



INTERNATIONAL Energy Market

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1. STRATEGIC ROLE OF NATURAL GAS IN THE WORLD

This paper is adapted and reduced from a keynote address by Lord John P. Browne, Group Chief Executive, BP, delivered at the 22nd World Gas Conference held in Tokyo, June 2003.

Across Asia natural gas now supplies 11% of energy demand outside the transport sector. We believe that we are on the verge of an even greater shift in favor of natural gas. A number of factors are combining to transform an already growing role, into something very dynamic which could bring enormous economic and environmental benefits. That is why this is such a historic moment. Let me describe the four factors which are making such a difference. First, the gradual liberalization of gas markets across the world. This is not just about deregulation though that is clearly important in specific markets. **It is also about the changing needs of the consumer in a global economy where the availability of choice drives competitive forces to lower costs.**

That means that we are seeing the beginnings of a shift away from the purchase of fixed volumes for extended periods to arrangements which involve greater flexibility of supply, and of price. We are seeing this trend in the liberalized markets of North America and Europe - and in the Atlantic Basin for LNG. Now, in the past it would have been said that without fixed contracts, investment, particularly in LNG, would have been regarded as too risky and would therefore not have been made. Equally, it would have been said that without fixed supply contracts some consumers would not invest in switching to gas. Those arguments may have been valid in the past but their force has been diminished by changes in technology which have altered the economics of the global gas business. But long-term contracts are and will remain a feature of this industry.



They can coexist with competitive markets as we have demonstrated in signing long term gas supply contracts for supply to liberalized markets in Europe. What we see developing is an industry whose growth is underpinned by a flexible mix of contract types and terms which reflect the realities of each particular marketplace. Secondly, technology has changed the economics at many different points in the supply chain. Upstream, the unit costs of the Majors fell during the 1990's In contrast to the trend of the industry at large, principally through a mixture of technology, increasing scale and fiercer competition which drove down the costs of exploration and development by around 2.5% per year. We, at BP, and others, continue to find world-class reservoirs. Technical advances have dramatically improved the economics of development. In Trinidad just three or four wells can now supply a full LNG train.

Moving down the supply chain technology has produced a dramatic reduction in the cost of new gas liquefaction plants. In the 1980s such plants typically cost US\$400 per ton to develop. Now the cost of comparable plants is \$200 per ton and still falling. In the 1980s the unit cost of new LNG shipping capacity was \$1,900 per cubic metre. Now it stands at \$1,200 and is still falling. In regasification we have seen costs fall over 25% since the 1980's because of economies of scale in vaporization and storage equipment. Overall, we expect those gains to continue, and overall we see the cost of LNG declining through this decade by as much as 25 to 30%.

And in the power business, the price of installed combined cycle gas turbine (CCGT) capacity has fallen from more than \$800 to below \$500 per kilowatt, as manufacturers have introduced and then standardized new technology. And that cost calculation is before you take into account the huge improvement in heat rate which CCGT enjoys against steam boiler technology. Indeed, one dollar invested today in gas-fired generation capacity produces three to four times the amount of electricity of the same dollar invested in coal-fired generation capacity. There is one other



important structural factor which contributes to the change in the market. The growth and consolidation of the major players in our industry has altered the way in which we view an LNG investment. Only 10, years ago the total investment in the creation of an LNG project through the chain from liquefaction, plants, ships, to regasification and power generation would have represented around 25% of our total market capitalization. Now, 10 years on, the same investment would represent less than 2% of our market value -- because we have grown, and the costs have fallen. Of course, size and scale are not the preeminent features for success in this new global gas industry that is emerging. But they do confer a capability to take on and manage new and increased types of risk which arise, as gas markets require increasing flexibility of supply.

Flexibility, in physical and commercial terms, lies at the heart of what will be a new order in natural gas. Flexibility underpins the development of the stranded resources of gas that exist around the world. Flexibility also optimizes the supply of that gas to markets. And most importantly, it is flexibility that meets the needs of traditional and new customers for gas – promoting choice and enhancing security of energy supply.

Tomorrow (June 2003) a vessel filled with liquefied natural gas will enter Tokyo Bay to discharge her cargo - a common event for the world's largest importer of LNG. But this particular cargo marks the completion of an extraordinary chain of physical and commercial arrangements which began in the Atlantic - and now end in the Pacific - a distance of over 4,000 nautical miles.

The chain was initiated by a long-standing customer in Japan - Tokyo Electric Power Company -- seeking additional volumes of gas at relatively short notice. It was enacted with a long standing LNG producer Adgas – with whom BP is a partner. And it was executed successfully because we are putting in place a range of flexible physical and commercial assets, and positions which recognize



the new order describe. The vessel - **the British Innovator** - has been commissioned without being tied to a dedicated gas supply source or end customer. She is designed to service every large liquefied natural gas terminal in the world - not a single region. Her cargo was destined for Spain from the Middle East -but the flexible nature of our customer and producer contracts allowed us to divert her to Japan. And our portfolio of gas supplies in the Atlantic allowed us to honour our commitment to our Spanish customer. This is not an isolated case -- nor are we standing still. Today we have reached agreement with the government of Oman and Oman LNG for the purchase of LNG over a six-year period commencing in 2004. These supplies will add to a growing portfolio of highly flexible and divertible gas sources.

2. LNG ECONOMICS AND NORTH AMERICAN DEVELOPMENTS

(adapted from Energy Info Source Inc and various other sources)

Interest in North American LNG development is being driven by favourable economics in all phases of the supply chain and supportive market fundamentals. Greater economies of scale have driven LNG production costs 30-40% lower than those encountered less than a decade ago. These lower costs have allowed LNG to become more competitive with natural gas prices.

- **Gas liquefaction costs between 1996 and 2000 averaged \$230 per ton, compared with \$560 per ton between 1986 and 1990.**
- **Between 1996 and 2000 the cost of a new tanker dropped by approximately 30%. In the 1990's an LNG vessel would take \$250 million to build, but today's vessels are significantly less, at approximately \$165 million.**

Historically, the cost of producing, shipping, and re-gasifying LNG has been prohibitive and uncompetitive with United States gas market prices. Costs of this



total process ranged well above \$3.00/mmbtu (not including netbacks to the owner and operator of the stranded gas reserves.) Assuming a \$0.50-1.00/mmbtu netback, a total deliverable gas price of over \$4.00/mmbtu could be attained on a cost basis. This \$4.00 plus number was well above past natural gas prices in the US. The new millennium, however, has brought lower LNG costs and raising US natural gas prices, making LNG an economically viable alternative at around \$3.50/mmbtu. Prices are expected to remain around this \$3.50 level for the foreseeable future due to growing availabilities of supply.

Basic LNG Economics

Fees	1995	2002
Netbacks	0.5	0.75
Pipelines	1	0.75
Liquefaction Plant	1.25	1
Shipping	1.25	0.65
Gasification	0.35	0.35
Delivered to Market	\$4.35	\$3.50

Source : Utilis Energy

LNG Project Requirements

Although worldwide natural gas supplies for LNG facilities are abundant and can be produced inexpensively, the processing and transportation equipment is capital intensive and highly specialized, requiring hundreds of millions of dollars of investment for each new facility. **For each cubic foot of natural gas delivered to end users, less than 30% of the cost is for the commodity itself, while more than 70% reflects the costs of processing and transportation.** The large capital costs for each link in an LNG project imply that projects can be undertaken by organizations with sufficient financial assets. Under the traditional LNG project structure, successful LNG projects required the cooperation of the host government (where the natural gas resources are located), the entity that owns the natural gas rights (private or state), the government of the consuming country, consuming organizations (national or



private electric utilities, gas companies, etc.), and a host of specialized organizations, including shipyards, financiers, tanker operators, construction companies, and process technology licensors.

No LNG project is likely to proceed unless the developers receive some assurance that they will be able to earn an acceptable return on their investments. A successful LNG project requires a price that is low enough to motivate consumers to use large volumes of natural gas, yet still high enough to persuade developers and borrowers to actually build the project. Although spot sales are on the rise, LNG developers will continue to seek long-term contracts for their product at a price sufficient to cover their capital costs, debt service, and still generate profits.

An LNG player withdraws

The general euphoria relating to North American LNG has been tempered slightly in 2003 by the financial challenges facing US energy firms. In the wake of recent industry trading scandals, bankruptcies and disappointing financial results, US energy firms are under greater scrutiny from Wall Street and are attempting to “clean up” their balance sheets by reducing debt. This has prompted one industry major, El Paso, to withdraw from its well-publicized plans to construct LNG import terminals in various North American locations. This unfortunate market withdrawal, however, is not expected to have a negative impact on the growing appeal of LNG in the North American market.

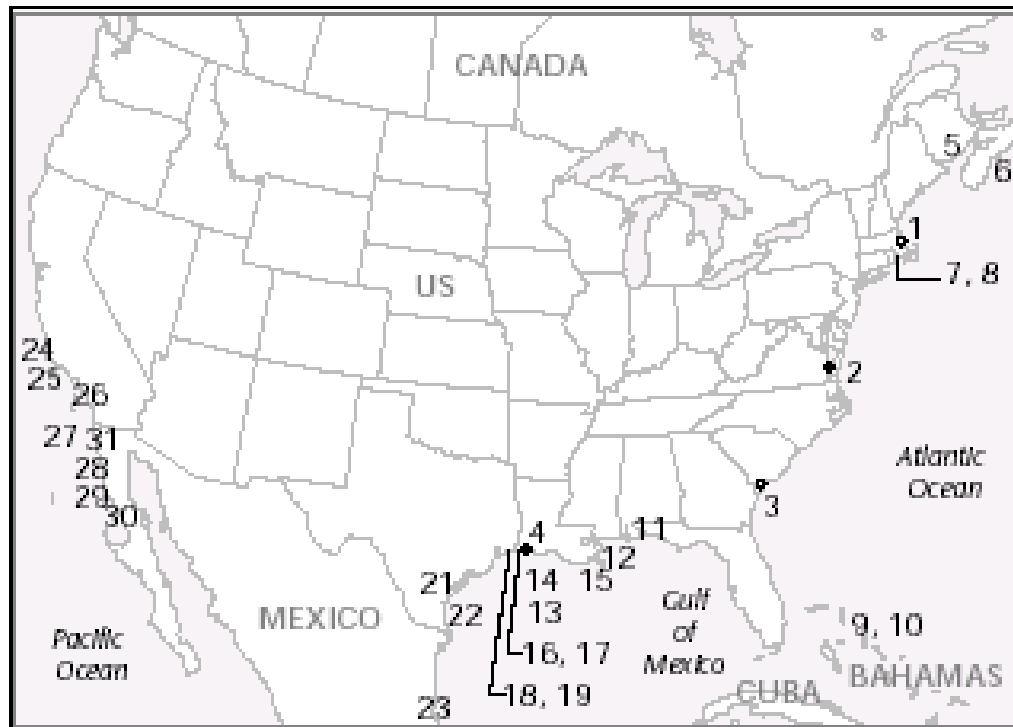
El Paso’s plans to leave the LNG business became public on February 5, 2003, when the firm released its 2003 Operational and Financial business plan. In this plan El Paso attributed its LNG exit to market risks and the high costs involved in citing new LNG terminals and decided instead to focus on its “core businesses”: natural gas pipelines, production, midstream and non-merchant power.



This is a dramatic turnaround in strategy when one looks back to the first quarter of 2001 when El Paso stated that LNG would be the key to the company's growth strategy. Plans were announced to construct multiple facilities in Mexico, the US, Gulf of Mexico and the Bahamas. In addition to traditional land-based LNG terminals, El Paso was also developing its EP Energy Bridge system that combines ocean-going regassification vessels with an offshore buoy system to deliver natural gas into targeted markets through pipelines.

While El Paso's dramatic shift in strategy is unfortunate for North American LNG development, it does create an opportunity for other, better financed, players to make a significant investment in this growing market.

Numerous LNG projects have been announced in recent months. In most cases these efforts are in their initial stages of development and most will not be built. The table below lists existing projects and many of these announced projects; and the figure below shows their locations.



Source : PIW

Figure 1: Location of existing and proposed LNG terminals listed on the next page (8)



Proposed North American LNG Terminal Projects

Terminal	Sponsor	Capacity
Existing Terminals		
1. Everett, Massachusetts	Tractebel	700 MMcf/d
2. Cove Point, Maryland	Dominion Resources	750 MMcf/d
3. Elba Island, Georgia	El Paso	435 MMcf/d
4. Lake Charles, Louisiana	Trunkline LNG	630 MMcf/d
Proposed		
5. Canaport, New Brunswick	Irving Oil	550 MMcf/d
6. Bear Head, Nova Scotia	Access North East Energy	750 MMcf/d
7. Weaver's Cove, Massachusetts	Poten & Partners	400 MMcf/d
8. Somerset LNG, Massachusetts	Somerset LNG	400 MMcf/d
9. Calypso, Bahamas	Tractebel	830 MMcf/d
10. Ocean Express, Bahamas	AES	842 MMcf/d
11. Mobile Bay, Alabama	Exxon Mobil	1 Bcf/d
12. Main Pass Energy Hub, off Louisiana	Freeport Sulfur	1.5 Bcf/d
13. Port Pelican, offshore Louisiana	ChevronTexaco	1.5 Bcf/d
14. West Cameron 182, offshore Louisiana	Royal Dutch/Shell	1 Bcf/d
15. Vermillion 179, offshore Louisiana	Conversion Gas Imports	1 Bcf/d
16. Liberty LNG, Cameron, Louisiana	Liberty LNG	1 Bcf/d
17. Cameron LNG, Hackberry, Louisiana	Sempra Energy	1.5 Bcf/d
18. Sabine Pass, Louisiana	Cheniere Energy	1.5 Bcf/d
19. Sabine Pass, Texas	Exxon Mobil	1 Bcf/d
20. Freeport, Texas	Freeport LNG	1.5 Bcf/d
21. Corpus Christi, Texas	Cheniere Energy	1.5 Bcf/d
22. Corpus Christi Texas	Exxon Mobil	1 Bcf/d
23. Altamira, Tamaulipas, Mexico	Royal Dutch/Shell	700 MMcf/d
24. Cabrillo Port, Off Oxnard, California	BHP Billiton	1.5 Bcf/d
25. Offshore Ventura, California	Crystal Energy	1 Bcf/d
26. Long Beach, California	Mitsubishi	1 Bcf/d
27. Coronado Islands, off Baja California	ChevronTexaco	1.5 Bcf/d
28. Costa Azul, Baja California	Sempra Energy	1.5 Bcf/d
29. Cost Azul, Baja California	Royal Dutch/Shell Group	1.5 Bcf/d
30. Ensenada, Baja California	ConocoPhillips	680 MMcf/d
31. Tijuana Regional Energy Centre, Baja California	Marathon Oil	750 MMcf/d



For now, tight LNG supply rather than lack of US import capacity is limiting deliveries to the USA. The shutdown of nearly a score of Japanese nuclear power plants increased Japanese LNG consumption by 3 million tons per year, or about 500 million cubic feet of gas per day during the 2002-03 winter. **Any surplus supplies from traditional sources in Abu Dhabi, Australia, Indonesia, Malaysia, Oman and Qatar went to Japan and South Korea over the winter.**

In the Atlantic Basin, Nigerian and Algerian LNG production, plus a small volume from Libya, all went to Europe, which also had a cold winter last year. All the LNG coming to the US over the winter came from Trinidad, the only short haul source for the US East and Gulf Coasts.

Numerous supply projects are in the works, but none will be available before late 2004 or 2005 at the earliest, and then only from expansions of existing plants in Australia, Nigeria, Qatar and Trinidad. **Greenfield projects will not begin operating until around 2007.** Between then and the end of the decade, significant LNG supplies from new ventures in Angola, Australia, Egypt, Equatorial Guinea, Indonesia, Nigeria, Norway, Qatar, Sakhalin in the Russian Far East, the Timor Sea, Trinidad, Venezuela, and possibility elsewhere - western Russia, Bolivia or Peru – will be flowing to markets around the world.

Qatar is one of the newer LNG players, but the small Mideast Gulf nation has the potential and the strong intent to become the great behemoth of the LNG business. State venture Qatar Petroleum (QP) has a goal of producing 60 million tons of LNG per year by 2015. That is more than 25% of current LNG consumption worldwide and would represent a five-fold increase in Qatar's present production. And the gas to make it happen exists in Qatar. The massive offshore North Field contains an estimated 900 trillion to 1 quadrillion cubic feet of gas in a single, continuous reservoir. Expansions are underway at both of its LNG companies, RasGas and QatarGas. Most gas from existing trains is committed to Asian buyers, but much of the expansion volumes will go to Europe



or the USA. Qatar recently confirmed plans to ship more than 20 million tons/yr to the USA through joint ventures with Exxon Mobil and ConocoPhillips, starting in 2008-09.

One potential supply source has dropped by the wayside. Backers in Alaska worked for more than two decades to establish an LNG export venture supplied by Alaskan North Slope production. Their efforts came to an end when US gas prices climbed to a level adequate to support the long-proposed pipeline to the lower 48 states.

Asia is by far the largest market and will remain so in total volumes for some time though its growth rate is below what is expected from Europe and North America. [Japan will continue to be the world's largest LNG user, but South Korea, Taiwan, and China will be the consumption drivers.](#) Europe's gas growth will come from economic development, especially in the Iberian Peninsula and eastern Europe, a move toward cleaner fuels, and the effect of declining gas output from the UK sector of the North Sea. Exxon and Qatar are planning to bring in as much as 15 million tons/yr of LNG to the UK starting in 2007, and BP has its own ambitions there. Some initially may go on to the continent via the Interconnector pipeline, but eventually the UK will need it all, and possibly more from other sources. Spain, Portugal, and Italy also will be consuming considerably more LNG.

The Caribbean Basin represents a minor market as the various islands there could handle only modest volumes. Still, the Puerto Rican experience indicates that even small markets can be lucrative if the supply is only a day's sailing away, as Tractebel has discovered. Independent power producer AES expects to have similar results in the Dominican Republic. Shell is developing a 1 Bcf/d terminal at Altamira, on Mexico's Gulf Coast. The project targets the Mexican domestic market rather than serving as an "offshore" delivery point for the US.



The USA is the perceived jewel. High gas prices that are not linked to oil, declining domestic supplies, and growing requirements of the electric power sector suggest that LNG consumption in the US alone could rise from less than 5 million tons/yr in 2002 to 25-50 million tons/yr in 2010. Some LNG volumes would offset falling deliveries of piped natural gas from Canada, which will need to keep more of its gas at home in order to meet domestic demand.

Spare Terminal Capacity

The US mainland has four existing terminals, only one of which comes anywhere near full utilization at this time. Nonetheless, all the capacity available today and all the expansion capacity proposed are fully booked. Capacity holders are waiting for supplies and tankers to come on stream before they can put all the space to work.

The Tractebel terminal at Everett, Massachusetts, had an original capacity of 480 MMcf/d, but a recently completed expansion project brought that up to more than 1 Bcf/d. Everett also has the highest utilization rate, thanks to regular deliveries from Trinidad and lesser volumes from Algeria.

Dominion Energy now owns the Cove Point, Maryland, LNG import terminal. It has an output capacity of 1 Bcf/d, but only 750 MMcf/d are available for imports. The remainder is dedicated to peaking LNG that Dominion's pipeline manufactures from domestic supplies. BP, Shell, and Statoil equally share the available capacity. Deliveries resumed there in late August 2003 after a 20-year hiatus, with the arrival of a BP tanker from Trinidad.

Elba Island, Georgia returned to service last year after being non-operating for two decades. Current capacity is 430 MMcf/d, with 57% held by BG and 43% by Marathon. An expansion to around 800 MMcf/d is being planned, and another



could follow. Shell will have all the additional capacity from the first expansion and possibly the second. El Paso plans to construct a new pipeline to ensure access to multiple regions.

The reopening of the Lake Charles, Louisiana, terminal in 1998 coincided with startup of the Trinidad supply project. Together they demonstrated the possibility of a viable spot LNG market in the US and the potential for long-term firm deliveries. BG has almost all the capacity locked up in a firm contract for 20 years. Current output is 630 MMcf/d, doubling to 1.2 Bcf/d in 2005.

Proposals for perhaps 20 new LNG terminals along the North American East Coast and Gulf of Mexico have appeared over the past four years, plus another 10 or so on the West Coast and Baja California.

Of course, not all will be built, but a combination of regulatory, commercial, and construction factors means work has to begin now simply to ensure that another 2 Bcf-4 Bcf/d of receiving capacity will be available when needed on the North American East and Gulf Coasts, plus 1 Bcf-3 Bcf/d of new-build facilities on the West Coast in either California or Mexico's Baja California or both. The best guess is that two to four will be needed on the Atlantic and Gulf region and two or three on the Pacific.

The Federal Energy Regulatory Commission (Ferc), which has primary oversight for most US energy transportation infrastructure, revised a long-held policy earlier this year that has given impetus to the proliferation of projects. Ferc changed the designation of LNG import terminals from transportation to production facilities, saying that from the market's perspective, an LNG facility is the equivalent of a new gas field. As a result, terminal owners and operators can retain all the capacity for themselves.



Three of the four existing terminals are “open access.” That is, the owner/operator must allow potential users to bid on the capacity through an “open season.” Unused capacity can be offered to the market on a secondary basis. Only Tractebel at Everett, Massachusetts, controls all of the import available space and serves as an LNG merchant in the terminal it owns and operates. The major oil companies argued hard for the reclassification of the facilities so that they could have proprietary terminals.

The next class of receiving terminals will not all look like the existing facilities that are based on the Japanese model designed decades ago. Several of the proposed Gulf of Mexico terminals involve offshore locations and/or innovative technology. One concept that has garnered the attention of the US Department of Energy (DOE) is storage in underground salt caverns, not in above ground tanks that tower over the surrounding area. At least three projects in development call for using salt cavern storage. Two also are offshore: Freeport Sulfur’s Main Pass Energy Hub and Conversion Gas Imports’ Vermilion Block 179 project. The third, HNG Storage’s Liberty project, will be in the Cameron, Louisiana, area, but developers have not decided on an onshore or offshore site. Vermilion Block 179 and Liberty would use Conversion Gas Imports’ patented “Bishop process” that uses seawater as the warming medium in a special heat exchanger. DOE also has endorsed that process. Another offshore project, ChevronTexaco’s Port Pelican, would use a gravity-based structure with storage in onboard tanks, but conventional regasification. Each of these could handle at least 1 Bcf/d.

From a regulatory standpoint, Sempra Energy’s 1.5 Bcf/d Cameron LNG project at Hackberry, Louisiana, is the most advanced, as it recently obtained the final environmental approval from Ferc. However, the commercial lead goes to Freeport LNG, a 1.5 Bcf/d project planned for Freeport, Texas. Dow Chemical has committed to taking 500 MMcf/d of the neighboring terminal’s capacity. The



Freeport project is one of four initially proposed by Cheniere Energy, but it sold a 60% stake to privately held Freeport LNG. Cheniere continues to work on other sites at Sabine Pass, Louisiana; Corpus Christi, Texas; and Brownsville, Texas.

The international oil companies are not going to give the terminal opportunities over solely to independent developers, especially now that US regulations permit proprietary facilities that do not have to be shared with others. The aforementioned Chevron Port Pelican project is one. Conoco has not said where it and partner QP will deliver their 7.5 million tons/yr (1 Bcf/d) output starting in 2008-09.

Besides taking capacity at Elba Island, Shell is looking at its own 1 Bcf/d offshore terminal that would be located in West Cameron Block 182, offshore Louisiana. It also plans a 500 MMcf/d facility in Mexico, at Altamira, Tamaulipas, which would serve the power generation market there. The company expects the imminent award of a tender from the Mexican power authority.

Exxon needs to find homes for twice that volume and is looking at three potential sites. The most likely are two 1 Bcf/d terminals, one near Mobile, Alabama, and the other at Sabine Pass, Texas. QP has indicated it would be an investor in those as well as in the Conoco terminal.

Sites on the US East Coast would be prime candidates for LNG facilities because of their proximity to the largest markets, but the **“not in my backyard”** forces may not permit their construction. The next best option could be siting in Canada or the Bahamas. Canadian developers are looking at two projects, Canaport and Bear Head, both in Nova Scotia. They would serve eastern Canadian markets as well as consumers in New England. The Bahamas has attracted three projects, but only two, sponsored by Tractebel and AES, are active. El Paso dropped its Bahamian venture and the Energy Bridge shipping/regasification concept earlier this year due to financial problems.



Opposition from local forces is not stopping everyone. Two LNG project developers are promoting separate receiving terminals within three miles of each other on Narragansett Bay in Massachusetts, about 60 miles south of Boston. Weaver's Cove Energy, the offspring of consulting firm Poten & Partners, is proposing a 400 MMcf/d regasification terminal with a peak capacity of 800 MMcf/d. Somerset LNG is pursuing a similarly sized plant.

On the US West Coast, virulent opposition from environmentalists and other groups preclude most onshore LNG terminal development, though a project involving Japanese industrial giant Mitsubishi at Long Beach has a slim chance.

Mitsubishi is a partner with Shell in Sakhalin-2, the probable LNG supplier. The two other proposals involve offshore locales in an effort to avoid the opposition onshore. Crystal Energy wishes to convert an unused production platform offshore Ventura to handle 1 Bcf/d, while BHP Billiton's Cabrillo Port would use a 1.5 Bcf/d floating facility. Both would deliver into the Southern California Gas system.

Offshore or across the border in Baja California, Mexico, are more promising sites. Proposals for five Mexican facilities are on the table, but even these are not completely free of environmental implications. Growing gas demand in the California power sector was an initial driver, but higher consumption there cannot support more than one LNG venture. An expanding economy and added electricity generation capacity in northwestern Mexico has created ample opportunity there. In addition, increased gas needs in other parts of the US Southwest could limit deliveries into California from traditional sources in Canada, the Rocky Mountains, Texas, and New Mexico, thereby boosting overall requirements in the region.

Chevron sees the North American West Coast as the most promising market for LNG from its planned Gorgon project offshore northwestern Australia and



possibly the recently discovered Jansz field. It is looking at a site for a 1 Bcf/d gravity- based structure off the California coast near the Coronado Islands.

The Conoco project once planned for the Tijuana-Ensenada area is on the back burner after erstwhile partner El Paso pulled out and the company found a more profitable Japanese buyer for its Bayu-Undan LNG. It could be revived to take LNG that now goes to Japan from the Kenai, Alaska, LNG plant it owns with Marathon Oil.

Sempra Energy and Shell are vying for first place at sites near Costal Azul, and both have most of the permits they need from local and federal Mexican authorities. Each LNG terminal has a proposed capacity of 1 Bcf/d. Though Sempra might have a slight lead on the regulatory front, Shell has both supply and market advantages. It has a preliminary agreement for some of the Gorgon LNG and also could tap Sakhalin supplies as well as other Pacific Basin sources. Besides delivering into the Mexican market, Shell could find a home in its own enhanced oil recovery operations in California.

The most advanced project, however, appears to be Marathon Oil's Tijuana Regional Energy Centre. The \$1.5 billion complex includes a 750 MMcf/d integrated LNG terminal, 1,200 megawatt power plant, and 20 million gallon per day water desalination plant. Construction is due for completion in December 2006, with start-up in the first quarter of 2007.

Best Prospects

The terminals that have the best chances of succeeding are the ones that establish both supply and market early. Here, the major oil companies have the advantage as they typically have stakes in the gas source fields, liquefaction facilities, and affiliated gas marketing organizations, or large internal gas needs to ensure buyers. BP, Chevron, Conoco, Exxon, and Shell meet some or all of these criteria.



Chevron and Exxon are pursuing proprietary terminal options. BP and Shell have taken space in existing facilities, though Shell is considering a proprietary project. BP is thought likely to take an equity position in one or more terminals developed by others. **Conoco also is reported in talks with an independent developer for all the capacity at its proposed facility for its Qatari joint venture.**

For the most part, independent terminal sponsors have two business models. Either they will operate solely as tolling or fee-for-service facilities, or they will combine merchant services, in which they buy and sell LNG for their own account, and tolling arrangements.

Conclusions

While North American LNG imports have become competitive on a sheer price basis with US natural gas, a shortage of domestic LNG import terminal capacity and the difficulties involved with constructing such assets have been the catalysts for the development of other supply terminals, namely, installations in Mexico, the Bahamas or offshore in close proximity to the US. Regasified LNG from these installations can then be delivered into US markets via traditional gas pipeline. Announcing intentions to build LNG import facilities and processing terminals, does not necessarily mean that these facilities will be constructed. Financing, regulatory and supply issues will be the key drivers in determining if these facilities become a reality. **Further forecasts show that expected incremental demand over the next decade will not be sufficient to justify, from an economic point of view, the construction of all proposed import terminals.** As a result, only the most attractive of these facilities, or the ones that can be built and become operational the quickest, will become a reality. **Under these conditions first mover advantage is critical.**

Even with the existing hurdles, it is clear to say that LNG will play a greater role in augmenting America's natural gas supply over the next twenty years. With US



natural gas demand expected to increase by almost 50% during that time, continued North American LNG infrastructure development is cardinal in meeting this increasing demand.

Finally, North American LNG has a potentially bright future — unless any one of a multitude of factors goes wrong. One would be the industry’s failure to proceed promptly with the necessary infrastructure at both the production and delivery ends. Some company will have to take the risks associated with the first venture. The alternative would be loss of opportunity, as markets unserved by the product of their choice would find a substitute. After all, prices necessary to support LNG could make ultra-clean coal a viable option in the power-generation market. Another threat would be some dramatic breakthrough in an alternate fuel or technology, say fuel cells or hydrogen fuel production, which would dampen demand for all conventional hydrocarbons. An unfortunate accident also could have far-reaching ramifications. LNG and eventually natural gas-to-liquids should become more than merely niche applications. The world has too much stranded gas and too great a need for clean fuels to let either one of these applications languish and not thrive.

3. BOLIVIA’S LNG PLAN FACES PROTESTS

Bolivia’s left-wing opposition parties and anti-government protest movements have begun a “war” on the government’s plan to export natural gas to Mexico and the USA through Chile.

Protesters initiated strikes, marches and road blockades in and around the capital La Paz on September 21, 2003.



The initial protests were triggered by coincided with an official visit to Mexico by president Gonzalo Sanchez de Lozada on 11 September during which he discussed gas exports with Mexico's president Vicente Fox.

The \$5bn export project, led by the Pacific Liquefied Natural Gas (LNG) consortium – grouping Spain's Repsol–YPF, the UK's BG and Anglo-Argentinian Pan American Energy – has been brought close to collapse by La Paz's indecision over which country – Chile or Peru – to route the pipeline through.

Historical enmity towards Chile, which seized territory and cut Bolivia's access to the sea in the war in 1879, means that exporting gas through Chile is deeply unpopular with Bolivians. Opponents of the project, such as opposition MAS party leader Evo Morales, are seeking to neutralize a government "hearts and minds" campaign that began this month in a bid to win public support for gas exports.

Exports are needed to recoup upstream investment totaling \$2.5bn since 1997. Bolivia's largest market for gas is Brazil, but Brazil's state-controlled oil firm Petrobras is in dispute with La Paz over take-or-pay obligations set out in a contract that began in 1999.

Pacific LNG aims to export gas worth \$5bn over 20 years. The scheme proposes construction of a 650km pipeline from Bolivian gas fields to a two-train gas liquefaction plant on the Chilean coast.

President Sanchez de Lozada promises a decision on the scheme will be made by December, but analysts believe he could be toppled if he opts for the Chilean gas pipeline route. And time for the project is fast running out. Uncertainty over the scheme has prompted US firm Sempra Energy to sign up Indonesia to supply 6mn-7mn t/yr of LNG to its proposed regasification terminal



in Baja California, Mexico. Sempra had been looking at Pacific LNG. **There are now many matters of uncertainty with respect to Bolivia's gas.**

4. NIGERIA LNG WINS CONTRACT

Total has signed a 20-year agreement to take 1.2bn m³/yr of liquefied natural gas (LNG) from Nigeria LNG's planned sixth train at Bonny Island. This is a significant boost for Nigeria LNG, in which Total is a partner alongside Shell, Italy's ENI and Nigeria's NNPC. The sixth train is expected to be completed around 2007 and to raise Nigeria LNG's total capacity by 4mn t/yr to 22mn t/yr of LNG and from 0.5mn t/yr of liquefied petroleum gas to 2.7mn t/yr. Endesa of Spain also signed a long term contract in early August to take 1 bn m³/yr of LNG from the train.

5. BRAZIL WOOS PRIVATE INVESTMENT

Brazil's new left-leaning government has reversed several of the market-friendly policies that the previous administration introduced to boost competition in the country's oil sector. This policy trend, combined with a dearth of commercially viable discoveries, is increasingly taking the shine off what just four years ago was considered one of the new global upstream hot spots.

Former president Fernando Henrique Cardoso opened the Brazilian oil sector in the late 'nineties to attract badly needed private-sector investments to boost production, reducing dependence on imports which would eventually lead to long-awaited self-sufficiency.

After five upstream bidding rounds, there are around 40 private-sector companies operating in Brazil. But apart from state-controlled oil giant Petrobras,



whose output stands at 1.54mn b/d, only Shell has started to produce oil in the country. Drilling for oil in Brazil requires huge investments, as about 80 % of its sedimentary basins are located in deep and ultra-deep waters and the oil is typically heavy. Few are prepared to risk the investment needed.

Natural gas

Brazil will spend \$1.8bn in the next five years to expand its natural gas market on the back of fresh discoveries, rising demand and gas sales agreement talks with Bolivia.

The natural gas expansion plan – expected to be unveiled by the government in October, 2003 – aims to extend the country's natural gas pipeline network, particularly to southeastern and northeastern states.

Biodiesel and Ethanol

The government is preparing a special tax system to boost the country's biodiesel market – aiming for a substantial decrease in diesel imports.

Biodiesel, an environment-friendly fuel made out of vegetable oils such as soya, will begin to be used in the country in 2005. The plan is to mix it with diesel initially at a proportion of 5%, increasing it gradually to 20% by 2020. Brazil imported 40.1mn bl of diesel last year, 17% of the volume it consumed.

The biodiesel programme is due to be unveiled in October, 2003, bringing a string of incentives, particularly fiscal ones. There are five biodiesel projects under development in Brazil – in the south eastern state of Rio de Janeiro, in the northeastern states of Rio Grande do Norte, Piaui Ceara, and in the central state of Mato Grosso.

The government is also seeking to increase its ethanol exports. Brazil is



the world's largest producer of the green fuel and has been negotiating with other countries such as Japan to develop a global export market for the product.

Brazil's domestic ethanol policy aims to support the sugar cane industry by providing captive demand for green fuel, which is one of the main derivatives of sugar cane. The amount of ethanol added to gasoline depends on federal decisions based on the size of the harvest and other market factors, such as the price of sugar. **The current mandatory ethanol content in gasoline is 20-25%.**

Brazil has a significant fleet of car adapted to burn 100% ethanol fuel, which is sold along alongside gasoline at the country's fuel stations.

The country's state-own development bank BNDES estimates investments of US\$2.5 billion in three years to increase exports by 5bn litres from just 7000mn litres. The country produces approximately 13bn litres/yr of ethanol at present.

6. URUGUAY CALLS OIL REFERENDUM

A referendum on whether Uruguay's state owned oil firm ANCAP can form a strategic partnership with a foreign investor has been scheduled for 7 December, 2003. A 2001 law opened ANCAP to private capital and deregulated the domestic market. But opponents gathered a petition of more than 650,000 signatures, enough under the country's constitution to force a plebiscite on the law. President Jorge Battle has warned that ANCAP will "disappear" if the strategic partnership initiative is rejected. Polls indicate that only 25% will vote in favour of opening ANCAP foreign investment. ANCAP has held talks with a number of firms, including Brazil's state-controlled Petrobras. Venezuela's state owned PDVSA, Shell, ChevronTexaco and Spain's Repsol-YPF.



7. JAPAN TO REPLACE STATE OIL COMPANY

Japan has outlined its new energy strategy to follow the break-up of loss making upstream firm Japan National Oil (JNOC).

The ministry of economy, trade and industry(Meti) has mapped out details of a new public corporation to replace JNOC, starting in February, 2004. Tokyo decided last year to dissolve the loss-making state-owned oil firm by April 2005. Most assets will be liquidated during the fourth quarter of this year to help cover accumulated losses of \$6.5bn.

JNOC had stakes in 91 upstream ventures, acquired in exchange for financing and loan guarantees to Japanese upstream firms. The scheme resulted in unprofitable and costly investments, with domestic consumers forced to buy the expensive end results.

Meti has decided to keep only four upstream investments accounting for nearly 80% of JNOC's asset value. These are its 65.7% stake in Japan Petroleum Exploration, 50% in Inpex, 89.8% in Japan Oil Development and 50% in Sakhalin Oil and Gas Development.

The new corporation will take on JNOC's task of financing overseas exploration and managing strategic oil stocks.

But Japanese energy consumers – particularly in the oil sector – remain skeptical of Meti's continuing involvement in major overseas exploration projects. A number of firms that have undergone painful cost-cutting now say cheaper oil is available on the open market.

Meti also wants private industry to take a leading role in Japan's overseas upstream exploration and development. But it still sees the government



continuing to provide support through investment or loan guarantees, and to ensure supply security by strengthening ties with foreign producers.

The ministry is giving priority to upstream exploration and development in eastern Siberia and Russia's far east, along with associated transportation infrastructure. Japan is competing with China for a crude oil pipeline from Siberia.

8. OPEC MEMBERS REVENUES INCREASE

Members of OPEC are enjoying a combination of high prices and high crude production that promises to raise their income back to the high levels of 2000. However, production will be cut after November 1, 2003 by 900,000 b/d as was unexpectedly decided at the September 24 OPEC meeting in Vienna. Most of the reduction will have to be shouldered by Saudi Arabia.

The 10 OPEC members averaged crude production of 25.8mn b/d in the first eight months of the year - while the organization's basket prices has averaged \$27.86/bl. If output levels and prices remain roughly unchanged. OPEC members can expect to see their crude export revenues will make the difference between running a budgetary surplus and a deficit. Saudi Arabia can expect to earn just over \$70bn from its crude exports this year – of which around \$60bn should enter the budget.

Saudi Arabis has budgeted for expenditure of \$55.7bn this year – some 7% below the previous year's actual spending. This frugality, together with expectation of high revenues, means that actually spending is likely to turn out 15% higher, at around \$64bn, leaving a surplus of some \$12bn – only the second time the budget has been in the black since 1981.



OPEC members reduced output targets at the September 24 OPEC meeting. Given the slower than expected return of Iraqi exports to pre-war levels, low global stocks and the approaching northern hemisphere winter, OPEC members were not expected to reduce their production before the end of the year – keeping average output some 10% above their 2002 average.

Consumers would like to see higher OPEC output. OPEC members are concerned about the possibility of a quick hike in Iraqi output, which could send prices plummeting. **The net result of the decision for OPEC producers to cut back production by November 1st has been an increase in oil prices.**

9. EQUATORIAL GUINEA INCREASES OUTPUT

ExxonMobil's surging output has turned Equatorial Guinea into sub-Saharan Africa's third biggest oil producer.

The country is on target to produce at least 350,000 b/d by the end of the year, compared with around 220,000 b/d last December. The growth is largely the result of the early startup of the \$900mn ExxonMobil-operated Zafiro Southern Expansion Area in July. The project is on track to reach 90,000 b/d by October 2003 month, well on the way to final capacity of 110,000 b/d.

Crude output at ExxonMobil's nearby Zafiro field has also vastly surpassed original predictions, rising by 30,000 b/d since last year to 180,000 b/d at present. Reserve estimates have risen from 30mn bl in 1996 to 1bn bl, of which over 250mn bl has been produced so far.

US integrated company Marathon Oil intends to invest another \$1.5bn on its gas projects in the country over the next few years. It already has



condensate and liquefied petroleum gas production, and is building a 3.4mn t/yr liquefied natural gas (LNG) plant on Bioko Island. The \$1bn project was approved in May, and is scheduled for start-up in 2007.

10. ECOPETROL LOOKS OUTWARD

Colombia's reorganized state-owned Ecopetrol is seeking opportunities to expand its operations abroad.

Energy and mines minister Luis Ernesto Mejia says the company, which has refocused on exploration and production activity, wants to convert itself into a multi-national company on the model of Brazil's state-controlled Petrobras.

"We already have proposals from other countries to have Ecopetrol operations such as exploration, production and transportation," Mejia said at a September, 2003, Colombian energy conference.

Colombia produces about 546,000 b/d of crude. But it is looking for ways to increase its oil revenue, and sending Ecopetrol beyond its borders is one way to accomplish that. Colombia's domestic oil production has fallen dramatically since 1999, when the nation was producing more than 800,000 b/d. Reserves have also fallen to 2.8bn bl.

Ecopetrol last year announced plans to cut its 7,400 workforce by 1,250 over four years and to sell non-strategic assets. The move was a response to declining output, rebel bombings, and theft of fuel.

The company's flagging performance, along with President Alvaro Uribe's programme of spinning off government-owned companies, led to a dramatic



reorganization of Ecopetrol between June and September. The company has been split into three state-owned parts, with the exploration and production segment retaining the Ecopetrol name. The newly created national hydrocarbons agency (ANH) was made part of the energy and mines ministry and given the role of awarding upstream operating arrangements. A third entity, the Energy Promotion Company, manages the “non-strategic” investments of Colombia’s energy sector.

Mejia did not say where the new Ecopetrol exploration and production firm might seek to operate, but neighbouring Ecuador and Peru have prospective oil areas that are desperately in need of outside investment. Ecuador’s new OCP pipeline has removed the primary bottleneck that had been holding back development of the country’s Amazon basin oil fields. Ecuador also has a history of working with Colombia on oil transportation.

11. VALERO/PDVSA TO BID FOR ARUBA REFINERY

US independent refiner Valero and Venezuela’s state-owned PDVSA says they may bid to buy El Paso’s 280,000 b/d Aruba refinery. Valero indicates that the plant may fit well with its US Gulf coast refining network. Valero, which earlier this year bought US independent Orion’s 185,000 b/d Norco refinery in Louisiana, has six US Gulf coast refineries. The Aruba refinery mostly produces distillates and vacuum gas oil feedstock.



12. VENEZUELA – STATUS OF THE OIL AND GAS INDUSTRY

Venezuela's long-running domestic political conflict has damaged the oil industry; and this damage will take as long to repair. Ironically, the confrontation has forced the country's populist president Hugo Chavez to reconsider the benefits of foreign private investment. State owned oil company PDVSA has lost much of its old financial power and political influence, and finds itself relegated from the forefront of the government's plans for the future for the future of the oil and gas industries. Opportunity knocks for companies interested in crude oil from Venezuela.

Led by senior managers in support of calls for early presidential elections, last December's strike virtually shut down the company for an entire month. Rather than capitulating to the overtly political demands of the strike's leadership, Chavez responded swiftly and harshly, firing nearly 19,000 PDVSA workers who joined the strike. At the same time he bought enough gasoline to keep the local market supplied – preventing unrest from spreading. And he succeeded in bringing oil production up from a low of 50,000 b/d to 2.75mn b/d by May – exceeding even the most optimistic expectations.

However, output has since started to decline. Lack of investment in western Venezuela is causing a decline in heavy oil output. And a shortage of skilled reservoir engineers is hampering recovery rates, although PDVSA is looking at using private contractors to help improve production profiles. Venezuelan officials continue to claim that total liquids production exceeds 3.1mn b/d. Many expect output to fall to around 2.5mn b/d and stay there for the rest of the year, although a recent surge in drilling activity could be a sign that PDVSA is trying to redress problems.

The strike at PDVSA gave President Chavez a new appreciation for foreign oil companies. Unlike the state-owned firm, they kept on producing as long



as they could – and their managers have stayed away from the political arena. Foreign companies' willingness to work with the Chavez government and PDVSA's financial and managerial weakness have combined to produce an about-face in government policy. Upstream oil projects have been reopened to private firms with great enthusiasm. Foreign technology and capital are needed to revamp older production areas in Lake Maracaibo, while new discoveries could benefit from private involvement. The government even appears willing to listen to proposals from private firms, rather than design new projects itself.

The strike cost PDVSA about \$7bn in lost revenues and emergency purchases of gasoline and diesel for the local market, has also further weakened the company's balance sheet for 2002/3. External auditors have yet to sign off on PDVSA's accounts . Until its accounts are audited, PDVSA cannot tap foreign markets for more capital. At the same time, it has drained all but \$697mn from a \$4.1bn special fund at the central bank to pay operating costs and make capital investments.

The company faces heavy capital spending requirements to upgrade its refineries to meet more stringent US environmental specifications in the coming years. Also, large investments in the liquefied natural gas business are being targeted. But with its core upstream oil business needing at least \$2.5bn/yr to maintain current levels of output, observers wonder where the capital will come from to further build Venezuela's production capacity. **Foreign firms stand ready and the government is courting them.**

LNG

Venezuela's small population and huge gas reserves should make it one of the worlds leading natural gas exporters. But continued delays mean that Caracas may have missed its chance to enter the liquefied natural gas (LNG) business at an opportune time.



The government is trying to make up the lost ground. The oil ministry recently kicked off a second licensing round in order to get blocks 3 and 5 into private investors' hands by the end of 2003. Earlier this year, it awarded two blocks in the waters of the Orinoco delta platform to private operators.

The delta platform is thought to hold vast gas reserves. It lies south of the sea border between Venezuela and Trinidad and Tobago, where huge gas finds have become common in recent years.

One of the most enthusiastic backers of the delta platform project has been ChevronTexaco, which is eager to add to its LNG holdings in the Atlantic basin. It believes that the expected absence of condensates in the delta platform gas will not adversely affect profitability.

Venezuela's delta platform gas blocks		
Block	Owner	Status
1	Open	BP preferred bidder: talks ongoing
2	ChevronTexaco (50%) ConocoPhillips (50%)	Exploratory drilling in 2004
3	Open	To be awarded by 15 Dec
4	Statoil (100%)	Exploratory drilling in 2004
5	Open	To be awarded by 15 December

ChevronTexaco has been joined by ConocoPhillips, which is looking to expand its LNG portfolio and find a means of bringing to market the estimated 2 trillion ft³ (57 bn m³) of gas in its Corocoro field in the nearby Gulf of Paria.

Venezuelan officials hope enough discoveries can be made in the delta platform to allow the addition of a second LNG production train at its Mariscal Sucre LNG consortium, which hopes to build the country's first LNG project by 2008. The joint venture is expected to be signed next year with a final investment decision for 2006.



But country risk has pushed up the cost of capital, and political turmoil is making life difficult for those who want to get into the business. PDVSA's weakened financial state makes it a less desirable partner - although the government is keen to own a stake in the LNG business. Investors hope that the political situation will have improved by the time major decisions are to be made.

Heavy Oil

The successful completion of three heavy oil upgraders has shown that Venezuela's Orinoco heavy oil is a viable and profitable resource.

The three completed upgraders produce around 400,000 b/d of synthetic crude oil. And once the Ameriven upgrader is completed in the middle of next year, the figure will jump to 580,000. **Some 270bn bl of heavy crude –more even than Saudi Arabia's conventional reserves – is recoverable from the heavy oil belt with existing technologies.** And at least another trillion barrels could be recovered as technology advances. There is no risk that there will not be enough reserves for everyone.

Exploratory talks between the government and the private sector partners on expanding the Sincor project have already begun. Sincor officials have proposed a \$2.2bn expansion of their existing upgrader, adding 120,000 b/d within seven years. ConocoPhillips has also been looking at its plans for adding a second upgrading train at its Petrozuata project, which would incorporate advanced hydrocracking technologies to produce ultra low sulphur middle distillates rather than synthetic crude oil. ExxonMobil has also expressed interest in adding to its Cerro Negro upgrader. Other firms with experience working in Canada's heavy oil sands have also expressed interest in moving into Venezuela.



Because there is little exploration risk, the main challenge for investors in heavy oil projects is to find a cost effective way of financing the multi billion dollar upgraders. Venezuela's political and economic crisis has battered its credit market toward more costly bank loans.

Nevertheless, more heavy oil projects are expected in Venezuela. With major oil companies struggling to replace their reserves, the prospect of producing 100,000-200,000 b/d for 30 years is too great to pass up; too attractive to ignore.

13. EUROPE CONSIDERS A RENEWABLE ECONOMY

At a two-day conference in Brussels in June, Romano Prodi, President of the European Commission, outlined a vision of Europe as having a zero-carbon economy by 2050. **He stated, "It is our declared goal of achieving a step-by-step shift towards a fully integrated hydrogen economy, by the middle of the century."**

While targets for 2050 are clearly speculative, and on a timescale probably beyond the lifespan – let alone the office – of present officials, the speech signaled a firm commitment by the EU to hydrogen. Speaking at the same meeting, Margot Wallström, EU Environment Commissioner, stated emphatically, that, "Global warming is the most significant environmental challenge facing both Europe and the world".

Spencer Abraham, US Secretary of Energy, was less bullish about a low carbon future. He cited as reasons for the US interest in hydrogen as:

- 1. reduction of air pollution.**
- 2. issues of energy security**
- 3. "long term potential challenges of climate change."**



The meeting received the report of the High Level Group for Hydrogen and Fuel Cell set up in October 2002. The report recommended five key actions:

1. the establishment of a political framework to enable new technologies to gain market entry;
2. a deployment strategy using “lighthouse” projects to help move from prototype to commercialization;
3. a strategic research agenda at the European level;
4. a European road map for hydrogen and fuel cells to guide transition; and
5. a European partnership to provide advice, stimulate initiatives and monitor progress.

It was pointed out that hydrogen is not necessarily a low CO₂ option as this will depend on the way the hydrogen is formed, and the number of steps it then has to go through before use. Some delegates saw natural gas as the source of hydrogen, others prefer coal-fired power, or even nuclear, as a way to generate the H₂ in the move to the Hydrogen Economy.

14. UK GOVERNMENT PLANS FOR 6,000 MW OFFSHORE WIND

In the largest single step in renewables the UK government has announced massive plans for offshore wind, with a target of installing 6,000 MW by 2010. **This is a step towards achieving the UK target of 10% of all its electricity from renewables by 2010.**

The government has worked closely with industry in drawing up the plans, and developers are confident that they will be able to obtain finance for the project.

Construction of the first wind farm in the new phase should begin within two years. The new areas – particularly around Norfolk – are further from the coast



than existing ones, and will avoid areas of particular environmental value, such as bird sanctuaries or fisheries.

From an earlier round of calls, the UK's first offshore windfarms are now under construction. The later wind farms are expected to have up to 300 wind turbines each – twice as many as the current largest offshore plant, Horns Rev, off the Atlantic Danish coast.

Results of a recent opinion survey, found that 74% were in favour of government's ambition to generate 20% of the UK's electricity from renewables by 2020, a central tenet of the recent Energy White Paper.

15. USA ENCOURAGES RENEWABLES

US secretary for Energy, Spencer Abraham, on a recent visit to the National Renewable Energy Laboratory in Golden, Colorado, indicated that government support **for renewable energy may be a better way to help the country's energy needs than tax breaks for fossil fuel producers. He stated that he supports federal tax incentive for both renewable and energy efficiency programmes, and for alternative-fuel vehicles and fuel cells, but not for traditional energy industries.**

He also asked Americans to help to alleviate possible forthcoming energy shortages as the natural gas supply tightens, by adopting efficiency measures for heating and cooling of homes and offices.

At the same time, the Solar Energy Industries Association has proposed new tax breaks to help remedy the shortage in natural gas. It called for an incentive that includes a US \$4W rebate on solar panel installations, a 25%



tax credit for solar system purchases, and a production tax credit for electricity produced from photovoltaic cells.

16. SPAIN SIGNALS CHANGES IN RENEWABLE ENERGY POLICY

Spain is showing a cooler policy towards renewables. A new proposal from the Energy Regulator, which the government is to adopt in November 2003, will change certain parameters. Presently, renewable generators benefit from a feed in tariff, earning a premium price for renewables. **Spain now has over 4,800MW of installed wind capacity, the second largest in the world, after Germany this and has grown by 700% in the past four years.**

The new proposal will take other factors into account, including operation and maintenance costs. The system is designed to allow firms to know exactly what income they can expect and not rely on volatile energy prices. However, renewable electricity generators fear this will push down premiums and slow rates of growth. Other factors likely to slow growth are lack of more prime sites for windpower development, and the need to find alternative sources of finance as bank loans become harder to raise.

17. CAMBODIA OBTAINS WORLD BANK SUPPORT FOR RURAL SOLAR ENERGY

The World Bank has launched a project to provide about one million Cambodian villagers with household solar power units. **The US \$10 million project is part of the World Bank's five-year National Renewable Electricity Action Plan launched in May, 2003.**



The World Bank will subsidize 25% of the cost of the solar power units, the most basic of which costs US\$400. The remaining costs will be covered by local micro finance plans.

Only 13% of Cambodia's' rural population access the national electricity grid, whilst 16% use car batteries, and the rest live without electricity.

18. CANADA'S OIL SANDS

The rapid growth of Western Canada's oil sands projects is turning into a potential field day for oil pipeline companies. Canadian conventional and synthetic crude production could reach as much as 4 million barrels per day by 2015, versus the current 2.3 million b/d, led by synthetic crude from oil sands. The new flows will also be seeking outlets in new markets – from the US Rockies and California to the Far East – but will need new pipeline infrastructure to reach them. Some 80% of Western Canada's conventional oil exports are currently sold to US Midwest refineries, which are not configured to process the diluted bitumen and synthetic crudes that will be coming out of its oil sands developments. Low conversion refineries in Asia with a larger share of their product mix directed toward the middle of the barrel, would be the natural buyers, analysts say. California refineries are set up to maximize gasoline yields using Alaskan North Slope crude, which may limit their appetite. However, oil sands pioneer Suncor Energy of Calgary is investing US\$225 million in the Denver, Colorado, refinery it acquired from ConocoPhillips to run synthetic crude, which is low in sulfur and around 30⁰⁻ API, as well as to meet new fuel standards. By year-end, Enbridge plans to have completed work on reversing the flow of its Cushing, Oklahoma, to Chicago pipeline. Known as the Spearhead project, the reversed line, which has a capacity of 300,000 b/d, will transport the first significant volumes of Canadian crude to Cushing. By expanding the outlets for Canadian oil, it could narrow the



\$2 per barrel discount to benchmark West Texas Intermediate that it usually commands.

The steady growth in oil sands production, which is expected to reach 1 million b/d by year end, has not yet required substantial investment in new pipelines, because of the parallel decline in Canada's conventional oil output which has released pipeline capacity. However, as investment in oil sands accelerates, spare pipeline capacity is running out.

19. USA BAN ON MTBE WILL RESULT IN INCREASED USE OF ETHANOL

(Source: US Department of Energy)

U.S. ethanol production, with corn as the primary feedstock, reached 1.7 billion gallons in 2001. Production is projected to increase to 4.0 billion gallons by 2025 with about 25% of the growth from the conversion of cellulosic biomass. Ethanol is used primarily in the Midwest as a gasoline volume extender and octane enhancer and also serves as an oxygenate in areas that are required to use oxygenated fuels (minimum 2.7% oxygen content by volume) during the winter months to reduce carbon monoxide emissions. Greater projected growth will be from cellulose, due to rapid improvement in the technology. Corn-based ethanol production may drop from 96% of total ethanol output in 2015 to 85% in 2025.

Ethanol is expected to replace MTBE as the oxygenate for reformulated gasoline (RFG) in 17 states that have placed limits on MTBE use mainly because of concerns about ground water contamination. California will begin the replacement of MTBE in January 2004; a signal for regional refineries to prepare for change.

The Federal Highway Bill of 1998 extended the excise tax exemption for ethanol through 2007 with reductions from 54 cents per gallon to 53 cents in 2001, 52



cents in 2003, and 51 cents in 2005. It is assumed that the exemption will be extended at 51 cents per gallon (nominal dollars) through 2025.

20. VENEZUELA CUTS OFF DOMINICAN REPUBLIC

Venezuela in the third week of September halted oil supplies to the Dominican Republic as a diplomatic row between the two nations escalated. The Dominican Republic, which consumes 160,000 b/d of crude and refined products, depends heavily on oil sold at concessionary terms by Venezuela and Mexico to fuel its economy. Relations between the two countries have deteriorated in recent months since the island state rejected Venezuelan demands for an investigation into, and the repatriation of former Venezuelan president Carlos Andres Perez, who resides in the Dominican Republic.



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