2nd Submission by BP to the PIU Energy Review

Introduction

1. In our preliminary submission (attached in Appendix 1), we identified four areas of concern to the Review where BP had particular reason to comment i.e. Security of Supply (with particular emphasis to Gas); Market Liberalisation; Solar; and the potential offered by energy efficiency.

2. We identified the central principles which, in our view, should underpin policy considerations in all these areas. Namely:

- that there is still great potential in the UKCS; but equally, the UK shouldn't be frightened of the long-term inevitability of losing energy self-sufficiency;
- that market liberalisation and connectivity issues would be crucial determinants in ensuring that the UK and Europe generally continued to enjoy abundant energy supplies at affordable prices; and
- that renewable energy sources are important for the future, but their immediate contribution should not be exaggerated.

3. The purpose of this submission is to expand on some of these points, and to offer further evidence for the conclusions drawn.

UK Energy Scene

4. Before considering points in greater detail, there are some general observations to be made concerning the UK Energy Scene and the scope of the Review.

5. The first concerns the reliability of energy forecasts. In terms of reserves, many have proved pessimistic in the past. In terms of prices, they have often been inaccurate. BP's view of the UK's oil and gas reserves is given in the next section. So far as oil prices are concerned, BP envisages a range of prices which appear credible and sustainable: prices outside that range are perfectly conceivable for the short-term, but would ultimately be expected to fall back into line. Our current mid-cycle assumption for planning purposes is Brent at $16 per barrel. But in terms of BP's own investment decisions, we test projects to be resilient (i.e. must cover cost of capital) at $11 per barrel.

6. The second observation concerns the environmental constraints which are often assumed to dominate energy policy considerations. It is the view of the Royal Commission on Environmental Pollution that the UK needs to make a 60 per cent reduction in its CO_2 emissions by 2050. BP is not opposed to the concept of targets; indeed, BP has its own environmental targets for internal purposes. Currently, it is BP's determination to reduce its own Greenhouse Gas emissions by 10 per cent by the year 2010 from a 1990 baseline. We're not so well placed to judge the validity of the Royal Commission's target for the UK as a whole. But whether well-founded or not, we are confident that no single measure or action will in itself be sufficient to achieve the objective. The development of new technologies, in particular, will transform the relative ease with which this environmental challenge is overcome. The essential requirement is to encourage the development of strong and healthy enterprises with

the necessary financial and technical capability to develop solutions for the future. There is a whole range of options from which to choose. BP, for example, has to date placed the main emphasis upon Solar Power. However, while it is almost impossible to quantify in advance the relative contributions to be made from renewable sources, energy efficiency, or cleaner fossil fuels (not to mention nuclear if the problems associated with this fuel could be overcome), it is clear that any short term penalty or deterrent to energy use which eroded wealth or a company's commercial strength would be counter productive from an environmental perspective.

7. So far as Solar specifically is concerned, BP was a major contributor to the final report of the Photovoltaic/Government-Industry Group and which contains a large volume of data relevant to this Review. The Group's main recommendations are summarised in Appendix 2. There is clearly no need to duplicate in our submission to this Review everything we have already said in the earlier report. But we would place particular emphasis on recommendation 8 i.e. "The most effective means of encouraging the deployment of PV in the UK would be a major Market Stimulation Programme featuring a 50% capital grant for 70,000 domestic roofs, and a similar grant scheme for larger non-domestic buildings costing around £150 million over 10 years." This recommendation is highlighted because it illustrates how, in some areas, the initiative lies with Government alone to act. The experience of other countries which have introduced similar market stimulation programmes has been encouraging. But this is not the sort of measure which private companies can introduce unilaterally, since it would be construed as market distortion. The other important aspect of policy is grid connection, which once again is outside the capability of companies such as BP to resolve alone. Without action in these two areas, it is very difficult to see how rapid market development can occur. With them both in place, however, rapid market growth could be anticipated as was the case in Germany during last year (albeit with a more attractive premium price buyback market stimulation policy).

8. Finally, as will be apparent from the following sections, it is our view that the greatest contribution which governments can make to energy policy generally is to remove artificial constraints upon the efficient working of the market, and to ensure that nothing discourages the necessary investment in infrastructure. Connectivity issues are central to safeguarding UK security of supply.

Outlook for UKCS Oil & Gas production and reserves

9. The UK oil and gas industry has a strong track record of developing oil and gas supplies from the UKCS. BP is equally optimistic about the future - there is still significant potential in producing fields, undeveloped discoveries and from further exploration. Figure 1 shows BP's most likely forecast of oil and gas production.

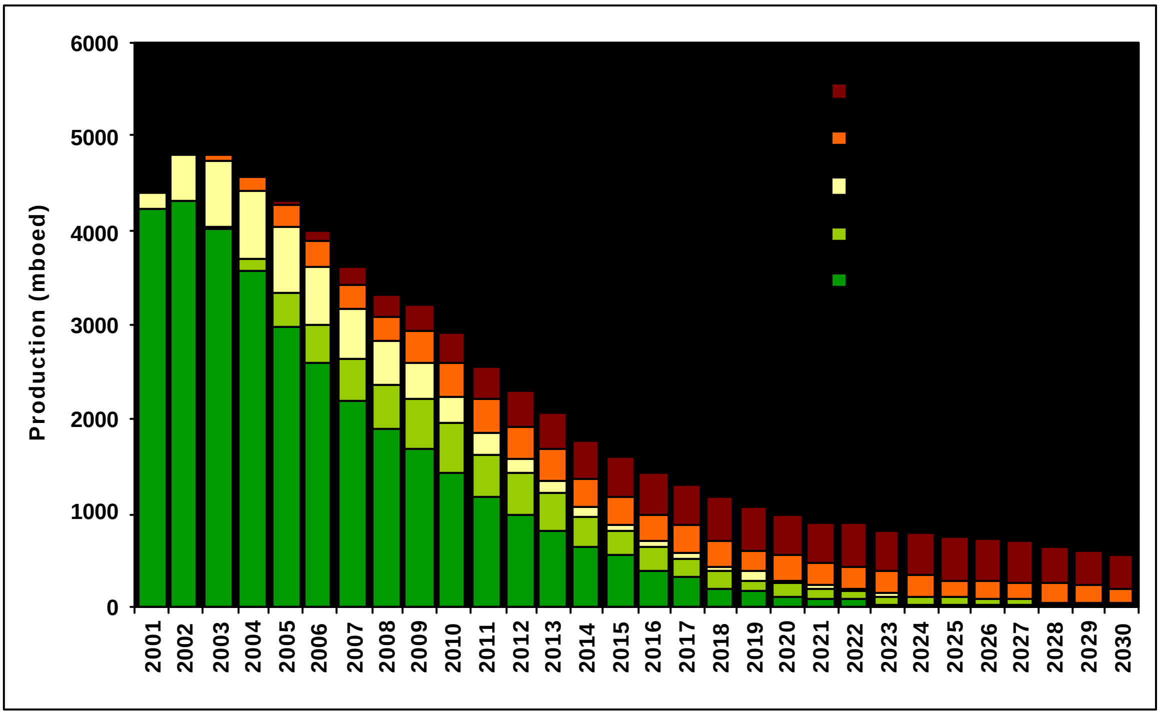

Fig. 1. UKCS Oil and Gas Production - Most Likely Case

This is consistent with other commentators. Key points are:

- Recovery from existing fields – BP believes that there is potential to improve field recovery factors. For example in the Forties field BP has seen recovery factors increase from an original 42% to a forecast 62% over the past 2 decades. We now have an aspiration to recover 70% of the original oil in place from Forties. If average North Sea recovery factors in all oil fields could be increased by 5%, an incremental 2 billion boe could be recovered.

  4D seismic and through tubing drilling are examples of technologies which give confidence to these predictions. They are having an impact today on many of BP's own fields :

  - 4D seismic gives us the ability to see the additional oil to be recovered. 4D seismic is the process of acquiring two or more 3D seismic surveys over time. It is then possible to improve the imaging of the reservoir and specifically observe the movement of fluids therein. This means that the placement of new wells can be improved and additional well targets can be identified. The scale with which BP is using this technology is significant. During the summer of 2000 we acquired 4D Seismic Surveys over eight fields and the plan is to acquire further 4D seismic surveys this year over the remaining fields. Forties has benefited – since 1997 we have doubled the initial well rates from our infill wells.

  - Through tubing drilling: We have been able to continue drilling conventional wells on Forties, but non conventional wells employing 'through tubing rotary drilling' (TTRD) will play a vital role in access. TTRD enables a sidetrack to be drilled from an existing well without the risk and cost of removing and re-running the existing completion. The technology offers significant cost savings and makes small infill targets viable. It is particularly important where no further well slots exist – e.g. Magnus. It also has the environmental benefit of greatly reducing drill cuttings. An extension to the technology is multi lateral drilling where we retain production from the original well and add through tubing sidetracks.

BP has a continuous programme of non conventional wells underway – up to ten this year alone, including multi lateral wells on Harding and Hoton, and TTRD on Bruce, Miller and Magnus. A TTRD well on Magnus came back on stream in April at 12,000 b/d against our original expectations of 5,000 bpd.

- Undeveloped discoveries – contain an estimated 4-5 billion boe of reserves. Although most of these discoveries are now being worked, many of them still carry significant geological and development risks. We conservatively estimate that 50% of these reserves will be produced.

- Exploration success – BP supports the DTI's view that there is approximately some 13 billion boe of undiscovered hydrocarbons on the UKCS, albeit with a wide range of uncertainty. However, we don't believe it is realistic to expect current levels of exploration activity to turn all of this potential into production. This is because many of the pools are too risky, too small or too remote from infrastructure to justify industry investment. In our most likely forecasts we estimate that 20-40% (3-5 bn boe) will eventually be recovered. This view is consistent with other industry work[1].

  BP's focus is West of Shetland, where we believe there is the greatest potential for new large discoveries. Success here would add upside to the above figures.

10. In summary BP believes that the PILOT target of 3 mmboe/d in 2010 is achievable. Indeed it may be conservative. However, the challenges involved in delivering this production should not be under estimated – the UKCS is maturing rapidly, fields are becoming smaller and more complex and there is increasing competition for investment from overseas opportunities. That is why maintaining the competitiveness of the UKCS is crucial.

Maintaining The Competitiveness of the UKCS

11. Continued focus on costs and the fiscal environment will be necessary to maintain competitiveness. We believe the key focus areas to be:

- Innovation and technology – the UK oil and gas industry has been at the forefront of technological and commercial innovation. Two current examples are described above. It is critical that this trend continues. Continued industry R&D and initiatives such as the Industry Technology Facilitator have an important role to play. However, the most important factors will be the recruitment & replacement of the industry's highly skilled and motivated workforce, and the continued diversity of the industry.

[1] Industry Ditch Bridging Group Report.

- Skills shortages – the issue of the industry's aging workforce is well recognised. Yet oil and gas production will be an important part of the UK economy for at least the next twenty to thirty years. Critical skills shortages are already being addressed by PILOT & UKOOA in the areas of technician training, helicopter pilots and medics. Industry will shortly debate the need for a strategic and integrated policy group to address skills shortages, recruitment and training across the industry. In summary this is an area of serious concern and is a policy issue that has to be addressed jointly by both government and industry. The key will be continuing to demonstrate that the industry can offer attractive and exciting careers, and innovative retention and training of the existing workforce.

- Diversity and new entrants – One of the keys to technological and commercial innovation is diversity. The industry has evolved to the point where there are many niches to exploit, and different operators and service companies all have their own unique part to play. BP has been the catalyst in bringing a number of new oil & gas companies into the North Sea over the past decade. Industry has a key role to play in creating the right environment for this change to continue. BP supports the initiatives that are being pursued (faster acreage turnover, more efficient asset trading and improved access to infrastructure) and encourages the Government to continue championing this change through PILOT.

  Diversity within the service industry is equally important. A healthy SME community is vital to the health of the industry – they are an important source of commercial and technological innovation. BP encourages Government to continue to nurture this sector, which is particularly vulnerable during low oil prices. Key areas for assistance are:

  - commercialising new ideas
  - developing HSE standards
  - diversification by developing export potential

- Cross industry collaboration – all of these initiatives speak to the need to work more closely across the industry. Involvement of Government facilitates a wider appreciation of policy implications, and has enhanced the effective operation of the whole supply chain (e.g. the DTI mentoring programme). BP has played a major role in the OGITF task force and PILOT because of the importance we attach to transferring best practice and knowledge. The Brownfield benchmarking initiative is an excellent prime example of this collaboration, which we believe will yield as much benefit as future exploration.

- Fiscal policy – The Government's policy of fiscal stability and appropriate regulation has made a critical contribution to the success story of the UKCS and the sustainability of its competitive position. A fiscal regime which reflects the realities of the UKCS and avoids disincentives is probably the most crucial requirement of all in maintaining industry confidence in further investment and activity. The UKCS requires a fiscal regime which acknowledges the additional problems which come from maturity.

The future for Gas

12. The growing importance of gas justifies special consideration of its potentiality, and of the policy requirements to maximise this potential.

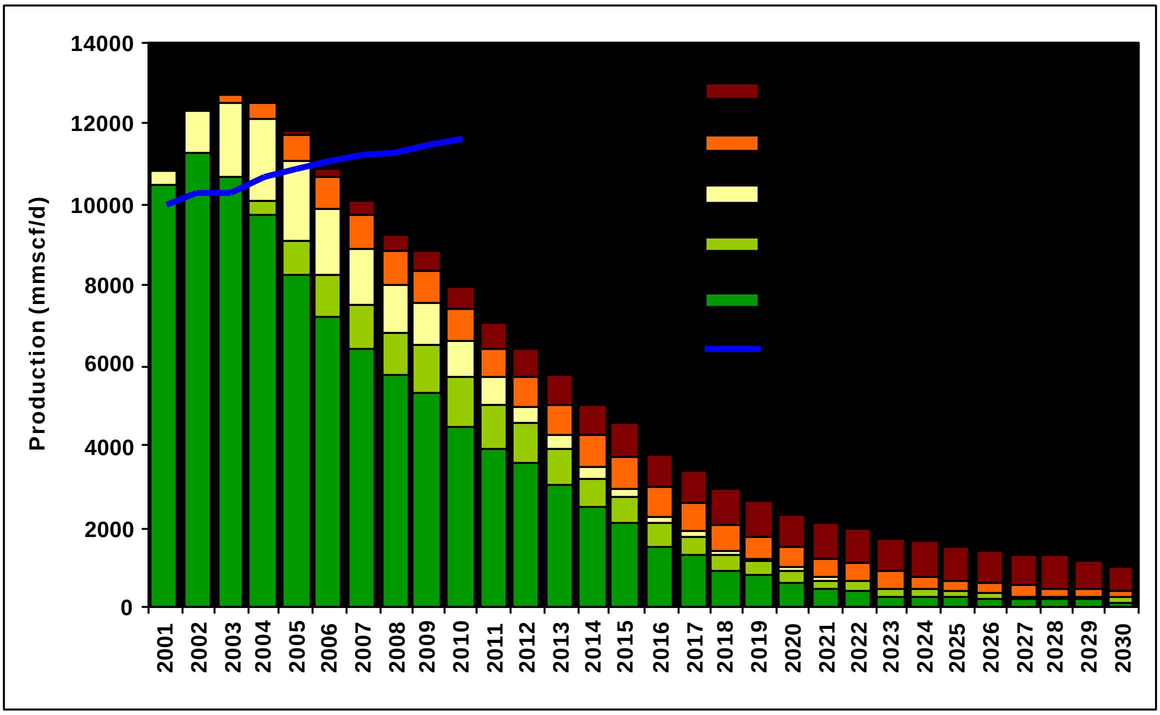

Fig. 2. UKCS Gas Production – Most Likely Case

13. Gas will continue to be a major contributor to indigenous fossil fuel production. However, this cannot continue indefinitely and production is likely to decline from 2004, unless significant volumes of gas are discovered West of Shetland. This is considered unlikely.

14. The outlook for gas demand is equally uncertain. There are three main possible scenarios for the next ten years :

- <u>Transco Base</u> – forecasts UK demand (including UK exports to the Republic of Ireland) reaching 112 bcm/a (10,800 mmscf/d) by 2010.
- <u>WEFA</u> – forecasts 120 bcm/a (11,600 mmscf/d) in 2010.
- <u>Power substitution</u> – forecasts 130 bcm/a (12,600 mmscf/d) in 2010. A possible upside scenario assumes continued switching from coal to gas share of the power generation market

15. Combined with the range of supply sources these indicate a shortfall within the next few years. By 2010 the UK's import requirement could range from 30 to 60 bcm/a. By 2020 up to 80-90% of the UK's gas could be imported. This analysis ignores the declining production from high swing fields in the Southern North Sea. Imports have already occurred to meet peak demand and this is expected to increase over the next few years, even if indigenous supply exceeds demand on an annual basis.

16. This therefore underlines the importance for the UK and Europe in assured access to international gas supplies. It has frequently been said that “Europe is surrounded by a sea of gas”. This generalization is true – especially when the increasingly globalised LNG market is considered. The key issue for UK and European Gas Supply is not the availability of gas in the ground, *but their connection to the markets.* Each potential supply source has its own characteristics & issues:

- <u>Norway</u> – is the obvious supply source for meeting any UK shortfall - it is closest to the UK and is the lowest cost supplier. Norway has c. 140 tcf of discovered gas resources. So far c. 45 tcf of these resources have been developed to meet market demand in Europe. Of the remaining reserves around 60 tcf are in the development planning or execution phase pending further demand. In addition the Norwegian Petroleum Directorate indicates a further c. 90 tcf of YTF potential – a view shared by BP. BP has already taken steps to import 1.6 BCMa of Norwegian gas into the UK from October 2001.

  In the longer term (post 2010) much will depend upon the pace of development of new Norwegian fields (e.g. Ormen Lange) and the pace of further exploration and development. Demand from Continental Europe will also be a factor. The issue of the pace of the exploration and development of future Norwegian gas supplies is a critical factor in evaluating future UK supply sources.

- <u>Netherlands</u> – the maturity of the gas basin and continuation of the present management policy for Groningen makes it highly unlikely that the Netherlands will be a material source of incremental supply to the UK.

- <u>Russia</u> – clearly Russian gas is available in abundant quantities in the ground. Notwithstanding political and transportation cost issues, the logistics of transporting gas to the UK from Russia are enormous. One of the key links and potential bottlenecks in the chain is the European distribution system – which emphasises the need to liberalise the European markets and infrastructure. The same issues apply to other remote gas in the Middle East, FSU and North Africa.

17. BP does not believe, in the medium term, that LNG has a significant role to play with regard to security of supply for the UK. However, there is likely to be a developing spot market for limited quantities of LNG at Zeebrugge, which could help with needle peaking on pricing. This, together with growing imports into Southern Europe from places such as Trinidad, Egypt, Algeria and Oman will provide suppliers and traders with greater optionality as to where gas can be sourced to satisfy their customer needs. More LNG delivered into Southern Europe will, of course, free up pipeline gas in Northern Europe to meet growing UK import requirements.

18. It is important, however, to acknowledge the important role to be played by Natural Gas Liquids. With the decline of oil and gas production in the UKCS, the traditional sources of Natural Gas Liquids (NGL's) that underpin a major part of the UK petrochemical industry will also decline. NGL's sourced from the Norwegian sector of the North Sea will be increasingly required from the second half of this decade to replace the growing gap in UKCS supply. Norwegian NGL's can provide a competitive source of long-term UK supply by being delivered through existing

UKCS gas infrastructure in association with the expected increase in Norwegian Gas supplies to the UK. However, historically Norway has promoted onshore processing of gas in Norway and export of the products by ship, with only sales gas exported by pipeline. It is critical to achieving this commercially that there is a suitable alignment between governments to enable appropriate offshore pipeline connections to be made between the NOCS and UKCS gas grids to deliver the necessary 'wet gas' into the UK where it is needed long-term.

Connectivity & Implications for Regulation

19. The previous paragraphs have summarised the availability of supplies from which the UK can hope to benefit as its own indigenous production declines. But of far greater concern than new physical supplies is the existence of adequate cross-border infrastructure to supply gas to the market, and the appropriate commercial arrangements to facilitate the interoperability of the networks. Any energy policy should ensure that regulatory frameworks encourage timely investment signals to increase the number and capacity of supply routes into the UK, and to ensure that sufficient capacity exists at entry points. This will require close dialogue between industry, DTI, Transco, Ofgem, the EC and International bodies in Norway, Denmark, Belgium, the Netherlands.

20. Areas requiring particular attention will include :

- UK offshore gas infrastructure and its connection to the Norwegian pipeline ‘grid’
- The NTS; its capacity at different landing points and mechanisms/incentives for future investments
- Flexibility; the role of UK and Continental storage and the Interconnector to meet peak winter demand and mitigate the risk of intermittent supply shortfalls in the UK.
- Integration of the UK with the European ‘grid’ and competitive flow of gas through this network from diverse supply sources.

Connectivity – offshore gas infrastructure

21. One aspect of connectivity concerns the offshore gas infrastructure. The UK has a history of developing an efficient network of offshore gas fields and transportation systems. This has continued in a fully liberalized UK gas market, demonstrating that the regulatory environment has been very successful at providing the right investment signals.

22. It is important to acknowledge, however, the significant differences between the upstream (production and processing) part of the gas industry and the downstream. The downstream market is characterised by a single homogeneous “sales quality” commodity which must meet certain specifications (for example, WOBBE, hydrocarbon dewpoint, CO_2, and H_2S).

23. Upstream gas, however, is not a homogeneous, or “sales quality” commodity. Production gas does not meet the quality specifications for downstream use. Moreover, its quality can vary significantly from field to field, and may even vary

over time in a particular field. Processing production gas into "sales quality" gas so that it may be delivered into the downstream system is one of the key activities of the upstream business. This involves taking a variety of products and transforming them into the uniform commodity that can then be consumed or traded in the "market". In the UK, dehydration, CO_2 removal, H_2S removal, mercury removal and NGL removal typically takes place at the terminal, although these processes can take place at various points in the physical system: offshore platforms, offshore pipelines, and onshore terminals. Each infrastructure system is quite individual in its configuration.

24. Most upstream production activity is undertaken on a joint basis with other parties. This has been the most efficient way of spreading the risk associated with the large expenditures needed to explore, develop and produce offshore supplies. This risk sharing has necessitated the development of a complex web of commercial agreements covering all aspects of the business, from exploration, through development, production, transportation and processing, allocation and sales. This risk sharing approach has been actively encouraged by the DTI, and remains an important commercial feature of the upstream in liberalised markets where long term take or pay contracts are no longer exclusively the industry standard.

25. Upstream transportation and processing infrastructure is built to deliver gas from a particular field or fields to the market and is an integral part of the development and its economics. However, once it is built, the infrastructure owners will seek to ensure that the facilities are used efficiently and will seek third party contract carriage business where possible. Infrastructure owners may also undertake expansions to accommodate third party business, or may oversize the initial facilities. This is done at the commercial risk of the infrastructure owners.

26. In the future, the upstream systems will face new challenges, with different customer requirements and increasing scrutiny from the European Commission. Cognisance should be taken of the fact that the majority of future gas developments in the UKCS will be small satellite fields, tied back to existing infrastructure. These developments will carry higher levels of unit cost, risk and uncertainty than the larger projects of the past. Offshore gas infrastructure owners need to play their part in facilitating these developments to ensure the timely, economic and sustainable development of North Sea resources.

27. Key principles that need to be adopted by infrastructure owners include fair competition between competing systems, non-discriminatory access, and transparency in the way that the industry conducts its business. The process of agreeing Transportation and Processing services needs to be simpler and more efficient (e.g. openly available pre-prepared contracts with indicative tariffs).

28. In many parts of the UK Offshore there is already substantial competition amongst infrastructure operators. This is particularly true in the Southern North Sea, where there are several lines linking the offshore to the onshore system or directly to the Interconnector. In other areas there may not be direct pipeline-to-pipeline competition, although there is the potential for producers to construct their own pipelines. In addition, the negotiations for the transportation and processing of gas are often part of a larger commercial arrangement involving oil, gas liquids, or gas sales, and therefore competitive pressures are brought to bear in a number of ways. To

the extent that there is already competition in the upstream infrastructure, it is undesirable for additional regulation to be introduced, and unnecessary for the interests of customers. The Offshore Code of Practice provides a framework for negotiations, and is currently being reviewed[2] to ensure that it meets the requirements of the EU Gas Directive.

29. Where it is judged there is not sufficient competition, the Government must consider carefully the appropriate means of "regulating" in light of the particular economic, technical and operational characteristics of the upstream. Infrastructure owners should be able to demonstrate a fair return for a fair risk (reflecting the nature of the service provided), with due account taken of any opportunity cost. In addition, any proposals for change should take account of some of the related policy objectives in the UK energy market, namely security and diversity of supply and the maximisation of the resource potential of the UK offshore, including from marginal fields.

Connectivity - Imports

30. As discussed, we expect significant imports in the future, especially from Norway. New Norwegian developments are unlikely to be connected directly to UK terminals; it is more likely that hubs or nodes will become established in Norway, with multiple export routes. Customers for these export routes will be individual companies than Norwegian Field Groups to comply with Competition Law; the demise of the GFU is already pointing in this direction. They will encourage competition between UK pipelines and will probably seek to ship their equity gas (independent of which field it come from) through more than one system. Thus, the UK gas infrastructure is likely to become part of a wider North Sea pipeline grid including Norway's existing systems and the NTS entry capacities.

31. Timely development of the appropriate connections will be necessary to create the right environment for efficient and low cost delivery of Norwegian gas to customers in the UK; however achieving this desirable outcome will depend critically on:

- maintaining a framework which encourages and provides incentives to infrastructure owners to innovate and invest to provide the physical pipeline linkages and the services required by this new customer set; and,
- clarity throughout the UK upstream industry on the commercial structures required to comply with EC Competition Law. Continuation of the currently prevailing uncertainty on this issue could jeopardize timely linkage to Norwegian supplies and hence UK security of supply.

Connectivity – Offshore vs. Onshore Regulation

32. The established model for regulating downstream transportation (price cap regulation) is based on the fact that the transporter acts as a common carrier for a homogeneous commodity. Similarly in other markets (electricity, telecoms, water) the regulatory models are designed to address the issues raised by a homogeneous

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[2] Review and Updating the Offshore Infrastructure Code of Practice and Proposals for Publication of Guiding Principles on Use of Legal Powers to Settle disputes. February 2001

commodity product. The same models are not necessarily applicable to the upstream. In the EU Gas Directive there is explicit recognition of the distinct nature of upstream pipeline networks i.e. "there are special economic, technical and operational characteristics relating to such networks such that separate treatment is required."

33. Over the next twenty years it is apparent that much of the UK's offshore gas infrastructure must meet the needs of both indigenous producers *and* international shippers. Even though pipeline systems will start to convey higher percentages of "sales quality" gas and become part of a wider European pipeline grid, there will be a continued requirement to transport and process different specifications of indigenous UK (and probably Norwegian) gas. Given this, it is appropriate that different regulatory regimes be applied upstream and downstream. This will ensure that energy market liberalisation as a whole develops in a manner which best balances the interests of the various parties and ensures good value and choice for the ultimate consumers as well as ensuring long term security of supply.

<u>Connectivity – regulatory conclusions</u>

34. The key differences are summarised in the table below, which details the key characteristics in the commercial arrangements between Transco and its customers and offshore infrastructure owners and their customers. Any regulatory framework should recognise these important differences and the unique requirements of the offshore customers. Given the success to date in the offshore industry and the vibrant nature of commercial relationships there, it is more likely that a light-handed approach is the most suitable regulatory model for upstream infrastructure.

Key Commercial Features of Upstream and Downstream Infrastructure

<u>Characteristic</u>	**Downstream**	**Upstream**
Product Involved	<u>Homogeneous</u> Gas enters the downstream system within a fairly narrow specification.	<u>Specialised</u> Every field has different quality characteristics.
Service Provided	<u>Simple</u> Transporter provides delivery service for "sales quality" gas, with only limited blending.	<u>Complex</u> Each field is of different quality, and therefore requires a fundamentally different service in terms of processing. And providing service to a particular customer can affect the provision of service to other customers (current and future). Transportation itself is fairly simple – and is only limited part of the overall service.
Contract Duration	<u>Short Term only</u> At present, capacity can only be secured for one year; only 6 months in the case of entry capacity (This regime will change with the proposed introduction of	<u>Long Term</u> Producers want long term contracts to ensure access to the market for the life of a field. Infrastructure owners want long term commitments to finance the required capex to meet the specific

	long term capacity auctions)	requirements of a producer.
Price	Uncertain Capacity prices are set by auction every month. Commodity prices vary from year to year.	Certain Price is either fixed for the duration of the contract or indexed to the product involved.
Risk	Most risk on Shippers Shippers bear much of the risk; transporter earns a lower return as a result	Most risk on Infrastructure Owners Infrastructure owners bear most of the risk in return for the *opportunity* to earn greater returns, but no guarantee.

35. These, and other points, are contained in BP's detailed response to the DTI, dated 11 May 2001, in respect of 'The Review and Updating the Offshore Infrastructure Code of Practice and Proposals for Publication of Guiding Principles on Use of Legal Powers to Settle Disputes, a copy of which is attached (Appendix 3).

Connectivity – Gas Balancing System

36. Just as there are significant differences between upstream and downstream pipeline infrastructure so there are major differences between gas and electricity supply. Ofgem has proposed changes to the UK gas balancing in a recent consultation [3] paper. BP submitted its response to these proposals on 9 April 2001, a copy of which is attached (Appendix 4).

37. In summary we are opposed to such a move without first carrying out a full cost / benefit analysis. We believe that the introduction of such a proposal would have a serious detrimental impact on the UK gas industry by introducing additional cost, complexity and price volatility which may lead to higher gas prices for UK consumers. We are supportive of the desire to have accurate cost targeting of system balancing costs, strong commercial incentives on shippers to balance their portfolios, strong commercial incentives on Transco and improved flows of information. However, we do not believe that Ofgem's perceived concerns have been either properly articulated nor widely discussed to determine whether more appropriate, lower cost, alternatives might be implemented.

38. The burden on the upstream of these proposals does not appear to have been fully considered in the consultation. There is clearly a significant cost implication for the upstream in Ofgem's proposals but the very real concern is that implementation of such a balancing regime would entail time, energy and resources being tied up divert in having to renegotiate *all* existing gas sales contracts, *all* current allocation agreements and attribution agreements and many third party transportation and processing agreements.

39. Given that the UK needs to focus on future of security of supply issues, time and effort would be better spent developing the commercial arrangements for new gas fields and enhancing the recovery from existing fields. Similarly, at a time when the

[3] The New gas Trading Arrangements – Further reform of the gas balancing regime – A Consultation Document, February 2001.

industry is focused on initiatives to increase upstream productivity through the reduction of operating costs, a move to within day balancing will serve to increase those costs and runs counter to the declared objective.

<u>Connectivity – the UK NTS & the auction process</u>

40. Transco also has a key role to play in UK security of supply to ensure that their Capital Expenditure programme is implemented at a level and at a time to ensure sufficient entry capacity exists to meet future import needs. This is currently under discussion with Ofgem as part of Transco's Price Control Review and the output is expected shortly. We would encourage the widest possible Industry debate in this matter as there is a widely held perception that insufficient capacity exists at certain gas terminals to meet immediate, and longer term needs (both for imports and UK developments). We believe that longer-term auctions – as well as improved output measures, strong incentives for Transco to deliver and an enhanced base planning process - will be a significant move forward. However, there needs to be greater clarity over the relationship between the auctions and output measures. We believe that Transco should be encouraged to invest through the use of well-defined output measures, which will ensure that they are exposed to a greater proportion of the costs and revenues associated with their investment decisions. Further, it is important that Ofgem adopts a rigorous and transparent process for monitoring Transco's capital expenditure.

41. It is generally accepted that the short-term auctions provoked a lot of uncertainty for Producers, and added additional risk to major investment decisions. However, BP is generally supportive of the principle of long-term capacity auctions, and it is hoped that those issues and concerns, highlighted by the offshore industry, will be fully addressed in the current discussions taking place on the form and structure of the long-term auctions. The discussions should also consider the issue of selling long-term capacity at a fixed price, reflecting long run marginal costs alongside capacity sold by auction. We do not believe that auctions alone will provide Transco with all the appropriate investment signals that it needs. We believe that there should be a more transparent base plan planning process and we, along with other Industry participants, are currently contributing to that debate in a series of workshops with Transco.

42. The long-term auctions are due to be in place from April 2002 and whilst Ofgem, in its review of Transco's Price control, goes some way in describing the way forward for auctions and output measures, there is still insufficient information concerning their structure and timetable for implementation.

43. BP's initial position on the release of long-term capacity is that

- primary release of capacity needs to extend to *at least* 'year 8' in order that producers developing long term projects are able to acquire entry capacity needed to market their production;
- the 'use it or lose it' principle is effective in preventing hoarding
- the 'top-down' approach will best suit the new regime since it will ensure that all capacity has been released to the market. Transco would then be required to buy back any capacity not made available. This should be based on 100% availability and not a proportion of that figure

- as previously proposed, 100% of the output measure should be sold in the long-term auction. Any unsold capacity should be made available as short term products i.e. daily, monthly or yearly.

Connectivity – flexibility (Interconnector & storage)

44. The UK gas market has a seasonal monthly swing around its annual average flow of ca.+/- 30 bcma. There is already a growing need for sources of gas to cover the winter months. As the UKCS 'swing contract' fields and Centrica's Morecambe Bay field gradually decline this seasonal requirement grows with each successive winter. Two sources of such seasonal gas are large scale UK Storage (e.g. Rough) and Continental storage linked to the UK via the Interconnector (IUK) in reverse flow.

45. The UK Continent Gas Interconnector has an export capacity of 20 bcma and an import capacity of 8.5 bcma. To date the Interconnector, has been used mainly to export gas to the Continent. There have been occasions, however, when it has been used to import gas to the UK in order to meet peak winter demand. In the future, the Interconnector will play an increasingly important role in meeting UK demand as indigenous resource declines and there is an increasing reliance on imports. BP has been instrumental in recent discussions amongst Interconnector Shippers to develop arrangements to increase flexibility and transparency in the commercial arrangements all with the aim of improving trading liquidity. These new arrangements are expected to be formalised in the near future. As the Interconnector's importance increases it is essential that continental liberalisation progresses at a pace to ensure that sufficient liquidity exists in continental Europe thus ensuring effective supplies to the UK. Interconnector Shippers have options to request that an expanded import capacity be made available which Shippers and Shareholders are currently investigating

46. Due to the continuing tightening of gas supply/demand and a deficit of sufficient swing production to meet UK peak day requirements, the issue of Storage is also vital. It has an increasingly crucial role to play in managing UK supply, and minimising the risk of within-day price volatility. We have recently responded to the Ofgem consultation into the proposed acquisition of BG Storage Ltd by Dynegy Inc. In our response we seek assurances that, should the acquisition be approved, there should be full operational separation from Dynegy's other businesses. This is to give comfort to users that Dynegy's UK trading arm, and their other gas commercial activities, will not have access to commercially sensitive information and will not be in a position to exploit or abuse its dominant storage position.

47. Whilst we recognise that Users will have some protection in so far as Dynegy's activities will be subject to the Competition Act 1998 and the Gas (Third Party Access and Accounts) Regulations 2000, we have concerns that these will be insufficient. Such general provisions may prove inadequate in giving confidence to users, in the absence of detailed undertakings or guidelines under the Act, which specifically address the current UK gas storage market. We believe that there is a need for Government, Ofgem and the Office of Fair Trading to give serious consideration to developing a set of licence conditions or statutory guidance for operation of storage facilities in the future which ensure, amongst other things, that there is no risk of capacity hoarding by a single company. One possibility is that

limits should be set on the amounts of capacity taken by a single company in a storage year. We would welcome the opportunity to discuss this issue further with Ofgem, Dynegy and other interested parties

48. Unlike the United States, where there is well-developed competition and choice in the provision of storage services, that is not currently the case in the UK. Although we are pleased to see a number of new storage products and services being developed and offered to the market, none of these is material in terms of volume nor can they provide the same degree of service as the BG Storage physical facilities. Rough and Hornsea will continue to provide the majority of the UK's storage facilities[4] for the foreseeable future and will continue to maintain a dominant position.

Market Liberalisation - & Its Implications For Connectivity

49. The UK is geographically well placed to benefit from future, competing supplies of 'dry' gas seeking new markets in Europe. The current barrier to accessing these supplies is a lack of connectivity across pipeline infrastructures and limited third-party access (TPA) to those pipelines.

50. BP strongly supports the completion of a single European market for gas. We believe that a fully functioning single market will considerably enhance security of supply for both the UK and continental Europe. The development of liberalised and regulated markets in Europe is crucial in this regard to ensure, through the creation of new trading hubs and cross-border transportation of gas, that stable, deep and liquid markets for gas exist. This provides end-users and suppliers with a genuine choice as to how and where their gas is sourced.

51. It is important that all Member States comply fully with the 2nd EU Gas Directive when it is adopted to ensure that the following downstream liberalisation elements are effectively implemented;

- Terms for third party access to downstream transmission and distribution services that are transparent, apply equally to all players with tariffs that are set on a cost-related basis;
- Appointment of strong independent country regulators who ensure transparency, stability and application of fair competition;
- Support gas release programmes which respect the sanctity of existing contracts but which provide gas supplies for new market participants;
- Provide improved physical and operational interconnectivity and integration of European gas grids.

52. The lack of gas-to-gas competition in Continental Europe has been the principal driver for the increase in UK gas prices since 2000. Most long-term contracts in Europe are indexed to oil, and the high oil price has given incentive for traders, shippers and suppliers to take advantage of the arbitrage opportunities by selling UK gas into Europe and European buyers sourced cheaper UK gas to meet their demand needs.

[4] 85% of storage space and 43% of deliverability capacity

53. Whilst liberalisation of continental arrangements has commenced, such developments remain in their infancy. The emerging spot markets at Zeebrugge witness a gradually deepening liquidity, but the reality of an inter-connected network of continental trading hubs remains a distant goal. Initiatives such as developing standard contracts for trading gas and transportation capacity will promote liquidity but significant barriers remain, such as the difficulty in securing economic access to continental storage facilities, gas quality specification issues and difficulty in accessing flexible supplies. Long term security of UK supplies and pricing will be dependent on the successful development of continental gas-to- gas competition, which we believe will require a concentrated effort to progress liberalisation with an associated gas release programme.

54. We see access to gas supplies as a major barrier to entry into the market. Programmes that release gas from existing long-term incumbent contracts on to new entrants such as those recently undertaken in Spain can provide the first steps to creating *effective* gas liquidity in the market. Gas release programmes respect the sanctity of contracts already entered into and honour take or pay obligations.

55. Comparable third party access is another key issue. The objective should be that the terms, conditions and tariffs are justifiable, cost related and that they apply equally to the incumbent's marketing activity and the new entrants. New entrants will not be able to build competitive, cost efficient portfolios of customers and suppliers if they are restricted to "point-to-point" transportation service. The incumbents operate an integrated, optimized portfolio – and it is this capability which needs to be provided for all.

56. The regulators must also be alert to detailed terms and conditions of the tariffs that are designed to create barriers to entry for new entrants e.g., onerous balancing requirements .

57. Liberalisation is not a process of de-regulation – but one of re-regulation. Experience in the UK and elsewhere demonstrates that strong independent regulation is an essential surrogate for competition in this transition phase from monopoly to liberalized market. Most importantly, in the absence of independent regulatory authorities, parties usually seek redress via the courts. If this occurs, there is the danger of many costly and time consuming diversions along legal byways which will undermine confidence in the policy direction.

58. Another important policy requirement concerns the integrated European market. If stable deep, liquid and future markets are to be secured, there is a requirement for pan-European integration of the gas infrastructure. This in turn requires integration both in a physically and operational sense. BP strongly supports the initiatives of the European Commission in promoting a European Gas Standards Industry Board (GSIB) along the lines of that in the US. The industry should be seeking sensible solutions to the inconsistencies between the national systems such as odorisation, exchanges between low-cal and high-cal grids, and so on. Without better integration, markets will not deliver the options for stability which are necessary. Depth is particularly important for the futures market and thriving markets are in everyone's interest.

59. While BP strongly supports the goals of competition and liberalisation, it must be recognised that this is a difficult journey. The structure of energy markets in Europe has been shaped by a long, complex history and regulatory change will create secondary consequences that will adversely impact some elements of the business (e.g., stranded assets, uneconomic contracts, etc.) It is vitally important that clear and effective regulatory initiatives be accompanied by an open dialogue that engages all parties in the industry in smoothing the path of transition. Similarly, the parties in the industry need to seize the opportunity to develop pragmatic and effective measures to ensure that the European energy markets function competitively and efficiently. The UK has a important role to play in sharing its experiences with the liberalization process and promoting this open, constructive dialogue both within Europe and with non-EU parties with strong interests in the energy market (e.g. Russia and Algeria).

UK Consumer Issues and Implications for Public Policy

Fuel Prices

60. UK fuel prices, before tax and duty, are amongst the cheapest in Europe, falling in terms by a third over the last 10 years. During the same period the proportion of tax has risen from 58% to over 75%. As regular investigations by the competition authorities have demonstrated, the UK retail market is highly competitive, transparent and efficient. However, there are still calls for action to reduce prices to the motorist. As our retail margins are low, in large part due to the highly competitive market in which we operate, and the level of taxation touches 75% of the retail price, our ability to reduce prices is extremely constrained.

61. The stock levels throughout the supply and distribution system are more than adequate, although levels at filling stations are dependent on regular deliveries. The Fuel Protests in September 2000 arose through unrest at the high price of fuel, especially amongst some sections of the farming and haulage communities. Stations ran dry primarily due to panic buying: at the same time, the problem was compounded when tankers were unable to leave stocked terminals. The terminals themselves had more than sufficient supplies of fuel. It is impossible on a practical level to increase fuel stocks at filling stations due to space constraints - and in normal circumstances it is also unnecessary to do so.

Cleaner Fuels

62. BP is committed to providing a range of cleaner fuels to the general public. In the short term these are predominantly conventional fuels with tighter specifications but increasingly we are looking to provide alternative fuels such as LPG/Autogas. All of these fuels give substantial air quality benefits especially in urban environments and they are aided by the duty incentives made available by HMG. Longer term we continue to work with a variety of motor manufacturers as they develop new technologies with the earliest benefits being achieved in urban fleets.

63. BP has led the introduction of a range of clean fuels both in the UK and globally in recent years. We are introducing our greener fuels in more than ninety of the world’s major cities. This campaign was launched in the UK in February 1999 with the introduction of ultra-low-sulphur diesel and since then we have extended this

range to include ultra-low-sulphur petrol, Autogas (liquefied petroleum gas) and lead free four-star. In addition to these cleaner fuels, we have undertaken to incorporate solar power at some two hundred of our service stations worldwide.

Duty Incentives for ULSP/ULSD and LPG

64. We support the use of duty incentives as a means of encouraging the uptake of cleaner fuels by the general public when they are introduced into the market. We introduced ultra-low-sulphur petrol in advance of any duty changes and absorbed the additional manufacturing costs ourselves. We undertook to pass on duty reductions directly to the consumer. We would certainly advocate continued use of the duty incentive as a means of encouraging cleaner or alternative fuels into the market.

65. We have seen a marked increase in the use of LPG (Autogas) as an alternative transport fuel. This has been greatly assisted by the use of duty incentives in the late 1990s. Indeed, we would not have seen the growth in the market had there not been generous tax incentives. However, LPG as a transport fuel is still in its infancy and sustained use of the incentive is needed to ensure that the public's confidence in the fuel remains. Many consumers who are considering converting to Autogas are concerned that as the market grows the fuel will be taxed more heavily. The example of CNG/LPG in the New Zealand in the 1980s, and elsewhere, is a good one. Substantial duty incentives were given to promote its use but were then abruptly withdrawn; this subsequently led to a near-market collapse. We would encourage the Government to provide a degree of certainty about alternative fuels. Certainly, maintaining the duty differential between motor fuels and Autogas for a minimum of five years would give greater stability as would the continuation of the Powershift programme and possibly a higher discount level for company car tax for cleaner vehicles.

66. We have become concerned that the recent surge in promoting compressed natural gas (CNG) is unsettling to the market, especially in relation to LPG. The alternative fuels market should be big and varied enough to cope with both LPG and CNG and in any case LPG is better suited to small-vehicle fleets and private cars (and is better suited for sales at filling stations) whilst CNG is perhaps more appropriate for larger trucks. For the benefit of a smooth and efficient allocation of resources, it would be preferable if sudden shifts in policy in favour of competing fuels were avoided.

Environmental Benefits of Ultra-Low-Sulphur Petrol and Diesel

67. BP is committed to introducing cleaner fuels that will achieve a sustainable improvement in urban air quality. Both of our products meet the European sulphur regulations for 2005 and have been introduced some five years ahead of legislation. BP's Cleaner Diesel is available at all BP service stations and is a premium quality ultra low sulphur diesel product that reduces harmful emissions. It emits 85 per cent less sulphur dioxide and up to a third less particulates and black smoke than standard diesel.

68. BP's ultra low sulphur petrol is marketed as Cleaner Unleaded. It has less than 50 ppm sulphur and less than 35 per cent aromatics. Specific benefits are: sulphur

levels in the fuel are reduced by 66 per cent which results in more efficient performance of the catalytic converter and reduced vehicle emissions; hydrocarbons are cut by up to 25 per cent and it creates less carbon monoxide and nitrogen oxide emissions.

Longer-term developments in cleaner fuels

69. As long as the market for natural gas and LPG remains stable BP envisages continued and increased use of these fuels. They apply an established technology and little new development is required. They are particularly effective in niche applications where the benefits are significant and can be very clean fuels for urban areas. The greater problems associated with Autogas have related more to rejections from local authorities for planning permission on forecourts and also vehicle conversions by non-authorised companies. Regulations need to be tightened to ensure only authorised installers undertake conversions so that the safety and integrity of LPG is maintained and real emissions benefits are achieved.

70. As motor manufacturers develop their vehicle technology we are committed to keep pace with our fuel developments; together we can then ensure that motorists obtain the best possible emissions performance from their vehicles. BP has been very encouraged by the help and support from several motor manufacturers, especially General Motors, with whom we have several collaborative projects.

71. Fuels cells with hydrogen are expected to play an important role with both mobile and stationary energy applications. Hydrogen is the cleanest alternative to the fossil fuels used today in transport. Hydrogen can be used to fuel internal combustion engine vehicles and BMW are actively developing these vehicles. Fuel cell technology is likely to have a key role, with several motor manufacturers developing hydrogen fuelled fuel cell vehicles prototypes. BP worked with General Motors to refuel the hydrogen powered Zafira fuel cell vehicle in demonstrations in Beijing and at the Sydney Olympics.

72. However, there are still potential problems which must be resolved if we are to ensure the viability of safe and effective storage of hydrogen for its use in a passenger vehicle. Several car manufacturers have announced plans to start commercialisation of cars with a fuel cell system from 2003-2004 using liquid fuels that liberate hydrogen on-board the vehicle to avoid this storage issue with hydrogen. BP is working with General Motors to develop the on-board conversion of liquid fuels such as gasoline to hydrogen using BP knowledge and experience of reforming technology.

73. BP is also a member of the California Fuel Cell Partnership and the first hydrogen refuelling station opened on November 1st 2000. The aim of the project is to support the commercialisation of fuel cell vehicles with the plan to have 50 vehicles operating by 2003.

74. The use of hydrogen for urban fleet vehicles is already possible. These fleet vehicles already operate from central depots, frequently along a known route and refuel at a depot on a daily basis where it will be easier to store hydrogen and dispense it. These vehicles will operate predominantly in urban areas and so the impact of zero tailpipe emissions will be significant. Daimler Chrysler announced the

introduction of 30 fuel cell buses in a pan European project, starting in 2002. Ten cities will each operate three hydrogen powered fuel cell vehicles. BP will be the major supplier of hydrogen to these vehicles. BP is using its expertise in the safe production and handling of hydrogen from many years of operations within its refinery and petrochemicals operations to allow the development of supply options to a number of fleet and passenger vehicles projects.

75. Bio-fuels may also have the potential to help reduce lifecycle greenhouse gas emissions from transport. But this is dependent on the choice of feedstock and the conversion process used; and considerable technological development is required before their benefits can be realised, and the costs become reasonable. Current bio-fuel technology has, at best, modest potential, and there are dangers in taking precipitate action in this area. Certainly, any promotion of bio-fuel must be accompanied by robust measures to prevent adverse impacts on biodiversity and water quality. BP would not support the setting of mandatory minimum levels of bio-fuel content in all transport fuel, since this could lead to supply shortages and increased price volatility. Moreover, it should be recognised that state aided bio-ethanol might also distort the traditional chemical chemicals and solvents markets for ethanol. Any such development, therefore, would need to be accompanied by appropriate anti-distortion measures. If the potential offered by bio-fuels is to be encouraged, it is important that it is restricted to those technologies which are not dependent on intensive farming, and which deliver clear life-cycle Greenhouse gas benefits.

76. We are witnessing great improvements in conventional fuels; and now, after a slow start, encouraging developments are taking place in alternative fuels such as LPG and CNG. In the longer term, motor manufacturers and oil companies are individually and collectively working on more radical developments. It is clear that these groups cannot pursue all the alternatives alone: environmental groups, academics and policy makers all too have a role. The Government has a key part to play in pulling together longer-term strategy, and promoting consumer knowledge of, and confidence in, new fuels.

Environment and Energy Efficiency

Demand side management

77. Liberalisation and increased competition will drive prices lower for consumers and give more efficient market signals. However, once inefficiencies have been removed from the incumbent monopoly - and once competition has reduced suppliers' margins - end-users cannot expect to continue to achieve significant year on year reductions savings in the prices they pay for their commodity costs. .

78. These will have to be achieved through different means. Customer's requirements to manage their total energy costs more closely (as well as to meet their environmental challenges) will force suppliers to develop products and services which meet these twin objectives. One way that industrial organisations are already seeking

to achieve greater energy efficiencies is through utilising energy management services. It is estimated that the take-up of energy management services will grow by more than a third in the next two years, reaching 28 per cent by the end of 2002. Moreover, the existing users will be spending on average 22 per cent more on energy management products (Datamonitor Report, 2001).

79. BP's response has been to consolidate and integrate its energy products and services businesses to form one organisation within a single location. This new organisation, BP Energy, represents a progressive move by BP and is aimed at developing and delivering a Total Energy Management (TEM) Offer. The emphasis and overall aim of TEM revolves tightly around improving energy efficiency – providing environmental benefits whilst also reducing the energy costs of our customers. In parallel, an internal programme (Group Energy Enhancement) aimed at further improving the energy efficiency of BP sites, is well underway, with challenging and measurable targets established for 2001 and beyond.

80. In simple terms, the strategy of BP Energy is to help customers meet new environmental legislation and manage their own energy portfolios more effectively. Competitive advantage will be secured through the combination of energy management expertise, an innovative approach to energy efficiency, breadth of product and service and best in class customer service. The offer will include:

- Risk Management including future emissions management and trading
- Out sourcing services such as CHP and CEM projects
- Consulting Services including H, S & E and emissions management.
- Energy Information Services such as monitoring, diagnostics, on-line access
- Energy products

81. Working with a number of customers, who had a range of existing energy management expertise, we identified total savings potential of up to 26 per cent of annual energy use and spend at some sites if they were to adopt all of the identified demand side initiatives. The average savings are, more commonly, in the range of 5 – 15 per cent per annum.

Measure	**Range of savings**	**Average annual energy saving**
Monitoring & targetting	3 – 5 %	4%
Energy Survey	5 – 10%	8%
Energy Training	2 – 6%	4%
Energy Strategy	2 – 6%	4%
Energy review/benchmarking	2 – 3%	3%
Process Integration	0 – 15%	7.5%

Our survey group comprised a range of end-user groups including, car manufacturers, paper manufactures, brewers, hospitals and colleges.

<u>Combined Heat & Power</u>

82. BP supports the Government's promotion of CHP and its desire to double UK use of high efficiency Combined Heat and Power by 2010. Achieving the target will deliver over one-fifth of the UK target of a 20 per cent reduction in CO2 emissions. However, to deliver this goal CHP needs a comprehensive strategy that provides a co-ordinated framework for action. This strategy needs to have both immediate and longer-term objectives.

83. The immediate objectives are to bring coherence and consistency to the current wide array of factors affecting CHP. In the longer term, the strategy needs to be designed to ensure CHP plays its full role in the transition to a more sustainable energy system in the UK.

84. In order to achieve the stated Government target of 10 GWe of CHP by 2010 it is essential that existing CHPs can remain in profitable, commercial operation; and that the market provides the necessary incentives to encourage investment in new CHP capacity.

Emissions Trading

85. The UK Government has established a UK Emissions Trading Scheme which will commence in 2002. However the European Commission (EC) and perhaps other international groupings are looking to establish emission trading schemes to enable GHG reductions to be made more cost-effectively by signalling the marginal price of GHG emissions abatement. Such trading schemes, and the creating of new emissions permit markets, are key to the cost-effective implementation of the Kyoto Protocol in the UK.

86. To minimise the costs of emission reductions a global watertight trading scheme is desirable. The UK Government has devised the UK emissions trading scheme which is currently voluntary. With the benefit of internal experience, BP believes that the following items are essential in development of emissions trading schemes:

- Linkage between National, EU and Global emissions trading schemes in term of a common currency (fungibility) and mutual permit recognition.
- UK Government to guarantee the validity of UK permits via a national registry and encourage trading in such permits;
- Clarifying the role of sinks following the Bonn Agreement at COP 6;
- Leading the development for CDM projects under the Kyoto Protocol to enable practical workable solutions to be established;
- Companies should be able to trade as entities rather than just countries trading with countries.

The Reduction of Emissions

87. In the case of the UK, GHG emissions have been reduced mainly by substitution of coal for natural gas in the electricity generation sector. The Government have a role in encouraging further emissions reductions cost-effectively. For example removing barriers such as the current NETA trading arrangements which reduce the ability of feed in electricity from renewable and CHP facilities, framing land-use planning legislation for solar and wind facilities and removing subsidies for

existing CO2 intensive energy sources such as coal. The Government also needs to clarify the role of sinks in reducing emissions following the Bonn Agreement.

88. Renewable energy certificates (RECs) can play a key role as a market based mechanism to promote renewable energy within a regulatory regime. Renewable generators feeding electricity into the grid also receive permits. These are required by electricity distributors to cover a renewables obligation. However a common UK and EU definition of renewable energy is required together with agreed certificate design, registry and accreditation. Reciprocal trading with parties in EU Member States against their national obligations would serve to underpin the EU (and UK) indicative 12 per cent renewable energy market share target.

Conclusions

89. This submission has largely concentrated on issues connected with gas, since this is the area where concerns over security of supply are at their height. We have accepted the PILOT target of 3 mmboe/d in 2010 as achievable. But we also realise that gas production is likely to decline from 2004, and that by 2010 the UK's import requirement could range from 30 to 60 bcm/a. By 2020, up to 90 per cent of the UK's gas requirements may need to be imported.

90. The argument of both this, and our first submission, is that this need not be a source of concern. There is no shortage of gas, as such. But there is a need to ensure that gas supplies can reach consumers, and that the necessary steps and investments are undertaken in good time. Most of the rationale and the recommendations in this submission are directed to this end. 'Connectivity' and 'Liberalisation' are inextricably linked. Together, they can help overcome the traditional fears over energy imports.

91. But if security of supply is one major concern, the environmental consequences of fuel consumption is another. While BP is enthusiastic over the long term prospects for Solar, we do not claim it offers a rapid, easy, or painless way of 'greening' energy consumption. We do argue, however, that much can be done to improve the environmental consequences of fossil fuel consumption, and to reach our greenhouse gas targets. In particular, we point to BP's work on cleaner fuels as illustrated above. And we emphasise the major contribution which suppliers can make to encourage our consumers to use less of our products. We do not regard this as a threat to our business viability. On the contrary, we see it as a source of competitive advantage.

92. It is inevitable that as vital a commodity as energy should attract public scrutiny and government concern. We make no complaints about that. But governments have the potential to make matters worse, as well as better. Political time horizons are not always consistent with the massive lead times associated with energy infrastructure investments. We welcome the opportunity presented by this Review to highlight both the opportunities and dangers facing governments in this crucial area of public interest.

APPENDIX 1 – PRELIMINARY SUBMISSION BY BP TO PIU ENERGY REVIEW

Introduction

1. The areas of the Energy Review where BP has most experience and involvement are as follows:

- Security of Supply, with particular emphasis on gas and 'connectivity' issues;
- Market Liberalisation, with its implications for both prices and security of supply;
- Environmental concerns, with particular emphasis on Solar and renewables.
- Energy Efficiency, with particular emphasis on Combined Heat & Power and advice to industry (we are developing a business, called 'Total Energy Management')

2. This is consistent with a view of UK Energy Policy which embraces four main dimensions i.e.:

- Competition Policy: how best to make energy markets work efficiently;
- Environmental Policy: how to integrate successfully environmental factors into energy markets through internalising externalities (which essentially involves clean air and climate issues)
- Fiscal Policy: how to arrive at an equitable basis of taxation and the distribution of rent from upstream energy production
- Security of Supply: how to ensure that energy supply is available at market prices as and when demanded.

3. BP has already submitted its views to Her Majesty's Government (HMG) and others on many of these issues. For example, BP Exploration is a major participant in PILOT, where there is a regular exchange of views and information on North Sea issues, and how best to realise the potential of the United Kingdom Continental Shelf (UKCS). BP UK Gas and Power has made a detailed submission to the DTI's Review and Updating of the Offshore Infrastructure Code of Practice (11th May 2001). BP Solar was a major participant in the Department of Trade and Industry's (DTI) Photovoltaic Government-Industry Group, and contributed to the Group's Final Report which was published on 26th March, 2001. BP has also made a submission to the European Commission, presenting our initial comments on the Green Paper 'Towards a European Strategy for the Security of Energy Supply'.

4. There are, however, some broad principles underlying all these submissions which we would like to emphasise in this paper. They embody an approach to the issue of Energy Policy from the perspective, based upon our experience and belief, that:

- Liberalisation of energy markets is of benefit to consumers (domestic and commercial) and to economies as a whole because the process encourages greater efficiency and leads to lower prices. It enables an economy to improve both its productivity and competitiveness.
- Market solutions to energy problems are almost always 'lowest cost' solutions. Other approaches – such as policy 'interventions' to address concerns over supply security – carry a higher cost, often in terms of

higher cost gas or higher cost electricity. Limitation of access to low cost energy imports would create a very real cost. For this reason,

- Policy interventions, if they are to be considered, must be justified on a transparent cost-benefit basis; and the same point applies to environmental goals.

With these broad principles in mind, we address some of the specific issues raised by the review.

Security of Supply & Market Liberalisation

5. Security of supply issues are often the most cited but least defined of factors. They are prompted by concerns over

? medium and long run supply availability from geographically proximate sources
? risk of long run resource depletion
? disruption of supplies for various reasons (physical disruption, political forces, accidents etc.)
? market failures

6. From a UK perspective, these concerns present themselves in terms of :

- Oil; fears over OPEC reliability, possible political disruption in the Middle East, and issues of long term oil resource availability.
- Gas: concerns over the longevity of UK resource base, the long term cost and resource availability of gas through continental Europe, the slow pace at which EU liberalisation is currently moving, and the risk of disruption to supplies from what some would regard as unreliable sources, such as Russia.
- Trade Union Militancy/Civil Disruption: A dependence on fuels/electric power capable of disruption by workforces, although this would normally be of limited duration.
- Integrity of energy grids and distribution systems – and the role of regulation to encourage long-term investment in the UK's gas infrastructure.

7. The greatest of these concerns currently concentrates on gas supplies, and a question for this Review is whether such concern is well-founded. BP would argue that it is exaggerated, and that those concerns which are legitimate can be remedied by appropriate government action. However, it is not difficult to see how this concern has arisen.

8. UK gas production is reasonably expected to peak and decline during the coming decade. At the same time, the European Union will very likely become more dependent upon longer distance gas supplies. There is a concern that new suppliers of EU Gas may prove unreliable, although there has been no evidence to date of this happening despite political disruptions in places such as Russia and Algeria.

9. This is the pessimistic view point. The same reality can be expressed differently. Namely, that the EU is surrounded by an abundance of potential supplies of gas, which it is very much in the interests of suppliers to make available to European consumers. These suppliers are in competition with each other, which

provides individual EU gas purchasers and aggregators with the opportunity to diversify suppliers and thus reduce risk. Added to this is the increasing diversity of LNG sources which are now coming from Trinidad and Nigeria to complement North African supplies. Both these projects have significant expansion potential, while new Atlantic basin projects in Egypt, Angola and Venezuela are also looking for a firm home in Europe. Even more encouraging is the fact that more distant LNG exporters in the Middle East are looking to Europe for both short-term and long-term contracts.

10. The following points support the more optimistic perspective of this issue.

Globalisation of International Gas Markets

Gas trade has been growing by about 9% p.a. for the last 20 years in the shape of international pipelines (such as from Canada to the US, from Russia and Norway to Germany and France, from Algeria to Italy and Spain). LNG – liquefied natural gas – has flowed from Alaska, Abu Dhabi, Indonesia and Australia to Japan and from Algeria to France and other EU destinations).

The number of international links has been growing rapidly in recent years. There are new pipelines from Argentina to Chile, from Bolivia to Brazil, from the UK to Belgium, from Malaysia to Singapore and from Turkmenistan to Iran. New LNG projects have also come on stream in Oman and Qatar for Asian markets, from Nigeria for European markets and from Trinidad for the US and Spain. 22% of gas consumed globally now crosses an international border. This is up from 15% in 1990. If intra-FSU gas trade is included this share rises to 27% in 2000. As much as 70 per cent of global gas reserves lie within economic transportation distance of the EU.

In addition, LNG sales into Europe are increasing as Middle East and Asian sellers find it harder to sell surplus capacity to existing Asian LNG markets, and as returns in Europe improve. During 2000, high US gas prices drew in spot cargoes of LNG from as far away as Algeria, Australia, Nigeria, Oman and Qatar. Malaysian LNG also reached Iberian markets.

This trend is set to continue and grow stronger as plans continue to be unveiled for expansions to most LNG projects and new schemes are under discussion or advanced planning in Irian Jaya, Sakhalin, Iran, Yemen, Angola, Venezuela and even Bolivia.

Connectivity

A greater concern than physical supplies should be the existence of adequate infrastructure (pipelines, terminals etc) and commercial arrangements to facilitate the interoperability of networks. In particular, a priority of UK Energy Policy should be to ensure that regulatory frameworks evolve to provide the appropriate investment incentives to increase the number and capacity of supply routes into the UK, and to ensure that sufficient capacity exists at appropriate entry points – this latter aspect will require close dialogue between industry, the DTI, Transco and Ofgem. BP stresses the importance for the UK in being able to secure and handle gas imports (including Natural Gas Liquids) from Norway. This means that more physical offshore connections are required between the NOCS grid and existing UKCS pipelines. The UK also must be an integral part of the European grid, and should promote full connectivity across the EU to allow the free flow of gas and diversification of UK supplies. This raises the role of the Interconnector, which itself is part of a separate study to which BP is contributing and which will form a part of BP's final submission.

Market Prices

It is not enough for the UK and the EU to be assured of physical supplies of gas – consumers and governments understandably wish to be confident that these will be available at market prices, as opposed to politically inspired levels through artificial restrictions and manipulation. Over the last twenty years, UK gas consumers have benefited from a real decline in oil prices to which the price of gas is linked. It is to be expected, however, that EU linkage to oil prices will diminish with increased liberalisation and the growth of gas-to-gas competition. The issue of prices is closely linked to that of Market Liberalisation.

Market Liberalisation

Downstream liberalisation provides the best guarantee against the imposition of excessive prices by the EU's current big players. Introducing competition and creating a dynamic gas market will also increase security of supply. However, steps must be taken to ensure that the market functions effectively throughout the process of liberalisation. A protracted period of turmoil due to ineffective or incomplete regulatory change could undermine the functioning of the market to the extent that security of supply becomes jeopardised. The appropriate policy response to this outcome is to ensure that the transition to a liberalised market is minimised through effective and comprehensive regulatory change which opens downstream gas markets to real competition. We do not believe there need be a conflict between market liberalisation and long-term or take-or-pay contracts; BP believes there is a role for both. It is equally necessary that the continuing upstream investments in developing resources and delivery assets are adequately recompensed without undue additional commercial risk posed by EU downstream liberalisation. The UK experience has shown how a market can be liberalised while maintaining upstream investment – BP's recently announced fifteen year deal with Statoil is an object lesson in this regard. What is crucial is that the liberalisation agenda should comprise a comprehensive programme of pragmatic regulatory initiatives, such as downstream Release Gas, comparable third-party access to the transmission systems and the appointment of empowered independent regulators. Progress to date has been partial in this area, and does not inspire confidence that a long and tortuous path to market liberalisation in the EU will be avoided. However, in other respects, there are more promising signs e.g. Spain has recently introduced a release gas programme for major volumes of Algerian gas. The need to address these initiatives will be a major component of BP's main submission.

11. These are the main issues which arise under the Security of Supply heading. There are, of course, others. The fiscal and regulatory regime of the UKCS, for example, will continue to have a major impact on the extent to which the UKCS attracts further investment and is therefore fully developed. The vision of PILOT is to

achieve 3 million barrels of oil equivalent per day (boepd) by 2010. So far, UKCS production has risen every year for the last ten years, which nobody would have dared to predict ten years ago. But this only happened because the UKCS remained attractive to industry in comparison with opportunities elsewhere – and it is a constant challenge to retain this advantage as the UKCS matures. It is impossible to separate the issues of UKCS Tax and regulation from how long UKCS production can be continued at significant levels. Technology is constantly stretching the profile – but this technology won't be encouraged without a supportive and stable tax regime.

12. However, there is no denying that the UKCS has now entered its mature phases – which is why UK Energy Policy cannot be seen in isolation, separate from either the EU or the global energy scene. In the final analysis, rising gas dependence – and ultimately dependence on imported gas – should not be a serious problem or concern. Gas resources are widely available; international gas markets are globalising. Any attempt to avoid this reality will only result in higher costs and reduced economic competitiveness. But as will be argued in our final submission, there are policy measures to be taken to reduce the risks of transition and to ensure that the UK is well placed to take advantage of the new realities offered by an international gas market.

The Environment

13. Clearly, a central tenet of UK Energy Policy must be how to meet this country's international and voluntary obligations to reduce its CO_2 emissions. As has often been remarked, it is only because gas has supplanted coal in so much electricity generation – although not yet to the extent that was once predicted – that the UK has to date been so well placed in this regard. Gas will continue to play a decisive environmental role. But in time, gas too could be regarded as environmentally inferior to other alternatives.

14. This raises the issue of nuclear power and the future for renewables. In terms of the current Energy Review, the question facing the Government is the same for both – should either or both receive special assistance? Should either be favoured over the other?

15. The first requirement is to encourage new technology – both in terms of energy efficiency and renewables - to make its own unique contribution, and to stress the importance of market mechanisms in this process. Technology is already making possible cleaner fuels in terms of local emissions; undoubtedly, it will do the same over time for global emissions. The question is how much time? In advising HMG's PV Government/Industry Group, BP has emphasised the importance of measures to stimulate the market – as opposed to the payment of direct subsidies to the *suppliers* of this market. For this reason, we are consistent in saying that competing fuels – such as nuclear or coal - should receive no special favours in relation to its competitors.

16. The UK Government, however, does have the option of encouraging the demand for renewable energy to increase at a faster pace than otherwise would be possible. This has been the rationale behind the various suggestions which have been made to stimulate the UK Solar Market - including a capital grant programme for commercial and domestic users, tax incentives, simplified connection agreements and,

most importantly, compulsory net metering to enable solar system owners to sell-back into the grid at attractive prices the energy which their own solar panels have generated. As mentioned above (para. 3) BP has already made detailed recommendations to HMG on this and related matters. Other measures are fully discussed in the PV Government-Industry Group Report – such as changes to building regulations, government procurement policies, and treatment for tax purposes. Obviously, it is also necessary to avoid unintentional discouragements – as currently faced, for example, by CHP and Wind Power developments as a result of the NETA reforms.

17. One should not exaggerate, however, the potential which renewables such as solar offer in the short-term. As the Report recognises, the global PV market has accelerated steadily over the past ten years. It suggests that by 2020, PV could come within the range of prices of the technologies in the Renewables Obligation. BP has already announced plans to increase its Solar business turnover to $1 billion by 2007, which represents significant growth. Over the next two years, we will double our solar business's capacity.

18. But none of this can supplant the dominance of fossil fuels – anymore than nuclear could if it too were expanded – over the short to medium term. That is why improving the environmental consequences of fossil fuels should be the first priority. That is why gas remains an attractive fuel environmentally (as well as commercially) for the purposes of power generation. In addition, policy makers should be reminded of the importance of fiscal incentives to accelerate the transition from fossil to renewables – both in terms of encouraging renewable technology, and in encouraging consumers to shift their pattern of consumption.

19. There is also a crucial role for energy efficiency to play. BP are advocates of the potential offered by Combined Heat and Power (CHP) and our later submission will expand on this aspect. We also see benefits - both in policy terms, but also in terms of our own commercial business – in increasing the quality and quantity of information to companies and businesses relating to their own energy consumption. BP is developing a business (Total Energy Management) whose purpose is to help our customers to use our products more efficiently and economically.

Conclusions

20. BP will seek to develop many of the above points in greater analytical detail in its final submission. But the points of principle can be identified already.

21. The UK still has significant oil and gas reserves, and the fiscal and regulatory regime is currently maintaining a positive investment climate aimed at bringing those reserves to market. A primary requirement of UK Energy Policy should be that the fiscal and regulatory regime continues to keep the UKCS competitive on a international scale. Provided this is so, concerns that UK gas reserves will soon be exhausted are misplaced.

22. On the other hand, the UK cannot hope to escape the need for imported energy. Already, under certain conditions, there is a need to import gas in wintertime during periods of peak demand. Norway is an important and competitive source of

gas for the UK market with significant future exploration potential. BP has already taken steps to ensure additional long term supplies are available to the UK market from October this year. That is why no UK Energy Policy can be conducted – or indeed, 'reviewed' – in a vacuum. Developments elsewhere in the EU and in the world are highly relevant.

23. The most urgent policy necessity is to facilitate liberalisation of the EU gas market without endangering EU Security of Supply. The two objectives are by no means incompatible and can be mutually beneficial if the liberalisation process is effective; but they do require changes of current policy and practice which will be fully explained in BP's main submission.

24. In terms of the environment, it is a common objective between HMG and BP that renewable energies should be developed. BP's primary interest is in Solar, and we have emphasised the potential which could be realised by measures to stimulate the UK market.

APPENDIX 2 – SUMMARY OF RECOMMENDATIONS OF THE PV GOVERNMENT-INDUSTRY GROUP

INSTITUTIONAL BARRIERS

1. A simplified (one page) Connection Agreement between the householder and the licensed electricity supplier and the adoption of profiling rather than half-hourly metering. This could be delivered through changes to G77. (Page 32)
2. Encourage Managers of the Government Estate, Local Authorities, NDPBs etc to identify new public sector building projects and give more active consideration to PV on public sector buildings, e.g. through Conferences/ Seminars and a Circular Letter and Green Ministers. (Page 31)
3. Encourage DETR to update the mainly factual annexes to Planning Policy Guidance 22 to more accurately reflect current more pro-active renewables policy. (Page 31)
4. Encourage the Embedded Generation Implementation Group to give serious consideration to recommending Dual Meters and to propose that suppliers pay the same rate for exports as they charge for imports. (Page 32-33)
5. Put a proposal to OFGEM to do work on assessing the necessary changes to the electricity network to allow easy connection of small-scale embedded generators such as domestic PV. (Page 32)
6. Encourage the British Standards Institute to make progress on the 15+ standards that are in development for PV (Page 34).
7. Support the industry in setting up a National Training and Accreditation Scheme (similar to CORGI) for installers and service personnel. (Page 34)

INCENTIVES

8. The most effective means of encouraging the deployment of PV in the UK would be a major Market Stimulation Programme featuring a 50% capital grant for 70,000 domestic roofs, (Page 36) and a similar grant scheme for larger non-domestic buildings (Page 38) costing around £150 million over 10 years.

9 A voluntary agreement with each of the licensed electricity suppliers to allow perhaps 5,000 householders over 10 years to receive the same price for exports of electricity as they are charged for imports, in combination with the installation of dual meters. Alternatively a mandatory requirement could be introduced by secondary legislation under the Electricity Act. (Page 33)

10. A voluntary agreement with the major private and social housing developers to have PV systems installed on a minimum of say 1% of their new/refurbished houses per year by 2010. (Page 38). 8
11. Write to Treasury/Customs & Excise making a case for Enhanced Capital Allowances to be given to businesses installing BIPV, and for individual homeowners to have a personal tax allowance for installing PV. (page 34)

OTHER

12. Encourage the PV industry and utilities to lease roof space from building owners, thus retaining ownership of the PV system whilst passing on the benefits of `green' electrons. (page 38)
13. Encourage a number of large showcase BIPV demonstrations on high-profile commercial and public buildings. This could form part of a voluntary agreement with developers and Government departments (we are already developing a limited demonstration scheme). (Page 39)
14. As many of the above recommendations will require the active co-operation of the PV, electricity and construction industries, it would be advisable to have some sort of Voluntary Agreement between all involved parties. This would probably involve the Minister having separate meetings with each major group, followed by a Solar Summit where they sign the agreement. (Page 39)

APPENDIX 3 – BP's Submission to 'The Review and Updating the Offshore Infrastructure Code of Practice and Proposals for Publication of Guiding Principles on Use of Legal Powers to Settle Disputes'

BP Response to Consultation on Review and Updating the Offshore Infrastructure Code of Practice and Proposals for Publication of Guiding Principle on Use of Legal Power to Settle Disputes

Background

1.1 The UKCS is now recognised as a mature province with its future reliant upon the development of increasingly small pools of hydrocarbons. In many instances these pools have remained undeveloped not simply because of their size but because of the significant technical difficulties and risks they present. In combination these factors mean that the economics of these projects are often marginal. Maximising the extraction of these resources will be a significant challenge and will require the full efforts of resource developers and infrastructure owners working together. As highlighted by the PILOT initiative, innovation – commercially, operationally and technically – will be key to achieving this objective. BP is already demonstrating its commitment to that effort, through the satellite accelerator initiative, the FPS small pools offer, and its investment in projects to supply offshore power from onshore generation, and to provide fibre optic links from shore to platform.

1.2 Greater cooperation, at an earlier stage in the development, will be needed to facilitate the identification of new and lower cost solutions to the technical and commercial challenges. In support of this initiative infrastructure owners will have to be prepared to be increasingly flexible over the type of service provided, offering solutions that cut across the traditional boundaries between the facilities of the resource owner and the infrastructure owner. As an infrastructure owner BP is continually looking at ways of reducing development costs through the provision of new services. An example of this is initiatives that offer economies of scale through aggregating the requirements of many developments, such as onshore mercury or water removal. BP is similarly exploring ways of adapting its existing field processing facilities to meet the needs of satellite developments. This evolution from dedicated field processing facilities to a centralised processing role, is in its earliest tentative stages with many technical and commercial issues to be resolved. However, there are already instances where efforts of this sort have offered lower cost solutions and accelerated development. The Erskine field development is a good example of a instance where the owners of an existing field (Lomond) pro-actively sought to modify their facilities, to provide a lower cost option than a new cluster development, and accelerated first production from the Erskine field by several years.

1.3 Responses to the PILOT cluster questionnaire highlighted that uncertainty in reserves and delivery/flow rate issues were two of the largest barriers to development. Infrastructure owners will also have a role in finding ways of sharing and minimising these and other commercial risks. BP is actively looking at new ways of addressing risk. In developing the FPS small pools offer BP sought to find a solution that addressed concerns over future oil price, reserves and quality. As a consequence the specification offered is wider and the level of tariff payable varies according to oil price and reserves. This approach represents a sharing of upside and downside risk, and significantly improves the economics of small field development. The Beauly field is one example of a development whose success is due in part to this initiative.

1.4 Since future developments will be almost wholly reliant on existing infrastructure a pre-requisite to success in all of the above, will be the ability of the infrastructure owners to provide a service for the economic life of any new field development. Against a backdrop of declining production from current fields and an ageing infrastructure base, the challenge will be to find ways of delaying the abandonment of existing infrastructure for as long as practicable.

1.5 Extending the technical life of assets will be dependent on obtaining and sustaining, sufficient levels of investment in new technology and other maintenance activities. Extending the economic life will be dependent upon cost reduction initiatives and the level of income from third party tariffing. Clearly, infrastructure owners have a strong incentive to ensure that the asset remains available for the economic life of their equity fields, and to meet any existing contractual commitments, however any guarantee of service beyond that time will be dependent upon anticipated income and throughput. Thus, confidence in the adequacy of future tariff levels will be key to extending the life of existing infrastructure, while obtaining a guarantee of a later infrastructure abandonment date will be key to any decision to invest in a development, whose economic life extends beyond the date currently guaranteed by the infrastructure owner.

1.6 BP is committed to achieving the PILOT objective of 3 million barrels of oil equivalent per day for 2010. This target can only be met by production from new developments and by maximising recovery from existing fields. BP's commitment to this effort is exemplified by the Magnus EOR project. This project combined $500 million of investment with technical and commercial innovation; to achieve not only enhanced oil recovery from a mature field but also a new export route for gas from West of Shetland. The project overcame significant hurdles, in terms of complexity and the number of parties involved, to achieve something that many thought impossible. It is that type of commitment and lateral thinking, which will be needed to create a sustainable future for the UKCS. Achieving an optimal regulatory environment will be key to promoting these behaviours, and ensuring a continued drive by infrastructure owners and resource developers to overcome the technical and commercial challenges associated with many new developments.

Appropriate Regulatory Environment

2.1 It is our belief that the optimal regulatory environment is one based on a system of negotiated third party access to infrastructure with a "light handed" rather than prescriptive approach to the regulation of this process. This approach has served the industry well in the past and is consistent with promoting proper utilisation of existing infrastructure through incentivising innovation and investment.

2.2 Many of the principles applied in the regulation of onshore gas transportation would be entirely inappropriate in the offshore environment. In the onshore environment, Transco enjoys a natural monopoly in the provision of transportation services and the cost of transportation has a direct impact on the prices paid by end users. In contrast, in the offshore, there is competition between service providers, and it is generally accepted that transportation and processing costs for a particular pipeline do not affect the wholesale price of gas, since it is a sufficiently competitive market[5]. There is therefore a need to apply a more rigorous system of regulation to the onshore, where it is vital that all users receive the same level of service and are charged a reasonable and consistent cost, in order to ensure fair competition. Conversely, the needs of offshore system users are best served by a more flexible system that promotes innovative and diverse service solutions that are optimal to each individual circumstance.

2.3 In preparing this response BP has reviewed a range of regulatory regimes adopted in a variety of industries and countries around the world. The review highlighted the great diversity of approach, with no single optimal solution. Our conclusion being that each system was developed to meet the individual needs of the particular industry and address the concerns prevalent at the time. Given the similarity between many facets of the UK offshore and the Australian and US equivalents, we note the commonality of many of the regulatory principles as support for the appropriateness of a light handed approach.

2.4 In Australia the Council of Australian Governments has been pursuing a policy of reform aimed at promoting "free and fair trade in natural gas". As part of that initiative the Gas Reform Implementation Group advocated the development of a system of third party access to upstream infrastructure based on an industry-agreed statement of best practice. In developing the statement APPEA (Australian Petroleum Production & Exploration Association) noted:

- the fact that upstream facilities are designed for a specific purposes, which may differ markedly from facility to facility;

[5] Letter from Geoffrey Riggs to Amanda Goodwin of UKOOA on Upstream Industry and Competition Law dated 20 November 2000

- the fact that facilities often provide for considerable redundancy to provide for continuity of supply;
- a view that commercial negotiation provides the least cost and most effective method for achieving third party access to upstream facilities;
- that examination of competition pressures and outcomes in the upstream industry has not revealed evidence of a failure of market forces to operate efficiently with respect to processing of third party gas streams.

The statement APPEA developed embodies many of the same concepts as the UK Code of Practice, including obligations to:

- respond in a timely manner to bona fide applications;
- grant access on fair and reasonable terms to capacity in excess of that committed for security of supply and reasonably anticipated future requirements;
- negotiate in good faith;
- honour existing contractual commitments including security and reliability of supply;
- recognise the legitimate business interest and investments of facility owners and access seekers;
- provide for continuing safety, efficiency and integrity of the facility;
- maintain environmental standards and obligations;

and thus establishes a "light handed" approach to regulation, in line with the existing UK framework.

2.5 In the US the Federal Energy Regulatory Commission (FERC) have opted for a distinction between the regulatory regimes applied to downstream gas transmission systems (falling under the jurisdiction of the Natural Gas Act) and offshore gathering systems (falling under the jurisdiction of the Outer Continental Shelf Land Act). In the downstream gas transmission systems are subject to a cost-of-service rate regulation and to individual Network Code-like terms and conditions of service. In the offshore case FERC is statutorily required to enforce a policy of "open access and non discrimination" but has chosen to interpret that obligation in a manner that allows a great deal of flexibility through the adoption of a "light handed" non rate based approach to regulation. In this regard they have satisfied themselves that reporting requirements relating to the terms offered to prospective users will provide a sound basis for ensuring the objectives of fair and non-discriminatory access are achieved and that the market operates efficiently.

<u>Balancing the Interests of Resource Developers and Infrastructure Owners</u>

3.1 Given the increasing dependence of UKCS resource developers on infrastructure service providers, BP are fully aligned with the need to maintain appropriate safeguards to ensure that the terms offered for third party access to infrastructure do not act as a barrier to development. We believe that the current environment protects the interests of resource developers in a variety of different ways.

3.2 We believe the principal protection is afforded through competition. In many areas of the UKCS there is strong competition pipe-to-pipe, terminal-to-terminal or owner-to-owner within a pipe. In many instances, the decision on the optimal field export option is taken after initial discussion with a number of infrastructure owners and the submission of competitive bids for the provision of the service.

3.3 As existing fields mature the amount of ullage available in infrastructure will increase. In response to this, infrastructure owners will naturally take an increasingly active role in marketing their infrastructure. BP has received significant interest in its enlinx initiative and believes that this is supportive of a conclusion that this change is already taking place. As the infrastructure owners' focus switches, from production of their equity fields to an increasing dependence upon securing third party business, the level of competition will become even greater and consequently, additional comfort will be provided that the tariff rates offered will be fully competitive.

3.4 In circumstances where the resource developer has limited offtake options he is afforded protection from the fact that his interests and those of the infrastructure owner are generally aligned, with both wishing to ensure that the development proceeds in order to obtain the income which will accrue. In our experience infrastructure tariffs are not normally a significant determinant to whether a development is economic or not. However, it is recognised that in some situations where the economics are particularly marginal the infrastructure tariff may play a part in determining whether the development proceeds or on the timing of field abandonment. In such cases the infrastructure owners will have a clear incentive to work with the resource developers to identify lower cost solutions or to examine ways of sharing upside and downside risk. The alignment of the parties and their ability to work together in this way ensures that infrastructure tariffs do not inhibit resource development.

3.5 Resource developers are also afforded legal protection from unfair treatment through the prohibitions contained in the EU and UK Competition Acts.

3.6 As a final safeguard resource developers have the right of appeal to the Secretary of State in the event of a dispute over the terms of access. To date no such references have been made. It is our view that this supports the conclusion that the existing regulatory arrangements are working well and that sufficient safeguards currently exist to ensure that resource development is not hindered by the terms offered for access to infrastructure.

3.7 Concerns regarding open and non-discriminatory access are addressed by the terms of the Code and the transparency afforded through the supply and publication of indicative terms.

Proposed Changes to Offshore Infrastructure Code of Practice

4.1 As highlighted previously the industry has set itself high targets for maximising resource recovery. There are many challenges standing in the way of meeting those targets. The greatest obstacles being the need for innovative, lower costs development solutions and the need to develop and extend the life of an aging infrastructure base. In reviewing the proposed changes to the regulatory regime we have sought to identify the principles that will best support the industry in meeting these objectives.

Effectiveness of the Code of Practice

4.2 It is BP’s view that the Code of Practice continues to be an appropriate and effective tool and generally enjoys a high level of industry support. This is evidenced by a recent UKOOA survey, in which the majority of respondents indicated that they believed only minor changes were required to the Code, to ensure that it remained relevant to the needs of the industry. In light of this we believe that the Code should be updated to reflect recent legislative change and to include current best practice.

Information Requirements

4.3.1 The upstream industry is characterised by the transportation and processing of a heterogeneous product, with each customer requiring a variety of different levels of service. In the future, as we increasingly seek optimal, situation specific solutions and as the characteristics of the fluids become more diverse, this variety will increase. In this environment, “standard” or actual contract tariffs offered for a specific service are of limited relevance to the industry as a whole and indeed may inhibit negotiation by raising false expectations and perceptions. For example, we have recently quoted a tariff to one applicant that was predicated on an expansion of the infrastructure and therefore included an element of capital cost recovery. It would be inappropriate for anyone developing a smaller resource pool, which could be accommodated within existing capacity, to use this as the basis for estimating the probable cost.

4.3.2 The Code currently provides for the provision and subsequent publication of indicative tariff terms. This requirement has significantly enhanced the level of transparency within the industry, through increasing the amount of data in the public domain. BP continues to support the publication of indicative tariff offers and the efforts to ensure full reporting of this information. As an infrastructure owner we would actively encourage resource developers to seek an indicative tariff offer as the best means of assessing the probable cost of the service they require.

4.3.3 Indicative tariff offers are made at a stage in the negotiation process when only a limited amount of information is known about the specific requirements of the development in question. Indicative tariffs are therefore a compromise between the general "example" terms envisaged in the main commercial conditions and the customised, service specific final contracted tariff terms. BP believes that their publication represents the appropriate means of addressing the need for transparency. Consequently, we would caution against prescriptively extending the requirements to publish information, through either, the extension of the requirement to publish Main Commercial Conditions to upstream pipelines, or the introduction of a new requirement to publish actual tariff information, without a fuller evaluation of the implications and perceived benefits. We believe that as infrastructure owners take an increasingly active role in marketing their infrastructure, progressively more information will be made available. Giving owners discretion in this way will permit them to supply information appropriate to the circumstances of their system.

4.3.4 With regard to the question of asymmetry of information requirements we do not believe that this will have any implications for the negotiation of a combined transportation and processing package. Where applicants desire a "bundled" service we would expect that they would simply request an indicative tariff offer for such a service and the negotiations would then proceed on that basis.

4.3.5 notwithstanding, our belief that the publication of actual contract terms is inappropriate, we are prepared to supply details of future contracted tariff terms to the department, on a confidential basis. This would provide additional comfort on our non-discriminatory approach, without jeopardising the commercial interests of the resource developer concerned.

Timely & Efficient Development

4.4.1 BP is committed to the objective of ensuring timely and efficient resource development and is actively seeking ways of streamlining and simplifying the access process. We are actively pursuing ways of making information on our systems and services more readily available. We believe that e-commerce offers solutions and have committed to the development of the enlinx system as means of making our transportation and processing services more easily accessible to our customers. We have committed to making this system available to the industry as a common means of supplying information relevant to infrastructure access and thereby simplifying the process for applicants.

4.4.2 It has been our experience that the industry is adept at delivering "just in time" agreements for transportation and processing. In some instances negotiations take several years in other cases they take several weeks. In responding to access requests infrastructure owners endeavour to meet the timetable aspirations of the applicant, with the timetable outlined in the Code viewed as backstop should the parties fail to otherwise agree.

4.4.3 As the industry develops BP believes that there will be an increasing requirement for contact between the parties at an earlier stage in the development to foster a greater degree of understanding and hence innovation. We believe that it would be valuable to given recognition to this less formal discussion stage within the Code of Practice timetable for handling third party enquiries. It is our view that it is at this stage that there is the greatest scope for adding value e.g. through joint technical studies aimed at identifying alternative lower cost or accelerated development options.

4.4.4 We recognise the value in developing new contracting strategies aligned with the needs of small field development and have committed legal resources to looking at ways of achieving this.

Tariff Determination

4.5 The determination of infrastructure tariffs is a complex process and consequently, we accept that there is scope for misunderstanding between the parties as to the justification for the particular tariff offered. It concerns us that, in some instances, this may have led to inferences that the tariff offered was too high when in fact there was a compelling technical or commercial explanation. BP is supportive of initiatives aimed at reducing the risk of such misunderstanding and generally improving the negotiation process. To this end we believe that the creation of a set of behavioural guidelines for infrastructure owners to follow in negotiation would be of value. Creating such principles may serve to bring further alignment to how companies act. An example of such guidelines would be the following:

Infrastructure providers will

- Always work to offer access and to find creative ways to accept new business when it is offered
- Approach the negotiation in an open and constructive manner
- Always be able to demonstrate the basis for the tariff offered

Infrastructure owners will not

- Delay the progress of negotiation without bona fide technical or operational reasons
- Offer different access terms to different parties where the disparities cannot be explained by differences in the level of services sought

Guiding Principles on Use of Legal Powers to Settle Disputes

5.1 In reviewing the proposal to publish guiding principles on dispute resolution, we have sought to evaluate whether such a change is likely to support or hinder the industry in meeting its objective of overcoming the barriers to small field development and prolonging the life of existing fields and infrastructure.

Background

5.2.1 The Code of Practice provides a framework for an enormous range of transactions from access to offshore platforms through to onshore terminals and covers the full spectrum of hydrocarbon fluids from oil through NGL to gas. The services offered range from simple transportation through to complex processing, storage, and export. In many cases the arrangements are further complicated by associated agreements covering remote operation of facilities, provision of field services or product purchase. There are few instances of applicants seeking a simple service with most desiring a complex suite of inter related services. Given this level of complexity and diversity, we firmly believe that a flexible process of negotiated third party access is optimal.

5.2.2 The process of negotiation provides for the parties to explore individual needs, identify areas of concern and risk, and ultimately find ways of managing these. Given the benefits accruing from a successful conclusion, it is in the interests of both parties to handle the discussions in an open and constructive way, which will foster good relations into the future. The outcome of the process will be a set of bespoke terms tailored to the individual needs of the field and mutually acceptable to both parties. This process has a proven record of identifying new lower cost solutions and enabling new developments.

5.2.3 Given our strong support for the negotiation process, we believe that all efforts should be made to resolve any contentious issues before recourse to dispute resolution. Accordingly we acknowledge the value of the continued support of the DTI in providing a background facilitation role to support the negotiation process.

5.2.4 We accept the requirement for a process of dispute resolution to be used <u>only</u> as a measure of last resort when all other options have been exhausted.

5.2.5 BP acknowledge the desire to bring greater clarity to the criteria for dispute resolution, but share the fear noted in the consultation that any attempt to simply encapsulate the principles of the highly complex tariff setting process will fail to give adequate recognition to all of the factors involved. Consequently, we believe that the product of any prescriptive attempt to do so, will serve to diminish the overall levels of trust and commitment within the industry. And ultimately, the option of abrogating responsibility, through "formula based" regulated terms, may serve to undermine the negotiation process itself and lead to more costly, less innovative and more standardized solutions. At a time when the future of the industry is reliant on continued investment and lower cost, innovative, situation specific solutions any move toward standard regulated solutions would undermine the future sustainability of resource development.

<u>Proposals contained in paragraph 4.16 of the consultation</u>

5.3 BP support the view advocated in the Lords Committee debate in 1975, that spare capacity has a commercial value and that the owner, having borne the cost and risk of installing such capacity, should be entitled to derive a fair commercial consideration for that value. We are similarly aligned with the statement, in 4.13 of the consultation, that there are many technical, economic and commercial variables and that any attempt to be too prescriptive in setting guidance on access terms is likely to overlook an important factor. Notwithstanding this commonality of intent, we believe that the principles outlined in 4.16 of the consultation are in fact too prescriptive; fail to recognise many of the relevant factors; and are inappropriate given the current needs of the industry.

5.4 BP believes that a system based on an incremental cost recovery is inconsistent with achieving the desired objectives. In the interests of equity the basic unit cost of system capacity should, as far as practicable, be the same for all users of the system and should be consistent with the full cost of providing such capacity, including an allowance for the recovery of the original and any future capital cost. This approach ensures that future small developments will enjoy the economies of scale previously afforded to larger developments, without introducing a requirement for infrastructure owners to use existing revenues from their equity production and third party fields to subsidise such developments. As the consultation recognises any approach which does not reflect the full cost of providing the service cannot be sustained in the longer term.

5.5 Any dispute resolution process also needs to recognise the significant efforts expanded by infrastructure owners in securing third party business and in identifying optimal solutions. In future there will be an increasing requirement for specific solutions to meet the needs of small field development, and correspondingly a higher burden on the commercial and technical resources of infrastructure owners. In many instances a number of different infrastructure owners will be invited to develop bespoke solutions for a prospective development. Often these discussions and technical studies will progress in parallel over several months, culminating in the submission of competitive bids. While this process delivers optimal, competitive solutions it is clearly resource intensive and costly and therefore the efforts expanded in this way need to be recognized in the tariff setting process.

5.6 In addition to all of the costs outlined above, there also needs to be due recognition of the level of risk taken by infrastructure owners. In future there will be a need for infrastructure owners to assume ever-greater levels of risk in order to provide solutions that meet the requirements of new developments. There are many forms of risk. In its simplest form it is the added liability to third parties associated with providing any service. Alternatively, where systems have been oversized to accommodate third party business there is clearly the initial risk of the speculative investment. Additionally, there are many risks associated with the provision of fixed tariff. Before committing the considerable levels of investment needed for a new development, resource developers require a robust economic case; a pre-requisite to this is a guarantee of service at a <u>fixed</u> tariff rate extending over the anticipated productive life of the field. Ideally, associated with this would be a tariff escalator based on the price of the relevant product. Providing such tariffs, in an environment where there is a high level of uncertainty associated with future product prices, throughput and income is difficult in itself. Combined with uncertainty over the future costs, of maintaining high levels of system integrity, reliability and safety, and meeting ever more stringent environmental constraints, it requires infrastructure owners to assume significant risk. Consequently, to ensure the continuation (and extension) of this practice in future, there needs to be due recognition of all facets of technical and commercial risk in the tariff setting process.

5.7 The provision of services to a third party will always have some impact on the existing users of the facility. The impact could be as simple as a loss of operational flexibility, through a reduction in the level of unutilized capacity, and consequently, a diminution of the level of security of supply for owners' equity production. Alternatively, the introduction of a new (and technically compatible) entrant into an oil system may, serve to marginally alter the characteristics of the combined stream and consequently, impact its market value. The consultation recognizes the potential for new third party gas to exert a back out effect on existing production but fails to take account of the many other impacts on infrastructure owners' production.

5.8 Overall there needs to be an appropriate level of return to attract investment; ensure the continued operation of the systems for as long as practicable; and to promote a continued drive on the part of infrastructure owners to secure third party business. In a profit seeking environment infrastructure owners will have a clear incentive to develop new services, overcome technical challenges, innovate commercially and actively cultivate new third party business. Conversely, in a lower return environment, infrastructure owners have an incentive to focus on optimising their own equity production and provide only the basic level of service. In the current environment BP is actively pursuing a Production Growth agenda, recognizing that its FACTS business would benefit if it helped resource developers optimise their production. This is achieved through open forums and one-on-one meetings with customers to identify bottlenecks that limit production. BP then searches internally or with its customers to find other situations where a similar challenge was faced and perhaps overcome. Thus the profit incentive ensures that every effort is made to maximize not only equity production but also third party production.

5.9 The existing infrastructure is operated, by a number of multi-national companies, to exacting environmental, health, safety and security of supply standards; based on good business practice and a desire to protect reputation. This investment was clearly motivated by a need to provide a reliable export route for the owners' equity production. However, as equity production declines, the focus will switch to third party business. We fear that if faced with the application of the proposed tariff setting guidelines owners may divest their interest, in pursuit of better investment prospects elsewhere.

5.10 Consequently, at this critical and challenging time for the industry we would strongly caution against the publication of dispute resolution guidelines outlined in the consultation. The ramifications of such a change cannot be fully anticipated and we believe will serve to undermine many of the industry's current initiatives.

5.11 If the department desires to publish guidance on dispute resolution, we believe that it needs to be soundly based and take account of <u>all</u> factors relevant to the determination of tariff. To ensure that this objective is met, the guidelines should be of a general rather than prescriptive nature, outlining the intent, the factors relevant to the determination and the process to be followed. An example of this might be a statement such as:

"The Secretary of State will use his powers to promote recovery of all economic hydrocarbon resource through provision of access to infrastructure on a basis consistent with balancing the differing interests and objectives of infrastructure owners and resource developers and ensuring fair payment to the infrastructure owner for all efforts made, risks taken, costs incurred and opportunities forgone"

accompanied by a brief description of the administrative process.

If desired the concept of fair payment could be expanded to include a non-exhaustive list of the factors that may be relevant, for example

- the current level of system operating costs and the estimated level of future operating costs for the infrastructure;
- historic, field specific and estimated future capital costs for the infrastructure;
- opportunity cost to the infrastructure owner (e.g. loss of operational flexibility, future potential to use the capacity for as yet undiscovered equity volumes);
- the amount of risk undertaken (e.g. through the selected tariff escalator, guarantee of service, nature of the fluids, reserves risk) by the infrastructure owner;
- the degree of effort and innovation demonstrated (e.g. identification of lower cost options, new technology) by the infrastructure owner;
- comparable tariff offers.

APPENDIX 4 – BP's Submission to Ofgem Consultation Paper

The New Gas Trading Arrangements – Further reform of the gas balancing regime – A Consultation Document – February 2001

1.0 Summary of BP's views on Ofgem's Consultation Document

We oppose strongly the introduction of a shorter balancing period as proposed on the grounds that:

- We believe the costs associated with Ofgem's proposal far outweigh the perceived benefits. We request that a full cost/benefit analysis be undertaken
- It will place an excessive commitment on resources and will effectively inhibit further developments in the UK gas industry
- We believe the practical implications of Ofgem's proposals have not been considered in full. The implications associated with the proposals must be clarified and understood by all UK gas industry participants
- We believe the proposal will result in less gas to market, particularly in depleting North Sea gas fields, where the costs associated with implementing the proposal will far outweigh the production revenue
- We believe the proposals may generate greater volatility in gas prices and have the impact of higher gas prices to consumers.
- We believe that a simpler, more practical and efficient alternative can be developed that will satisfy the principles outlined in the consultation document
- Adoption of Ofgem's proposal would necessitate determination of gas ownership on a shorter period and would thus require renegotiation of all gas sales contracts, all current allocation and attribution agreements and many third party transportation and processing agreements.
- Producers are currently able to mitigate the impact of physical constraints and any outages through limited within day flow rate flexibility thus ensuring that the maximum potential volume of gas is delivered to market on a given day. Reducing the allocation period will remove this flexibility and will therefore reduce the volume of gas which can be delivered to market in aggregate on a given day.
- Given the specialist nature of the skills required to negotiate, design and build the systems changes required, simultaneous implementation of the proposal would be impracticable. It typically takes several years to negotiate, design and implement changes of this sort.

Before proceeding with any change we request that Ofgem consults with the industry with a view to identifying alternative approaches to satisfy the principles of reform as outlined in the consultation document. Each alternative should be reviewed in detail and a cost/benefit analysis performed.

2.0 Background on existing upstream arrangements

The aim of this section is to outline common industry practices deployed by the upstream industry in order to facilitate the operation of the existing gas market.

2.1 Introduction

Many shippers obtain their gas supplies through Gas Sales Agreements with producers. Typically this gas is delivered to the shipper at the entry point into the NTS and is sourced from a specific offshore field. Prior to delivery the gas must be transported and processed and this is carried out under Transportation and Processing agreements between producers and the owners of the relevant infrastructure. Since there are often many offshore fields using the same infrastructure the upstream industry has developed agreements entitled Allocation and Attribution agreements setting out the rules governing the entitlement to gas delivered into the NTS from the common infrastructure.

2.2 Upstream Nominations

Under the provisions of the Gas Sales Agreements the shippers exercise their rights by making requests for gas termed "nominations". These nominations are normally in the form of a delivery rate to apply from a specified hour of the day until superseded by a new rate request.

When negotiating these agreements producers would prefer to operate their facilities at a maximum constant rate since this gives the highest reliability, greatest efficiency and minimises any potential safety hazards. However the shippers, as purchasers of the gas, insist upon flexibility.

The consequence is that the Gas Sales Agreements contain a compromise between the desires of the shippers and the physical constraints of the producers' facilities. This compromise is expressed as a limitation on maximum rate, minimum rate and on the permissible rate of change that may be requested by the shipper. An example of this would be a requirement to give 12 hours notice for any rate change up to 50% of the current rate and 24 hours notice for any change exceeding 50%. Requests for rate changes within these limitations and also within the specified contractual maximum delivery rate are classified as Proper Nominations. Producers have an absolute obligation to meet all Proper Nominations and a further Reasonable Endeavours obligation to meet any component of the nomination out with the rate of change or maximum rate limitations.

The Gas Sales Agreements are coherent with the existing daily balancing arrangements in that the obligation on the producers is to deliver on any given day a quantity of gas equivalent to the time-weighted average of all the nominations in force during such day. This equates to an End-of-Day (EOD) target against which field performance will be monitored and failure penalised.

Additionally, producers are under a reasonable endeavours obligation to deliver the gas uniformly in accordance with nominations. In many instances gas production from a specific offshore field is sold separately by each field owner to different shippers. Nominations are therefore received by individual producers, aggregated by the Field Operator, and passed to the Terminal Operator, who in turn aggregates the nominations from each of the fields using the infrastructure and endeavours to deliver sufficient gas to meet the total terminal nomination.

Terminal Operators advise Transco of the intended rate of delivery for each hour of the day in their Daily Flow Notification (DFN). The figures quoted are the aggregate nominations received, adjusted to reflect what the Terminal Operator believes will be physically achievable. DFNs are updated during the day to reflect any nomination or operational changes.

In the upstream, shipper nominations do not represent ownership of the gas, they are simply requests for delivery, ownership is determined post delivery through the provisions of the allocation and attribution agreements. It is not unusual for the total system nomination to exceed the total quantity of gas available. This is reflective of the fact that shippers will often make reasonable endeavours nominations, a proportion of which may not in fact be met. Operation in this way sets high aspirational targets for the facility operators and ensures maximum utilisation of the limited production capacity.

In some instances there may be insufficient gas to meet all of the terminal nominations because of production losses associated with:

1. Field outages
2. Offshore Processing Facility outages
3. Terminal outages

<u>In all instances, the producers and terminal operators will do their utmost to deliver the desired End-of-Day quantity: however, where there is insufficient gas to meet all nominations, Proper Nominations are given priority over Reasonable Endeavours Nominations.</u>

<u>2.3 Determination of Gas Ownership</u>

The process of determining gas ownership is lengthy, complex and requires knowledge of all inputs into the system (e.g. each Field's metered production and composition) and all outputs from the system (e.g. metered sales gas, metered NGL products, fuel consumption together with their composition).

In the simplified case where there is only one pipeline input to the gas terminal, the first stage in the process is to determine the quantity of terminal products actually produced by each Field inputting into the pipeline. This step is termed product "allocation". When this step is complete this data is used in conjunction with the prioritised nominations in respect of each Field to determine ownership of the gas. In some cases an exchange of gas may take place ("Substitution") between Fields to assist in meeting the aggregate nomination. This step is termed product "attribution".
Where the producers from a single Field do not deliver in "common" to a single buyer further stages of allocation and attribution are required to apportion sales gas entitlement between producers and between sales contracts. Only after this step is complete can the quantity of gas delivered to each shipper be identified.

Given the considerable data requirements and the number of steps involved it is not surprising that a multitude of systems are required with the workload spread between large computer systems and manual processing. Details of gas ownership are not available until several days after the Gas Day to which the data relates. The design of the systems and the process outlined above are coherent with current gas sales contracts in which the period of allocation is a Gas Day.

2.4 Physical Constraints

When considering the within day flexibility that can be provided by the upstream producers it needs to be recognised that the gas industry, unlike the electricity industry, cannot provide virtually instantaneous rate changes. Gas producers employ hundreds of miles of pipe work and complex processing equipment, hence, there is a significant time lag between increased wellhead production and increased deliveries at the terminal outlet. The lead-time can be reduced by line pack in the offshore pipelines but this effect is greatly exaggerated.

In the past it has been recognised that while the demand for gas clearly varies within day it is optimal to keep the offshore delivery rate as constant as possible. Since it is cheaper (and more secure) to provide diurnal storage than to meet instantaneous demand from additional offshore capacity.

2.5 Physical Flows

The existing daily balancing regime is coherent with the physical restrictions on the producers' facilities. The delivery period of a day permits:

1. Actions to ensure the EOD target will be met despite outages for short periods during the day ("catch-up")
2. Management of the ramping process i.e. it will always be necessary to deliver in excess of the current nominated rate for a period in order to achieve any higher rate of delivery specified for a future time and similarly with any decline (these over deliveries are eliminated by adjustment of actual delivery rate versus the nominated rate of delivery to ensure the EOD target is achieved)

This limited flexibility allows producers to perform to a very high standard, meeting the vast majority of firm nominations and also exceeding contractual expectations by delivering a large proportion of reasonable endeavours gas. This ensures that shippers are afforded the maximum flexibility achievable and that the maximum volume of gas is brought to market.

3.0 Implications of Within-Day Bal ancing

3.1 Additional Information Requirements

As highlighted previously the upstream gas industry currently determines gas ownership on a period of a Gas Day. Ofgem's proposal for the introduction of a shorter balancing period relies on the knowledge of Shipper gas inputs to the Transco system on an hourly basis.

While aggregate flow information is available on this basis, provision of individual shipper data would necessitate determination of gas ownership by the upstream industry on a shorter period and would thus require renegotiation of all gas sales contracts, all current allocation and attribution agreements, and many third party transportation and processing agreements.

It would be impractical to deem ownership of gas input to the NTS using shipper AT Link nominations. This could result in a disparity between the downstream view of gas ownership and the upstream view and would fail to provide an incentive on shippers to accurately reflect their forecast of upstream deliveries on AT link.

3.2 Costs of Ofgem Proposal

As stated previously we have not had sufficient time to provide an estimate of the costs associated with the introduction of a within-day balancing regime. However, outlined below are the areas in which we think costs are likely to be incurred:

3.2.1 Contract Renegotiation & System Replacement

Most of the current allocation and attribution systems will require complete replacement generating external IT costs of several million pounds for each system. This will affect not only Terminal systems but also Field level systems because of the staged approach to allocation outlined previously.

Changes to the CATS and SEAL systems are likely to be less onerous because they were both designed to provide within-day information on gas ownership – none the less changes will be required even to these systems since they provide for within-day catch-up if the nominations for a particular period are not met.

Renegotiation of all the gas sales agreements, allocation and attribution agreements and many of the transportation and processing agreements will be a lengthy process (it typically takes several years to negotiate amendments to allocation agreements) involving every party in the upstream industry and generating enormous manpower costs.

3.2.2 Metering and Data Transfer Systems

There will be vast costs associated with replacing or upgrading existing metering and data transfer arrangements.

3.2.3 Operating Costs

The costs of operating the Terminal and Field allocation systems will increase considerably as significantly more personnel will be required to operate the systems and disseminate information. There will also be cost increases associated with supporting the revised metering and data transfer systems.

Similarly in the downstream there will be significantly increased operating costs for Transco and other downstream participants associated with handling the additional data flow and monitoring inputs, offtakes and line pack for each individual balancing period. The introduction of these costs will create a higher barrier to entry and will discourage participation by small players.

All of the above costs will be in addition to the enormous manpower and system development costs likely to be incurred by Transco and other downstream participants in moving to a shorter balancing period. In light of this analysis we strongly believe that the figures quoted in the consultation document represent a gross underestimate of the final cost. The recovery of these costs will have a direct impact across the whole gas value chain and may ultimately result in an increase in gas prices to UK Consumers.

We do not believe that such a massive investment is required in order to alleviate Transco's balancing costs, currently reducing year-on-year with a previous yearly estimate of £8million. Nor do we accept the need for such a vast investment due to the introduction of the New Electricity Trading Arrangements (NETA), and the potential increase in CCGT generation and any potential knock-on effects these will have on Transco's balancing costs.

3.3 Within Day Flow Control

A move to a shorter balancing period would necessitate a change to all gas sales contracts, allocation and attribution agreements, and many transportation and processing agreements to permit shippers' full control of flow into the NTS on an hourly basis.
The provision of this additional certainty on flow can only be achieved by sacrificing some of the current contractual flexibility. Thus it is likely that the existing reasonable endeavours provisions within the gas sales agreements will require to be replaced by hourly rate of change limitations to ensure that the process of rate change can be satisfactorily managed in a shorter balancing period. This change is likely to reduce the volume of gas that can be brought to market.

Similarly the move to a shorter balancing period will reduce the producers' ability to mitigate the impact of outages, thus altering the balance of risk and reward between buyer and seller, therefore necessitating a revision to the existing price/penalty regime.

The contract renegotiation will also have to provide for the recovery of the upstream costs incurred in the change. Since the costs are largely the same for all systems regardless of the volume of gas remaining to be produced, it is not clear how abandonment of some fields could be avoided given the enormity of the likely costs per unit of production.

3.4 Impact on the Gas Market

We believe that a move to shorter balancing periods will increase market price volatility through the introduction of additional pressure on an ever-tightening supply/demand balance. As highlighted previously the flexibility required to hourly balance peak demand cannot be supplied by upstream producers. Indeed the move to a shorter balancing period is likely to curtail, as opposed to enhance, the flexibility and reliability currently afforded to shippers, thereby reducing the volumes of gas which can be brought to market.

4.0 Way Forward

We believe that a number of alternatives should be explored fully prior to considering the implementation of a within-day mechanism. Below we have outlined a few such alternatives and we believe that the details associated with these proposals should form part of future industry debate.

The current proposal seems to be a classic example of using a "sledge hammer to crack a nut" since the desire for vastly increased data requirements is partly motivated by a desire to eliminate the practice employed by a small number of Shippers of profiling their offshore nominations while declaring the daily average on AT link. To address this issue we would propose that Ofgem adopts a more thorough, properly project managed investigation, where the relevant data requested can be used by Ofgem to identify those involved in such behaviour. Recent investigations by Ofgem have suggested the data requests made are irrelevant and cannot be used to properly identify those causing the problem. We also believe that the recent modifications to the gas balancing regime, namely, the removal of Shipper imbalancing tolerances, should be given sufficient time to become established, in order to determine whether Transco's balancing costs will be further reduced, given the greater commercial incentives this change places on shippers to better balance their portfolios.

We also believe that the introduction of a line pack option should be further explored as a separate entity and not simply developed in conjunction with a within-day balancing mechanism. Should it be introduced along with the within-day balancing proposal then the acquisition of line pack will be a necessity as opposed to a luxury and hence the industry will not only be paying vast costs for the introduction of a within-day regime but also the additional costs of the enforced acquisition of a scarce commodity via a price auction. Bearing in mind the recent trends in entry capacity auctions and the excessive revenue over-recovery made by Transco, such a concept should be considered carefully.

A separate line pack option will give shippers the opportunity to purchase the required balancing tolerance and may further reduce the need for Transco to take balancing actions thereby reducing costs.

There also exist a number of other alternatives currently being discussed in industry, an example of which includes the use of a phased scheduling approach. We request that Ofgem further consults the industry on these proposals and then considers each alternative on its own merits, performing a full cost/benefit analysis for each proposal.

2nd Submission by BP to the PIU Energy Review

Introduction

1. In our preliminary submission (attached in Appendix 1), we identified four areas of concern to the Review where BP had particular reason to comment i.e. Security of Supply (with particular emphasis to Gas); Market Liberalisation; Solar; and the potential offered by energy efficiency.

2. We identified the central principles which, in our view, should underpin policy considerations in all these areas. Namely:

- that there is still great potential in the UKCS; but equally, the UK shouldn't be frightened of the long-term inevitability of losing energy self-sufficiency;
- that market liberalisation and connectivity issues would be crucial determinants in ensuring that the UK and Europe generally continued to enjoy abundant energy supplies at affordable prices; and
- that renewable energy sources are important for the future, but their immediate contribution should not be exaggerated.

3. The purpose of this submission is to expand on some of these points, and to offer further evidence for the conclusions drawn.

UK Energy Scene

4. Before considering points in greater detail, there are some general observations to be made concerning the UK Energy Scene and the scope of the Review.

5. The first concerns the reliability of energy forecasts. In terms of reserves, many have proved pessimistic in the past. In terms of prices, they have often been inaccurate. BP's view of the UK's oil and gas reserves is given in the next section. So far as oil prices are concerned, BP envisages a range of prices which appear credible and sustainable: prices outside that range are perfectly conceivable for the short-term, but would ultimately be expected to fall back into line. Our current mid-cycle assumption for planning purposes is Brent at $16 per barrel. But in terms of BP's own investment decisions, we test projects to be resilient (i.e. must cover cost of capital) at $11 per barrel.

6. The second observation concerns the environmental constraints which are often assumed to dominate energy policy considerations. It is the view of the Royal Commission on Environmental Pollution that the UK needs to make a 60 per cent reduction in its CO_2 emissions by 2050. BP is not opposed to the concept of targets; indeed, BP has its own environmental targets for internal purposes. Currently, it is BP's determination to reduce its own Greenhouse Gas emissions by 10 per cent by the year 2010 from a 1990 baseline. We're not so well placed to judge the validity of the Royal Commission's target for the UK as a whole. But whether well-founded or not, we are confident that no single measure or action will in itself be sufficient to achieve the objective. The development of new technologies, in particular, will transform the relative ease with which this environmental challenge is overcome. The essential

requirement is to encourage the development of strong and healthy enterprises with the necessary financial and technical capability to develop solutions for the future. There is a whole range of options from which to choose. BP, for example, has to date placed the main emphasis upon Solar Power. However, while it is almost impossible to quantify in advance the relative contributions to be made from renewable sources, energy efficiency, or cleaner fossil fuels (not to mention nuclear if the problems associated with this fuel could be overcome), it is clear that any short term penalty or deterrent to energy use which eroded wealth or a company's commercial strength would be counter productive from an environmental perspective.

7. So far as Solar specifically is concerned, BP was a major contributor to the final report of the Photovoltaic/Government-Industry Group and which contains a large volume of data relevant to this Review. The Group's main recommendations are summarised in Appendix 2. There is clearly no need to duplicate in our submission to this Review everything we have already said in the earlier report. But we would place particular emphasis on recommendation 8 i.e. "The most effective means of encouraging the deployment of PV in the UK would be a major Market Stimulation Programme featuring a 50% capital grant for 70,000 domestic roofs, and a similar grant scheme for larger non-domestic buildings costing around £150 million over 10 years." This recommendation is highlighted because it illustrates how, in some areas, the initiative lies with Government alone to act. The experience of other countries which have introduced similar market stimulation programmes has been encouraging. But this is not the sort of measure which private companies can introduce unilaterally, since it would be construed as market distortion. The other important aspect of policy is grid connection, which once again is outside the capability of companies such as BP to resolve alone. Without action in these two areas, it is very difficult to see how rapid market development can occur. With them both in place, however, rapid market growth could be anticipated as was the case in Germany during last year (albeit with a more attractive premium price buyback market stimulation policy).

8. Finally, as will be apparent from the following sections, it is our view that the greatest contribution which governments can make to energy policy generally is to remove artificial constraints upon the efficient working of the market, and to ensure that nothing discourages the necessary investment in infrastructure. Connectivity issues are central to safeguarding UK security of supply.

Outlook for UKCS Oil & Gas production and reserves

9. The UK oil and gas industry has a strong track record of developing oil and gas supplies from the UKCS. BP is equally optimistic about the future - there is still significant potential in producing fields, undeveloped discoveries and from further exploration. Figure 1 shows BP's most likely forecast of oil and gas production.

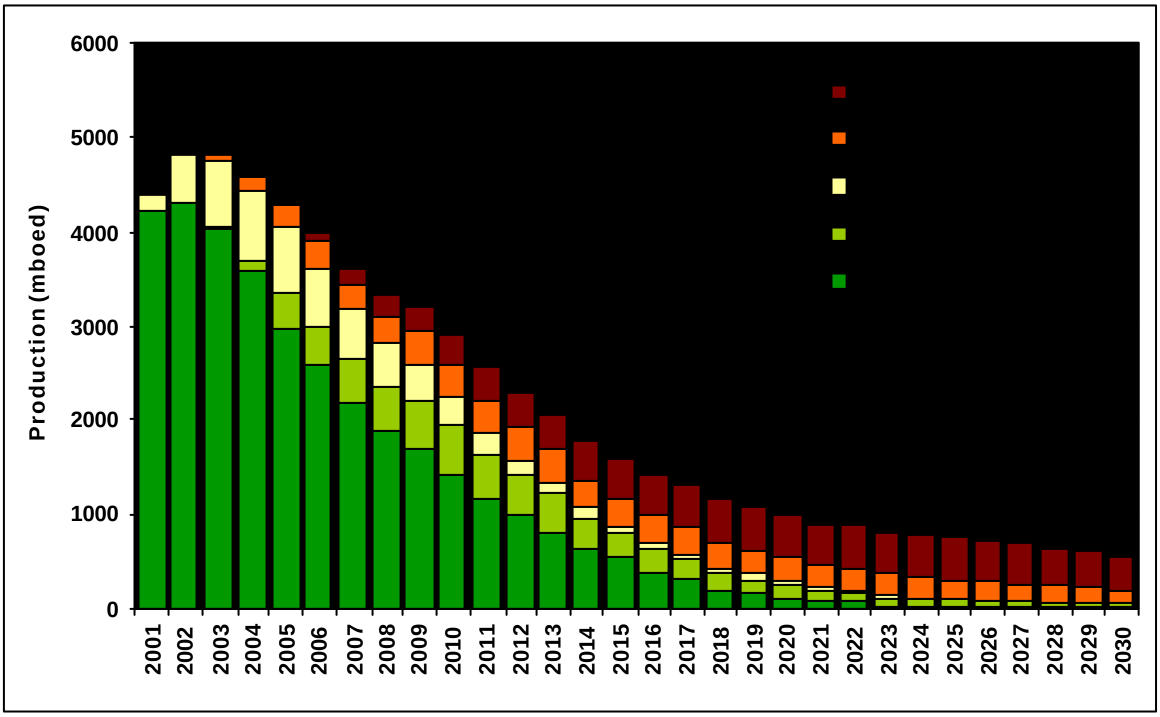

Fig. 1. UKCS Oil and Gas Production - Most Likely Case

This is consistent with other commentators. Key points are:

- Recovery from existing fields – BP believes that there is potential to improve field recovery factors. For example in the Forties field BP has seen recovery factors increase from an original 42% to a forecast 62% over the past 2 decades. We now have an aspiration to recover 70% of the original oil in place from Forties. If average North Sea recovery factors in all oil fields could be increased by 5%, an incremental 2 billion boe could be recovered.

  4D seismic and through tubing drilling are examples of technologies which give confidence to these predictions. They are having an impact today on many of BP's own fields :

  - 4D seismic gives us the ability to see the additional oil to be recovered. 4D seismic is the process of acquiring two or more 3D seismic surveys over time. It is then possible to improve the imaging of the reservoir and specifically observe the movement of fluids therein. This means that the placement of new wells can be improved and additional well targets can be identified. The scale with which BP is using this technology is significant. During the summer of 2000 we acquired 4D Seismic Surveys over eight fields and the plan is to acquire further 4D seismic surveys this year over the remaining fields. Forties has benefited – since 1997 we have doubled the initial well rates from our infill wells.

  - Through tubing drilling: We have been able to continue drilling conventional wells on Forties, but non conventional wells employing 'through tubing rotary drilling' (TTRD) will play a vital role in access. TTRD enables a sidetrack to be drilled from an existing well without the risk and cost of removing and re-running the existing completion. The technology offers significant cost savings and makes small infill targets viable. It is particularly important where no further well slots exist – e.g. Magnus. It also has the environmental benefit of greatly reducing drill cuttings. An extension to the technology is multi lateral drilling where we retain production from the original well and add through tubing sidetracks.

BP has a continuous programme of non conventional wells underway – up to ten this year alone, including multi lateral wells on Harding and Hoton, and TTRD on Bruce, Miller and Magnus. A TTRD well on Magnus came back on stream in April at 12,000 b/d against our original expectations of 5,000 bpd.

- Undeveloped discoveries – contain an estimated 4-5 billion boe of reserves. Although most of these discoveries are now being worked, many of them still carry significant geological and development risks. We conservatively estimate that 50% of these reserves will be produced.

- Exploration success – BP supports the DTI's view that there is approximately some 13 billion boe of undiscovered hydrocarbons on the UKCS, albeit with a wide range of uncertainty. However, we don't believe it is realistic to expect current levels of exploration activity to turn all of this potential into production. This is because many of the pools are too risky, too small or too remote from infrastructure to justify industry investment. In our most likely forecasts we estimate that 20-40% (3-5 bn boe) will eventually be recovered. This view is consistent with other industry work[6].

  BP's focus is West of Shetland, where we believe there is the greatest potential for new large discoveries. Success here would add upside to the above figures.

10. In summary BP believes that the PILOT target of 3 mmboe/d in 2010 is achievable. Indeed it may be conservative. However, the challenges involved in delivering this production should not be under estimated – the UKCS is maturing rapidly, fields are becoming smaller and more complex and there is increasing competition for investment from overseas opportunities. That is why maintaining the competitiveness of the UKCS is crucial.

Maintaining The Competitiveness of the UKCS

11. Continued focus on costs and the fiscal environment will be necessary to maintain competitiveness. We believe the key focus areas to be:

- Innovation and technology – the UK oil and gas industry has been at the forefront of technological and commercial innovation. Two current examples are described above. It is critical that this trend continues. Continued industry R&D and initiatives such as the Industry Technology Facilitator have an important role to play. However, the most important factors will be the recruitment & replacement

[6] Industry Ditch Bridging Group Report.

of the industry's highly skilled and motivated workforce, and the continued diversity of the industry.

- Skills shortages – the issue of the industry's aging workforce is well recognised. Yet oil and gas production will be an important part of the UK economy for at least the next twenty to thirty years. Critical skills shortages are already being addressed by PILOT & UKOOA in the areas of technician training, helicopter pilots and medics. Industry will shortly debate the need for a strategic and integrated policy group to address skills shortages, recruitment and training across the industry. In summary this is an area of serious concern and is a policy issue that has to be addressed jointly by both government and industry. The key will be continuing to demonstrate that the industry can offer attractive and exciting careers, and innovative retention and training of the existing workforce.

- Diversity and new entrants – One of the keys to technological and commercial innovation is diversity. The industry has evolved to the point where there are many niches to exploit, and different operators and service companies all have their own unique part to play. BP has been the catalyst in bringing a number of new oil & gas companies into the North Sea over the past decade. Industry has a key role to play in creating the right environment for this change to continue. BP supports the initiatives that are being pursued (faster acreage turnover, more efficient asset trading and improved access to infrastructure) and encourages the Government to continue championing this change through PILOT.

  Diversity within the service industry is equally important. A healthy SME community is vital to the health of the industry – they are an important source of commercial and technological innovation. BP encourages Government to continue to nurture this sector, which is particularly vulnerable during low oil prices. Key areas for assistance are:

  - commercialising new ideas
  - developing HSE standards
  - diversification by developing export potential

- Cross industry collaboration – all of these initiatives speak to the need to work more closely across the industry. Involvement of Government facilitates a wider appreciation of policy implications, and has enhanced the effective operation of the whole supply chain (e.g. the DTI mentoring programme). BP has played a major role in the OGITF task force and PILOT because of the importance we attach to transferring best practice and knowledge. The Brownfield benchmarking initiative is an excellent prime example of this collaboration, which we believe will yield as much benefit as future exploration.

- Fiscal policy – The Government's policy of fiscal stability and appropriate regulation has made a critical contribution to the success story of the UKCS and the sustainability of its competitive position. A fiscal regime which reflects the realities of the UKCS and avoids disincentives is probably the most crucial requirement of all in maintaining industry confidence in further investment and activity. The UKCS requires a fiscal regime which acknowledges the additional problems which come from maturity.

The future for Gas

12. The growing importance of gas justifies special consideration of its potentiality, and of the policy requirements to maximise this potential.

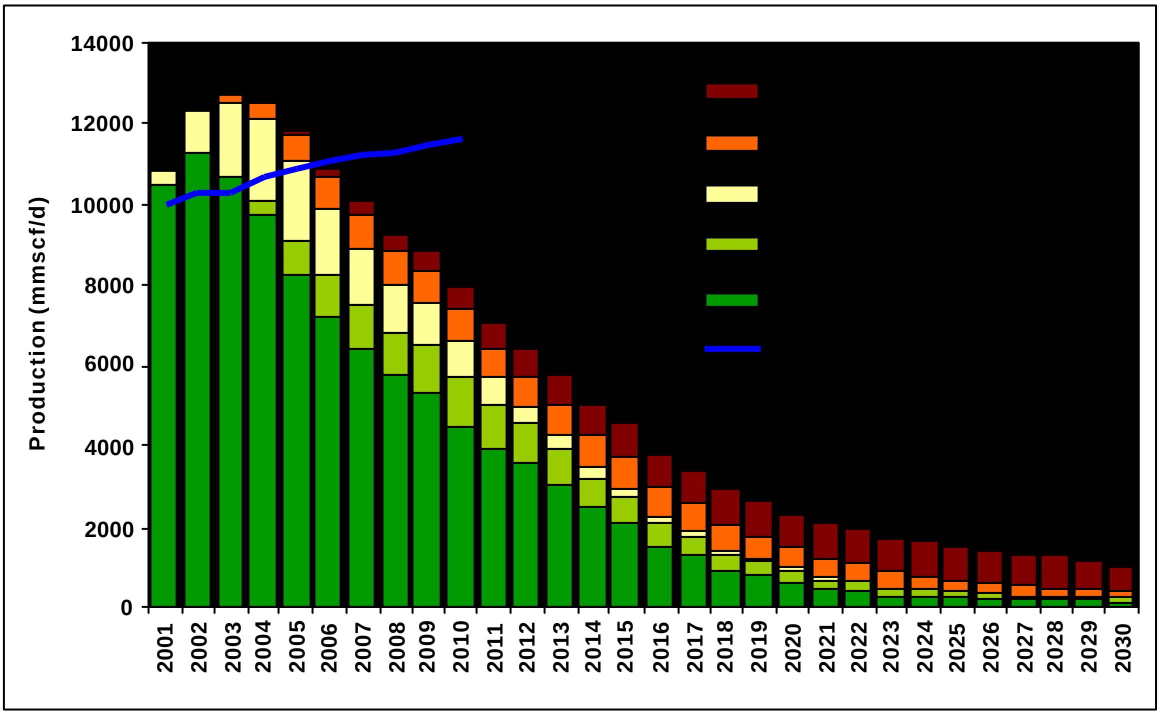

Fig. 2. UKCS Gas Production – Most Likely Case

13. Gas will continue to be a major contributor to indigenous fossil fuel production. However, this cannot continue indefinitely and production is likely to decline from 2004, unless significant volumes of gas are discovered West of Shetland. This is considered unlikely.

14. The outlook for gas demand is equally uncertain. There are three main possible scenarios for the next ten years :

- Transco Base – forecasts UK demand (including UK exports to the Republic of Ireland) reaching 112 bcm/a (10,800 mmscf/d) by 2010.
- WEFA – forecasts 120 bcm/a (11,600 mmscf/d) in 2010.
- Power substitution – forecasts 130 bcm/a (12,600 mmscf/d) in 2010. A possible upside scenario assumes continued switching from coal to gas share of the power generation market

15. Combined with the range of supply sources these indicate a shortfall within the next few years. By 2010 the UK's import requirement could range from 30 to 60 bcm/a. By 2020 up to 80-90% of the UK's gas could be imported. This analysis ignores the declining production from high swing fields in the Southern North Sea.

Imports have already occurred to meet peak demand and this is expected to increase over the next few years, even if indigenous supply exceeds demand on an annual basis.

16. This therefore underlines the importance for the UK and Europe in assured access to international gas supplies. It has frequently been said that “Europe is surrounded by a sea of gas”. This generalization is true – especially when the increasingly globalised LNG market is considered. The key issue for UK and European Gas Supply is not the availability of gas in the ground, *but their connection to the markets.* Each potential supply source has its own characteristics & issues:

- Norway – is the obvious supply source for meeting any UK shortfall - it is closest to the UK and is the lowest cost supplier. Norway has c. 140 tcf of discovered gas resources. So far c. 45 tcf of these resources have been developed to meet market demand in Europe. Of the remaining reserves around 60 tcf are in the development planning or execution phase pending further demand. In addition the Norwegian Petroleum Directorate indicates a further c. 90 tcf of YTF potential – a view shared by BP. BP has already taken steps to import 1.6 BCMa of Norwegian gas into the UK from October 2001.

  In the longer term (post 2010) much will depend upon the pace of development of new Norwegian fields (e.g. Ormen Lange) and the pace of further exploration and development. Demand from Continental Europe will also be a factor. The issue of the pace of the exploration and development of future Norwegian gas supplies is a critical factor in evaluating future UK supply sources.

- Netherlands – the maturity of the gas basin and continuation of the present management policy for Groningen makes it highly unlikely that the Netherlands will be a material source of incremental supply to the UK.

- Russia – clearly Russian gas is available in abundant quantities in the ground. Notwithstanding political and transportation cost issues, the logistics of transporting gas to the UK from Russia are enormous. One of the key links and potential bottlenecks in the chain is the European distribution system – which emphasises the need to liberalise the European markets and infrastructure. The same issues apply to other remote gas in the Middle East, FSU and North Africa.

17. BP does not believe, in the medium term, that LNG has a significant role to play with regard to security of supply for the UK. However, there is likely to be a developing spot market for limited quantities of LNG at Zeebrugge, which could help with needle peaking on pricing. This, together with growing imports into Southern Europe from places such as Trinidad, Egypt, Algeria and Oman will provide suppliers and traders with greater optionality as to where gas can be sourced to satisfy their customer needs. More LNG delivered into Southern Europe will, of course, free up pipeline gas in Northern Europe to meet growing UK import requirements.

18. It is important, however, to acknowledge the important role to be played by Natural Gas Liquids. With the decline of oil and gas production in the UKCS, the traditional sources of Natural Gas Liquids (NGL's) that underpin a major part of the UK petrochemical industry will also decline. NGL's sourced from the Norwegian

sector of the North Sea will be increasingly required from the second half of this decade to replace the growing gap in UKCS supply. Norwegian NGL's can provide a competitive source of long-term UK supply by being delivered through existing UKCS gas infrastructure in association with the expected increase in Norwegian Gas supplies to the UK. However, historically Norway has promoted onshore processing of gas in Norway and export of the products by ship, with only sales gas exported by pipeline. It is critical to achieving this commercially that there is a suitable alignment between governments to enable appropriate offshore pipeline connections to be made between the NOCS and UKCS gas grids to deliver the necessary 'wet gas' into the UK where it is needed long-term.

Connectivity & Implications for Regulation

19. The previous paragraphs have summarised the availability of supplies from which the UK can hope to benefit as its own indigenous production declines. But of far greater concern than new physical supplies is the existence of adequate cross-border infrastructure to supply gas to the market, and the appropriate commercial arrangements to facilitate the interoperability of the networks. Any energy policy should ensure that regulatory frameworks encourage timely investment signals to increase the number and capacity of supply routes into the UK, and to ensure that sufficient capacity exists at entry points. This will require close dialogue between industry, DTI, Transco, Ofgem, the EC and International bodies in Norway, Denmark, Belgium, the Netherlands.

20. Areas requiring particular attention will include :

- UK offshore gas infrastructure and its connection to the Norwegian pipeline ‘grid’
- The NTS; its capacity at different landing points and mechanisms/incentives for future investments
- Flexibility; the role of UK and Continental storage and the Interconnector to meet peak winter demand and mitigate the risk of intermittent supply shortfalls in the UK.
- Integration of the UK with the European ‘grid’ and competitive flow of gas through this network from diverse supply sources.

Connectivity – offshore gas infrastructure

21. One aspect of connectivity concerns the offshore gas infrastructure. The UK has a history of developing an efficient network of offshore gas fields and transportation systems. This has continued in a fully liberalized UK gas market, demonstrating that the regulatory environment has been very successful at providing the right investment signals.

22. It is important to acknowledge, however, the significant differences between the upstream (production and processing) part of the gas industry and the downstream. The downstream market is characterised by a single homogeneous “sales quality” commodity which must meet certain specifications (for example, WOBBE, hydrocarbon dewpoint, CO_2, and H_2S).

23. Upstream gas, however, is not a homogeneous, or "sales quality" commodity. Production gas does not meet the quality specifications for downstream use. Moreover, its quality can vary significantly from field to field, and may even vary over time in a particular field. Processing production gas into "sales quality" gas so that it may be delivered into the downstream system is one of the key activities of the upstream business. This involves taking a variety of products and transforming them into the uniform commodity that can then be consumed or traded in the "market". In the UK, dehydration, CO2 removal, H2S removal, mercury removal and NGL removal typically takes place at the terminal, although these processes can take place at various points in the physical system: offshore platforms, offshore pipelines, and onshore terminals. Each infrastructure system is quite individual in its configuration.

24. Most upstream production activity is undertaken on a joint basis with other parties. This has been the most efficient way of spreading the risk associated with the large expenditures needed to explore, develop and produce offshore supplies. This risk sharing has necessitated the development of a complex web of commercial agreements covering all aspects of the business, from exploration, through development, production, transportation and processing, allocation and sales. This risk sharing approach has been actively encouraged by the DTI, and remains an important commercial feature of the upstream in liberalised markets where long term take or pay contracts are no longer exclusively the industry standard.

25. Upstream transportation and processing infrastructure is built to deliver gas from a particular field or fields to the market and is an integral part of the development and its economics. However, once it is built, the infrastructure owners will seek to ensure that the facilities are used efficiently and will seek third party contract carriage business where possible. Infrastructure owners may also undertake expansions to accommodate third party business, or may oversize the initial facilities. This is done at the commercial risk of the infrastructure owners.

26. In the future, the upstream systems will face new challenges, with different customer requirements and increasing scrutiny from the European Commission. Cognisance should be taken of the fact that the majority of future gas developments in the UKCS will be small satellite fields, tied back to existing infrastructure. These developments will carry higher levels of unit cost, risk and uncertainty than the larger projects of the past. Offshore gas infrastructure owners need to play their part in facilitating these developments to ensure the timely, economic and sustainable development of North Sea resources.

27. Key principles that need to be adopted by infrastructure owners include fair competition between competing systems, non-discriminatory access, and transparency in the way that the industry conducts its business. The process of agreeing Transportation and Processing services needs to be simpler and more efficient (e.g. openly available pre-prepared contracts with indicative tariffs).

28. In many parts of the UK Offshore there is already substantial competition amongst infrastructure operators. This is particularly true in the Southern North Sea, where there are several lines linking the offshore to the onshore system or directly to the Interconnector. In other areas there may not be direct pipeline-to-pipeline competition, although there is the potential for producers to construct their own

pipelines. In addition, the negotiations for the transportation and processing of gas are often part of a larger commercial arrangement involving oil, gas liquids, or gas sales, and therefore competitive pressures are brought to bear in a number of ways. To the extent that there is already competition in the upstream infrastructure, it is undesirable for additional regulation to be introduced, and unnecessary for the interests of customers. The Offshore Code of Practice provides a framework for negotiations, and is currently being reviewed[7] to ensure that it meets the requirements of the EU Gas Directive.

29. Where it is judged there is not sufficient competition, the Government must consider carefully the appropriate means of "regulating" in light of the particular economic, technical and operational characteristics of the upstream. Infrastructure owners should be able to demonstrate a fair return for a fair risk (reflecting the nature of the service provided), with due account taken of any opportunity cost. In addition, any proposals for change should take account of some of the related policy objectives in the UK energy market, namely security and diversity of supply and the maximisation of the resource potential of the UK offshore, including from marginal fields.

<u>Connectivity - Imports</u>

30. As discussed, we expect significant imports in the future, especially from Norway. New Norwegian developments are unlikely to be connected directly to UK terminals; it is more likely that hubs or nodes will become established in Norway, with multiple export routes. Customers for these export routes will be individual companies than Norwegian Field Groups to comply with Competition Law; the demise of the GFU is already pointing in this direction. They will encourage competition between UK pipelines and will probably seek to ship their equity gas (independent of which field it come from) through more than one system. Thus, the UK gas infrastructure is likely to become part of a wider North Sea pipeline grid including Norway's existing systems and the NTS entry capacities.

31. Timely development of the appropriate connections will be necessary to create the right environment for efficient and low cost delivery of Norwegian gas to customers in the UK; however achieving this desirable outcome will depend critically on:

- maintaining a framework which encourages and provides incentives to infrastructure owners to innovate and invest to provide the physical pipeline linkages and the services required by this new customer set; and,
- clarity throughout the UK upstream industry on the commercial structures required to comply with EC Competition Law. Continuation of the currently prevailing uncertainty on this issue could jeopardize timely linkage to Norwegian supplies and hence UK security of supply.

<u>Connectivity – Offshore vs. Onshore Regulation</u>

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[7] Review and Updating the Offshore Infrastructure Code of Practice and Proposals for Publication of Guiding Principles on Use of Legal Powers to Settle disputes. February 2001

32. The established model for regulating downstream transportation (price cap regulation) is based on the fact that the transporter acts as a common carrier for a homogeneous commodity. Similarly in other markets (electricity, telecoms, water) the regulatory models are designed to address the issues raised by a homogeneous commodity product. The same models are not necessarily applicable to the upstream. In the EU Gas Directive there is explicit recognition of the distinct nature of upstream pipeline networks i.e. "there are special economic, technical and operational characteristics relating to such networks such that separate treatment is required."

33. Over the next twenty years it is apparent that much of the UK's offshore gas infrastructure must meet the needs of both indigenous producers *and* international shippers. Even though pipeline systems will start to convey higher percentages of "sales quality" gas and become part of a wider European pipeline grid, there will be a continued requirement to transport and process different specifications of indigenous UK (and probably Norwegian) gas. Given this, it is appropriate that different regulatory regimes be applied upstream and downstream. This will ensure that energy market liberalisation as a whole develops in a manner which best balances the interests of the various parties and ensures good value and choice for the ultimate consumers as well as ensuring long term security of supply.

Connectivity – regulatory conclusions

34. The key differences are summarised in the table below, which details the key characteristics in the commercial arrangements between Transco and its customers and offshore infrastructure owners and their customers. Any regulatory framework should recognise these important differences and the unique requirements of the offshore customers. Given the success to date in the offshore industry and the vibrant nature of commercial relationships there, it is more likely that a light-handed approach is the most suitable regulatory model for upstream infrastructure.

Key Commercial Features of Upstream and Downstream Infrastructure

Characteristic	**Downstream**	**Upstream**
Product Involved	Homogeneous Gas enters the downstream system within a fairly narrow specification.	Specialised Every field has different quality characteristics.
Service Provided	Simple Transporter provides delivery service for "sales quality" gas, with only limited blending.	Complex Each field is of different quality, and therefore requires a fundamentally different service in terms of processing. And providing service to a particular customer can affect the provision of service to other customers (current and future). Transportation itself is fairly simple – and is only limited part of the overall service.
Contract Duration	Short Term only At present, capacity can only be secured for one	Long Term Producers want long term contracts to ensure access to the market for the life

	year; only 6 months in the case of entry capacity (This regime will change with the proposed introduction of long term capacity auctions)	of a field. Infrastructure owners want long term commitments to finance the required capex to meet the specific requirements of a producer.
Price	Uncertain Capacity prices are set by auction every month. Commodity prices vary from year to year.	Certain Price is either fixed for the duration of the contract or indexed to the product involved.
Risk	Most risk on Shippers Shippers bear much of the risk; transporter earns a lower return as a result	Most risk on Infrastructure Owners Infrastructure owners bear most of the risk in return for the *opportunity* to earn greater returns, but no guarantee.

35. These, and other points, are contained in BP's detailed response to the DTI, dated 11 May 2001, in respect of 'The Review and Updating the Offshore Infrastructure Code of Practice and Proposals for Publication of Guiding Principles on Use of Legal Powers to Settle Disputes, a copy of which is attached (Appendix 3).

Connectivity – Gas Balancing System

36. Just as there are significant differences between upstream and downstream pipeline infrastructure so there are major differences between gas and electricity supply. Ofgem has proposed changes to the UK gas balancing in a recent consultation [8] paper. BP submitted its response to these proposals on 9 April 2001, a copy of which is attached (Appendix 4).

37. In summary we are opposed to such a move without first carrying out a full cost / benefit analysis. We believe that the introduction of such a proposal would have a serious detrimental impact on the UK gas industry by introducing additional cost, complexity and price volatility which may lead to higher gas prices for UK consumers. We are supportive of the desire to have accurate cost targeting of system balancing costs, strong commercial incentives on shippers to balance their portfolios, strong commercial incentives on Transco and improved flows of information. However, we do not believe that Ofgem's perceived concerns have been either properly articulated nor widely discussed to determine whether more appropriate, lower cost, alternatives might be implemented.

38. The burden on the upstream of these proposals does not appear to have been fully considered in the consultation. There is clearly a significant cost implication for the upstream in Ofgem's proposals but the very real concern is that implementation of such a balancing regime would entail time, energy and resources being tied up divert in having to renegotiate *all* existing gas sales contracts, *all* current allocation agreements and attribution agreements and many third party transportation and processing agreements.

[8] The New gas Trading Arrangements – Further reform of the gas balancing regime – A Consultation Document, February 2001.

39. Given that the UK needs to focus on future of security of supply issues, time and effort would be better spent developing the commercial arrangements for new gas fields and enhancing the recovery from existing fields. Similarly, at a time when the industry is focused on initiatives to increase upstream productivity through the reduction of operating costs, a move to within day balancing will serve to increase those costs and runs counter to the declared objective.

Connectivity – the UK NTS & the auction process

40. Transco also has a key role to play in UK security of supply to ensure that their Capital Expenditure programme is implemented at a level and at a time to ensure sufficient entry capacity exists to meet future import needs. This is currently under discussion with Ofgem as part of Transco's Price Control Review and the output is expected shortly. We would encourage the widest possible Industry debate in this matter as there is a widely held perception that insufficient capacity exists at certain gas terminals to meet immediate, and longer term needs (both for imports and UK developments). We believe that longer-term auctions – as well as improved output measures, strong incentives for Transco to deliver and an enhanced base planning process - will be a significant move forward. However, there needs to be greater clarity over the relationship between the auctions and output measures. We believe that Transco should be encouraged to invest through the use of well-defined output measures, which will ensure that they are exposed to a greater proportion of the costs and revenues associated with their investment decisions. Further, it is important that Ofgem adopts a rigorous and transparent process for monitoring Transco's capital expenditure.

41. It is generally accepted that the short-term auctions provoked a lot of uncertainty for Producers, and added additional risk to major investment decisions. However, BP is generally supportive of the principle of long-term capacity auctions, and it is hoped that those issues and concerns, highlighted by the offshore industry, will be fully addressed in the current discussions taking place on the form and structure of the long-term auctions. The discussions should also consider the issue of selling long-term capacity at a fixed price, reflecting long run marginal costs alongside capacity sold by auction. We do not believe that auctions alone will provide Transco with all the appropriate investment signals that it needs. We believe that there should be a more transparent base plan planning process and we, along with other Industry participants, are currently contributing to that debate in a series of workshops with Transco.

42. The long-term auctions are due to be in place from April 2002 and whilst Ofgem, in its review of Transco's Price control, goes some way in describing the way forward for auctions and output measures, there is still insufficient information concerning their structure and timetable for implementation.

43. BP's initial position on the release of long-term capacity is that

- primary release of capacity needs to extend to *at least* 'year 8' in order that producers developing long term projects are able to acquire entry capacity needed to market their production;
- the 'use it or lose it' principle is effective in preventing hoarding

- the 'top-down' approach will best suit the new regime since it will ensure that all capacity has been released to the market. Transco would then be required to buy back any capacity not made available. This should be based on 100% availability and not a proportion of that figure
- as previously proposed, 100% of the output measure should be sold in the long-term auction. Any unsold capacity should be made available as short term products i.e. daily, monthly or yearly.

Connectivity – flexibility (Interconnector & storage)

44. The UK gas market has a seasonal monthly swing around its annual average flow of ca.+/- 30 bcma. There is already a growing need for sources of gas to cover the winter months. As the UKCS ‘swing contract’ fields and Centrica’s Morecambe Bay field gradually decline this seasonal requirement grows with each successive winter. Two sources of such seasonal gas are large scale UK Storage (e.g. Rough) and Continental storage linked to the UK via the Interconnector (IUK) in reverse flow.

45. The UK Continent Gas Interconnector has an export capacity of 20 bcma and an import capacity of 8.5 bcma. To date the Interconnector, has been used mainly to export gas to the Continent. There have been occasions, however, when it has been used to import gas to the UK in order to meet peak winter demand. In the future, the Interconnector will play an increasingly important role in meeting UK demand as indigenous resource declines and there is an increasing reliance on imports. BP has been instrumental in recent discussions amongst Interconnector Shippers to develop arrangements to increase flexibility and transparency in the commercial arrangements all with the aim of improving trading liquidity. These new arrangements are expected to be formalised in the near future. As the Interconnector's importance increases it is essential that continental liberalisation progresses at a pace to ensure that sufficient liquidity exists in continental Europe thus ensuring effective supplies to the UK. Interconnector Shippers have options to request that an expanded import capacity be made available which Shippers and Shareholders are currently investigating

46. Due to the continuing tightening of gas supply/demand and a deficit of sufficient swing production to meet UK peak day requirements, the issue of Storage is also vital. It has an increasingly crucial role to play in managing UK supply, and minimising the risk of within-day price volatility. We have recently responded to the Ofgem consultation into the proposed acquisition of BG Storage Ltd by Dynegy Inc. In our response we seek assurances that, should the acquisition be approved, there should be full operational separation from Dynegy’s other businesses. This is to give comfort to users that Dynegy’s UK trading arm, and their other gas commercial activities, will not have access to commercially sensitive information and will not be in a position to exploit or abuse its dominant storage position.

47. Whilst we recognise that Users will have some protection in so far as Dynegy’s activities will be subject to the Competition Act 1998 and the Gas (Third Party Access and Accounts) Regulations 2000, we have concerns that these will be insufficient. Such general provisions may prove inadequate in giving confidence to users, in the absence of detailed undertakings or guidelines under the Act, which specifically address the current UK gas storage market. We believe that there is a

need for Government, Ofgem and the Office of Fair Trading to give serious consideration to developing a set of licence conditions or statutory guidance for operation of storage facilities in the future which ensure, amongst other things, that there is no risk of capacity hoarding by a single company. One possibility is that limits should be set on the amounts of capacity taken by a single company in a storage year. We would welcome the opportunity to discuss this issue further with Ofgem, Dynegy and other interested parties

48. Unlike the United States, where there is well-developed competition and choice in the provision of storage services, that is not currently the case in the UK. Although we are pleased to see a number of new storage products and services being developed and offered to the market, none of these is material in terms of volume nor can they provide the same degree of service as the BG Storage physical facilities. Rough and Hornsea will continue to provide the majority of the UK's storage facilities[9] for the foreseeable future and will continue to maintain a dominant position.

Market Liberalisation - & Its Implications For Connectivity

49. The UK is geographically well placed to benefit from future, competing supplies of 'dry' gas seeking new markets in Europe. The current barrier to accessing these supplies is a lack of connectivity across pipeline infrastructures and limited third-party access (TPA) to those pipelines.

50. BP strongly supports the completion of a single European market for gas. We believe that a fully functioning single market will considerably enhance security of supply for both the UK and continental Europe. The development of liberalised and regulated markets in Europe is crucial in this regard to ensure, through the creation of new trading hubs and cross-border transportation of gas, that stable, deep and liquid markets for gas exist. This provides end-users and suppliers with a genuine choice as to how and where their gas is sourced.

51. It is important that all Member States comply fully with the 2nd EU Gas Directive when it is adopted to ensure that the following downstream liberalisation elements are effectively implemented;

- Terms for third party access to downstream transmission and distribution services that are transparent, apply equally to all players with tariffs that are set on a cost-related basis;
- Appointment of strong independent country regulators who ensure transparency, stability and application of fair competition;
- Support gas release programmes which respect the sanctity of existing contracts but which provide gas supplies for new market participants;
- Provide improved physical and operational interconnectivity and integration of European gas grids.

52. The lack of gas-to-gas competition in Continental Europe has been the principal driver for the increase in UK gas prices since 2000. Most long-term contracts in Europe are indexed to oil, and the high oil price has given incentive for

[9] 85% of storage space and 43% of deliverability capacity

traders, shippers and suppliers to take advantage of the arbitrage opportunities by selling UK gas into Europe and European buyers sourced cheaper UK gas to meet their demand needs.

53. Whilst liberalisation of continental arrangements has commenced, such developments remain in their infancy. The emerging spot markets at Zeebrugge witness a gradually deepening liquidity, but the reality of an inter-connected network of continental trading hubs remains a distant goal. Initiatives such as developing standard contracts for trading gas and transportation capacity will promote liquidity but significant barriers remain, such as the difficulty in securing economic access to continental storage facilities, gas quality specification issues and difficulty in accessing flexible supplies. Long term security of UK supplies and pricing will be dependent on the successful development of continental gas-to- gas competition, which we believe will require a concentrated effort to progress liberalisation with an associated gas release programme.

54. We see access to gas supplies as a major barrier to entry into the market. Programmes that release gas from existing long-term incumbent contracts on to new entrants such as those recently undertaken in Spain can provide the first steps to creating *effective* gas liquidity in the market. Gas release programmes respect the sanctity of contracts already entered into and honour take or pay obligations.

55. Comparable third party access is another key issue. The objective should be that the terms, conditions and tariffs are justifiable, cost related and that they apply equally to the incumbent's marketing activity and the new entrants. New entrants will not be able to build competitive, cost efficient portfolios of customers and suppliers if they are restricted to "point-to-point" transportation service. The incumbents operate an integrated, optimized portfolio – and it is this capability which needs to be provided for all.

56. The regulators must also be alert to detailed terms and conditions of the tariffs that are designed to create barriers to entry for new entrants e.g., onerous balancing requirements .

57. Liberalisation is not a process of de-regulation – but one of re-regulation. Experience in the UK and elsewhere demonstrates that strong independent regulation is an essential surrogate for competition in this transition phase from monopoly to liberalized market. Most importantly, in the absence of independent regulatory authorities, parties usually seek redress via the courts. If this occurs, there is the danger of many costly and time consuming diversions along legal byways which will undermine confidence in the policy direction.

58. Another important policy requirement concerns the integrated European market. If stable deep, liquid and future markets are to be secured, there is a requirement for pan-European integration of the gas infrastructure. This in turn requires integration both in a physically and operational sense. BP strongly supports the initiatives of the European Commission in promoting a European Gas Standards Industry Board (GSIB) along the lines of that in the US. The industry should be seeking sensible solutions to the inconsistencies between the national systems such as odorisation, exchanges between low-cal and high-cal grids, and so on. Without better

integration, markets will not deliver the options for stability which are necessary. Depth is particularly important for the futures market and thriving markets are in everyone's interest.

59. While BP strongly supports the goals of competition and liberalisation, it must be recognised that this is a difficult journey. The structure of energy markets in Europe has been shaped by a long, complex history and regulatory change will create secondary consequences that will adversely impact some elements of the business (e.g., stranded assets, uneconomic contracts, etc.) It is vitally important that clear and effective regulatory initiatives be accompanied by an open dialogue that engages all parties in the industry in smoothing the path of transition. Similarly, the parties in the industry need to seize the opportunity to develop pragmatic and effective measures to ensure that the European energy markets function competitively and efficiently. The UK has a important role to play in sharing its experiences with the liberalization process and promoting this open, constructive dialogue both within Europe and with non-EU parties with strong interests in the energy market (e.g. Russia and Algeria).

UK Consumer Issues and Implications for Public Policy

Fuel Prices

60. UK fuel prices, before tax and duty, are amongst the cheapest in Europe, falling in terms by a third over the last 10 years. During the same period the proportion of tax has risen from 58% to over 75%. As regular investigations by the competition authorities have demonstrated, the UK retail market is highly competitive, transparent and efficient. However, there are still calls for action to reduce prices to the motorist. As our retail margins are low, in large part due to the highly competitive market in which we operate, and the level of taxation touches 75% of the retail price, our ability to reduce prices is extremely constrained.

61. The stock levels throughout the supply and distribution system are more than adequate, although levels at filling stations are dependent on regular deliveries. The Fuel Protests in September 2000 arose through unrest at the high price of fuel, especially amongst some sections of the farming and haulage communities. Stations ran dry primarily due to panic buying: at the same time, the problem was compounded when tankers were unable to leave stocked terminals. The terminals themselves had more than sufficient supplies of fuel. It is impossible on a practical level to increase fuel stocks at filling stations due to space constraints - and in normal circumstances it is also unnecessary to do so.

Cleaner Fuels

62. BP is committed to providing a range of cleaner fuels to the general public. In the short term these are predominantly conventional fuels with tighter specifications but increasingly we are looking to provide alternative fuels such as LPG/Autogas. All of these fuels give substantial air quality benefits especially in urban environments and they are aided by the duty incentives made available by HMG. Longer term we continue to work with a variety of motor manufacturers as they develop new technologies with the earliest benefits being achieved in urban fleets.

63. BP has led the introduction of a range of clean fuels both in the UK and globally in recent years. We are introducing our greener fuels in more than ninety of the world's major cities. This campaign was launched in the UK in February 1999 with the introduction of ultra-low-sulphur diesel and since then we have extended this range to include ultra-low-sulphur petrol, Autogas (liquefied petroleum gas) and lead free four-star. In addition to these cleaner fuels, we have undertaken to incorporate solar power at some two hundred of our service stations worldwide.

Duty Incentives for ULSP/ULSD and LPG

64. We support the use of duty incentives as a means of encouraging the uptake of cleaner fuels by the general public when they are introduced into the market. We introduced ultra-low-sulphur petrol in advance of any duty changes and absorbed the additional manufacturing costs ourselves. We undertook to pass on duty reductions directly to the consumer. We would certainly advocate continued use of the duty incentive as a means of encouraging cleaner or alternative fuels into the market.

65. We have seen a marked increase in the use of LPG (Autogas) as an alternative transport fuel. This has been greatly assisted by the use of duty incentives in the late 1990s. Indeed, we would not have seen the growth in the market had there not been generous tax incentives. However, LPG as a transport fuel is still in its infancy and sustained use of the incentive is needed to ensure that the public's confidence in the fuel remains. Many consumers who are considering converting to Autogas are concerned that as the market grows the fuel will be taxed more heavily. The example of CNG/LPG in the New Zealand in the 1980s, and elsewhere, is a good one. Substantial duty incentives were given to promote its use but were then abruptly withdrawn; this subsequently led to a near-market collapse. We would encourage the Government to provide a degree of certainty about alternative fuels. Certainly, maintaining the duty differential between motor fuels and Autogas for a minimum of five years would give greater stability as would the continuation of the Powershift programme and possibly a higher discount level for company car tax for cleaner vehicles.

66. We have become concerned that the recent surge in promoting compressed natural gas (CNG) is unsettling to the market, especially in relation to LPG. The alternative fuels market should be big and varied enough to cope with both LPG and CNG and in any case LPG is better suited to small-vehicle fleets and private cars (and is better suited for sales at filling stations) whilst CNG is perhaps more appropriate for larger trucks. For the benefit of a smooth and efficient allocation of resources, it would be preferable if sudden shifts in policy in favour of competing fuels were avoided.

Environmental Benefits of Ultra-Low-Sulphur Petrol and Diesel

67. BP is committed to introducing cleaner fuels that will achieve a sustainable improvement in urban air quality. Both of our products meet the European sulphur regulations for 2005 and have been introduced some five years ahead of legislation. BP's Cleaner Diesel is available at all BP service stations and is a premium quality ultra low sulphur diesel product that reduces harmful emissions. It emits 85 per cent

less sulphur dioxide and up to a third less particulates and black smoke than standard diesel.

68. BP's ultra low sulphur petrol is marketed as Cleaner Unleaded. It has less than 50 ppm sulphur and less than 35 per cent aromatics. Specific benefits are: sulphur levels in the fuel are reduced by 66 per cent which results in more efficient performance of the catalytic converter and reduced vehicle emissions; hydrocarbons are cut by up to 25 per cent and it creates less carbon monoxide and nitrogen oxide emissions.

Longer-term developments in cleaner fuels

69. As long as the market for natural gas and LPG remains stable BP envisages continued and increased use of these fuels. They apply an established technology and little new development is required. They are particularly effective in niche applications where the benefits are significant and can be very clean fuels for urban areas. The greater problems associated with Autogas have related more to rejections from local authorities for planning permission on forecourts and also vehicle conversions by non-authorised companies. Regulations need to be tightened to ensure only authorised installers undertake conversions so that the safety and integrity of LPG is maintained and real emissions benefits are achieved.

70. As motor manufacturers develop their vehicle technology we are committed to keep pace with our fuel developments; together we can then ensure that motorists obtain the best possible emissions performance from their vehicles. BP has been very encouraged by the help and support from several motor manufacturers, especially General Motors, with whom we have several collaborative projects.

71. Fuels cells with hydrogen are expected to play an important role with both mobile and stationary energy applications. Hydrogen is the cleanest alternative to the fossil fuels used today in transport. Hydrogen can be used to fuel internal combustion engine vehicles and BMW are actively developing these vehicles. Fuel cell technology is likely to have a key role, with several motor manufacturers developing hydrogen fuelled fuel cell vehicles prototypes. BP worked with General Motors to refuel the hydrogen powered Zafira fuel cell vehicle in demonstrations in Beijing and at the Sydney Olympics.

72. However, there are still potential problems which must be resolved if we are to ensure the viability of safe and effective storage of hydrogen for its use in a passenger vehicle. Several car manufacturers have announced plans to start commercialisation of cars with a fuel cell system from 2003-2004 using liquid fuels that liberate hydrogen on-board the vehicle to avoid this storage issue with hydrogen. BP is working with General Motors to develop the on-board conversion of liquid fuels such as gasoline to hydrogen using BP knowledge and experience of reforming technology.

73. BP is also a member of the California Fuel Cell Partnership and the first hydrogen refuelling station opened on November 1st 2000. The aim of the project is to support the commercialisation of fuel cell vehicles with the plan to have 50 vehicles operating by 2003.

74. The use of hydrogen for urban fleet vehicles is already possible. These fleet vehicles already operate from central depots, frequently along a known route and refuel at a depot on a daily basis where it will be easier to store hydrogen and dispense it. These vehicles will operate predominantly in urban areas and so the impact of zero tailpipe emissions will be significant. Daimler Chrysler announced the introduction of 30 fuel cell buses in a pan European project, starting in 2002. Ten cities will each operate three hydrogen powered fuel cell vehicles. BP will be the major supplier of hydrogen to these vehicles. BP is using its expertise in the safe production and handling of hydrogen from many years of operations within its refinery and petrochemicals operations to allow the development of supply options to a number of fleet and passenger vehicles projects.

75. Bio-fuels may also have the potential to help reduce lifecycle greenhouse gas emissions from transport. But this is dependent on the choice of feedstock and the conversion process used; and considerable technological development is required before their benefits can be realised, and the costs become reasonable. Current bio-fuel technology has, at best, modest potential, and there are dangers in taking precipitate action in this area. Certainly, any promotion of bio-fuel must be accompanied by robust measures to prevent adverse impacts on biodiversity and water quality. BP would not support the setting of mandatory minimum levels of bio-fuel content in all transport fuel, since this could lead to supply shortages and increased price volatility. Moreover, it should be recognised that state aided bio-ethanol might also distort the traditional chemical chemicals and solvents markets for ethanol. Any such development, therefore, would need to be accompanied by appropriate anti-distortion measures. If the potential offered by bio-fuels is to be encouraged, it is important that it is restricted to those technologies which are not dependent on intensive farming, and which deliver clear life-cycle Greenhouse gas benefits.

76. We are witnessing great improvements in conventional fuels; and now, after a slow start, encouraging developments are taking place in alternative fuels such as LPG and CNG. In the longer term, motor manufacturers and oil companies are individually and collectively working on more radical developments. It is clear that these groups cannot pursue all the alternatives alone: environmental groups, academics and policy makers all too have a role. The Government has a key part to play in pulling together longer-term strategy, and promoting consumer knowledge of, and confidence in, new fuels.

Environment and Energy Efficiency

Demand side management

77. Liberalisation and increased competition will drive prices lower for consumers and give more efficient market signals. However, once inefficiencies have been removed from the incumbent monopoly - and once competition has reduced suppliers' margins - end-users cannot expect to continue to achieve significant year on year reductions savings in the prices they pay for their commodity costs. .

78. These will have to be achieved through different means. Customer's requirements to manage their total energy costs more closely (as well as to meet their environmental challenges) will force suppliers to develop products and services which meet these twin objectives. One way that industrial organisations are already seeking to achieve greater energy efficiencies is through utilising energy management services. It is estimated that the take-up of energy management services will grow by more than a third in the next two years, reaching 28 per cent by the end of 2002. Moreover, the existing users will be spending on average 22 per cent more on energy management products (Datamonitor Report, 2001).

79. BP's response has been to consolidate and integrate its energy products and services businesses to form one organisation within a single location. This new organisation, BP Energy, represents a progressive move by BP and is aimed at developing and delivering a Total Energy Management (TEM) Offer. The emphasis and overall aim of TEM revolves tightly around improving energy efficiency – providing environmental benefits whilst also reducing the energy costs of our customers. In parallel, an internal programme (Group Energy Enhancement) aimed at further improving the energy efficiency of BP sites, is well underway, with challenging and measurable targets established for 2001 and beyond.

80. In simple terms, the strategy of BP Energy is to help customers meet new environmental legislation and manage their own energy portfolios more effectively. Competitive advantage will be secured through the combination of energy management expertise, an innovative approach to energy efficiency, breadth of product and service and best in class customer service. The offer will include:

- Risk Management including future emissions management and trading
- Out sourcing services such as CHP and CEM projects
- Consulting Services including H, S & E and emissions management.
- Energy Information Services such as monitoring, diagnostics, on-line access
- Energy products

81. Working with a number of customers, who had a range of existing energy management expertise, we identified total savings potential of up to 26 per cent of annual energy use and spend at some sites if they were to adopt all of the identified demand side initiatives. The average savings are, more commonly, in the range of 5 – 15 per cent per annum.

Measure	**Range of savings**	**Average annual energy saving**
Monitoring & targetting	3 – 5 %	4%
Energy Survey	5 – 10%	8%
Energy Training	2 – 6%	4%
Energy Strategy	2 – 6%	4%
Energy review/benchmarking	2 – 3%	3%
Process Integration	0 – 15%	7.5%

Our survey group comprised a range of end-user groups including, car manufacturers, paper manufactures, brewers, hospitals and colleges.

Combined Heat & Power

82. BP supports the Government's promotion of CHP and its desire to double UK use of high efficiency Combined Heat and Power by 2010. Achieving the target will deliver over one-fifth of the UK target of a 20 per cent reduction in CO2 emissions. However, to deliver this goal CHP needs a comprehensive strategy that provides a co-ordinated framework for action. This strategy needs to have both immediate and longer-term objectives.

83. The immediate objectives are to bring coherence and consistency to the current wide array of factors affecting CHP. In the longer term, the strategy needs to be designed to ensure CHP plays its full role in the transition to a more sustainable energy system in the UK.

84. In order to achieve the stated Government target of 10 GWe of CHP by 2010 it is essential that existing CHPs can remain in profitable, commercial operation; and that the market provides the necessary incentives to encourage investment in new CHP capacity.

Emissions Trading

85. The UK Government has established a UK Emissions Trading Scheme which will commence in 2002. However the European Commission (EC) and perhaps other international groupings are looking to establish emission trading schemes to enable GHG reductions to be made more cost-effectively by signalling the marginal price of GHG emissions abatement. Such trading schemes, and the creating of new emissions permit markets, are key to the cost-effective implementation of the Kyoto Protocol in the UK.

86. To minimise the costs of emission reductions a global watertight trading scheme is desirable. The UK Government has devised the UK emissions trading scheme which is currently voluntary. With the benefit of internal experience, BP believes that the following items are essential in development of emissions trading schemes:

- Linkage between National, EU and Global emissions trading schemes in term of a common currency (fungibility) and mutual permit recognition.
- UK Government to guarantee the validity of UK permits via a national registry and encourage trading in such permits;
- Clarifying the role of sinks following the Bonn Agreement at COP 6;
- Leading the development for CDM projects under the Kyoto Protocol to enable practical workable solutions to be established;
- Companies should be able to trade as entities rather than just countries trading with countries.

The Reduction of Emissions

87. In the case of the UK, GHG emissions have been reduced mainly by substitution of coal for natural gas in the electricity generation sector. The Government have a role in encouraging further emissions reductions cost-effectively. For example removing barriers such as the current NETA trading arrangements which reduce the ability of feed in electricity from renewable and CHP facilities, framing land-use planning legislation for solar and wind facilities and removing subsidies for existing CO2 intensive energy sources such as coal. The Government also needs to clarify the role of sinks in reducing emissions following the Bonn Agreement.

88. Renewable energy certificates (RECs) can play a key role as a market based mechanism to promote renewable energy within a regulatory regime. Renewable generators feeding electricity into the grid also receive permits. These are required by electricity distributors to cover a renewables obligation. However a common UK and EU definition of renewable energy is required together with agreed certificate design, registry and accreditation. Reciprocal trading with parties in EU Member States against their national obligations would serve to underpin the EU (and UK) indicative 12 per cent renewable energy market share target.

Conclusions

89. This submission has largely concentrated on issues connected with gas, since this is the area where concerns over security of supply are at their height. We have accepted the PILOT target of 3 mmboe/d in 2010 as achievable. But we also realise that gas production is likely to decline from 2004, and that by 2010 the UK’s import requirement could range from 30 to 60 bcm/a. By 2020, up to 90 per cent of the UK’s gas requirements may need to be imported.

90. The argument of both this, and our first submission, is that this need not be a source of concern. There is no shortage of gas, as such. But there is a need to ensure that gas supplies can reach consumers, and that the necessary steps and investments are undertaken in good time. Most of the rationale and the recommendations in this submission are directed to this end. ‘Connectivity’ and ‘Liberalisation’ are inextricably linked. Together, they can help overcome the traditional fears over energy imports.

91. But if security of supply is one major concern, the environmental consequences of fuel consumption is another. While BP is enthusiastic over the long term prospects for Solar, we do not claim it offers a rapid, easy, or painless way of ‘greening’ energy consumption. We do argue, however, that much can be done to improve the environmental consequences of fossil fuel consumption, and to reach our greenhouse gas targets. In particular, we point to BP’s work on cleaner fuels as illustrated above. And we emphasise the major contribution which suppliers can make to encourage our consumers to use less of our products. We do not regard this as a threat to our business viability. On the contrary, we see it as a source of competitive advantage.

92. It is inevitable that as vital a commodity as energy should attract public scrutiny and government concern. We make no complaints about that. But governments have the potential to make matters worse, as well as better. Political time horizons are not always consistent with the massive lead times associated with

energy infrastructure investments. We welcome the opportunity presented by this Review to highlight both the opportunities and dangers facing governments in this crucial area of public interest.

APPENDIX 1 – PRELIMINARY SUBMISSION BY BP TO PIU ENERGY REVIEW

Introduction

1. The areas of the Energy Review where BP has most experience and involvement are as follows:

- Security of Supply, with particular emphasis on gas and 'connectivity' issues;
- Market Liberalisation, with its implications for both prices and security of supply;
- Environmental concerns, with particular emphasis on Solar and renewables.
- Energy Efficiency, with particular emphasis on Combined Heat & Power and advice to industry (we are developing a business, called 'Total Energy Management')

2. This is consistent with a view of UK Energy Policy which embraces four main dimensions i.e.:

- Competition Policy: how best to make energy markets work efficiently;
- Environmental Policy: how to integrate successfully environmental factors into energy markets through internalising externalities (which essentially involves clean air and climate issues)
- Fiscal Policy: how to arrive at an equitable basis of taxation and the distribution of rent from upstream energy production
- Security of Supply: how to ensure that energy supply is available at market prices as and when demanded.

3. BP has already submitted its views to Her Majesty's Government (HMG) and others on many of these issues. For example, BP Exploration is a major participant in PILOT, where there is a regular exchange of views and information on North Sea issues, and how best to realise the potential of the United Kingdom Continental Shelf (UKCS). BP UK Gas and Power has made a detailed submission to the DTI's Review and Updating of the Offshore Infrastructure Code of Practice (11th May 2001). BP Solar was a major participant in the Department of Trade and Industry's (DTI) Photovoltaic Government-Industry Group, and contributed to the Group's Final Report which was published on 26th March, 2001. BP has also made a submission to the European Commission, presenting our initial comments on the Green Paper 'Towards a European Strategy for the Security of Energy Supply'.

4. There are, however, some broad principles underlying all these submissions which we would like to emphasise in this paper. They embody an approach to the issue of Energy Policy from the perspective, based upon our experience and belief, that:

- Liberalisation of energy markets is of benefit to consumers (domestic and commercial) and to economies as a whole because the process encourages greater efficiency and leads to lower prices. It enables an economy to improve both its productivity and competitiveness.
- Market solutions to energy problems are almost always 'lowest cost' solutions. Other approaches – such as policy 'interventions' to address concerns over supply security – carry a higher cost, often in terms of

higher cost gas or higher cost electricity. Limitation of access to low cost energy imports would create a very real cost. For this reason,

- Policy interventions, if they are to be considered, must be justified on a transparent cost-benefit basis; and the same point applies to environmental goals.

With these broad principles in mind, we address some of the specific issues raised by the review.

Security of Supply & Market Liberalisation

5. Security of supply issues are often the most cited but least defined of factors. They are prompted by concerns over

? medium and long run supply availability from geographically proximate sources
? risk of long run resource depletion
? disruption of supplies for various reasons (physical disruption, political forces, accidents etc.)
? market failures

6. From a UK perspective, these concerns present themselves in terms of :

- Oil; fears over OPEC reliability, possible political disruption in the Middle East, and issues of long term oil resource availability.
- Gas: concerns over the longevity of UK resource base, the long term cost and resource availability of gas through continental Europe, the slow pace at which EU liberalisation is currently moving, and the risk of disruption to supplies from what some would regard as unreliable sources, such as Russia.
- Trade Union Militancy/Civil Disruption: A dependence on fuels/electric power capable of disruption by workforces, although this would normally be of limited duration.
- Integrity of energy grids and distribution systems – and the role of regulation to encourage long-term investment in the UK's gas infrastructure.

7. The greatest of these concerns currently concentrates on gas supplies, and a question for this Review is whether such concern is well-founded. BP would argue that it is exaggerated, and that those concerns which are legitimate can be remedied by appropriate government action. However, it is not difficult to see how this concern has arisen.

8. UK gas production is reasonably expected to peak and decline during the coming decade. At the same time, the European Union will very likely become more dependent upon longer distance gas supplies. There is a concern that new suppliers of EU Gas may prove unreliable, although there has been no evidence to date of this happening despite political disruptions in places such as Russia and Algeria.

9. This is the pessimistic view point. The same reality can be expressed differently. Namely, that the EU is surrounded by an abundance of potential supplies of gas, which it is very much in the interests of suppliers to make available to European consumers. These suppliers are in competition with each other, which

provides individual EU gas purchasers and aggregators with the opportunity to diversify suppliers and thus reduce risk. Added to this is the increasing diversity of LNG sources which are now coming from Trinidad and Nigeria to complement North African supplies. Both these projects have significant expansion potential, while new Atlantic basin projects in Egypt, Angola and Venezuela are also looking for a firm home in Europe. Even more encouraging is the fact that more distant LNG exporters in the Middle East are looking to Europe for both short-term and long-term contracts.

10. The following points support the more optimistic perspective of this issue.

<u>Globalisation of International Gas Markets</u>
Gas trade has been growing by about 9% p.a. for the last 20 years in the shape of international pipelines (such as from Canada to the US, from Russia and Norway to Germany and France, from Algeria to Italy and Spain). LNG – liquefied natural gas – has flowed from Alaska, Abu Dhabi, Indonesia and Australia to Japan and from Algeria to France and other EU destinations).

The number of international links has been growing rapidly in recent years. There are new pipelines from Argentina to Chile, from Bolivia to Brazil, from the UK to Belgium, from Malaysia to Singapore and from Turkmenistan to Iran. New LNG projects have also come on stream in Oman and Qatar for Asian markets, from Nigeria for European markets and from Trinidad for the US and Spain. 22% of gas consumed globally now crosses an international border. This is up from 15% in 1990. If intra-FSU gas trade is included this share rises to 27% in 2000. As much as 70 per cent of global gas reserves lie within economic transportation distance of the EU.

In addition, LNG sales into Europe are increasing as Middle East and Asian sellers find it harder to sell surplus capacity to existing Asian LNG markets, and as returns in Europe improve. During 2000, high US gas prices drew in spot cargoes of LNG from as far away as Algeria, Australia, Nigeria, Oman and Qatar. Malaysian LNG also reached Iberian markets.

This trend is set to continue and grow stronger as plans continue to be unveiled for expansions to most LNG projects and new schemes are under discussion or advanced planning in Irian Jaya, Sakhalin, Iran, Yemen, Angola, Venezuela and even Bolivia.

<u>Connectivity</u>
A greater concern than physical supplies should be the existence of adequate infrastructure (pipelines, terminals etc) and commercial arrangements to facilitate the interoperability of networks. In particular, a priority of UK Energy Policy should be to ensure that regulatory frameworks evolve to provide the appropriate investment incentives to increase the number and capacity of supply routes into the UK, and to ensure that sufficient capacity exists at appropriate entry points – this latter aspect will require close dialogue between industry, the DTI, Transco and Ofgem. BP stresses the importance for the UK in being able to secure and handle gas imports (including Natural Gas Liquids) from Norway. This means that more physical offshore connections are required between the NOCS grid and existing UKCS pipelines. The UK

also must be an integral part of the European grid, and should promote full connectivity across the EU to allow the free flow of gas and diversification of UK supplies. This raises the role of the Interconnector, which itself is part of a separate study to which BP is contributing and which will form a part of BP's final submission.

Market Prices

It is not enough for the UK and the EU to be assured of physical supplies of gas – consumers and governments understandably wish to be confident that these will be available at market prices, as opposed to politically inspired levels through artificial restrictions and manipulation. Over the last twenty years, UK gas consumers have benefited from a real decline in oil prices to which the price of gas is linked. It is to be expected, however, that EU linkage to oil prices will diminish with increased liberalisation and the growth of gas-to-gas competition. The issue of prices is closely linked to that of Market Liberalisation.

Market Liberalisation

Downstream liberalisation provides the best guarantee against the imposition of excessive prices by the EU's current big players. Introducing competition and creating a dynamic gas market will also increase security of supply. However, steps must be taken to ensure that the market functions effectively throughout the process of liberalisation. A protracted period of turmoil due to ineffective or incomplete regulatory change could undermine the functioning of the market to the extent that security of supply becomes jeopardised. The appropriate policy response to this outcome is to ensure that the transition to a liberalised market is minimised through effective and comprehensive regulatory change which opens downstream gas markets to real competition. We do not believe there need be a conflict between market liberalisation and long-term or take-or-pay contracts; BP believes there is a role for both. It is equally necessary that the continuing upstream investments in developing resources and delivery assets are adequately recompensed without undue additional commercial risk posed by EU downstream liberalisation. The UK experience has shown how a market can be liberalised while maintaining upstream investment – BP's recently announced fifteen year deal with Statoil is an object lesson in this regard. What is crucial is that the liberalisation agenda should comprise a comprehensive programme of pragmatic regulatory initiatives, such as downstream Release Gas, comparable third-party access to the transmission systems and the appointment of empowered independent regulators. Progress to date has been partial in this area, and does not inspire confidence that a long and tortuous path to market liberalisation in the EU will be avoided. However, in other respects, there are more promising signs e.g. Spain has recently introduced a release gas programme for major volumes of Algerian gas. The need to address these initiatives will be a major component of BP's main submission.

11. These are the main issues which arise under the Security of Supply heading. There are, of course, others. The fiscal and regulatory regime of the UKCS, for example, will continue to have a major impact on the extent to which the UKCS attracts further investment and is therefore fully developed. The vision of PILOT is to

achieve 3 million barrels of oil equivalent per day (boepd) by 2010. So far, UKCS production has risen every year for the last ten years, which nobody would have dared to predict ten years ago. But this only happened because the UKCS remained attractive to industry in comparison with opportunities elsewhere – and it is a constant challenge to retain this advantage as the UKCS matures. It is impossible to separate the issues of UKCS Tax and regulation from how long UKCS production can be continued at significant levels. Technology is constantly stretching the profile – but this technology won't be encouraged without a supportive and stable tax regime.

12. However, there is no denying that the UKCS has now entered its mature phases – which is why UK Energy Policy cannot be seen in isolation, separate from either the EU or the global energy scene. In the final analysis, rising gas dependence – and ultimately dependence on imported gas – should not be a serious problem or concern. Gas resources are widely available; international gas markets are globalising. Any attempt to avoid this reality will only result in higher costs and reduced economic competitiveness. But as will be argued in our final submission, there are policy measures to be taken to reduce the risks of transition and to ensure that the UK is well placed to take advantage of the new realities offered by an international gas market.

<u>The Environment</u>

13. Clearly, a central tenet of UK Energy Policy must be how to meet this country's international and voluntary obligations to reduce its CO_2 emissions. As has often been remarked, it is only because gas has supplanted coal in so much electricity generation – although not yet to the extent that was once predicted – that the UK has to date been so well placed in this regard. Gas will continue to play a decisive environmental role. But in time, gas too could be regarded as environmentally inferior to other alternatives.

14. This raises the issue of nuclear power and the future for renewables. In terms of the current Energy Review, the question facing the Government is the same for both – should either or both receive special assistance? Should either be favoured over the other?

15. The first requirement is to encourage new technology – both in terms of energy efficiency and renewables - to make its own unique contribution, and to stress the importance of market mechanisms in this process. Technology is already making possible cleaner fuels in terms of local emissions; undoubtedly, it will do the same over time for global emissions. The question is how much time? In advising HMG's PV Government/Industry Group, BP has emphasised the importance of measures to stimulate the market – as opposed to the payment of direct subsidies to the *suppliers* of this market. For this reason, we are consistent in saying that competing fuels – such as nuclear or coal - should receive no special favours in relation to its competitors.

16. The UK Government, however, does have the option of encouraging the demand for renewable energy to increase at a faster pace than otherwise would be possible. This has been the rationale behind the various suggestions which have been made to stimulate the UK Solar Market - including a capital grant programme for commercial and domestic users, tax incentives, simplified connection agreements and,

most importantly, compulsory net metering to enable solar system owners to sell-back into the grid at attractive prices the energy which their own solar panels have generated. As mentioned above (para. 3) BP has already made detailed recommendations to HMG on this and related matters. Other measures are fully discussed in the PV Government-Industry Group Report – such as changes to building regulations, government procurement policies, and treatment for tax purposes. Obviously, it is also necessary to avoid unintentional discouragements – as currently faced, for example, by CHP and Wind Power developments as a result of the NETA reforms.

17. One should not exaggerate, however, the potential which renewables such as solar offer in the short-term. As the Report recognises, the global PV market has accelerated steadily over the past ten years. It suggests that by 2020, PV could come within the range of prices of the technologies in the Renewables Obligation. BP has already announced plans to increase its Solar business turnover to $1 billion by 2007, which represents significant growth. Over the next two years, we will double our solar business's capacity.

18. But none of this can supplant the dominance of fossil fuels – anymore than nuclear could if it too were expanded – over the short to medium term. That is why improving the environmental consequences of fossil fuels should be the first priority. That is why gas remains an attractive fuel environmentally (as well as commercially) for the purposes of power generation. In addition, policy makers should be reminded of the importance of fiscal incentives to accelerate the transition from fossil to renewables – both in terms of encouraging renewable technology, and in encouraging consumers to shift their pattern of consumption.

19. There is also a crucial role for energy efficiency to play. BP are advocates of the potential offered by Combined Heat and Power (CHP) and our later submission will expand on this aspect. We also see benefits - both in policy terms, but also in terms of our own commercial business – in increasing the quality and quantity of information to companies and businesses relating to their own energy consumption. BP is developing a business (Total Energy Management) whose purpose is to help our customers to use our products more efficiently and economically.

Conclusions

20. BP will seek to develop many of the above points in greater analytical detail in its final submission. But the points of principle can be identified already.

21. The UK still has significant oil and gas reserves, and the fiscal and regulatory regime is currently maintaining a positive investment climate aimed at bringing those reserves to market. A primary requirement of UK Energy Policy should be that the fiscal and regulatory regime continues to keep the UKCS competitive on a international scale. Provided this is so, concerns that UK gas reserves will soon be exhausted are misplaced.

22. On the other hand, the UK cannot hope to escape the need for imported energy. Already, under certain conditions, there is a need to import gas in wintertime during periods of peak demand. Norway is an important and competitive source of

gas for the UK market with significant future exploration potential. BP has already taken steps to ensure additional long term supplies are available to the UK market from October this year. That is why no UK Energy Policy can be conducted – or indeed, 'reviewed' – in a vacuum. Developments elsewhere in the EU and in the world are highly relevant.

23. The most urgent policy necessity is to facilitate liberalisation of the EU gas market without endangering EU Security of Supply. The two objectives are by no means incompatible and can be mutually beneficial if the liberalisation process is effective; but they do require changes of current policy and practice which will be fully explained in BP's main submission.

24. In terms of the environment, it is a common objective between HMG and BP that renewable energies should be developed. BP's primary interest is in Solar, and we have emphasised the potential which could be realised by measures to stimulate the UK market.

APPENDIX 2 – SUMMARY OF RECOMMENDATIONS OF THE PV GOVERNMENT-INDUSTRY GROUP

INSTITUTIONAL BARRIERS

1. A simplified (one page) Connection Agreement between the householder and the licensed electricity supplier and the adoption of profiling rather than half-hourly metering. This could be delivered through changes to G77. (Page 32)
2. Encourage Managers of the Government Estate, Local Authorities, NDPBs etc to identify new public sector building projects and give more active consideration to PV on public sector buildings, e.g. through Conferences/ Seminars and a Circular Letter and Green Ministers. (Page 31)
3. Encourage DETR to update the mainly factual annexes to Planning Policy Guidance 22 to more accurately reflect current more pro-active renewables policy. (Page 31)
4. Encourage the Embedded Generation Implementation Group to give serious consideration to recommending Dual Meters and to propose that suppliers pay the same rate for exports as they charge for imports. (Page 32-33)
5. Put a proposal to OFGEM to do work on assessing the necessary changes to the electricity network to allow easy connection of small-scale embedded generators such as domestic PV. (Page 32)
6. Encourage the British Standards Institute to make progress on the 15+ standards that are in development for PV (Page 34).
7. Support the industry in setting up a National Training and Accreditation Scheme (similar to CORGI) for installers and service personnel. (Page 34)

INCENTIVES

8. The most effective means of encouraging the deployment of PV in the UK would be a major Market Stimulation Programme featuring a 50% capital grant for 70,000 domestic roofs, (Page 36) and a similar grant scheme for larger non-domestic buildings (Page 38) costing around £150 million over 10 years.

9 A voluntary agreement with each of the licensed electricity suppliers to allow perhaps 5,000 householders over 10 years to receive the same price for exports of electricity as they are charged for imports, in combination with the installation of dual meters. Alternatively a mandatory requirement could be introduced by secondary legislation under the Electricity Act. (Page 33)

10. A voluntary agreement with the major private and social housing developers to have PV systems installed on a minimum of say 1% of their new/refurbished houses per year by 2010. (Page 38). 8
11. Write to Treasury/Customs & Excise making a case for Enhanced Capital Allowances to be given to businesses installing BIPV, and for individual homeowners to have a personal tax allowance for installing PV. (page 34)

OTHER

12. Encourage the PV industry and utilities to lease roof space from building owners, thus retaining ownership of the PV system whilst passing on the benefits of `green' electrons. (page 38)
13. Encourage a number of large showcase BIPV demonstrations on high-profile commercial and public buildings. This could form part of a voluntary agreement with developers and Government departments (we are already developing a limited demonstration scheme). (Page 39)
14. As many of the above recommendations will require the active co-operation of the PV, electricity and construction industries, it would be advisable to have some sort of Voluntary Agreement between all involved parties. This would probably involve the Minister having separate meetings with each major group, followed by a Solar Summit where they sign the agreement. (Page 39)

APPENDIX 3 – BP's Submission to 'The Review and Updating the Offshore Infrastructure Code of Practice and Proposals for Publication of Guiding Principles on Use of Legal Powers to Settle Disputes'

BP Response to Consultation on Review and Updating the Offshore Infrastructure Code of Practice and Proposals for Publication of Guiding Principle on Use of Legal Power to Settle Disputes

<u>Background</u>

1.1 The UKCS is now recognised as a mature province with its future reliant upon the development of increasingly small pools of hydrocarbons. In many instances these pools have remained undeveloped not simply because of their size but because of the significant technical difficulties and risks they present. In combination these factors mean that the economics of these projects are often marginal. Maximising the extraction of these resources will be a significant challenge and will require the full efforts of resource developers and infrastructure owners working together. As highlighted by the PILOT initiative, innovation – commercially, operationally and technically – will be key to achieving this objective. BP is already demonstrating its commitment to that effort, through the satellite accelerator initiative, the FPS small pools offer, and its investment in projects to supply offshore power from onshore generation, and to provide fibre optic links from shore to platform.

1.2 Greater cooperation, at an earlier stage in the development, will be needed to facilitate the identification of new and lower cost solutions to the technical and commercial challenges. In support of this initiative infrastructure owners will have to be prepared to be increasingly flexible over the type of service provided, offering solutions that cut across the traditional boundaries between the facilities of the resource owner and the infrastructure owner. As an infrastructure owner BP is continually looking at ways of reducing development costs through the provision of new services. An example of this is initiatives that offer economies of scale through aggregating the requirements of many developments, such as onshore mercury or water removal. BP is similarly exploring ways of adapting its existing field processing facilities to meet the needs of satellite developments. This evolution from dedicated field processing facilities to a centralised processing role, is in its earliest tentative stages with many technical and commercial issues to be resolved. However, there are already instances where efforts of this sort have offered lower cost solutions and accelerated development. The Erskine field development is a good example of a instance where the owners of an existing field (Lomond) pro-actively sought to modify their facilities, to provide a lower cost option than a new cluster development, and accelerated first production from the Erskine field by several years.

1.4 Responses to the PILOT cluster questionnaire highlighted that uncertainty in reserves and delivery/flow rate issues were two of the largest barriers to development. Infrastructure owners will also have a role in finding ways of sharing and minimising these and other commercial risks. BP is actively looking at new ways of addressing risk. In developing the FPS small pools offer BP sought to find a solution that addressed concerns over future oil price, reserves and quality. As a consequence the specification offered is wider and the level of tariff payable varies according to oil price and reserves. This approach represents a sharing of upside and downside risk, and significantly improves the economics of small field development. The Beauly field is one example of a development whose success is due in part to this initiative.

1.4 Since future developments will be almost wholly reliant on existing infrastructure a pre-requisite to success in all of the above, will be the ability of the infrastructure owners to provide a service for the economic life of any new field development. Against a backdrop of declining production from current fields and an ageing infrastructure base, the challenge will be to find ways of delaying the abandonment of existing infrastructure for as long as practicable.

1.5 Extending the technical life of assets will be dependent on obtaining and sustaining, sufficient levels of investment in new technology and other maintenance activities. Extending the economic life will be dependent upon cost reduction initiatives and the level of income from third party tariffing. Clearly, infrastructure owners have a strong incentive to ensure that the asset remains available for the economic life of their equity fields, and to meet any existing contractual commitments, however any guarantee of service beyond that time will be dependent upon anticipated income and throughput. Thus, confidence in the adequacy of future tariff levels will be key to extending the life of existing infrastructure, while obtaining a guarantee of a later infrastructure abandonment date will be key to any decision to invest in a development, whose economic life extends beyond the date currently guaranteed by the infrastructure owner.

1.6 BP is committed to achieving the PILOT objective of 3 million barrels of oil equivalent per day for 2010. This target can only be met by production from new developments and by maximising recovery from existing fields. BP's commitment to this effort is exemplified by the Magnus EOR project. This project combined $500 million of investment with technical and commercial innovation; to achieve not only enhanced oil recovery from a mature field but also a new export route for gas from West of Shetland. The project overcame significant hurdles, in terms of complexity and the number of parties involved, to achieve something that many thought impossible. It is that type of commitment and lateral thinking, which will be needed to create a sustainable future for the UKCS. Achieving an optimal regulatory environment will be key to promoting these behaviours, and ensuring a continued drive by infrastructure owners and resource developers to overcome the technical and commercial challenges associated with many new developments.

Appropriate Regulatory Environment

2.1 It is our belief that the optimal regulatory environment is one based on a system of negotiated third party access to infrastructure with a "light handed" rather than prescriptive approach to the regulation of this process. This approach has served the industry well in the past and is consistent with promoting proper utilisation of existing infrastructure through incentivising innovation and investment.

2.3 Many of the principles applied in the regulation of onshore gas transportation would be entirely inappropriate in the offshore environment. In the onshore environment, Transco enjoys a natural monopoly in the provision of transportation services and the cost of transportation has a direct impact on the prices paid by end users. In contrast, in the offshore, there is competition between service providers, and it is generally accepted that transportation and processing costs for a particular pipeline do not affect the wholesale price of gas, since it is a sufficiently competitive market[10]. There is therefore a need to apply a more rigorous system of regulation to the onshore, where it is vital that all users receive the same level of service and are charged a reasonable and consistent cost, in order to ensure fair competition. Conversely, the needs of offshore system users are best served by a more flexible system that promotes innovative and diverse service solutions that are optimal to each individual circumstance.

2.3 In preparing this response BP has reviewed a range of regulatory regimes adopted in a variety of industries and countries around the world. The review highlighted the great diversity of approach, with no single optimal solution. Our conclusion being that each system was developed to meet the individual needs of the particular industry and address the concerns prevalent at the time. Given the similarity between many facets of the UK offshore and the Australian and US equivalents, we note the commonality of many of the regulatory principles as support for the appropriateness of a light handed approach.

2.5 In Australia the Council of Australian Governments has been pursuing a policy of reform aimed at promoting "free and fair trade in natural gas". As part of that initiative the Gas Reform Implementation Group advocated the development of a system of third party access to upstream infrastructure based on an industry-agreed statement of best practice. In developing the statement APPEA (Australian Petroleum Production & Exploration Association) noted:

- the fact that upstream facilities are designed for a specific purposes, which may differ markedly from facility to facility;

[10] Letter from Geoffrey Riggs to Amanda Goodwin of UKOOA on Upstream Industry and Competition Law dated 20 November 2000

- the fact that facilities often provide for considerable redundancy to provide for continuity of supply;
- a view that commercial negotiation provides the least cost and most effective method for achieving third party access to upstream facilities;
- that examination of competition pressures and outcomes in the upstream industry has not revealed evidence of a failure of market forces to operate efficiently with respect to processing of third party gas streams.

The statement APPEA developed embodies many of the same concepts as the UK Code of Practice, including obligations to:

- respond in a timely manner to bona fide applications;
- grant access on fair and reasonable terms to capacity in excess of that committed for security of supply and reasonably anticipated future requirements;
- negotiate in good faith;
- honour existing contractual commitments including security and reliability of supply;
- recognise the legitimate business interest and investments of facility owners and access seekers;
- provide for continuing safety, efficiency and integrity of the facility;
- maintain environmental standards and obligations;

and thus establishes a "light handed" approach to regulation, in line with the existing UK framework.

2.5 In the US the Federal Energy Regulatory Commission (FERC) have opted for a distinction between the regulatory regimes applied to downstream gas transmission systems (falling under the jurisdiction of the Natural Gas Act) and offshore gathering systems (falling under the jurisdiction of the Outer Continental Shelf Land Act). In the downstream gas transmission systems are subject to a cost-of-service rate regulation and to individual Network Code-like terms and conditions of service. In the offshore case FERC is statutorily required to enforce a policy of "open access and non discrimination" but has chosen to interpret that obligation in a manner that allows a great deal of flexibility through the adoption of a "light handed" non rate based approach to regulation. In this regard they have satisfied themselves that reporting requirements relating to the terms offered to prospective users will provide a sound basis for ensuring the objectives of fair and non-discriminatory access are achieved and that the market operates efficiently.

<u>Balancing the Interests of Resource Developers and Infrastructure Owners</u>

3.1 Given the increasing dependence of UKCS resource developers on infrastructure service providers, BP are fully aligned with the need to maintain appropriate safeguards to ensure that the terms offered for third party access to infrastructure do not act as a barrier to development. We believe that the current environment protects the interests of resource developers in a variety of different ways.

3.2 We believe the principal protection is afforded through competition. In many areas of the UKCS there is strong competition pipe-to-pipe, terminal-to-terminal or owner-to-owner within a pipe. In many instances, the decision on the optimal field export option is taken after initial discussion with a number of infrastructure owners and the submission of competitive bids for the provision of the service.

3.3 As existing fields mature the amount of ullage available in infrastructure will increase. In response to this, infrastructure owners will naturally take an increasingly active role in marketing their infrastructure. BP has received significant interest in its enlinx initiative and believes that this is supportive of a conclusion that this change is already taking place. As the infrastructure owners' focus switches, from production of their equity fields to an increasing dependence upon securing third party business, the level of competition will become even greater and consequently, additional comfort will be provided that the tariff rates offered will be fully competitive.

3.4 In circumstances where the resource developer has limited offtake options he is afforded protection from the fact that his interests and those of the infrastructure owner are generally aligned, with both wishing to ensure that the development proceeds in order to obtain the income which will accrue. In our experience infrastructure tariffs are not normally a significant determinant to whether a development is economic or not. However, it is recognised that in some situations where the economics are particularly marginal the infrastructure tariff may play a part in determining whether the development proceeds or on the timing of field abandonment. In such cases the infrastructure owners will have a clear incentive to work with the resource developers to identify lower cost solutions or to examine ways of sharing upside and downside risk. The alignment of the parties and their ability to work together in this way ensures that infrastructure tariffs do not inhibit resource development.

3.5 Resource developers are also afforded legal protection from unfair treatment through the prohibitions contained in the EU and UK Competition Acts.

3.6 As a final safeguard resource developers have the right of appeal to the Secretary of State in the event of a dispute over the terms of access. To date no such references have been made. It is our view that this supports the conclusion that the existing regulatory arrangements are working well and that sufficient safeguards currently exist to ensure that resource development is not hindered by the terms offered for access to infrastructure.

3.7 Concerns regarding open and non-discriminatory access are addressed by the terms of the Code and the transparency afforded through the supply and publication of indicative terms.

Proposed Changes to Offshore Infrastructure Code of Practice

4.1 As highlighted previously the industry has set itself high targets for maximising resource recovery. There are many challenges standing in the way of meeting those targets. The greatest obstacles being the need for innovative, lower costs development solutions and the need to develop and extend the life of an aging infrastructure base. In reviewing the proposed changes to the regulatory regime we have sought to identify the principles that will best support the industry in meeting these objectives.

Effectiveness of the Code of Practice

4.2 It is BP's view that the Code of Practice continues to be an appropriate and effective tool and generally enjoys a high level of industry support. This is evidenced by a recent UKOOA survey, in which the majority of respondents indicated that they believed only minor changes were required to the Code, to ensure that it remained relevant to the needs of the industry. In light of this we believe that the Code should be updated to reflect recent legislative change and to include current best practice.

Information Requirements

4.3.1 The upstream industry is characterised by the transportation and processing of a heterogeneous product, with each customer requiring a variety of different levels of service. In the future, as we increasingly seek optimal, situation specific solutions and as the characteristics of the fluids become more diverse, this variety will increase. In this environment, "standard" or actual contract tariffs offered for a specific service are of limited relevance to the industry as a whole and indeed may inhibit negotiation by raising false expectations and perceptions. For example, we have recently quoted a tariff to one applicant that was predicated on an expansion of the infrastructure and therefore included an element of capital cost recovery. It would be inappropriate for anyone developing a smaller resource pool, which could be accommodated within existing capacity, to use this as the basis for estimating the probable cost.

4.3.2 The Code currently provides for the provision and subsequent publication of indicative tariff terms. This requirement has significantly enhanced the level of transparency within the industry, through increasing the amount of data in the public domain. BP continues to support the publication of indicative tariff offers and the efforts to ensure full reporting of this information. As an infrastructure owner we would actively encourage resource developers to seek an indicative tariff offer as the best means of assessing the probable cost of the service they require.

4.3.3 Indicative tariff offers are made at a stage in the negotiation process when only a limited amount of information is known about the specific requirements of the development in question. Indicative tariffs are therefore a compromise between the general "example" terms envisaged in the main commercial conditions and the customised, service specific final contracted tariff terms. BP believes that their publication represents the appropriate means of addressing the need for transparency. Consequently, we would caution against prescriptively extending the requirements to publish information, through either, the extension of the requirement to publish Main Commercial Conditions to upstream pipelines, or the introduction of a new requirement to publish actual tariff information, without a fuller evaluation of the implications and perceived benefits. We believe that as infrastructure owners take an increasingly active role in marketing their infrastructure, progressively more information will be made available. Giving owners discretion in this way will permit them to supply information appropriate to the circumstances of their system.

4.3.4 With regard to the question of asymmetry of information requirements we do not believe that this will have any implications for the negotiation of a combined transportation and processing package. Where applicants desire a "bundled" service we would expect that they would simply request an indicative tariff offer for such a service and the negotiations would then proceed on that basis.

4.3.5 notwithstanding, our belief that the publication of actual contract terms is inappropriate, we are prepared to supply details of future contracted tariff terms to the department, on a confidential basis. This would provide additional comfort on our non-discriminatory approach, without jeopardising the commercial interests of the resource developer concerned.

<u>Timely & Efficient Development</u>

4.4.1 BP is committed to the objective of ensuring timely and efficient resource development and is actively seeking ways of streamlining and simplifying the access process. We are actively pursuing ways of making information on our systems and services more readily available. We believe that e-commerce offers solutions and have committed to the development of the enlinx system as means of making our transportation and processing services more easily accessible to our customers. We have committed to making this system available to the industry as a common means of supplying information relevant to infrastructure access and thereby simplifying the process for applicants.

4.4.2 It has been our experience that the industry is adept at delivering "just in time" agreements for transportation and processing. In some instances negotiations take several years in other cases they take several weeks. In responding to access requests infrastructure owners endeavour to meet the timetable aspirations of the applicant, with the timetable outlined in the Code viewed as backstop should the parties fail to otherwise agree.

4.4.5 As the industry develops BP believes that there will be an increasing requirement for contact between the parties at an earlier stage in the development to foster a greater degree of understanding and hence innovation. We believe that it would be valuable to given recognition to this less formal discussion stage within the Code of Practice timetable for handling third party enquiries. It is our view that it is at this stage that there is the greatest scope for adding value e.g. through joint technical studies aimed at identifying alternative lower cost or accelerated development options.

4.4.6 We recognise the value in developing new contracting strategies aligned with the needs of small field development and have committed legal resources to looking at ways of achieving this.

Tariff Determination

4.5 The determination of infrastructure tariffs is a complex process and consequently, we accept that there is scope for misunderstanding between the parties as to the justification for the particular tariff offered. It concerns us that, in some instances, this may have led to inferences that the tariff offered was too high when in fact there was a compelling technical or commercial explanation. BP is supportive of initiatives aimed at reducing the risk of such misunderstanding and generally improving the negotiation process. To this end we believe that the creation of a set of behavioural guidelines for infrastructure owners to follow in negotiation would be of value. Creating such principles may serve to bring further alignment to how companies act. An example of such guidelines would be the following:

Infrastructure providers will

- Always work to offer access and to find creative ways to accept new business when it is offered
- Approach the negotiation in an open and constructive manner
- Always be able to demonstrate the basis for the tariff offered

Infrastructure owners will not

- Delay the progress of negotiation without bona fide technical or operational reasons
- Offer different access terms to different parties where the disparities cannot be explained by differences in the level of services sought

Guiding Principles on Use of Legal Powers to Settle Disputes

5.1 In reviewing the proposal to publish guiding principles on dispute resolution, we have sought to evaluate whether such a change is likely to support or hinder the industry in meeting its objective of overcoming the barriers to small field development and prolonging the life of existing fields and infrastructure.

Background

5.2.1 The Code of Practice provides a framework for an enormous range of transactions from access to offshore platforms through to onshore terminals and covers the full spectrum of hydrocarbon fluids from oil through NGL to gas. The services offered range from simple transportation through to complex processing, storage, and export. In many cases the arrangements are further complicated by associated agreements covering remote operation of facilities, provision of field services or product purchase. There are few instances of applicants seeking a simple service with most desiring a complex suite of inter related services. Given this level of complexity and diversity, we firmly believe that a flexible process of negotiated third party access is optimal.

5.2.2 The process of negotiation provides for the parties to explore individual needs, identify areas of concern and risk, and ultimately find ways of managing these. Given the benefits accruing from a successful conclusion, it is in the interests of both parties to handle the discussions in an open and constructive way, which will foster good relations into the future. The outcome of the process will be a set of bespoke terms tailored to the individual needs of the field and mutually acceptable to both parties. This process has a proven record of identifying new lower cost solutions and enabling new developments.

5.2.3 Given our strong support for the negotiation process, we believe that all efforts should be made to resolve any contentious issues before recourse to dispute resolution. Accordingly we acknowledge the value of the continued support of the DTI in providing a background facilitation role to support the negotiation process.

5.2.4 We accept the requirement for a process of dispute resolution to be used only as a measure of last resort when all other options have been exhausted.

5.2.5 BP acknowledge the desire to bring greater clarity to the criteria for dispute resolution, but share the fear noted in the consultation that any attempt to simply encapsulate the principles of the highly complex tariff setting process will fail to give adequate recognition to all of the factors involved. Consequently, we believe that the product of any prescriptive attempt to do so, will serve to diminish the overall levels of trust and commitment within the industry. And ultimately, the option of abrogating responsibility, through "formula based" regulated terms, may serve to undermine the negotiation process itself and lead to more costly, less innovative and more standardized solutions. At a time when the future of the industry is reliant on continued investment and lower cost, innovative, situation specific solutions any move toward standard regulated solutions would undermine the future sustainability of resource development.

<u>Proposals contained in paragraph 4.16 of the consultation</u>

5.3 BP support the view advocated in the Lords Committee debate in 1975, that spare capacity has a commercial value and that the owner, having borne the cost and risk of installing such capacity, should be entitled to derive a fair commercial consideration for that value. We are similarly aligned with the statement, in 4.13 of the consultation, that there are many technical, economic and commercial variables and that any attempt to be too prescriptive in setting guidance on access terms is likely to overlook an important factor. Notwithstanding this commonality of intent, we believe that the principles outlined in 4.16 of the consultation are in fact too prescriptive; fail to recognise many of the relevant factors; and are inappropriate given the current needs of the industry.

5.4 BP believes that a system based on an incremental cost recovery is inconsistent with achieving the desired objectives. In the interests of equity the basic unit cost of system capacity should, as far as practicable, be the same for all users of the system and should be consistent with the full cost of providing such capacity, including an allowance for the recovery of the original and any future capital cost. This approach ensures that future small developments will enjoy the economies of scale previously afforded to larger developments, without introducing a requirement for infrastructure owners to use existing revenues from their equity production and third party fields to subsidise such developments. As the consultation recognises any approach which does not reflect the full cost of providing the service cannot be sustained in the longer term.

5.5 Any dispute resolution process also needs to recognise the significant efforts expanded by infrastructure owners in securing third party business and in identifying optimal solutions. In future there will be an increasing requirement for specific solutions to meet the needs of small field development, and correspondingly a higher burden on the commercial and technical resources of infrastructure owners. In many instances a number of different infrastructure owners will be invited to develop bespoke solutions for a prospective development. Often these discussions and technical studies will progress in parallel over several months, culminating in the submission of competitive bids. While this process delivers optimal, competitive solutions it is clearly resource intensive and costly and therefore the efforts expanded in this way need to be recognized in the tariff setting process.

5.6 In addition to all of the costs outlined above, there also needs to be due recognition of the level of risk taken by infrastructure owners. In future there will be a need for infrastructure owners to assume ever-greater levels of risk in order to provide solutions that meet the requirements of new developments. There are many forms of risk. In its simplest form it is the added liability to third parties associated with providing any service. Alternatively, where systems have been oversized to accommodate third party business there is clearly the initial risk of the speculative investment. Additionally, there are many risks associated with the provision of fixed tariff. Before committing the considerable levels of investment needed for a new development, resource developers require a robust economic case; a pre-requisite to this is a guarantee of service at a <u>fixed</u> tariff rate extending over the anticipated productive life of the field. Ideally, associated with this would be a tariff escalator based on the price of the relevant product. Providing such tariffs, in an environment where there is a high level of uncertainty associated with future product prices, throughput and income is difficult in itself. Combined with uncertainty over the future costs, of maintaining high levels of system integrity, reliability and safety, and meeting ever more stringent environmental constraints, it requires infrastructure owners to assume significant risk. Consequently, to ensure the continuation (and extension) of this practice in future, there needs to be due recognition of all facets of technical and commercial risk in the tariff setting process.

5.7 The provision of services to a third party will always have some impact on the existing users of the facility. The impact could be as simple as a loss of operational flexibility, through a reduction in the level of unutilized capacity, and consequently, a diminution of the level of security of supply for owners' equity production. Alternatively, the introduction of a new (and technically compatible) entrant into an oil system may, serve to marginally alter the characteristics of the combined stream and consequently, impact its market value. The consultation recognizes the potential for new third party gas to exert a back out effect on existing production but fails to take account of the many other impacts on infrastructure owners' production.

5.8 Overall there needs to be an appropriate level of return to attract investment; ensure the continued operation of the systems for as long as practicable; and to promote a continued drive on the part of infrastructure owners to secure third party business. In a profit seeking environment infrastructure owners will have a clear incentive to develop new services, overcome technical challenges, innovate commercially and actively cultivate new third party business. Conversely, in a lower return environment, infrastructure owners have an incentive to focus on optimising their own equity production and provide only the basic level of service. In the current environment BP is actively pursuing a Production Growth agenda, recognizing that its FACTS business would benefit if it helped resource developers optimise their production. This is achieved through open forums and one-on-one meetings with customers to identify bottlenecks that limit production. BP then searches internally or with its customers to find other situations where a similar challenge was faced and perhaps overcome. Thus the profit incentive ensures that every effort is made to maximize not only equity production but also third party production.

5.9 The existing infrastructure is operated, by a number of multi-national companies, to exacting environmental, health, safety and security of supply standards; based on good business practice and a desire to protect reputation. This investment was clearly motivated by a need to provide a reliable export route for the owners' equity production. However, as equity production declines, the focus will switch to third party business. We fear that if faced with the application of the proposed tariff setting guidelines owners may divest their interest, in pursuit of better investment prospects elsewhere.

5.10 Consequently, at this critical and challenging time for the industry we would strongly caution against the publication of dispute resolution guidelines outlined in the consultation. The ramifications of such a change cannot be fully anticipated and we believe will serve to undermine many of the industry's current initiatives.

5.11 If the department desires to publish guidance on dispute resolution, we believe that it needs to be soundly based and take account of <u>all</u> factors relevant to the determination of tariff. To ensure that this objective is met, the guidelines should be of a general rather than prescriptive nature, outlining the intent, the factors relevant to the determination and the process to be followed. An example of this might be a statement such as:

"The Secretary of State will use his powers to promote recovery of all economic hydrocarbon resource through provision of access to infrastructure on a basis consistent with balancing the differing interests and objectives of infrastructure owners and resource developers and ensuring fair payment to the infrastructure owner for all efforts made, risks taken, costs incurred and opportunities forgone"

accompanied by a brief description of the administrative process.

If desired the concept of fair payment could be expanded to include a non-exhaustive list of the factors that may be relevant, for example

- the current level of system operating costs and the estimated level of future operating costs for the infrastructure;
- historic, field specific and estimated future capital costs for the infrastructure;
- opportunity cost to the infrastructure owner (e.g. loss of operational flexibility, future potential to use the capacity for as yet undiscovered equity volumes);
- the amount of risk undertaken (e.g. through the selected tariff escalator, guarantee of service, nature of the fluids, reserves risk) by the infrastructure owner;
- the degree of effort and innovation demonstrated (e.g. identification of lower cost options, new technology) by the infrastructure owner;
- comparable tariff offers.

APPENDIX 4 – BP's Submission to Ofgem Consultation Paper

The New Gas Trading Arrangements – Further reform of the gas balancing regime – A Consultation Document – February 2001

1.0 Summary of BP's views on Ofgem's Consultation Document

We oppose strongly the introduction of a shorter balancing period as proposed on the grounds that:

- We believe the costs associated with Ofgem's proposal far outweigh the perceived benefits. We request that a full cost/benefit analysis be undertaken
- It will place an excessive commitment on resources and will effectively inhibit further developments in the UK gas industry
- We believe the practical implications of Ofgem's proposals have not been considered in full. The implications associated with the proposals must be clarified and understood by all UK gas industry participants
- We believe the proposal will result in less gas to market, particularly in depleting North Sea gas fields, where the costs associated with implementing the proposal will far outweigh the production revenue
- We believe the proposals may generate greater volatility in gas prices and have the impact of higher gas prices to consumers.
- We believe that a simpler, more practical and efficient alternative can be developed that will satisfy the principles outlined in the consultation document
- Adoption of Ofgem's proposal would necessitate determination of gas ownership on a shorter period and would thus require renegotiation of all gas sales contracts, all current allocation and attribution agreements and many third party transportation and processing agreements.
- Producers are currently able to mitigate the impact of physical constraints and any outages through limited within day flow rate flexibility thus ensuring that the maximum potential volume of gas is delivered to market on a given day. Reducing the allocation period will remove this flexibility and will therefore reduce the volume of gas which can be delivered to market in aggregate on a given day.
- Given the specialist nature of the skills required to negotiate, design and build the systems changes required, simultaneous implementation of the proposal would be impracticable. It typically takes several years to negotiate, design and implement changes of this sort.

Before proceeding with any change we request that Ofgem consults with the industry with a view to identifying alternative approaches to satisfy the principles of reform as outlined in the consultation document. Each alternative should be reviewed in detail and a cost/benefit analysis performed.

2.0 Background on existing upstream arrangements

The aim of this section is to outline common industry practices deployed by the upstream industry in order to facilitate the operation of the existing gas market.

2.1 Introduction

Many shippers obtain their gas supplies through Gas Sales Agreements with producers. Typically this gas is delivered to the shipper at the entry point into the NTS and is sourced from a specific offshore field. Prior to delivery the gas must be transported and processed and this is carried out under Transportation and Processing agreements between producers and the owners of the relevant infrastructure. Since there are often many offshore fields using the same infrastructure the upstream industry has developed agreements entitled Allocation and Attribution agreements setting out the rules governing the entitlement to gas delivered into the NTS from the common infrastructure.

2.2 Upstream Nominations

Under the provisions of the Gas Sales Agreements the shippers exercise their rights by making requests for gas termed "nominations". These nominations are normally in the form of a delivery rate to apply from a specified hour of the day until superseded by a new rate request.

When negotiating these agreements producers would prefer to operate their facilities at a maximum constant rate since this gives the highest reliability, greatest efficiency and minimises any potential safety hazards. However the shippers, as purchasers of the gas, insist upon flexibility.

The consequence is that the Gas Sales Agreements contain a compromise between the desires of the shippers and the physical constraints of the producers' facilities. This compromise is expressed as a limitation on maximum rate, minimum rate and on the permissible rate of change that may be requested by the shipper. An example of this would be a requirement to give 12 hours notice for any rate change up to 50% of the current rate and 24 hours notice for any change exceeding 50%. Requests for rate changes within these limitations and also within the specified contractual maximum delivery rate are classified as Proper Nominations. Producers have an absolute obligation to meet all Proper Nominations and a further Reasonable Endeavours obligation to meet any component of the nomination out with the rate of change or maximum rate limitations.

The Gas Sales Agreements are coherent with the existing daily balancing arrangements in that the obligation on the producers is to deliver on any given day a quantity of gas equivalent to the time-weighted average of all the nominations in force during such day. This equates to an End-of-Day (EOD) target against which field performance will be monitored and failure penalised.

Additionally, producers are under a reasonable endeavours obligation to deliver the gas uniformly in accordance with nominations. In many instances gas production from a specific offshore field is sold separately by each field owner to different shippers. Nominations are therefore received by individual producers, aggregated by the Field Operator, and passed to the Terminal Operator, who in turn aggregates the nominations from each of the fields using the infrastructure and endeavours to deliver sufficient gas to meet the total terminal nomination.

Terminal Operators advise Transco of the intended rate of delivery for each hour of the day in their Daily Flow Notification (DFN). The figures quoted are the aggregate nominations received, adjusted to reflect what the Terminal Operator believes will be physically achievable. DFNs are updated during the day to reflect any nomination or operational changes.

In the upstream, shipper nominations do not represent ownership of the gas, they are simply requests for delivery, ownership is determined post delivery through the provisions of the allocation and attribution agreements. It is not unusual for the total system nomination to exceed the total quantity of gas available. This is reflective of the fact that shippers will often make reasonable endeavours nominations, a proportion of which may not in fact be met. Operation in this way sets high aspirational targets for the facility operators and ensures maximum utilisation of the limited production capacity.

In some instances there may be insufficient gas to meet all of the terminal nominations because of production losses associated with:

1. Field outages
4. Offshore Processing Facility outages
5. Terminal outages

In all instances, the producers and terminal operators will do their utmost to deliver the desired End-of-Day quantity: however, where there is insufficient gas to meet all nominations, Proper Nominations are given priority over Reasonable Endeavours Nominations.

2.3 Determination of Gas Ownership

The process of determining gas ownership is lengthy, complex and requires knowledge of all inputs into the system (e.g. each Field's metered production and composition) and all outputs from the system (e.g. metered sales gas, metered NGL products, fuel consumption together with their composition).

In the simplified case where there is only one pipeline input to the gas terminal, the first stage in the process is to determine the quantity of terminal products actually produced by each Field inputting into the pipeline. This step is termed product "allocation". When this step is complete this data is used in conjunction with the prioritised nominations in respect of each Field to determine ownership of the gas. In some cases an exchange of gas may take place ("Substitution") between Fields to assist in meeting the aggregate nomination. This step is termed product "attribution".

Where the producers from a single Field do not deliver in "common" to a single buyer further stages of allocation and attribution are required to apportion sales gas entitlement between producers and between sales contracts. Only after this step is complete can the quantity of gas delivered to each shipper be identified.

Given the considerable data requirements and the number of steps involved it is not surprising that a multitude of systems are required with the workload spread between large computer systems and manual processing. Details of gas ownership are not available until several days after the Gas Day to which the data relates. The design of the systems and the process outlined above are coherent with current gas sales contracts in which the period of allocation is a Gas Day.

2.4 Physical Constraints

When considering the within day flexibility that can be provided by the upstream producers it needs to be recognised that the gas industry, unlike the electricity industry, cannot provide virtually instantaneous rate changes. Gas producers employ hundreds of miles of pipe work and complex processing equipment, hence, there is a significant time lag between increased wellhead production and increased deliveries at the terminal outlet. The lead-time can be reduced by line pack in the offshore pipelines but this effect is greatly exaggerated.

In the past it has been recognised that while the demand for gas clearly varies within day it is optimal to keep the offshore delivery rate as constant as possible. Since it is cheaper (and more secure) to provide diurnal storage than to meet instantaneous demand from additional offshore capacity.

2.5 Physical Flows

The existing daily balancing regime is coherent with the physical restrictions on the producers' facilities. The delivery period of a day permits:

3. Actions to ensure the EOD target will be met despite outages for short periods during the day ("catch-up")
4. Management of the ramping process i.e. it will always be necessary to deliver in excess of the current nominated rate for a period in order to achieve any higher rate of delivery specified for a future time and similarly with any decline (these over deliveries are eliminated by adjustment of actual delivery rate versus the nominated rate of delivery to ensure the EOD target is achieved)

This limited flexibility allows producers to perform to a very high standard, meeting the vast majority of firm nominations and also exceeding contractual expectations by delivering a large proportion of reasonable endeavours gas. This ensures that shippers are afforded the maximum flexibility achievable and that the maximum volume of gas is brought to market.

3.0 Implications of Within-Day Balancing

3.1 Additional Information Requirements

As highlighted previously the upstream gas industry currently determines gas ownership on a period of a Gas Day. Ofgem's proposal for the introduction of a shorter balancing period relies on the knowledge of Shipper gas inputs to the Transco system on an hourly basis.

While aggregate flow information is available on this basis, provision of individual shipper data would necessitate determination of gas ownership by the upstream industry on a shorter period and would thus require renegotiation of all gas sales contracts, all current allocation and attribution agreements, and many third party transportation and processing agreements.

It would be impractical to deem ownership of gas input to the NTS using shipper AT Link nominations. This could result in a disparity between the downstream view of gas ownership and the upstream view and would fail to provide an incentive on shippers to accurately reflect their forecast of upstream deliveries on AT link.

3.2 Costs of Ofgem Proposal

As stated previously we have not had sufficient time to provide an estimate of the costs associated with the introduction of a within-day balancing regime. However, outlined below are the areas in which we think costs are likely to be incurred:

3.2.1 Contract Renegotiation & System Replacement

Most of the current allocation and attribution systems will require complete replacement generating external IT costs of several million pounds for each system. This will affect not only Terminal systems but also Field level systems because of the staged approach to allocation outlined previously.

Changes to the CATS and SEAL systems are likely to be less onerous because they were both designed to provide within-day information on gas ownership – none the less changes will be required even to these systems since they provide for within-day catch-up if the nominations for a particular period are not met.

Renegotiation of all the gas sales agreements, allocation and attribution agreements and many of the transportation and processing agreements will be a lengthy process (it typically takes several years to negotiate amendments to allocation agreements) involving every party in the upstream industry and generating enormous manpower costs.

3.2.2 Metering and Data Transfer Systems

There will be vast costs associated with replacing or upgrading existing metering and data transfer arrangements.

3.2.3 Operating Costs

The costs of operating the Terminal and Field allocation systems will increase considerably as significantly more personnel will be required to operate the systems and disseminate information. There will also be cost increases associated with supporting the revised metering and data transfer systems.

Similarly in the downstream there will be significantly increased operating costs for Transco and other downstream participants associated with handling the additional data flow and monitoring inputs, offtakes and line pack for each individual balancing period. The introduction of these costs will create a higher barrier to entry and will discourage participation by small players.

All of the above costs will be in addition to the enormous manpower and system development costs likely to be incurred by Transco and other downstream participants in moving to a shorter balancing period. In light of this analysis we strongly believe that the figures quoted in the consultation document represent a gross underestimate of the final cost. The recovery of these costs will have a direct impact across the whole gas value chain and may ultimately result in an increase in gas prices to UK Consumers.

We do not believe that such a massive investment is required in order to alleviate Transco’s balancing costs, currently reducing year-on-year with a previous yearly estimate of £8million. Nor do we accept the need for such a vast investment due to the introduction of the New Electricity Trading Arrangements (NETA), and the potential increase in CCGT generation and any potential knock-on effects these will have on Transco’s balancing costs.

<u>3.3 Within Day Flow Control</u>

A move to a shorter balancing period would necessitate a change to all gas sales contracts, allocation and attribution agreements, and many transportation and processing agreements to permit shippers’ full control of flow into the NTS on an hourly basis.

The provision of this additional certainty on flow can only be achieved by sacrificing some of the current contractual flexibility. Thus it is likely that the existing reasonable endeavours provisions within the gas sales agreements will require to be replaced by hourly rate of change limitations to ensure that the process of rate change can be satisfactorily managed in a shorter balancing period. This change is likely to reduce the volume of gas that can be brought to market.

Similarly the move to a shorter balancing period will reduce the producers’ ability to mitigate the impact of outages, thus altering the balance of risk and reward between buyer and seller, therefore necessitating a revision to the existing price/penalty regime.

The contract renegotiation will also have to provide for the recovery of the upstream costs incurred in the change. Since the costs are largely the same for all systems regardless of the volume of gas remaining to be produced, it is not clear how abandonment of some fields could be avoided given the enormity of the likely costs per unit of production.

<u>3.5 Impact on the Gas Market</u>

We believe that a move to shorter balancing periods will increase market price volatility through the introduction of additional pressure on an ever-tightening supply/demand balance. As highlighted previously the flexibility required to hourly balance peak demand cannot be supplied by upstream producers. Indeed the move to a shorter balancing period is likely to curtail, as opposed to enhance, the flexibility and reliability currently afforded to shippers, thereby reducing the volumes of gas which can be brought to market.

4.0 Way Forward

We believe that a number of alternatives should be explored fully prior to considering the implementation of a within-day mechanism. Below we have outlined a few such alternatives and we believe that the details associated with these proposals should form part of future industry debate.

The current proposal seems to be a classic example of using a "sledge hammer to crack a nut" since the desire for vastly increased data requirements is partly motivated by a desire to eliminate the practice employed by a small number of Shippers of profiling their offshore nominations while declaring the daily average on AT link. To address this issue we would propose that Ofgem adopts a more thorough, properly project managed investigation, where the relevant data requested can be used by Ofgem to identify those involved in such behaviour. Recent investigations by Ofgem have suggested the data requests made are irrelevant and cannot be used to properly identify those causing the problem. We also believe that the recent modifications to the gas balancing regime, namely, the removal of Shipper imbalancing tolerances, should be given sufficient time to become established, in order to determine whether Transco's balancing costs will be further reduced, given the greater commercial incentives this change places on shippers to better balance their portfolios.

We also believe that the introduction of a line pack option should be further explored as a separate entity and not simply developed in conjunction with a within-day balancing mechanism. Should it be introduced along with the within-day balancing proposal then the acquisition of line pack will be a necessity as opposed to a luxury and hence the industry will not only be paying vast costs for the introduction of a within-day regime but also the additional costs of the enforced acquisition of a scarce commodity via a price auction. Bearing in mind the recent trends in entry capacity auctions and the excessive revenue over-recovery made by Transco, such a concept should be considered carefully.

A separate line pack option will give shippers the opportunity to purchase the required balancing tolerance and may further reduce the need for Transco to take balancing actions thereby reducing costs.

There also exist a number of other alternatives currently being discussed in industry, an example of which includes the use of a phased scheduling approach. We request that Ofgem further consults the industry on these proposals and then considers each alternative on its own merits, performing a full cost/benefit analysis for each proposal.