – we were one of only two suppliers that met all of our obligations for the procurement of real renewable electricity. That is quite significant, particularly when we can tell you that, by comparison to paying the buy-out price as a number of our competitors did, this delivered us at least a 10% cost advantage in the cost of complying with the Renewables obligation in the first period. We believe that this is a real demonstration of our trading skills.

We have made very significant headway in the procurement of renewable electricity for CP2 period for 2003/2004. And we have a small number of deals pushing out into the forwards market, but that will grow over time.

A final point on this graph: you might notice a big gap. In a structurally short market we don't believe in going long. We have built in, to our views on the marketplace, the potential for us not to meet all of our obligation for the moment.

The next point on the Renewables obligation. There is a general perception that Centrica is way behind in this market place and that your Innogy and Powergens have stormed ahead of us, and they have all these assets around the country. We want to make four points to dispel that myth.

a. A drop in the ocean

One is that the steps that have been taken to date in terms of people putting in place Renewables capacity are a drop in the ocean by comparison to where we need to be in 2010. In fact, given the announcement on Tuesday that there will be a consultation on extending the growth in the Renewables obligation up to 2015, this is even more applicable, these drop in the ocean words.

b. NFFA arrangements

Secondly, we should note that all of these projects that were done in the early/mid-1990s and late 1990s were done under the NFFA arrangements. Therefore, none of the power or ROCs from these projects actually goes into the portfolio of these people. They get sold onto the marketplace by this quango called the Non Fossil Purchasing Agency, the NFPA, in biannual options.

c. Advancement of technology

The third point we would make is that the technology is moving very fast here. The things that people did in the 1990s are no longer relevant in any real way. People were developing wind farms with the capacity of each turbine being 600/700 kilowatts. Now people are building turbines with capacities on individual turbines of four megawatts. So a six-fold increase in the capacity of the turbines.

d. Independent generators

Finally, if you look at this other graph here, these are independent generators that have been in this marketplace. We believe these are very good entrepreneurial, hungry developers who are all very keen to have strategic partners, and that's where we came in.

2. Offshore Wind

This pie chart is also meant to demonstrate that there is a mountain to climb, but we have an appetite to get up there and start climbing the mountain. This pie piece here shows the existing facilities on the amount of power and renewable tickets that they are likely to feed into the market by 2010, at that time we expect the total obligation to be 35TWh or thereabouts.

The further potential for onshore wind is significant, but it is limited, everybody believes, by grid connection, but more importantly, by planning. There will be a point at which we reach saturation and the local planning authorities will then not allow people to build more onshore wind, particularly as and when offshore wind proves itself as being viable.

This yellow piece is the "committed" offshore wind. That is the offshore wind that we have picked out as being "committed" – very much in double quotes – and the stuff that it has consents and capital grants from round one of the kroner states process. Not a lot of that is really committed.

This blue pie over here is what people need to do in order to get us to where we need to be in 2010. So a hell of a long way to go.

In order to get there, it is our belief that offshore wind is the only form of generation that can provide the required scale. We believe that we are very well placed in that marketplace, given both our strategic partners and our offshore skills. We would stress that: we believe we are the only UK electricity supplier with any significant degree of offshore skills. Those offshore skills will deliver us cost synergies and risk reduction within our development of offshore wind which will not be there in a number of the other developers.

3. Economics of offshore wind

What do the economics of offshore wind look like? This is a very indicative graph based on a notional 100-megawatt offshore wind farm. It is a 100-megawatt development where the construction is carried out in two seasons. Total cost: £100 million. Annual op cost of £4 million. The right-hand side shows the revenue that one would expect to receive from that type of a power station. The deep blue bar at the bottom is just the value of the electricity and other benefits and other things that one gets as a small renewable generator.

The light blue bar at the top is the value of the Green-ness of the electricity, the ROC itself. Comparing that to the costs, the orange bit on the bottom being the capex just amortised in a kind of depreciation sense of the word over the total number of megawatt hours that this thing would produce over its lifetime. The opex is the yellow bit. The gap in-between is the investment returns, which are significant. We believe that returns in the order of 12-15% are available to these types of projects. That in itself isn't surprising because being the marginal technology, unless offshore wind can be deployed, and can be deployed with these kinds of returns, then it won't get deployed and the price moves up. It is kind of a self-fulfilling prophesy; that unless offshore wind can be remunerated, then the prices of ROCs continues to rise.

4. Emissions Trading Scheme

Moving onto Emissions Trading. I am getting to the end of my presentation now. You've all seen this before, I'm sure. We are not planning to give you any kind of a detailed description of the Emissions Trading Scheme, because we would be here for another three hours. Basically, the Emissions Trading Scheme, the one thing that distinguishes it from above all else now, is the sheer tightness of the timescale between where we are now in December 2003 and when the scheme actually kicks in, in January 2005. Everything is way behind. The one thing that cannot slip, which is the one thing that always slips in UK things, is the start up.

If this was BETTA, all we would do is move this over here. With the Emissions Trading Scheme it cannot be moved without another Directive, and you will not agree another Directive with all the member states.

That sheer compression of the timetable adds another of dynamics into the marketplace. One is that it means that we believe that liquidity in the first year will be low. The second is that the work that needs to be done by every industry player, in terms of getting ready to do this, is immense over the next year.

We have three interests in the Emissions Trading Scheme.

- Firstly, we are an emitter. We own eight facilities that will be facilities under the scheme. Six are gas-fired power stations. One is Bruce's facilities at Rough. The other is Morecambe. Both of the latter are parts of the scheme because of the compression facilities.

- Secondly, our primary interest in Emissions Trading is in its impact on UK power prices, and what that means for our competitive position.

- Thirdly, as was asked in one of the questions earlier, potential knock-on impacts into the gas market.

5. The Value of Carbon

I really want to demonstrate just how much uncertainty there is in one of the primary issues here. What is a tonne of CO_2 worth? The right to emit one tonne of CO_2?

You guys out there, as clever as you are, have come up with estimates in the region of €5 a tonne, up to €30 a tonne. And we are the same. Depending on the assumptions you put into this, there is enormous scope for getting a different answer on what the value of CO_2 will be. Some of the key uncertainties at the moment:

- One, is the glide path that the different member states take towards Kyoto compliance in the first few years.

- Two, is the tightness of the marketplace.

- Three, is the cost of abatement.

- Four, is the linking directive which allows carbon credits from other countries to be imported into the EU.

All of these things are very unclear yet. But there are people willing to put their money where their mouth is. There are trades happening in CO_2 2005 vintage at the moment, and they're happening at kind of €12-13 a tonne. That bearishness in prices within this price range is something that I think we would echo, particularly given a lack of appetite among the member states to see dramatic increases in the price of fuels over the next couple of years, combined with a lack of appetite for seeing big windfalls accrued to polluters in the same period.

6. Winners and Losers

We do believe that there will be winners and lowers in this marketplace. We clearly have read in a number of cases that there is a perception that Centrica will be a net loser out of this. We wanted to pick up on that. One is, we have shown you covered graphs which suggest that we are significantly covered for the first phase of the scheme. We have shown you a graph to suggest that other generator suppliers are not as well balanced as you might have thought.

Picking up on one specific thing though: our customer base is split into two different sets of customers – a residential customer base and a business customer base. For the residential customer base, our asset portfolio, including Spalding, produces 75% of the needs of our residential customer demand. The maximum potential is pushing towards 90%.

That is important for two reasons, related to our business load. One is that that business load is something that… The perception is that that isn't a massive contributor to the overall valuation of the corporate. But, much more importantly, we have already got evidence that that marketplace is already passing through the increased value of carbon.

Why? Because a lot of multi-year contracts get sold to business customers, and we are still competitive in that marketplace, even at these very increased forward power prices. We sell all of the power to that business market on a back-to-back basis which completely de-risks it at the point of entry.

I've mentioned that we have a high level of cover in place for phase one and moderate CO_2 prices. I also wanted to pick up that the advantage that one may have as an owner of a coal plant, from the Emissions Trading Directive, is strictly time-limited. Firstly, we believe that any windfall will be capped off at the new entry price. If people try to pass through too rich a carbon price into the power price, then that will stimulate a new entrance CCGT which will dilute the windfall itself. Secondly, there will be more and more auctioning in later phases. Thirdly, the Large Combustion Plant Directive will put a number of coal stations out of business over the period of phase two. We should also say that, as a less carbon efficient technology, coal should get squeezed out of the generation mix on any sensible economic assumptions.

7. Centrica's ETS Action Plan

a. Review asset cover

What is our plan of action, as regards the Emissions Trading Scheme? We are doing one thing that we always do anyway: looking at our contract cover and our asset cover. In particular, in relation to assets, we will consider purchasing further assets. Sarwjit will come onto that in a moment. We will also consider development options: acquiring the right to develop an asset should things happen in a way that doesn't favour us. We should also say that our drive into the zero carbon renewables technology will also mitigate this risk.

b. Review contract cover

We constantly review our contract cover.

c. Prepare for trading

We are in detailed preparations for trading – putting in place all the master agreements, netting agreements, credit support for trading with major European counter-parties.

d. Lobbying

We have obviously, like you would expect us to, have been very involved in the governmental relations aspect to make sure that the detailed rules of the game don't come out in a way that is not sensible for retail market competition.

IX. Summary

To summarise what I have said so far:

- Our fleet of power stations has been acquired at low cost.

- The portfolio of assets and contracts gives us flexibility, optionality to optimally shape against our demand and to maximise profit potential.
- The portfolio gives us significant cover against volatile spark spreads.
- We will seek to, over the coming years, at least maintain our competitive advantage in power procurement, if not improve it.
- We are on track to deliver against our Renewables Obligation, and we have a firm plan of action on emissions trading.

That's all I wanted to say. I think Jake wants to open it up for questions again now.

Questions and Answers

!

Martin Brough, Dresdner Kleinwort Wasserstein

Drawing out the hedging and stuff: you rightly say that you'd have less a requirement for hedging physically the business sales. But on that analogy, although you have 75% cover of your residential sales from physical generation, isn't it true to say that your competitors are one and a half to two times generation to their residential sales?

Gearóid Lane

To make a detailed speculation about the supply and demand for each individual supplier is a difficult thing. I would say there are a range of answers, depending on which supplier you look at. I would certainly say that our existing generation portfolio, compared against purely residential sales, is probably lighter than some of our competitors, but only a bit. 75% up to 85% of physical cover is pretty substantial. And, as I say, it would not take all that much additional action within the power market in terms of acquisitions or development options to make that 100%.

Robert Marshall-Lee, Newton Investment Management

What is the payoff, in terms of increasing load factors on your existing plants, in terms of loss of ability to flex and therefore create the shape that you need there? The second question: you talked about coal load factors decreasing. Do you see coal shifting to a more shaping role, rather than baseload role, particularly with regard to the increase of wind production? A quick reaction there.

Gearóid Lane

I'll take those in turn. In terms of the gas stations, it is a very complex equation as to how you optimise the production levels of the stations within the portfolio. It's something that John's team does, using some quite complicated techniques. There is clearly a trade-off between how hard you run the stations and how much cover you have against Super Peaks. But there are also two different ways that the forward market can move at the moment.

Prices may rise in the Super Peaks to be the kind of means of reflecting the tightening supply/demand match. That would be driven by increasing gaming opportunities, or increased levels of very expensive marginal price plant being pulled into the system from time to time. That could drag up the peak to off-peak ratio within prices. But it is also possible that the stimulus to new entry will be emissions trading. A high value of carbon passing through to the market price will actually increase the general level of prices, rather than the peakiness of prices.

What we are saying is that we do have that flexibility, and at least it back-stops our risk. We are not saying that that is what we do, and we are not saying that at the moment it is financially the right thing to do. But we are saying that it is an insurance policy. The decision as to what actual load factor to use will be determined on a kind of dynamic basis day by day.

Jake Ulrich

Maybe we will get some more kit.

Gearóid Lane

The second question was about coal moving to lower load factors, and what that may do to prices. That is a certainty in any case. Never mind the Large Combustion Plant Directive or the Emission Trading Scheme, the sulphur limits on their own will force these stations to be more and more a peaking plant. So we do see that trend continuing, but it will be reinforced by the high coal prices we see at the moment, if those prices increase.

What do we do about that? The situation we are in at the moment with the coal fleet is that there are a number of strategic coal assets that are selling their output into very short-term markets. That includes Drax which can't sell forward because, AES, it doesn't have a credit rating, and the banks haven't put it in. Obviously the international power deal has collapsed. It includes FFF, which as you know is the subject of a sales process at the moment. And it includes the International.Power Rugeley plant.

We are considering our options in respect of entering into commercial arrangements with those operators, many of whom are very hungry for arrangements, and many of whom are subject to deals at the moment. But as and when coal prices give the signal that we need to do something about our peak cover, there will be several options open to us.

Jason Goddard, CSFB

Thank you. Just on that question of peak cover, could the first hydropump storage assets have a place in your portfolio? I think they might be up for sale.

Gearóid Lane

We are certainly that Edison Mission have appointed not one but two sets of financial advisers in the last week to assist them on potential disposals of the pump storage assets. There are pluses and minuses for pump storage that need to be taken into account. On the one hand, on the face of it, pump storage provides a diurnal swing capability which might fit nicely into our portfolio. It's a day/night arbitrage tool that can work very well within our shape.

But if you study in any detail the finances of any of those plants, a large chunk of their revenue is driven by different contracts altogether – arrangements that they enter into with the National Grid for grid support, for frequency response, for rapid response services. Putting those revenue streams onto our books may be less attractive. Overall we will consider or options in respect of the plant and keep an eye on what may happen in respect of their sale. Is that fair, Jake?

Jake Ulrich

Obviously the concept would work. The two issues: price and what Ofgem thinks about it.

Gearóid Lane

I didn't even want to say that!

Jake Ulrich

After the last hearing, one is enough!

Gearóid Lane

Back to the Competition Commission!

Vhantil Charles, Capital Group

Just a follow-up question with regards to the potential new assets you could buy to supplement your existing assets: has there been a movement upwards in these prices, given the current increase in power prices?

Gearóid Lane

The main thing you can say is that we are just going to have to wait and see because no plant has changed hands really since then. The Medway transaction took place in the last couple of months, but it was just a reworking of the existing contractual arrangements between SSE and the other owners. That was at a continued low price, despite some upward movement in the market prices. One may take that as some evidence that the asset market may not react in the same way.

But I would say also that people should be aware that this upward trend in power prices doesn't have to last forever. Here is one scenario: we don't see any very cold periods this winter, and/or we don't see any huge further outages in production plant, and prices are actually soft in the prompt market as they have been in the period to date. There is every chance, in that scenario, that power prices in the spring for the forward curve could correct back downwards. Maybe not necessarily down to the £15 level, but a significant chunk could come off those power prices.

I would say that both the seller and the buyer of an asset would have to reflect that in any asset and price, and I don't think anybody at this point, certainly not us, will be getting some rush of blood to the head saying we must pay twice the price we paid for the last asset, and blow the bank on the next one. That is certainly not our intention.

Jake Ulrich

On the other hand, I would not expect to replicate the price per KW that we have had in the past. The curve is moving. It is a question of whether it is real and how long it is sustainable. We will wait for some evidence.

Bobby Chada, Morgan Stanley

I have a couple of questions. One is, the chart you show on page 21. It is basically your hedge position over the next four years, both equity and contracts, and then the uplift. It is a pretty straightforward question. Are those hedges at fixed prices or are you including the floating price contracts that you signed? Some of the British Energy contracts didn't fix the price.

Gearóid Lane

No it doesn't include any floating price contracts, but it is not a fully fixed price, in that the position *vis-à-vis* our own power station fleet would not necessarily be fixed price, unless we have hedged forward the gas for all of that period. We are not going to reveal in detail what our power station fuel hedging strategy is. But we do have one, which will involve a combination of both. It is neither nor. It doesn't include any floating price deals, that's for sure.

Bobby Chada, Morgan Stanley

So contracts you have signed with other people are fixed price in this chart?

Gearóid Lane

Yes.

Jake Ulrich

Or spark-related.

Bobby Chada, Morgan Stanley

The second question: when you sell power effectively from your own power stations to yourself, how do you set the price? Is it a market price? One of the comments earlier suggested that it wasn't market related.

Sarwjit Sambhi

The question is: how do we charge the downstream for electricity costs? The answer is: it is effectively at cost. The way that we view the power stations are basically as conversion centres for gas molecules into electrons. We just pass the cost straight through to British Gas.

Gearóid Lane

The internal transfer pricing is not the issue, as Sarwjit says, it is about what it means to the corporate. To the corporate it means that we have secured that forward power at the cost of the gas plus the cost of the station of itself amortised.

Unidentified Speaker

Last question: I noticed that there was no price along the side of this chart. I wondered when these contracts were entered into?

Gearóid Lane

Clearly we could not put a price along that axis because it would be deeply competitive information that we could not reveal. But we would say that we believe that the phasing in of power into our book has been done at very good times. You only have to look at the British Energy deal, and at what you might believe to be the valuation of that deal now, to get a flavour of that.

Jake Ulrich

A reasonable forward curve in that period.

Andrew Wright, UBS

I noticed, when you talk about the impact or the possible windfall for coal plant from emission trading, you correctly say that that would be limited by new entrant cost of gas plant. I was surprised though that you mentioned there the possibility of those power stations getting free allocations of emissions. Is that something that you are aware that the government is considering? Or is it perhaps more likely that they'll have to pay for allocations, in which case the new entrant price will rise with the carbon price?

Gearóid Lane

It is our understanding that that is the subject of a bun fight at the moment, but don't quote me on that. It is an open discussion. A decision hasn't necessarily yet been reached solidly. It will be reached very quickly. But the point actually holds with or without. Even if a new entrant power station has to pay for its allowances for the remainder of the current trading phase of the ETS, what is certain from the Directive itself and from what is famously called the Non Paper, that was in a new entrant in one phase will become an incumbent in the next phase. Therefore, even if you had to pay for your allowances for a period of two or three years, the fact that you will then be an incumbent and capable of taking your share of the windfall, means that that windfall should get competed away if it drives prices above new entry.

Andrew Wright, UBS

Is that new entry with or without the marginal cost of carbon allowances?

Gearóid Lane

There are two new entry prices, depending on that decision. But the two new entry prices are not as far apart as you might think. The new entry price: if you got a free allocation from day one, yes, it will be a lower price. But if you have to pay for your allowances for a two or three year period, and then get them free, or at least on the same basis as the other generators, it is actually over a 25-year lifespan, or 30-year lifespan of a CCGT, that period of two or three years when you had to pay for your allowances doesn't, on any sensible analysis, massively alter the new entry cost. Sorry, I don't know if I've explained that well.

Andrew Wright, UBS

That's fine. Just one other question on renewables and wind farms. Given that the returns are so attractive from power generation and it is a structurally short market, why are you not trying to give as much of that action as possible, at least up to the level of your obligation? Why are you limiting yourself, in terms of the proportion of equity ownership in wind farms?

Gearóid Lane

The mechanism by which renewable generation gets valued highly depends on there being a structural shortfall in the marketplace. If all of the developers of renewable plant developed right up to the level of their obligation, then the price of the ROC will fall down to £30[?] escalated to the buyout price. Or even below, if people miscalculated and went a little bit long. It is possible, within that market structure, for one generator to say, yes, I'm going to get a much bigger share of this pie. I'm going to develop all of my needs, or even more than I need myself, from my own generation assets.

But there is a severe danger that if a number of people took that approach then the value of renewable electricity would crash. We are not saying, by any means, that we will stop once we get to that level. We will continually reassess whether or not further investment beyond any level, or below any level, is the right way to go. A sensible base case assumption is: you don't go too long against a market that needs to be structurally short.

Phil Bentley

It is also a question of managing the portfolio and how much we want to put in on one bet, as it were. Half a billion quid over the next five years is not an insignificant bet on a structural shortage of ROCs. We are quite confident that there will always be generators of renewable energy who do not have a customer outlet. Therefore, if we can buy from them, we are happy that they have deployed their capital, and we look for a balance again. It is not any different, really, to what we have talked about for gas and electricity. It absolutely fits with the same view.

Jake Ulrich

It's like anything else. It is how much you buy relative to your competitors.

Sarwjit Sambhi

The other thing to note, in that bar, it is not just equity investment. We are seeking to strike long-term PPAs with other builders of windpower assets, and share in some of the upside on ROCs.

Gearóid Lane

As indeed we have done within the Barrow project already.

Peter Atherton, Citigroup

Can I touch on the politics of the Emissions Trading Scheme?

Gearóid Lane

Is there politics in it?

Peter Atherton, Citigroup

On one hand you are talking to the government, but you are also talking to your own customers. Have you got a sense of what the government's view on this is, of what is actually tolerable as far as the consumer – both retail and industrial – is concerned, in terms of the impact that this could have on power prices in the near term?

Gearóid Lane

Let me turn the question round a little bit because I think it will answer it. If customers in the UK were paying for a reduction in CO_2, at 10, 20, 30 euros a tonne, that may be palatable. Given how much work we need to do to get to Kyoto, which is actually not huge, it would not necessarily represent a huge cost to UK consumers. What has gone wrong, horribly wrong, is that that cost of abatement is not being paid for the abatement, it is being paid for every megawatt hour that you consume. The free allocation of allowances to generators, which is the fundamental thing that has created the problem in the first places, such as, "I'm not paying 30 euros a tonne, or 20 euros a tonne, or 10 euros a tonne for the few tonnes I need to get rid of, but for all the ones that are actually emitting in the first place. That is just a decision that cannot be reversed within the confines of the Emissions Trading Scheme itself.

But that fact in itself does limit the appetite for customers to bite this. If the customer sees that their electricity bill per annum is going up by £10 a year for a household, they say, that's good, it's going towards emissions' reduction. But if it is going up by £40 or £50 a year and the profits are actually going to some coal generator, or even some gas generator, it is not as acceptable.

There is a limit to the acceptability of this scheme to the consumers, which is driven by the design of the scheme, and that is causing people within government to really scratch their heads about things that can be done to mitigate this. If I were a betting man, which if course I'm not, I would say that it is unsustainable over a 15-20-25-year period, for this windfall to be sustained at the cost of consumers.

Peter Atherton, Citigroup

Has Centrica bought any permits at £15-£16?

Gearóid Lane

At the moment we haven't participated in the trading market, in terms of putting trades in place. We have concentrated up to now on getting ourselves prepared for trading, and getting all the IETAs and margining agreements and everything in place that we need. The trades that have taken place so far, we believe are amongst very large players who just want to start putting a footprint on the price of carbon.

Finance and Strategy

Sarwjit Sambhi

Director, Finance and Strategy

I. Introduction

I will try and be brief. I wanted to cover three areas:

- Some of the issues that affect the general financial shape of CEMG for each of the big moving parts, and some of the smaller ones. Gas production, industrial and wholesaling, and Accord.

- To give an indication of what future capital outlays might look like.

- Cover how sensitive the P&L is to gas and electricity price movement, focusing on 2004.

II. Gas Production

Taking each in turn; the big moving parts. I'll start with the biggest: gas production. The chart on the left-hand side is one that I think most of you have seen at the time of the interims when Phil presented this. It shows the Morecambe profile percentage of 2002 actuals. These are the two lines here: operating profit and production. They're basically moving at the same rate.

What we have overlaid on this is our new equity investment programme. What is in that: it is a pipeline of projects, some investments that we already have. It excludes existing producing assets outside of Morecambe, but it includes new developments such as Goldeneye, Rose, and developments which we are prospecting for at the moment, potential acquisitions. Obviously each one of those has a different probability of success.

But if we overlay that, and just look at what the profile is, in terms of percentage of revenues for both the costs and operating profit, it has a different shape to Morecambe. That isn't new news to you. It has a different profitability profile, in terms of return on average capital employed. But, if I look at an indicative year, there are good signs that some of the developments we are making at the moment – Rose, Goldeneye, etc – are going to pretty soon start delivering return on average capital employed – again this is an annual measure so it will change – of around 12%. In some years it will be in excess of that, depending on the spending profile.

The other point to make is, if this is the indicative profile, and we are being conservative, and if we are successful, what is the reserves' position at the end of 2007? Based on our analysis, based on our current plans, that would be about 1tcf. Not replacing all of the Morecambe volumes, but replacing a large chunk.

III. Industrial and Wholesale

I&W: Industrial and Wholesale. The last two years, 2002-2003, have been good years for industrial and wholesale, principally because of the sales that we made on gas wholesale. How did we make those sales? These sales came about basically from length that we inherit, if you like, from a downturn in BGR demand because of weather. We take that length, and we can sell it back on into the market. Purely opportunistic, but for the last two years, 02/03, where, as you all know, we have had warmer weather than the 20-year average, we have been able to sell around two billion therms a year. We do not plan for that. If we did, we would be planning for abnormal weather. So in terms of expectations going forward, we assume that we make minimal wholesale sales. Clearly, if next year again is an abnormal weather year, we will see some wholesale profits.

The last two years just show that the optionality in our portfolio, and our ability to weather a perfect storm. On the industrial sales, it declines by about a billion therms over time. The other thing to note though: the overall volumes decline, but because of the portfolio mix – this includes our long-term interruptible contracts – because of the portfolio mix changing, and some of the contracts dropping off, the weighted average selling price actually increases by about 10% over this period.

IV. Accord

The last two years have not been good for Accord, principally because of Enron and TXU – the demise of both of those companies in the UK. We are starting to see, for the market as a whole, trading recovery. This chart shows the churn ratio of traded volumes to physical volumes for gas. The signs are encouraging. That should be reflected through into the Accord P&L.

An important point to note: clearly Accord doesn't trade anywhere near these multiples. The churn ratio for Accord, using our physical downstream sales as the denominator, is nearer two and a half to three times.

The other important point to note is that Accord is a very tightly governed business unit within Centrica. It has very little capital at risk, which constrains the amount of trading activity it can undertake. In terms of management controls, Jake and I have daily P&L reporting on this business, daily counter party exposure. This is a business that has a lot of eyeballs on it.

V. Capital Outlays

Moving on to capital outlays. Upstream Gas, in terms of the outlay cumulative to 2008, if we are successful with our plans, £500 million of investment is required. On power, Gearóid mentioned that we are reviewing our cover. There is the potential that we may buy new assets. We have earmarked £250 million, cumulatively to 2008. Renewables: I won't labour on that. That has been the subject of an announcement in the summer. The £80 million that you see in calendar 2004 we haven't committed to yet. In terms of the portion that we have committed, it is basically our share of the Barrow project.

1. Maintenance Capex

Maintenance capex: this is really what we require to maintain our existing assets. Cumulatively, to 2008, we have planned for about £250 million. Next year is going to be slightly higher than average at about £80 million. The reason for that is, within Morecambe we do have one under-balanced drilling campaign for one infill well. We do have re-wheeling replacement of the impellers for compression, both onshore and offshore at Morecambe. In terms of power stations, we do have to replace the turbine blades at both Peterborough and Roosecote stations.

VI. Sensitivity to Gas Price Movement

Sensitivity of our P&L to electricity and gas price movement. Gas first. When gas price moves, it affects a lot of moving parts within Centrica. On the cost side, clearly our purchase costs increase, and there is also a PRT impact because of the way we account for PRT. The increase in 2004 – and the starting position is the cover ratio that both Ian and Gearóid took you through – if gas goes up by 1p a therm in 2004, the purchase costs increase by 62 million. That is offset by an increase in our gas sales within CEMG and upstream revenue, that increases in combination by 27 million. So net: 35 million impact. Out of a gas cost bill of three billion if you include transportation, this is a good position to be in.

VII. Sensitivity to Electricity Price Movement

Electricity: if, in 2004, prices across all Shaped products increase by £1 per megawatt hour, then the exposure we would have for CEMG would be about £4 million. That doesn't include our Shaped needs. If you include the Shaped needs, and I explain what I mean by that with the bottom graph. These are the three kind of key power products that we use to make Shape to serve our downstream demand: Stomper, Winter Peak, EFA Block 5, or Super Peak.

If you look at 2002/2003, they are priced higher than baseload, with the extreme being Super Peak being 250% higher than baseload. So if baseload went up by £1, you would expect Super Peak to go up by £2.50 per megawatt hour.

If I assume a profile that looks like this, and I Shape that in terms of my downstream demand, actually, a £1 per megawatt hour increase in baseload would really be a £5 million impact in 2004. Again, this assumes the cover that we have locked in, that Gearóid went through.

That is all I wanted to cover.

Questions and Answers

Andrew Wright, UBS

Could I just clarify those last two charts? You are not looking there at Group sensitivity. You are looking there at CEMG sensitivity, or is it Group sensitivity on the assumption that the revenues in the other parts of the business remain unchanged?

Sarwjit Sambhi

This is Group sensitivity.

Andrew Wright, UBS

Group sensitivity, right?

Phil Bentley

It is assuming that there is no price change. It is Group to the extent that gas included production as well as gas procurement exposures – and the net off there. But it is assuming that there will be no pass-through of that to the end customer. Obviously, that is one of the key decisions that we are wrestling with at the moment, in terms of how we price for 2004. As you've obviously seen now, we set our prices in January for the full year, based on our view of the forward curve. By the time you get to the second half of this year, you've seen prices much higher. We need to readjust that in the pricing decision that we then take to restore gross margins back in 1 January or whenever we make this pricing decision valid from of 2004.

So we obviously always intend to maintain our gas gross margin, and actually to increase slightly our electricity gross margin. As you know, we are pricing at a discount to the market. Powergen have just announced electricity price increases of 6%. That puts us now at double-digit discount to our number one competitor. We are looking to recover that and pick some extra gross margin up at the same time.

Jason Goddard, CSFB

Why do you think there haven't been more retailers, after the Powergen announcement of an increase in tariffs, that have followed suit for January? And I just wonder, on these slides at the end here, if you can give me an extra piece of analysis of what you would have to do to your downstream tariffs to cover the impact of an extra 1p per therm in Upstream Gas, an extra £1 per megawatt hour.

Sarwjit Sambhi

I'll let Phil take that one.

Phil Bentley

Well, sales of gas is £4 billion of gas sales, and is just over £1 billion of electricity sales. So I'm sure you can work that out.

Gearóid Lane

In simple terms, if your gas cost goes up by 1p per therm and you want to keep your margins, it's not rocket science, it's 1p per therm.

Jake Ulrich

Well, it's only about half of it in costs. You can do the maths.

Phil Bentley

The only point to make then is, forget the 1p a therm, but look at it on a gross revenue point of view. That's the way to look at it. Within our cost of goods, transportation is, as much as our procurement basis is as well, you have to maintain gross margin as Jake says, you have to understand the transportation. Clearly, you can work out what the effect on our cost of goods for the commodity is. Just equate it at the top-line revenue line.

Sarwjit Sambhi

I just didn't want to give the absolute number.

Jason Goddard, CSFB

And the other question – as to why the other retailers haven't followed Powergen.

Phil Bentley

That is a question that you have got to pose to them. Our view is that everyone is watching everyone else. We are the price leader. We are 40% of the UK residential energy market. I guess a number of people are looking to see what we do. Powergen are 20% of the market. We are 40% of the market. If we two go, I think you'll see other people follow fairly quickly after.

Jake Ulrich

People are just waiting for us to make the move, and then they'll price accordingly.

Bobby Chada, Morgan Stanley

I wanted to ask another question on the pricing and tariff policy. It is my understanding that last year you set your tariffs based on what the forward curve looked like, in January. So the comparison that we can do ourselves is to look at what the forward curve looks like today.

Jake Ulrich

No, you can't look at it that way. You would have to know exactly what the floating/fixed was when we fixed the tariff. There has been a deterioration of the earnings, but I think we've covered that.

Phil Bentley

If where you are going is to try and get a forecast for the end of the year, I guess it is part of the question, clearly, yes, in the first half of the year, we advised we had about 40 million of weather there. As you saw, we recovered quite a bit of that in the wholesaling activity, which was particularly high in profit terms in the first half. But in the second half, the forward curve on the spot has eventuated out at a price higher than the implied forward curve at the beginning of the year. And so, clearly, the margin in the second half is going to be lower than in the first half. That is a feature of why it is we need then to reprice in the beginning of the following year, to get the margin back up to our target run-rate margin.

What does that say? It says we have a lag on our pricing strategy. It is something within British Gas we have talked about. We have Paul Bowtell the FD of British Gas up there in the corner. We do not have to price once a year, but we do. Can we move this market towards more regular repricing? That is a question we have to look at in terms of consumer response to that.

We will say that our view, if you like, of the world, is that the price might well soften. If we see that, we will pass that back to customers. We are not looking to get any more than the gross margin target that we have set.

Richard Budgett, Allianz Dresdner Asset Management

Can I just clarify these two charts' sensitivities? From what base are you talking from? A £1 increase from what? Your current assumptions about 2004 or from 2003 base?

Sarwjit Sambhi

It is a £1 based on our 2004 assumed electricity and gas costs, recognising the amount that we have already fixed in, and the floating amount is based on the current forward curve. Does that answer the question?

Richard Budgett, Allianz Dresdner Asset Management

Yes.

Jamie Tunnicliffe, ABN Amro

Over what period is it reasonable to assume that you close that discount on the electricity side, in terms of the gross margin? Where you are discounting on the electricity side against…?

Phil Bentley

We've said, over our five-year plan, that we intend to close that discount. We haven't been any more specific than that. It will depend on consumer reaction and competitor pricing.

Austin Earl, Newman Ragazzi

I have a couple of questions. One on this presentation, one on the previous one. On this one, just a quick clarification: on the capex, the cumulative was 04 to 08? Or was that 03 to 08?

Sarwjit Sambhi

No, the cumulative is 04 to 08.

Austin Hill, New Merogazia

On the previous presentation, on slide 21, there is chart showing yourselves and six competitors, in terms of the hedge that you have. What I don't understand – maybe it is ignorance about the industry – but if many of the other competitors have a similar hedge to yourselves, it would seem to me that from a competitive point of view, if you are all caught short on capacity when prices go up, you then pass on those prices, presumably with a lag. But equally vice versa. I don't know how the regulator views this. Do they allow this to go on, that, in the end, presumably it is correct that the end customer should pay more if the prices go up, or pay less if prices go down? Am I reading that correctly, in terms of the interpretation of how your competitors will react?

Gearóid Lane

I have a couple of thoughts on that. One is that in order to get a full answer to that question you would need to drill down into the individual market sectors. Clearly the very large industrial market: those guys got a price reduction on the day they needed to drive the prices down. Nobody would blink an eyelid of they get the price increases the day the prices go back up. They will. But I'm not sure anyone would cry too much into their beer. That's the way the decisions have been taken within that sector about how they want to contract for electricity. Within the residential sector, there would be a higher level of oversight, but there is a realisation that, as wholesale prices go up – as you say yourself, with some lag – it would be expected that those price increases would pass through to end consumers. I can't see that there is any logical argument that we would be able to say that those price increases can't pass through, to the extent that they do represent a real cost.

Jake Ulrich

More of a soft landing.

Gearóid Lane

Yes. Phasing and timing.

Phil Bentley

I think what you're seeing as well is more commentary on security of supply than perhaps we have done in the last two years. You might argue, therefore, that that is of greater concern than specific consumer end prices for the government as a whole. That is something else to weigh in.

Gearóid Lane

And the government itself, in the Energy Point Papers, signalled that the environmental initiatives that had been taken will increase cost to consumers.

Closing Remarks

Jake Ulrich

Managing Director, CEMG

I. Summary

The final slide. I hope that you can take a few things away. Obviously you will all take different things away. They may be different than this. These are the things I hoped that we made clear today. We do have a quality asset portfolio. We do have a lot of contractual flexibility. The procurement strategy is very flexible. We are never going to be 100% solid asset or fully hedged. And we are not going to be 0% hedged in our equipment.

Gearóid and the team are making fairly good progress in advancing the Renewables and Emissions Trading Strategy. We have addressed it, we do know what we are doing. It is not something that has caught us by surprise. You can continue to expect a fairly strong cash flow from the core energy business.

Thank you very much.

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