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© Petroleum Corporation of Jamaica
36 Trafalgar Road
Kingston 10
Jamaica

Telephone: (876) 929 5380-9
Fax: (876)929 2409
Email: ica@pcj.com
Website: www.pcj.com



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1. MAJORS ON A SPENDING SPREE

High oil prices are prompting a spending spree by the major oil companies. However, their choice of projects and investments is unpredictable and diverse. The latest large expenditure is a gas to liquids (GTL) plant in Qatar. Shell will provide \$5bn. This follows a \$12bn commitment from ExxonMobil to take LNG from Qatar to the U.S.A. At the same time BP is making a \$6.85 bn investment in Russian joint venture TNK-BP.

Shell says its 140,000 b/d unit in Qatar will be the first world-scale GLT plant. Shell Chairman Phillip Watts says, "It represents a coming of age of a technology of fundamental importance – for natural gas exporters and for fuel consumers." GLT's main advantage over LNG is that it produces clean middle distillates, "refining" gas into gasoil and naphtha, rather than simply altering the state of gas. This cuts the capital cost compared with LNG, which must be stored, regasified and piped to consumers. In contrast GTL products can use existing product distribution and marketing networks. Shell will produce GTL fuels as "uniquely clean, with a vital role of reducing engine emissions," and it will sell blends.

GTL will cost more than a conventional refinery but Shell expects satisfactory returns even at oil prices below \$20/bl. Qatar's smaller 35,000 b/d Sasol GTL project suggest a total cost of about \$15.50/bl of product. This breaks down into \$2/bl for the gas, \$6/bl for conversion process, \$4.50/bl operating costs, \$1.6/bl capital costs for special superclean tankers, and \$1.40/bl to run these ships. Shell has pushed down LNG costs by nearly 50% since entering the sector, and will expect greater economies of scale than Sasol, but GTL remain an expensive business.

In Qatari LNG, ExxonMobil has first mover advantage. It plans to ship its LNG to a huge new terminal in the US Gulf, and may even use salt caverns in Louisiana/Texas to store gas.



BP is not the first major in Russian gas. Shell is leading the Sakhalin Energy Consortium, operator of the \$10 bn Sakhalin II oil and LNG project, which launched a second phase before BP tied up its TNK deal. Sakhalin Energy was the first foreign company to get licences to develop oil and gas reserves in Russia.

However, being first is less important than being profitable.

2. BP TO POST RECORD PROFIT

BP, the world's second-largest oil producer, is on course to post record profits this year despite warning that earnings were being hit by the weaker dollar and a squeeze on its petrol retail business worldwide.

In a mixed trading update ahead of third quarter results on October 28, BP said refining margins had improved in the past three months but higher costs and adverse foreign exchange effects would partially offset these benefits.

Elsewhere in the energy sector, the UK government said it had signed an agreement with Norway that could meet up to a fifth of Britain's annual gas demand from 2006-07 by enabling industry to invest in the proposed "Britpipe" project.

The deal came as EDF Energy, the UK arm of the French state-owned power group, said it had contributed €154m (£108m) to the group's first-half net profits of €728m. EDF, which owns London Electricity and the Sweb network in south-west England, said the acquisition of Seeboard had helped double sales to €2.66bn.



3. RUMOURS REGARDING EXXONMOBIL AND RUSSIAN OIL FIRMS MERGER

(adapted from the Guardian, October 3, 2003)

Yukos and Sibneft have completed a \$45bn (£26.9bn) merger to create Russia's biggest company amid reports that US oil giant ExxonMobil was in talks to acquire a stake in the new group.

Shares of Yukos and Sibneft rose despite a Yukos denial of an imminent deal with ExxonMobil. Mikhail Khodorkovsky, Yukos chief executive, said there was no foreign investment deal involving the new group.

"There is no deal, but when there is a deal we will make you happy by telling you," Mr. Khodorkovsky told reporters on the sidelines of a major economic forum in Moscow.

But Mr. Khodorkovsky's denials failed to quell speculation of a link-up between the new Russian group and a foreign company. The presence of ExxonMobil's chief executive, Lee Raymond, in Moscow at the same economic forum, only fuelled rumours of the company's desire to move aggressively into the Russian oil market.

The Financial Times reported that ExxonMobil, the world's largest public company, was interested in acquiring a 40% stake in Yukos-Sibneft and possibly as much as 50% that would cost at least \$25bn.

"There's no smoke without fire," Konstantine Shapsharov, a dealer at Alfa-Bank, told Reuters. "These rumours that Exxon will buy a stake in the new company appeared a couple of days ago and people believe a deal will be announced at some stage."



The Yukos-Sibneft group will be Russia's largest publicly listed company by far, putting it on a par with France's Total, the world's fourth largest oil company. The world's second biggest oil exporter behind Saudi Arabia and a regular thorn in the side of the OPEC oil cartel, Russia also possesses the world's largest natural gas reserves.

Sibneft's shareholders are led by Roman Abramovich, the Russian billionaire who has branched out into English football from oil by buying Chelsea, the Premiership club. Mr. Abramovich is thought to be keen on reducing his assets in Russia.

Russia's oil industry has been attracting increasing interest from foreign companies after the country's economic rebound from financial crisis in 1998, when Russia defaulted on its foreign debt. BP, the British energy giant, earlier this year announced a ground-breaking \$6bn investment in a joint venture with TNK.

In the meantime the chief executive and majority shareholder in Yukos has been arrested on seven charges of embezzlement, conspiracy to commit fraud, and tax evasion. This has caused the value of Yukos stock to drop by about 15%.

4. GLOBAL WARMING IMMINENT OR NOT?

(Adapted from The Scotsman, October 2, 2003)

Catastrophic global warming due to fossil-fuel burning is unlikely because oil and gas will run out too quickly, scientists have claimed.

The controversial theory forecasts that all the fuel will be burned before there is enough carbon dioxide in the atmosphere to bring into reality melting ice-caps and searing temperatures.



Geologists at Uppsala University in Sweden claim there are not sufficient reserves of oil and gas left in the world for even the most modest of the scenarios put forward by the Intergovernmental Panel on Climate Change (IPCC) to come to pass.

Predictions of global meltdown by the IPCC created the drive for the Kyoto Protocol, an international agreement requiring compliant nations to restrict their emissions.

In response to the controversial theory, published October 2nd in the journal New Scientist, the IPCC staunchly defends its predictions, saying it had considered a range of estimates of oil and gas reserves, and drawing attention to the fact that coal-burning could easily make up the shortfall claimed by the Swedish scientists.

The IPCC put forward a range of future scenarios, from extravagant consumption of oil and gas to a quick change-over to greener energy sources.

Although estimates of oil and gas reserves vary widely, the Swedish researchers represent a growing body of experts who claim oil supplies will peak by 2010, and gas shortly after. They believe oil and gas reserves amount to the equivalent of 3,500 billion barrels - much less than the 5,000 billion barrels estimated in the IPCC's most optimistic model.

The worst-case scenario sees 18,000 billion barrels of oil and gas being burned - five times the amount researchers believe is left. Nebjosa Nakicenovic, an energy economist at the University of Vienna, who led the IPCC team that formulated the forecasts, insisted his predictions were still legitimate.

He said the team calculated a much broader, internationally accepted range of oil



and gas estimates than the "conservative" Swedes, and drew attention to the huge reserves of coal that could still be exploited.

But Dr Kevin Anderson, a scientist with the Tyndall Centre for Climate Change Research, Britain's most esteemed climate research institution, said lessons from history should not easily be forgotten.

He asked: "On how many occasions over the past three decades have we heard the cry of wolf over oil reserves?"

"According to many experts of the day, we should now have either run out of oil or be parting with \$100-plus for each of the remaining few precious barrels.

"Instead, our roads are clogged with ever more inefficient 4x4s guzzling gas, and our skies are increasingly clogged with aircraft - the most fuel-profligate form of transport.

"It seems that as the price of oil rises, so does our ability to either find new reserves or develop methods to extract more oil from each reservoir."

He said that burning 3,500 billion barrels - the Swedes' conservative estimate - would see concentrations rise towards 1,000 parts per million (ppm). To put this in perspective, it was 280ppm before the industrial revolution, it is now 360ppm and, according to the Royal Commission on Environment and Pollution, must not exceed 450-550ppm if climate change is to be avoided.

Dr Anderson concluded: "Simplistic analysis neglecting the combustion of coal, our appalling record at forecasting fuel reserves and underestimating the carbon dioxide impact of known reserves is a dangerous basis ... [for] policy."



5. THE DAY THE LIGHTS WENT OUT IN NEW YORK

(Adapted from the Scotsman, September 26, 2003)

It is a little-understood component of electricity, so arcane that engineers sometimes call it "imaginary power". But it was a shortage of this elusive force, largely unknown and unappreciated by the general public but critical to the operation of the nation's electrical grid, that experts now say probably set off the largest blackout in North American history in August 2003.

Imaginary power, known to scientists as reactive power, cannot turn on lights or run toasters. Yet power plants and lines need it to create the conditions that allow hundreds of thousands of megawatts to flow across the continent. Scientists often compare it to poles holding up the vast tent that is the country's power grid.

Experts now think that on 14 August, northern Ohio had a severe shortage of reactive power, which ultimately caused the power plant and transmission line failures that set the blackout in motion. Demand for reactive power was unusually high because of a large volume of long-distance transmissions streaming through Ohio to destinations, including Canada, that needed power to meet local demand. But the supply of reactive power was low because some plants were out of service and, possibly, because other plants were not producing enough of it. That troubles with reactive power could be behind the failure is not a surprise to many industry officials and other energy experts.

Profound changes in the electricity markets, driven by deregulation, have made such a precarious combination of conditions more likely in recent years, according to industry officials, academics and power consultants. The United States and Canadian investigation into the August blackout has not been



completed. **But among experts who have studied the failure, a consensus has emerged that market-driven problems with reactive power existed that day and played into the blackout.**

"It is definitely a contributor," said Raymond Palmieri, a compliance programme manager at East Central Area Reliability Co-ordination Agreement, an industry group charged with ensuring the delivery of power in the Midwest, including Ohio, where the blackout started.

Mr. Palmieri said it appeared that a lack of reactive power, measured in what are known as VARs, led to low voltage on transmission lines and threatened the stability of the system.

Some power industry officials have said they were embarrassed by the events of 14 August, when tens of millions of people from Michigan to Connecticut lost power. Potentially more embarrassing is that the threat of reactive power problems was so widely known. Analysts have blamed instability in reactive power that brought on voltage collapses for a blackout on the Pacific coast in July 1996 and a 1978 blackout across France. And for years, experts have warned that market changes like the breakup of utility monopolies and greater reliance on long-distance transmission have increased the need for reactive power but curbed the motivation to produce it.

A reactive-power deficit alone cannot explain what happened in August, because even when such problems arise, power companies and regional agencies that monitor the grid are supposed to intervene and stabilise the system. But if the intervention is too slow, voltage on power lines can collapse suddenly, and the lights go out.

Reactive power, like ordinary or "real" power, results from the interplay of electricity's two basic elements: the flow of electrons through the wires and the



force pushing them along. These two factors oscillate at slightly different moments, many times per second.

When the flow and the force are aligned, they produce real power, measured in watts, which does the apparent work in the system, running lights and televisions. When they are not, they produce reactive power, measured in VARs, or volt-amperes reactive. Power plants, power lines and some kinds of machinery consume reactive power, using it to maintain the magnetic fields that they need to operate.

Traditionally, a local utility was a largely self-sufficient monopoly that generated nearly all the power its system needed, including reactive power. It owned all the power plants in its territory, and most electricity was produced near where it was used. Deregulation, urged on by Congress a decade ago, transformed that system in ways that were much in evidence on 14 August.

One of the most important changes was the proliferation of "merchant plants" - power plants located in a particular utility's region but owned by a different company.

In just the past 15 months, three merchant plants began operating in southeastern Ohio. On the day the lights went out, several plants in Ohio and Michigan that are operated by the utilities where they are located were down for repairs, and units at two other plants shut down that day for reasons that remain unclear.

Power plants can produce both VARs and watts, and can fine-tune the output of both. When the same company owned all of a region's power plants and transmission wires, and had all the customers, it had no choice but to ensure that there was enough reactive power.

But merchant plants, pumping electricity through someone else's lines,



often have little or no incentive to produce VARs, because they are paid primarily for producing real power.

"The real money is in the watts, not the VARs," says Karl Stahlkopf, the senior vice-president of the Hawaiian Electric Company, who studied the 1996 blackout.

Hours before last month's blackout, operators at First Energy, the utility that serves much of north-eastern Ohio, noticed a peculiar thing: voltage across their system was below normal, a sign of insufficient reactive power. Even though First Energy was importing thousands of megawatts from southern Ohio, "we were exporting VARs outside the First Energy system the whole day", says Charles Jones, a senior vice-president. "That's not normal."

Mr. Jones said merchant plants in the region were producing large amounts of real power but very little reactive power to support it. The owners of three new merchant plants in south-east Ohio, the Duke Energy Corporation and PSEG Power, say the plants were generating nearly as many megawatts as they could on 14 August, but would not say how many VARs they were producing.

Another change has been a sharp rise in long-distance power transactions. More than ever, a plant outside Cincinnati, for example, might feed Chicago. That trend, and a rising demand for power, has increased the burden on transmission lines.



6. MEXICO APPOINTS NEW ENERGY SECRETARY

President Vicente Fox has appointed Felipe Calderon as Mexico's new energy secretary as part of his efforts to push electricity sector reforms through congress before year-end.

Calderon, a lawyer and long-serving politician from Fox's ruling National Action (PAN) party, replaces Ernesto Martens in the role.

Fox said he is counting on Calderon's knowledge of the political workings of congress and his experience in conducting political negotiations to push forward planned sector reforms, in contrast to the low-profile approach to running the energy secretariat which Martens favored.

Federal Electricity Commission (CFE) general director Alfredo Elias retained his job during the Fox reshuffle, and still enjoys strong backing from Fox.

The reshuffle came just hours after an unusually downbeat state of the union address, in which Fox told congress that the economic viability of both the CFE and state-owned oil and gas company Pemex are "seriously compromised". And this, he added, "puts the future of our country in jeopardy".

Calderon said his "main mission" is to push electricity reforms through congress before regional elections in mid 2004 and presidential elections in 2006 make political consensus-building more difficult.

Calderon said that the Fox government set its expectations for reform too high during its first three years in power and must now be more realistic, and that reform of the gas sector will have to wait, even though the industry's need for change is far more pressing than in the electricity sector.



7. JAPAN SEEKS MIDEAST GULF LNG IMPORTS

Japanese liquefied natural gas (LNG) customers intend to have their contract volumes with Indonesia when contracts end in 2010/2011. Japanese buyers seemingly want to reduce their commitments from current levels of 12mn t/yr to around 6mn t/yr and are already looking for alternative sources of supply in the Mideast Gulf. At the top of the list is Qatar, with its huge North Field reserves of 900 trillion ft³ (25 trillion m³). But Japanese trading houses are having difficulty convincing Qatar to commit further volumes to Japan. **Qatar appears to favour markets in Europe and North America for its planned new LNG trains.**

8. MEXICO TO BOOST GAS PRODUCTION

Mexico's state-owned oil company Pemex has announced that it will invest around \$90.3bn/yr until 2010 to boost reserves and increase production of natural gas and crude oil.

More than half of that amount, (about \$47.4bn) will be spent in the next three and a half years, according to Pemex general director Raul Munoz. About 72% will be spent on exploration and production, 18% on refining, and 10% on natural gas and petrochemicals.

Munoz says that he wants Pemex to produce 7bn ft³/d of natural gas by 2006. Pemex is on schedule to average production of around 4.549bn ft³/d of natural gas this year, Munoz said.

Energy officials have said Mexico's natural gas demand is expected to rise by 7.4% each year between 2003 and 2010, fueled by the country's growing fleet of gas-fired power plants.



Gas imports have fast been outpacing the minimal production increases seen so far at Pemex, leading Pemex director general Raul Munoz to suggest the Federal Electricity Commission (CFE) should look elsewhere for natural gas.

CFE officials in turn have complained that uncertainty over the future availability of natural gas has dampened investor interest in government tenders to develop independent power plants (IPPs).

Benchmark prices for natural gas and fuel oil in northern Mexico jumped by 103% on average between January 2002 and May 2003, the CDE said in August, which helped push it to a \$125mn loss in the first half of this year.

In a positive note, less than 5% of the Mexican population is left without any access to mains electricity, according to a new report from the federal electricity commission (CFE).

The CFE said 95.3% of Mexicans now have access to power. Urban populations are 98.4% electrified, while only 85.8% of rural populations have mains electricity.

The CFE said it needs to bring mains electricity to another 74,068 communities, although only 4,177 of these communities have over 100 inhabitants. The CFE said this effort will require major investments in new infrastructure.

9. FENOSA EXITS DOMINICAN REPUBLIC DISTRIBUTION

Union Fenosa, Spain's third largest power firm, has agreed to cut its losses on two Dominican Republic electric distribution businesses and hand over its 50% stake in the firms to the island's government. Union Fenosa will lose 160mn euros (\$181mn) on the deal.



Union Fenosa decided to pull out of Edenorte and Edesur “in the context of an economic, financial and energy crisis in (the Dominican Republic) in the last few years, aggravated by the collapse of the island’s second largest bank and the subsequent depreciation of the Dominican peso by over 100%.” The firm said rising fuel prices have added to financial problems at Edenorte, which was already suffering from power shortages in the north of the Dominican Republic.

The Dominican government will initially pay Union Fenosa 13.3mn euros for the handover of its distribution business. It will operate the distribution assets Edenorte and Edesur under a lease arrangement over the next 12 years, which will allow Union Fenosa a 15% return on its original investment and cover the two firms’ financial obligations and operating costs.

The lease arrangement will allow Edenorte and Edesur to service debts which they owe to the Palamara and La Vega power plants, which Union Fenosa also owns.

10. STATOIL SCANDAL CLAIMS CHIEF EXECUTIVE

The resignation of Statoil chairman Leif Terje Loddessol and chief executive Olav Fjell in September was supposed to draw a line under a scandal over alleged bribery payments that has engulfed the Norwegian energy firm.

But the decision by Statoil’s board of directors to commission auditors Ernst and Young to investigate consultancy contracts signed since part-privatisation in 2001 may see further evidence of corporate malpractice emerge.

Statoil says only contracts it has signed with small or one-man operations, similar to the one at the centre of the scandal, are being investigated. While it refused to specify exactly how many exists, it says the total is fewer than ten.



The controversy stems from a police investigation into a \$5.2mn payment Statoil made as part of a \$15mn contract with London-based consultancy from Horton investment. The Norwegian police allege that Abbas Yazdi, the Iranian head of Horton Investment. The Norwegian police allege that Abbas Yazdi, the Iranian head of Horton Investment, used part of the proceeds from the contract to bribe officials from Iran's state-owned oil firm NIOC in return for entry phases six to eight of the South Pars Development, which the company won last November.

Some board members became increasingly unhappy with the outcome of the meeting made the chairman's and chief executive's handling of the affair when it emerged that both had known full details of the Horton contract for the past few months. And Fjell had to rely on the chairman's support to narrowly avoid a vote of no confidence by the board of directors on 19 September.

But mounting pressure on the Norwegian energy minister by board members still unhappy with the outcome of the meeting made the chairman's position untenable and he resigned, paving the way for another non confidence vote on Fjell.

It may be some time before the full repercussions of the September event become clear. But the firm has announced that corporate strategy remains unchanged and that future operations will be unaffected.

However, the scandal throw up a number of dilemmas for Statoil. The company needs to expand its international exploration and production business to maintain production growth. Drilling opportunities in the Norwegian continental shelf are drying up, and Statoil aims to increase international exploration and production business to maintain production growth. Drilling opportunities in the Norwegian continental shelf are drying up, and Statoil aims to increase international upstream assets from 10% of its portfolio to 25 % by 2007. But the current controversy could hamper Statoil's future expansion plans.



Statoil's Production

(1,000 b/d)	Jan-Jul	Jan-Jul	Vol	%
		2002	Chg	Chg
Refining throughout	4,639	4,273	366	8.6
Demand*	5,139	4,743	396	8.3
Domestic crude production	3,434	3,406	28	0.8
Crude imports	1,751	1,348	403	29.9
Crude exports	163	128	43	35.8
Net crude flow	5,022	4,634	388	8.4
Production imports	518	332	186	56.0
Production export	272	176	96	54.5

Statoil has in the past made much of its high ethical standards, and leveraged its corruption-free history and former status as a state owned oil company in negotiations with other national oil firms over access to reserves. The current investigation has damaged its ability to do so in future.

Statoil's track record outside Norway is mixed, but recent developments have been promising. Playing the national oil company card, it has established a presence in Venezuela, Brazil, Azerbaijan, Iran, and most recently Algeria. Overseas operations currently account for less than 8% of Statoil's overall production, but they are central to the company's growth objectives.

11. QATAR NATURAL GAS EXPANSION

Qatar is the centre of activity in natural gas. Shell had no measurable presence in the country only two years ago, but is now launching two mega-projects, starting with a definitive agreement in October with state



Qatar Petroleum (QP) for a 140,000 barrel per day GTL project and related facilities. The \$4 billion plus venture would include two 70,000 b/d GTL trains, plus recovery of about 90,000 b/d of condensates and liquefied petroleum gases. Startup on the first phase would come in late 2008 – early 2009, with the second unit following in 2010. Shell also would have an upstream phase to develop the gas supply, thus avoiding the need to acquire feedstock from resources developed by archival Exxon Mobil.

Shell also has an LNG project in development with Qatargas for a 7.8 million ton per year train that would be a twin of the project Qatargas and US ConocoPhillips are pursuing. The output would be destined for the US, where Shell would receive the LNG at a terminal to be constructed in the Gulf of Mexico on West Cameron Block 182. The company is slated to file an application with the US Coast Guard for the West Cameron facility by early November. The terminal would handle about 1 billion cubic feet per day of gas, equal to the entire output of the Qatari liquefaction plant. Water depths could handle the so called “super size” tankers capable of delivering more than 200,000 cubic metres (4 billion cubic feet) of LNG, and the site is near several large – capacity natural gas pipelines to move regasified LNG onshore.

Shell’s large scale project in Qatar have come as a shock to Exxon, which through its Mobil legacy, its assets and subsequent endeavors appeared to have an unassailable lead in the country. They also come hard on the heels of Conoco’s LNG agreement with QP – which appears to be encouraging the competitive scramble. QP has several motivations, not the least of which is gaining as large a share as possible in the expanding US-UK European LNG markets. QP and Exxon have just signed a previously announced deal to supply 15.6 million tons/yr of LNG to the US. Now, the Qataris want Exxon to move forward on its 100,000 b/d GTL project that has been under development since at least 1996. QP and Sasol began construction on their 34,000 b/d Oryx GTL plant earlier this year.



On another North American LNG project, Shell appears to be getting a partner. The company and US Sempra Energy have been pursuing separate LNG receiving terminals for Costa Azul in Baja California, Mexico; but now they are reportedly combining efforts for a single 1 Bcf-1.5 Bcf/d facility.

Shell will be obtaining some of the LNG from Australia's North West Shelf, while other supplies are expected from the Shell-led Sakhalin II project in Russia. Consolidation in the area, where five terminals have been proposed, was expected. Marathon Oil has a 750 million cubic foot per day integrated LNG power water desalination project planned for Tijuana that also has supply and market arrangements.

When reports first broke about seven years ago that Exxon and Qatar Petroleum (QP) were negotiating a deal to construct a natural gas – to liquids (GTL) plant to exploit Qatar's massive gas reserves, the deal was viewed as the first in an expected series of commercial GTL ventures around the world. Though a dozen or so plants are in development in Qatar or elsewhere, none have been built. The only definitive agreement, including financing, is between South Africa's Sasol and QP. Site preparation for their 34,000 barrel per day Oryx GTL plant has already begun in Qatar's Ras Laffan Industrial City. The small Mideast nation has ambitious natural gas (LNG) output has priority for now. Technology and market development are two reasons. The Fischer-Tropsch process core to GTL manufacturing has never been demonstrated at the scale now proposed, adding to the financial and operating risk. Plus, global demand for LNG is soaring, especially in the US.

Nevertheless, if all goes according to plans, Qatar could have up to 700,000 barrels per day of GTL capacity within a decade. Besides Oryx and the proposed Exxon Mobil and the Sasol Chevron joint venture. Shell and QP are expected to sign a memorandum of understanding for two trains with a total capacity of 140,000 b/d in about a month. **The projects are intended to turn the Gulf state into the world's GTL capital.** Sasol awarded the



construction contract for Oryx to French Technip earlier this year, and the plant is due on stream in late 2005. When completed, it will be the world's first truly commercial GTL plant. Two other plants exist – a 30,000 b/d plant owned by South Africa's Petro SA, formerly Mossgas, and Shell's 12,500 b/d unit at Bintulu, Malaysia but both are considered demonstration projects. Fluor Daniel has begun engineering design work for the Exxon project and Shell is conducting preliminary engineering design work for the Exxon project. Shell is conducting preliminary engineering design work on its venture.

Elsewhere

Several Russian companies, notably Yukos and Gazprom, also have lofty GTL hopes as a way to monetize gas with no pipeline outlet to either domestic or export markets and reduce undesirable flaring. Yukos, now YukosSibneft, retained US GTL developer Syntroleum to conduct a feasibility study for a 13,000 b/d GTL plant in East Siberia for its Yakutgazprom subsidiary. Gazprom has Syntroleum reviewing 12 potential GTL locations. In addition, Yukos acquired GTL developer Davy Process Technologies from Norway's Kvaerner in 2001. Davy is investigating a scheme that would see associated gas from East Siberia converted to gas oil, and then blended and sold as part of a crude stream, as a means to allow large scale development of huge oil deposits that otherwise might remain unexploited.

Just as major oil companies have focused their downstream refining assets on mega-projects to produce high purity diesel and other ultra-clean transportation fuels, Syntroleum and US Renteck, another small GTL technology holder, have redirected their business strategies. In its "hydrocarbon – to – liquids" efforts, Renteck plans to build plants adjacent to integrated coal – or petroleum coke fueled gasification and power stations. Syntroleum now focuses on solving gas disposal dilemmas for upstream operators through smaller, barge mounted plants that would convert 170 cubic feet of gas per day into almost 20,000 b/d of products, **including the high purity**



diesel that is the most prominent GTL fuel. Syntroleum has identified 40 shallow water locations suitable for the buyers adjacent to stranded gas deposits of 1 trillion- 3 trillion cubic feet, less than is generally required for LNG.

12. ABU DHABI EMBARKS ON MAJOR EXPANSION

Abu Dhabi is well on its way to completing a more than \$6bn investment programme to increase oil, gas and products capacities by 2007. Oil production capacity will rise by almost 500,000 b/d, or 20%, to 2.9mn b/d.

The emirate's three main operators have awarded over \$800mn worth of contracts so far this year. The biggest single capacity is to be added by revamping surface facilities. The plan is to debottleneck the central processing facility at the Zirku island – the main centre for processing, storage and loading crude from all of offshore Zadeo's fields. This project is at an earlier stage than others, and Tebodin of the Netherlands is carrying out a study.

Zadco has long lagged behind the other operators in terms of modernization, and this project will help it catch up. State owned oil company Adnoc has an 88% share in Zadco but is taking its time over choosing a partner.

The other main expansion will be onshore. Operator Adeo, which groups Adnoc with BP, Shell, Total, ExxonMobil and Lisbon-based Partex, is to add 230,000 b/d of capacity, largely at three fields. At the Bab field, Japanese engineering firm JGC is to add 100,000 b/d of capacity under a \$91mn contract signed in March, 2003. The other main project is the development to 110,000 b/d to the adjoining Rumaitha and al-Dabbiya fields, which only produce 10,000 b/d at present. Technip-Coflexip of France and local engineering company NNPC won the \$613mn contract earlier this year.



Abu Dhabi based Dolphin Energy has signed a long-awaited deal to supply gas for 25 years from Qatar's giant offshore North Field to Abu Dhabi Water and Electricity Authority. The gas sales agreement is the first major supply contract of its kind to be signed by Dolphin which is owned by the Abu Dhabi state-owned UAW offsets Group in partnership with Total and Occidental.

13. IRAN TO TENDER FIRST LNG PROJECT

In November Iran intends to invite engineering firms to bid to build the country's first liquefied natural gas (LNG) plant. However it has yet to settle on partners for the scheme.

Iran's National Gas Export Company (Nigec) – an affiliate of state-owned NIOC – has already preselected engineering firms to bid for the \$1bn main engineering contract to build a two-train, 4.8mn t/yr LNG plant at Assaluyeh using gas from phases 11 and 12 of the South Pars gas field development. The firms include South Korea's Hyundai, Japan's JGC, Italy's Snaprogetti and France's Technip. Nigec wants foreign contractors to team up with local engineering firms. But the foreign companies are seeking freedom to choose their own partners.

Tehran is seeking foreign partners to jointly develop the scheme with Nigec. The UK's BG is discussing the possibility of taking a minority stake in a joint venture with Nigec. BG is seeking to operate and develop one LNG train with a capacity of around 2.4mn t/yr. The firm is considering exports to India and Europe where it is involved in the distribution of gas. Total and Malaysia's Petronas are working on a rival proposal.

NIOC has indicated in the past that it will retain a 40% share in all LNG export ventures.

Iranian oil officials remain upbeat about Iran's prospect of offering regular exports of LNG to Asia or Europe over the next five years.



However, political issues continue to obstruct big investments in Iran. UN nuclear watchdog, the IAEA, has set a deadline of the end of October for Tehran to sign an additional protocol on nuclear non-proliferation and give proof that Iran is not seeking to develop nuclear weapons at several suspected sites across the country.

Iran is considering possible changes to its buy back contracts in an effort to attract more investment to the country's upstream. The main change being contemplated is the development of a mechanism that would allow foreign oil companies undertaking a buy back project to maintain an involvement in the scheme once they have handed it back to NIOC. The inability to benefit from marginal improvements or debottlenecking has been one of companies' main criticisms of the buy-back model.

One possibility being mooted is that NIOC should award service contracts to the foreign companies for the assets they are handling over. Iran sees this as a way of reducing costs and improving efficiency.

14. EXPLORATION ACTIVITIES IN EAST AFRICA

Exploration activity in east Africa is rising, with Tanzania's Songo Songo gas field development leading the way.

The region has long been neglected by the oil industry, but better investment conditions in Tanzania, Kenya and Uganda have stirred new interest. Hopes have also been raised because the region's offshore geology appears similar to that of prolific west Africa, while neighbouring Sudan already produces 280,000 b/d. With much of the best acreage in west Africa taken, smaller firms are turning in to the east. And recent work showing promising geological structures, there is attracting more investors.



East Africa's most significant gas venture, the \$220mn World Bank-backed gas project on Songo Songo island offshore Tanzania, will see gas piped 230km to the port of Dar es Sallam by May, 2004. The project is expected to form the basis for the development of a gas industry and infrastructure in Tanzania and will eventually produce 70mn ft³/d (721mn m³/yr).

Songo Songo is operated by UK registered Pan African Energy, while the UK's Commonwealth Development Corporation operates the Songas pipeline to Dar el Salaam. The city's existing power plant is being converted to run on gas.

Songo Songo is encouraging other initiatives, including the possibility of gas exports to Kenya. Pan African Energy may extent the pipeline north from Dar es-Salaam to the Kenyan port of Mombasa. And UK firm Aminex has started drilling Tanzania's first offshore exploration well for 12 years, in the Nyuni licence area. Aminex hopes to find oil and gas, and has access rights to the Songas pipeline if it does. Shell is also bringing its muscle to the region, with plans for seismic surveys on blocks 9-12 off Tanzania's north coast.

In Kenya, most of the deepwater blocks have been awarded. Australia's Woodside, which took over operatorship and a 40% stake in UK firm Dana Petroleum's four blocks in May, is expected to speed up exploration. Woodside's seismic programme – the first exploration offshore Kenya for nearly 20 years – has started, and drilling may begin as early as 2005.

For years, investors kept away from Uganda, given a lack of field data and security problems. But Canadian firm Heritage Oil and its partner South Africa-based Energy Africa made discoveries in block 3 in western Uganda this year. Uganda is landlocked and the discoveries are far from key markets. But the partners claim that seismic reveals a 1 bn/bbl potential in the Semlike valley and other basins.



15. JAPAN BEGINS ENERGY EFFICIENT “CELL PRODUCTION SYSTEM” OF MANUFACTURING

For many people, the term "modern factory" conjures up an image of products being assembled on a conveyor belt. A production system using conveyor belts was invented as early as 1785. U.S. automaker giant Ford began production using such a system in 1913.

The conveyor belt system with well-designed production lines used to be considered a very efficient production method in terms of productivity and thus was installed in many factories. In the last several years, however, a new production system has been introduced in Japan's manufacturing industry. It has brought with it both economic and environmental successes.

The conventional method, in which workers line up along conveyor belts, has been switched to the new "cell" (small unit) method in which one or a few workers completely assemble each product from start to finish. In contrast with the U.S.-born idea of mass production, this new system is known as "on-demand" production, which is based on actual consumer orders.

As an example, Ricoh, a leading company in the field of on-demand production has undergone significant changes in its production process over the last few years. It switched from mass-market production based on sales projections to on-demand production, based on a new system requiring no conveyer belts.

Upon receiving an order right at the customer's premises, a Ricoh salesperson fills in the electronic order form with the product name and optional features desired by the customer, and transmits this information to the company's Gotemba Plant immediately by electronic network. The information is transferred into an order slip in the plant, immediately initiating the manufacturing process.



This plant has adopted the "Cell-Formation Production System" in which the whole manufacturing process is completed in the cell, with no conveyor belts. Having several production patterns (called "cell formations") ready, this system can flexibly change the volume of production on a weekly basis, and efficiently and speedily supply products, even in the face of big fluctuations in demand.

To meet the diverse needs of consumers, the company has shifted from conventional mass production to the Cell Production System, suitable for manufacturing just the right number of products in many variations. One big plus of this system is the elimination of conveyor belts, resulting in substantially lower power consumption.

Ricoh Unitechno's plant has also shifted from conveyor belts to carts, and from large electric carts to handmade robot carts. As a result, both power consumption and carbon dioxide (CO₂) emissions dropped to one-eightieth of previous levels. At this plant a photovoltaic power generation system can supply all the electricity needed in the assembly process.

In Japan, not only Ricoh, but also other major manufacturers such as Canon, Sony, and NEC have adopted the Cell Production System with good results.

For example, as a result of introducing the Cell Production System between 1998 to 2001, Canon successfully eliminated the need for 18 km of conveyor belts, 549,000 square metres of space, 37 automatic warehouses, and 17 external warehouses. In 2001 the company's productivity went up by 35%, production time was cut by 31%, and electrical savings cut the equivalent of 41,650 tons of CO₂ emissions. As a result, Canon cut its production costs by 35% and saved 118.8 billion yen (about U.S.\$1 billion).

Nearly a hundred years after Henry Ford introduced the conveyor belt system, a new paradigm shift in the manufacturing industry is now occurring in Japan. Its implications for business, and for the environment, are significant.



16. SUPPORT FOR LNG IN THE USA

(adapted partly from Energy Info Source Inc.)

With natural gas production struggling to keep pace with demand in the United States, a new emphasis has been placed on liquefied natural gas (LNG), which is extracted from basins around the globe before it is super-cooled to a liquid form and shipped to points of use. **Some are bullish on LNG, noting that such imports have swelled from 5 billion cubic feet (bcf) per year in 1995 to almost 155 bcf in 2002 – a mere fraction, however, of 23 trillion cubic feet (tcf) consumed annually in the U.S.A.**

If LNG is to become profitable for companies involved in the production, transportation and development process, the price of natural gas must be at least \$3 per million BTU's. And with the recent price spike to as high as \$8 per MMBtu, some conglomerates are now wetting their lips. One of the central questions remains, however – whether the high demand for natural gas by electric generators will keep prices high and support an LNG market. If so, the world's LNG suppliers would find the U.S. market quite attractive.

“Changing U.S. natural gas fundamentals that point to higher normalized prices and declining LNG technology costs suggest the beginning of a favourable trend for potential LNG exporters,” says Peter Rigby, credit analyst with Standard & Poors in a new report. “If sponsors are willing to use their balance sheets by contributing more equity or liquidity support to mitigate commodity price risk, the rewards may be significant.”

US natural gas producers have long complained that mature wells and restrictive laws have increased the cost of production. With supplies stagnating and demand rising, price pressures are increasing. Higher prices and falling LNG liquefaction and transportation costs could be the catalyst to sustain a long-term LNG market in the U.S.



Greenfield projects in the Atlantic and Pacific basins that are interested in supplying the U.S. market are plentiful. In the Pacific basin, stranded gas reserves in Australia, Alaska, Indonesia, Malaysia and Peru could support new or expansion projects, says S&P. Similarly, in the Atlantic basin, Algeria, Egypt, Nigeria, Trinidad, Venezuela and West Africa could also support new projects dedicated to the United States, it says. Finally, in the Persian Gulf region, Oman and Qatar would like to find new markets for their abundant stranded gas reserves.

But the risks are high. The underlying dynamics that affect natural gas prices are a moving target and may add to the recurring price volatility. For projects with plenty of debt, it could cause credit risks similar to what the merchant generation sector has witnessed. And, the difficulty getting sites permitted could also contribute to that uncertainty. By financing projects internally, S&P says that stronger companies can withstand the price fluctuations.

Others, however, say that the risk can be managed through “hedging.” If you have a big generating infrastructure, you can buy LNG on a 25 year contract and manage the ups and downs through spot natural gas purchases,” says Jeff Egan, president of Aptech Engineering in San Jose, Calif.

The U.S. is already preparing for the possibility of greater LNG imports. The Federal Energy Regulatory Commission has given final approval to El Paso Corp. so that it could expand its Elba Island near Savannah, Georgia – a facility that had been mothballed since 1982 because of lack of demand. The \$145 million project will expand the plant by 80% to accept up to 7.3 bcf of gas per day. Storage capacity will also increase to 3.3 bcf when the expansion is completed by September 2005.



Other plants in Everett, Mass and in Lake Charles, La. operate now and will be at full capacity by 2010. Another facility in Cove Point, Md. is expected to begin functioning later this year (2003).

Belgian-owned Tractebel has received environmental permits to build a 90-mile pipeline from to Bahamas to Florida, from the Bahamas to Florida, as well as an LNG receiving terminal in the Grand Cayman Island in the Bahamas.

To get to the gas, a well must be drilled before it is liquefied, shipped and then stored in a LNG facility that also serves to “regasify” it. A typical liquefying plant costs about \$1 billion while the tankers that are use to transport it cost nearly \$200 million a piece. Meanwhile, the LNG terminal costs \$250-\$400 million.

Historically, Greenfield LNG projects have been highly leveraged. To secure debt financing, S&P says that developers must be creditworthy and able to obtain long-term contracts with other viable parties, or buyers of the LNG. Ultimately, the demand by end-users must substantiate the deal. Developers must put together a world class construction consortium that can bring projects to completion on time and on budget.

LNG sponsors have been able to meet those conditions and win financing over the past decade, says S&P. It points to Ras Laffan in Qatar, which raised \$1.2 billion in bonds from the U.S capital markets and has attained a BBB+ rating as well as Oman LNG, which got \$1.3 billion using a bank loan and is rated an A-.

High Risks

But a sustainable LNG market in the U.S. may be challenging mainly because prices have gyrated in recent years. Therefore, few U.S. buyers will be willing to sign long-term contracts that fix gas prices, says S&P. Without long term



guarantees, companies would have to sell on the spot market, which underscores the need for them to capitalize internally, says S&P.

“Moreover, lenders that have been recently burned in the U.S. merchant energy market may be reluctant to take commodity price risk, given uncertainty about the direction and magnitude of future gas price movements,” says S&P’s Rigby.

Still, the factors that figure into gas prices tend to push them up. Natural gas, of course, has been labeled the fuel of choice because it is clean burning. And, as such, 90% of all proposed electric generation plants are to be fueled using gas. As the economy rebounds and as general industry production improves over the next few years, newer plants will get built. The conclusion among many experts is that risk-takers will be lured by the prospect of higher gas prices.

Risks are further mitigated by the declining cost of LNG technology. Liquefaction, for example, used to cost \$500 per ton 1988 but it now cost \$200 per ton. Tanker costs, meanwhile, have dropped from \$250 million each to less than \$200 million. Competition among Asian shipbuilders could reduce that expensive further, perhaps to as low as \$150 million.

LNG has promise and will likely experience high growth in the coming years if natural gas prices remain high. But, ramping up production will take time and so it will remain a small portion of the USA’s overall energy portfolio for the foreseeable future.

LNG plans enhance engineering contracting services

Engineering firms are working hard to gain lucrative contracts from the liquefied natural gas (LNG) boom.

Companies reeling from cutbacks in infrastructural spending due to the worldwide economic slowdown are latching on to LNG regasification schemes as a source of much-needed work. The fact that a regasification terminal has not



been built in North America in the past 20 years partly levels the playing field in the race for work.

Around 80% of the world's LNG regasification facilities are in Japan and South Korea, with many of the facilities built by Japan's JGC and South Korea's Daewoo. US engineering firm Halliburton claims it is the leading company outside Asia with experience in building regasification terminals. It says it has been involved in 70% of all regasification terminals built outside Japan.

But US contractors Bechtel, Halliburton, and Fluor Corporation as well as France's Technip Coflexip, Spain's Técnicas Reunidas, and Italian firms Techint and Snamprogetti, have all been involved in the building of LNG liquefaction plants around the world.

The contractors claim their experience in handling LNG makes them well qualified to build the receiving terminals located in the USA. It claims to have a strong understanding of the fundamentals of building a regasification facility.

US energy firm Cheniere has tapped Bechtel to build its two proposed LNG terminals in Corpus Christi, Texas and Sabine Pass, Louisiana. Freeport LNG chose Technip to build its 1.5bn ft³/d (15.5bn m³/yr) terminal because of Technip's 45 years of experience in working with LNG.

US independent Marathon says it has decided to jointly award the contract to build its regasification plant in Baja California to Halliburton and Techint . Construction is scheduled to begin in the first quarter of next year, with start up in 2007.

Political Support

An increase in liquefied natural gas (LNG) import capacity is one of the few feasible ways of alleviating a tight US gas supply outlook, according to the



National Petroleum Council (NPC), which advises energy secretary Spencer Abraham.

An NPC report concluded in September, along with an earlier congressional testimony by US Federal Reserve chairman Alan Greenspan, has greatly enhanced the political support for building LNG terminals. Long term futures markets indicate that LNG's market penetration will increase because prices will be sustained above break-even levels for LNG investment, Greenspan says.

But some public opposition will still remain. That opposition and restrictive regulations **could limit LNG's growth to 14% of US gas supply – 12.5bn ft³/d (29bn m³/yr) – by 2025**, the NPC report says. The committee is recommending a regulatory framework in which LNG permit decisions are accelerated so they are made within a year of application. Speeding decisions on permit applications would be a major step towards boosting US LNG import capacity to 15bn ft³/d by 2025, it says. Some analysts expect that four or five new terminals will be built in the next 10 years.

Among the spate of new maritime and “anti-terrorism” laws enacted after 11 September 2001 attacks is one giving the US Coast Guard jurisdiction over imported terminal operations. It allows the Coast Guard to set firm deadlines for completing permit application reviews. The deadline setting authority is intended to shorten construction times for LNG terminals.

US energy regulator Ferc has also streamlined its approval process for LNG plant construction by dumping the “open access” rule that would have required a commission-approved cost-based rates schedule and an open access tariff for the new LNG terminal service. Ferc has removed a major obstacle to LNG investment by dropping this rule.

Despite the efforts by President Bush to accelerate the permitting process and provide other regulatory relief, these new maritime and “anti-terrorism” laws



contain provisions bolstering LNG ship and terminal security procedures that could add costs and slow operations. The measures include new procedures requiring the Coast Guard to assess the vulnerability of LNG terminals to attack. Terminal operators must devise inspections, patrols and attack-repelling plans with federal and local officials. Also, the Coast Guard must check the backgrounds of all LNG vessel crews.

Improved security and a regulatory revamp alone will not assuage public concerns that endanger the industry's development, the NPC says. The Bush administration must lead an "aggressive" education programme to show the need for LNG if the US is to avoid high prices in the long term.

The NPC report echoes Greenspan's testimony to Congress earlier this year that nothing could boost natural gas supplies as quickly as adding more LNG imports facilities. **Long term natural gas prices, fuelled by rising use in the power sector, will stay above \$4-5'000 ft³, Greenspan says, sufficient to spur new investment in LNG facilities.** Alan Greenspan's iconic stature gave his pronouncements strong support within Congress.

Alliances with the Arab World

Major oil firms have been looking for new upstream investment opportunities in the Arab world since the nationalization of the 'seventies – but the critical tightening of US natural gas supplies is shifting attention towards liquefied natural gas (LNG).

"The improved economic viability of LNG exports from the Mid Gulf to the USA and Europe will globalise gas markets that are currently regional," ExxonMobil chief executive Lee Raymond said at the US-Arab forum in Detroit in August. Gas is turning global, says US independent Marathon Oil's chief executive Clarence Cazalot, and Arab nations should make sure they participate.



Cazalot says the new market for LNG is sure to spawn a liquid spot market to replace the system of term agreements that characterizes current LNG deals. Even term LNG agreements will probably be based on a spot price such as the US Henry Hub benchmark, he said.

As the market develops, the huge gas reserves of the Arab world make the region potentially as important to the emerging LNG balance as it is to the balance in oil, US oil executives say.

Making new LNG markets work will go a long way to addressing the energy security concerns of western nations seeing yet another thread of dependence on Arab state-controlled energy production.

As in oil, huge new investments are needed. Cazalot sees US gas demand doubling by 2030, with domestic North American output unable to match the growth. Executives says they are taking to heart a National Petroleum Council study which found that LNG imports will be a significant part of the US natural gas mix within the next 15 years.

To prepare for this outcome, the executives say the US government should expedite permitting of LNG import terminals, while Arab governments should open themselves to more outside investment in upstream gas development and gasification of LNG export terminals.

17. NIGERIAN PRESIDENTIAL OIL ADVISOR LUKMAN RESIGNS

Nigeria's presidential oil advisor Rilwanu Lukman – essentially its oil minister – has resigned, throwing the country's oil industry into disarray. The departure came during a stand-off between unions and the government over downstream liberalization.



Lukman not say why he was leaving. But sources close to his office say he had been uncomfortable with developments in the industry for sometime. He was unhappy with last June's decision by the government to transfer responsibility for control and development of oil acreage from the oil ministry to stateowned NNPC, which "virtually left Mr. Lukman with nothing to do."

He was also not happy with recent alterations between NNPC and the state-funded Revenue Mobilisation Allocation and Fiscal Commission (RMAFC) over crude term contract allocations, and product trade. The commission alleges that Nigeria loses about 300bn naira/yr (\$2bn/yr) in revenues.

It is also reported that Lukman has clashed with NNPC group managing director Jackson Gaius-Obaseki. Sources close to the presidency claim that the president asked Lukman to resign.

Oil industry operators describe the departure as a "big blow" to the credibility of Nigeria's oil sector. Lukman had formerly served as oil minister and OPEC secretary-general.

The drama came during a stand-off between oil unions and the government over products pricing. The unions had threatened a nationwide general strike from 9 October in protest against abandoning of subsidies for petroleum products and an eventual deregulation of Nigeria's downstream sector.

After fuel marketers were given the go-ahead to raise fuel prices earlier this month, gasoline prices rose to as high as N50/litre compared with the previously fixed price of N34/l (27 cents/litre).

But Adams Oshiomhole, the president of the Nigeria Labour Congress – the country's umbrella union – says the strike was shelved following a climb down by marketers, who put prices back down to N34/l.



Lukman's departure may thwart Obasanjo's plan to liberalise petroleum product prices and privatize NNPC downstream assets, as well as make the sector's financial and procurement functions more transparent. NNPC opposes many of the measures and has attempted to block progress.

Lukman's role as special adviser for oil was somewhat ambiguous in the early days of Obasanjo's administration. However Lukman gained full ministerial status and executive responsibility in 2000. In the process Jackson Gaus Obaseki, is purported to have exploited Lukman's absences abroad, in order to consolidate his influence within Nigeria.

At OPEC, Lukman played a leading role as a consensus builder, and he was dubbed one of the group's "three wise men" for his role in the intense negotiations among ministers in the aftermath of the 1986 oil price collapse. Former OPEC colleagues have described Lukman as the best secretary general the organization ever had. He also was one of OPEC's most cerebral and diplomatic ministers.

Although Lukman was best known in Nigeria for his work in the oil sector, he was an aggressive advocate of developing Nigeria's vast natural gas reserves.

Meanwhile, Nigeria is selling its four state owned refineries in a demonstration of its resolve to deregulate the downstream oil industry. The sale signals the start of privatization of stateowned NNPC, as the refineries are among its subsidiaries.

The NNPC refineries previously paid a special piece of \$20/bl crude, not the current price of more than \$25/bl. It also allocated 450,000 b/d for its refineries – more than it could refine. It transferred excess crude to international trader Vitol for marketing through its Calson trading joint venture with NNPC. The government reduced NNPC's allocation to 300,000 b/d as part of its deregulation policy on 1st October.



As a result of the new system the price of gasoline at NNPC outlets will rise by 12.5% to about 30 cents per litre. The move should encourage downstream investment and the government expects companies operating in the country to show interest in the refineries.

18. CHINA'S OIL DEMAND INCREASE

China's economy is putting the devastating impact of serious acute respiratory syndrome (SARS) behind it and the country's surging oil demand is on track to provide as much as one-third of global oil demand growth this year. Chinese oil demand was up 8.3% - or 396,000 barrels per day - to 5.14 million b/d in the year through July, according to data from Oil Market Intelligence. If it were sustained at this rate, China would account for 36% of the 1.11 million b/d in global oil demand growth the International Energy Agency is currently predicting for 2003. As domestic crude production is flat, demand growth is being met by imports, which were up 30%, or 403,000 b/d to the end of July (see table). Crude production from a giant PetroChina-operated Daqing field was down 4% in the year through June at just over 1 million b/d and officials predict a decline to only 600,000 b/d by 2010. Daqing accounts for over 30% of China's total crude output.

The second half of this year is shaping up quite differently. The earlier increase in imports was tilted towards the first four months of the year due to heavy stocking ahead of Iraq war. While the war was in progress, Chinese product demand was down by as much as 10% in the wake of SARS. Through refinery throughput is now up nearly 9%, much of the imported crude is still in refiners' storage, potentially backing out fresh crude imports in the fourth quarter.

Seasonal patterns aside, transport and power generation fuels underpin the robust apparent demand. China's booming passenger car market is supporting a 10.4% increase in gasoline output to 1.07 million barrels per



day, while gas oil production is up 8.3% to 1.71 million b/d. A hike in petrochemical feedstock imports points to the increasing maturity of the economy. Throughput at China's two refiners – PetroChina and Sinopec – is running at around 4.64 million b/d, but the shutting of small, illegal topping units at oil fields means that the giants are struggling to meet fuel oil demand. Fuel oil imports averaged 418,000 b/d through July, accounting for 85% of total product imports, and were 60% up on a year ago. Though still modest, imports of naphtha and gas oil for petrochemical feedstocks have both more than doubled this year. Total naphtha demand is estimated at 300,000 b/d.

19. OPIC FINANCES RUSSIAN OIL

OPIC Executive Vice President and Chief operating Officer Ross J. Connelly signed an agreement in September with Russia's leading oil producer committing OPIC to \$130 million in financing for a project that will enable Russia to expand its oil export capacity in a cost effective manner.

Connelly and Vagit Alekperov, president of OAO Lukoil, signed the agreement at the U.S. Russia Commercial Energy Summit in St. Petersburg, sponsored by the U.S. Departments of Commerce and Energy and their Russian counterparts. U.S. Secretary of Commerce Donald Evans witnessed the signing.

The agreement was concluded on the eve of *Investing in Russia – Partnership for Growth*, an OPIC-sponsored conference in St. Petersburg intended to support U.S.- Russian trade and investment.

OPIC will provide the loan guaranty to HBK Fund LP, a Dallas-based limited partnership, for a loan the fund will make to an indirect subsidiary of Lukoil

The project consists of the construction and operation of a crude oil and petroleum products exports terminal on the western coast of Vysotsky Island on



the Gulf of Finland. OPIC financing will cover the first two phases of the project, including construction of rail links and upgrades, two tank farms and a marine jetty, as well as dredging in the Gulf of Finland to allow for the passage of crude and product tankers.

20. ECUADOR'S NEW PIPELINE HAS PROBLEMS

Completion of Ecuador's new privately run OCP crude oil pipeline this summer, has caused pipeline politics to flare between the foreign companies that developed the line and the government. Much to the dismay of the OCP partners – which include Encana, Occidental, Repson YPF, ENI, Perenco, Petrobras Energia, and engineering firm Techint – the government decided at the end of September not to use the new line as previously planned and will rely instead on the Sote pipeline to transport its crude production. The government decision shocked the OCP consortium, which was counting on regular government use of their line to help recover their \$1.4 billion investment. The Sote pipeline, which has capacity of 390,000 barrels per day, its transporting 155,000 b/d of crude with API gravity of 23.7^o or higher to feed the domestic refining system. – 45,000 b/d to the La Libertad refinery and 110,000 b/d to Esmeraldas – with another 150,000 b/d or so for export. The idea was that Petroecuador would direct its lower gravity crude to the OCP, but the volumes that the state-owned firm will direct that way are now in doubt, as is the scope for improvement in the quality of Ecuador's Oriente export stream. The OCP was built to deliver a new heavy crude variety called Napo – with gravity of 18.8^o-19.2^o API – from the Amazon jungle for likely export to the US Gulf Coast.

Facing criticism over opening Ecuador's key oil sector to foreign players and paying to transport national oil exports through a privately owned line, the government backed down on its initial plan to use the OCP. The government imposed a discounted fee of between \$1.51-\$1.71 per barrel to ship the 30,000 barrels per day originally contracted by Petroecuador. As a result, the 450,000 b/d OCP, expected to pump 250,000 b/d by end-2004, will have about



half of its capacity unfilled. The OCP line began a trial new line is reducing the amount of heavy crude going through the end of the year. While the new line is reducing the amount of heavy crude going through the Sote line, it is allowing Ecuador's production and exports to increase by about 100,000 b/d this autumn.

Even with the government decision to withhold supplies from the new OCP line, its Sote line will also remain at much less than full capacity. Because of the OCP pipeline, Ecuador's total production is on an upswing, but the rise is tempered by what is still seen as a poor investment climate by foreign oil companies. Petroecuador's output has been declining since 2000, and the new production from the heavier fields of foreign producers has been constrained by lack of pipeline capacity until now. Total average out for Ecuador for the first half of 2003 was 368,000 b/d, or 3% lower than the year ago period due to aging fields, lack of investment, and lack of pipeline capacity. Of that, Petroecuador produced an average of about 210,000 b/d. Thanks to the new production brought in from the heavier fields feeding the OCP pipeline, Ecuador's output could reach 500,000 b/d by the end of the year.

21. VENEZUELA REASSESES HEAVY OIL PROJECTS

Venezuela's government is making a radical reassessment of the value of the country's vast Orinoco heavy oil belt.

"In 10 years we want the Orinoco belt to be looked at as the world's largest light oil reserve," says deputy oil minister Luis Vierma. **The change of view has already consigned further development of the country's Orimulsion business to the margins and spurred Venezuela's push for OPEC to award quotas based on member states' oil reserves.**



The 1.7 trillion bl of extra-heavy crude and bitumen contained in the Orinoco heavy oil belt has long been recognized as a potentially huge resource by Venezuelan officials. But technical difficulties extracting the oil and lack of suitable markets for 8.5° API crude have prevented its development. Orimulsion, a patented fuel made from a blend of bitumen and water produced by state-owned oil company PDVSA, arose as a first attempt to develop the resource. The fuel is marketed as a substitute for coal for use in electricity plants, and has had some success penetrating markets in Europe, Canada and Asia. PDVSA currently produces some 5.5mn t/yr of Orimulsion, and construction of a second production plant with PetroChina is to begin in late 2004.

But Caracas is starting to see Orimulsion, which sells for around \$38/t, as a waste of resources and a loss of potential government revenues. Unless pricing can be improved, further expansions beyond PDVSA contractual obligations are unlikely.

The true potential of the heavy oil belt has only come to light through the success of Venezuela's heavy oil upgrading projects. Private companies bought billions of dollars in capital, as well as sophisticated horizontal drilling expertise and experience earned in Canada's oil sands, to Venezuela. The three projects that have been completed so far, in partnership with PDVSA's, produce 400,000 b/d of upgraded heavy crude oil, which is readily finding markets in the US Gulf coast. A fourth project is due to be completed in mid-2004, lifting Venezuelan synthetic crude production to 680,000 b/d. Venezuelan officials believe up to 275bn bl of Orinoco heavy crude can be commercially exploited with current technologies.

Government officials are ambivalent about the heavy oil projects. The upgraders have given Venezuela a vast new production basin, **but the fiscal incentives given to the private companies that lead the four projects mean Venezuela will earn only 1% royalties for the first nine years of each project's**



operations – rather than the 30% PDVSA pays the government on its conventional output.

The government is encouraging private companies to prepare new proposals to further develop the heavy oil belt, but it is also setting new conditions. Rates of recovery at the wellhead must be improved from 8-9% currently and new upgrading technologies, such as PDVSA's proprietary "HDH+" heavy oil hydrocracking process, must be tested. And fiscal incentives for heavy oil upgraders will be minimized as the success of the first four projects has demonstrated the viability of Venezuela's synthetic oil business.

22. WIND TURBINES GET LARGER

(adapted from The Scotsman, 19th September 2003)

Supporters say it provides an infinite source of clean, cheap and sustainable energy and can save us from the chaos of projected climate change and global warming. Critics argue that its turbines scar the landscape and claim that over dependence on the vagaries of wind power will return us to the three-day week and cold meals by candle-light of the 1970s.

The fog of such simplistic arguments can obscure the fact that wind is the world's fastest-growing energy source, and a technology that has progressed more quickly than any other energy-generating method in the 25 years since its arrival.

In Denmark, wind farms are a ubiquitous feature of any journey through the countryside. It has recently completed and is now producing power from the world's biggest offshore wind farm - Horns Reef. Sited 16 kilometres off the south-west coast of the country, its 80 turbines cover 20 square kilometres, and it provides a perfect model to indicate the direction of Scotland's future renewable



energy projects - if ambitious Westminster government and Scottish Executive targets are to be met.

Unlike the Danes, whose public opposition to nuclear power plants forced them to meet their country's energy needs through alternative generating sources, UK investment in such technology is still in its infancy. But, according to the leading manufacturers of the turbine generators that convert wind energy into electricity, this leaves the UK in a unique position.

The units at Horns Reef, built by Vestas, the world's leading manufacturer of wind turbines, each have a two megawatt (MW) generating capacity, with a total combined output of 160MW. This is far in excess of the majority of the country's turbines which have been erected over the past 20 years. When the Danes first began to put up turbines, they were not a tried and tested method of generating energy and, compared with today's units, often woefully inefficient.

Consequently, although Denmark generates 18% of its electricity from wind - the largest percentage of the complete electricity generation of any country in the world - a large proportion of the turbines have a minuscule generating capacity compared to the turbines now being designed and tested at cutting-edge projects like Horns Reef.

Anders Stouge, of the confederation of Danish Industries, said: "The UK is fortunate in coming late into investing in this technology in that it can avoid a huge number of small turbines. In the northern areas of Denmark we have literally hundreds of these which rotate very fast and are also noisy. This certainly impacts on the aesthetic of the area.

"Today, you can have just a few turbines rotating at a much slower speed, and these don't irritate the eye in the same way and are relatively silent. This will be a huge issue in getting public backing for wind energy in the UK."



Although old turbines built in the early years of the industry are still contributing power to the grid, many are now being ripped up and replaced. Just one of the multi-MW models can now generate the same amount of energy as eight of the earlier models.

This is good news for Scotland, which has the best wind resources in western Europe. Developers hope it can provide both the Westminster target of producing 10 per cent of electricity from renewable sources by 2010, and also the Scottish Executive target of 40 per cent by 2020.

Currently, 82 wind farms, ranging in size from one to 46 turbines, are built and running throughout the UK. Collectively, those farms account for 1,030 turbines dotted around the country, which together produce a total annual power output of 587.6MW - capable of meeting the electricity needs of 386,000 homes. A simple calculation reveals that on average, each turbine produces just over 500 kilowatts of electricity, or 0.5MW.

Although several hundred of these turbines, which contribute to the UK grid, produce as little as 300 kilowatts, developers have more recently started to use the multi-megawatt machines which will quell the anger of those who claim that wind farms are ruining the countryside.

This could be a crucial factor in winning the battle to get the public on-side for wind energy projects.

NEG Micon, the world's second largest wind-turbine manufacturer, is about to test its latest prototype turbine in Denmark. Standing 100 metres high with a blade diameter of 110 metres, the machine is capable of producing 4.2MW annually. Primarily intended for offshore wind farms, it demonstrates the rapid technological advances in the period since Horns Reef came on line at the beginning of this year.



Emma Collins, the managing director of NEG Micon's UK operations, said: "At the moment, in the drive to get the cost down, 4.2 MW is by no means the limit of capacity for future turbines. We are already looking at developing the next generation of turbines beyond this model."

These larger, more powerful machines, and the more efficient models of up to 8MW which industry sources say will be developed in the ensuing years, will play a crucial role if Britain's energy supply is to be transformed in line with the renewable targets.

The cost of producing a unit of saleable electricity on shore is currently about 3.5 pence, making it economically competitive with conventional electricity-generating methods, such as oil, coal, gas and nuclear.

It is when developers make that jump to offshore that problems occur due to increased installation, service and maintenance costs, and the unit price rises to approximately five pence. This is why the research and development side of wind energy is so important, as every year, through new technologies, companies aim to reduce generating costs by 10 per cent.

A move to offshore plans, and the rash of current proposals by firms keen to cash in on the boom which renewables targets have created (campaigners against wind farms claim there are just short of 200 being considered in Scotland alone) was signaled by the government in July. Patricia Hewitt, the Secretary of State for Trade and Industry, highlighted vast areas of the sea - off Essex, Norfolk and north-west England, and in the shallow waters of the Moray and Solway Firths - for potential offshore projects.

A planning application to the Scottish Executive is already at an advanced stage



for a 60-turbine farm on the Robin Rigg sandbank in the Solway Firth, with a generating capacity of about 180MW.

Both Vestas and NEG Micon have manufacturing facilities in Scotland, leaving the country well-placed to capitalise on the predicted offshore wind farm boom.

Egon Poulson, of Vestas, in Denmark, said: "Britain has a unique opportunity to invest in offshore wind energy. Conventional power sources that have been used for years will inevitably rise in price as they become more scarce, but power from wind turbines will go down as they become more and more efficient. Presently, wind is without doubt the future of power generation."

Maff Smith, the development manager for Scottish Renewables, which represents the growing domestic wind farm industry, said: "Some projects in Scotland are waiting until the larger size turbines come on line. By the time the Beatrice development in the Moray Firth, is ready for construction in about 2007 they are likely to use five MW turbines. The industry is continuing to develop and moving ahead very well, and what is important is that we are seeing the jobs coming through. While Denmark made a lot of the early gains in wind technology, it is extremely encouraging to see Scotland now taking some of the jobs. The on-going development of wind energy here is going to stimulate foreign manufacturing suppliers to continue setting up Scottish bases."

23. MORE REFINERIES TO BE SOLD

A number of refineries could come up for sale over the next year as major oil companies continue to shift their focus away from downstream. US independent refiners are waiting to benefit.



Premcor president Hank Kuchta told a conference in Connecticut in late September that he expects US majors to begin another wave of refinery sales next year. ConocoPhillips is understood to be selling up to \$4bn of assets. Premcor currently owns three refineries, and is interested in buying more in the eastern two-thirds of the US.

Premcor staff, mostly former Tosco and ConocoPhillips executives, are very familiar with ConocoPhillips' plants especially the Bayway refinery near New York, once Tosco's top carrier. Premcor is looking for plants of at least 100,000 b/d that are in or can readily serve US markets and that have "reasonable complexity."

Any purchase must also immediately add to Premcor's profits. Premcor last year closed an Illinois refinery because it was too small to make the upgrading and environmental improvements economical. And with stricter emissions and fuel quality standards coming into force, Kuchta expects more plants to close.

Meanwhile, Sunoco is trying to complete its first refinery purchase in nearly a decade, and says it will consider a plant outside its core region of the northeast. Sunoco processes primarily imported light sweet crude for its refineries.

Valero has made clear that it is considering buying El Paso's 280,000 b/d Aruba refinery and has been the most active acquirer of recent years, both of plants and rival refining companies.

Frontier, whose proposed merger with fellow Rockies refiner Holly collapsed earlier this year, will benefit from higher runs of heavy crudes, especially from Canada, which has growing supply and a limited outlet for its blends.

Several refineries are on the block that have been announced, and several that have not been disclosed. The number of plants sold or put up for sale has slowed since earlier in the year. Western Refining bought the half of the 106,000b/d El Paso, Texas refinery it did not already own from ChevronTexaco. Sunoco in April



agreed to buy Orion's 185,000 b/d Louisiana refinery for \$400mn and in March completed its purchase of El Paso's 98, 000 b/d Corpus Christi, Texas Plant.





24. CARIBBEAN ENERGY UPDATE

– with particular emphasis on refining capacity

(adapted from Alexander's Gas and Oil Connections, Oil and gas Journal, and other sources)

The Caribbean region plays an important role as a petroleum processing and transshipment area, with several major refineries and independent storage facilities.

Furthermore, Trinidad and Tobago is becoming an increasingly significant supplier (and potential supplier) of LNG to Europe the United States, and Caribbean markets.

The islands of the Caribbean basin, with a total population of approximately 37 mm in 2002, are predominantly net energy importers, with the exception of oil and gas rich Trinidad and Tobago. Agriculture and natural resource extraction activities continue to constitute the basis of the islands' economies, though tourism and service sectors are growing.

In the larger economies, manufacturing is also important, such as oil and natural gas production in Trinidad; pharmaceuticals and cement in Puerto Rico; and textiles in the Dominican Republic and Jamaica. Economic growth, however, varies across the region. While many of the islands' economies contracted in 2002, Trinidad and Tobago and the Dominican Republic's economies continued to grow, with real gross domestic product (GDP) growth rates of 2.6 % and 4.1 %, respectively.

Over the past decade, Caribbean states have made efforts to integrate their economies. The major regional organization is the Caribbean Community and Common Market (CARICOM), whose members include the South American states of Guyana and Suriname and the Central American State of Belize, and the Caribbean islands of Antigua and Barbuda, The Bahamas, Barbados, Dominica, Grenada, Haiti, Jamaica, Montserrat, St Kitts and Nevis, St Lucia, St



Vincent and the Grenadines and Trinidad and Tobago.

All other islands, with the exception of Cuba, have either associate or observer status. The Caribbean Community has three objectives:

- a) **economic cooperation through the Caribbean Single Market Economy;**
- b) **coordination of foreign policy among the independent Member States; and**
- c) **common services and cooperation in functional matters such as health, education and culture, communications, and industrial relations.**

CARICOM countries have steadily reduced tariffs among members. Besides CARICOM, the other main organizations of the region include the Association of Caribbean States, the Eastern Caribbean Currency Union and the associated Eastern Caribbean Central Bank.

Oil and natural gas

In 2001, the islands of the Caribbean region consumed a combined total of 2.2 quadrillion Btu of energy. Oil is the dominant fuel, accounting for about 92 % of total 2001 energy consumption. The Caribbean relies on imported oil for most of its energy needs. Barbados, the Dominican Republic, Haiti, and Jamaica are party to the San Jose Accord, under which Mexico and Venezuela supply crude oil and refined products under favourable terms. Venezuela also has an additional favourable supply agreement which is presently accessed by Cuba, Jamaica, and until September, the Dominican Republic.

Natural gas and hydropower are used in countries that have these domestic resources. Natural gas is used most extensively in Trinidad and Tobago, where natural gas-intensive industries, such as steel, fertilizer, and petrochemicals are



important to the country's economy. Puerto Rico and the Dominican Republic import LNG from Trinidad and Tobago for power generation.

Only three Caribbean countries have oil and natural gas reserves: Barbados, Cuba, and Trinidad and Tobago. Of these, Trinidad and Tobago is the only exporter.

Trinidad and Tobago

Trinidad and Tobago is the Caribbean's largest producer of oil and gas. In 2002, oil production averaged about 141,500 bpd, of which 121,833 bpd was crude oil. Crude oil reserves, at an estimated 716 mm barrels, are expected to last approximately only another decade unless new reserves are found. **BP is the nation's largest oil and gas producer. Petrotrin, the state oil company, is the second largest oil producer.**

In contrast, the country's natural gas reserves are expected to increase significantly in coming years. Proven natural gas reserves currently stand at 23.5 tcf. In 2002, the country produced 596 bn cf of natural gas.

Trinidad and Tobago has become one of the major natural gas development centres in the world. Natural gas is expected to surpass oil as the main revenue earner for the country in the second half of this decade. About 36 % of its natural gas was exported in 2002 as LNG, while the rest was used domestically, particularly for ammonia and methane manufacturing.

Trinidad now has nine ammonia complexes, six methanol units, a urea plant, and an iron and steel complex. By the second quarter of 2004, the largest methanol plant in the world, Atlas, is expected to be completed. Atlas will be surpassed by an even bigger methanol project, M5000 facility, which is due to enter production in 2004. Trinidad is the world's leading exporter of both ammonia and methanol.



Exploration and production

Both natural gas and oil exploration activities in Trinidad and Tobago have continued at a fast pace over the last three years. During 2000-2001, British Petroleum Trinidad (BPTT) alone added more than 6 tcf to its own reserves. EOG Resources (US) announced in May 2002 a new discovery in its SECC block, located off Trinidad's eastern shore.

The new discovery is expected to add 250-350 bn cf of natural gas to the field's existing reserves. Repsol-YPF and BPTT discovered in September 2002 nearly 1 tcf in the Iron Horse field, located east of Trinidad and Tobago.

Recent developments

The Trinidad and Tobago government granted approval in March 2003 to BHP Billiton, TotalFinaElf, and Talisman Energy to proceed with the \$ 726 mm first phase development of the Greater Angostura project, located off the north-eastern coast of Trinidad. The companies will be developing Block 2(C). Billiton estimates that the block contains up to 160 mm barrels of oil and 1.75 tcf of natural gas. It is expected that this field could produce 75,000 to 100,000 bpd, significantly increasing the country's crude oil production.

In April 2002, BG International, Billiton, Talisman, and TotalFinaElf signed a production sharing contract (PSC) with the government for the adjacent Block 3(a). The group plans to drill two wells in the Block towards in late 2003/early 2004.

Deepwater exploration

In 1998, Shell, BP, Arco and ExxonMobil received licences to drill off the eastern coast of Trinidad in water depths ranging from 2,460 to 4,921 feet. The four deepwater Blocks -- 25(a), 25(b), 26 and 27 -- have yet to produce oil after drilling seven wells. In March 2003, Shell returned Block 25(a) to the Trinidad government, after the well proved to be non-commercial.



The Trinidad & Tobago government is not giving up hope of finding commercial deposits of oil. In June 2002, the government, in conjunction with 12 foreign firms, undertook a new seismic study of previously unexplored regions with depths ranging from 5,576 to 9,480 feet.

New licensing round

Trinidad and Tobago launched a nine-block licensing round, in the summer of 2003.

The first two Blocks, 23(a) and 24(b), are in ultra-deep water. They are located near the area where the government recently conducted a seismic study (mentioned above). Blocks 2(ab), 3(b) and 4(a) are located in shallow waters to the east of Trinidad. Blocks 1(a) and 1(b) are west of Trinidad in the Gulf of Paria. The finally two Blocks, 22 and 24, also located near 23(a) and 24(b), but are not as deep.

Trinidad and Tobago has been in negotiations with Venezuela to develop and possibly combine the two countries' gas reserves in the Deltana region, located of the Paria Peninsula. These negotiations, however, have been placed on hold because of difference between the parties concerned.

Natural Pipelines

The Trinidad and Tobago government plans to build an undersea natural gas pipeline throughout much of the eastern Caribbean states. The proposed 600-mile pipeline would run north from Trinidad, connecting to other islands en route to the French island of Guadeloupe.

The pipeline would serve the islands Martinique, Guadeloupe, Barbados, Grenada, St Vincent, Grenadines, St Lucia and Dominica. There has also been discussion of possibly extending the pipeline to Florida.



LNG

Trinidad and Tobago is presently the largest LNG exporter to the United States. The Atlantic LNG Company of Trinidad and Tobago currently operates three LNG trains on Trinidad. The Atlantic plant is considered the largest single-train plant ever built, and the first LNG producer in the Latin America and Caribbean region.

The plant recently underwent a \$ 1 bn expansion to triple its capacity from 3 mm to 9 mm tpy by adding a second and third train. Train 2 began operation in August 2002, while Train 3 came on line in April 2003. About 62.5 % of the total output of Trains 2/3 is committed to the Spanish market. The remaining 37.5 % is sold in the US market, mainly in the southeast, through the Elba Island Terminal and to Lake Charles. The Dominican Republic also imports LNG from Trinidad.

BP is building one of the world's largest offshore gas processing units, the Kapok platform, as part of a \$ 600 mm project to supply gas to these additional trains. BPTT is also constructing a 30-mile long pipeline, the "Bombax". The pipeline will feed natural gas from Kapok to Atlantic LNG's Trains 2 and 3, and to the Atlas Methanol plant. The pipeline will be one of the world's largest, with a transport capacity 2 bn cfpd.

Partners of Train 1 are BP, BG, Repsol, Tractebel, and National Gas Company of Trinidad and Tobago (NGC). Partners of Train 2 and 3 are BP, BG and Repsol.

Negotiations for the construction of a fourth train, which, according to design plans, would raise Trinidad and Tobago's LNG production capacity to 13.8 mm tpy, are ongoing. The construction of the fourth train should come online at the end of 2005 or early 2006. The government has also indicated that it would be interested in constructing a fifth and sixth train.



Trinidad Refinery seeks \$1bn upgrade

Trinidad and Tobago's state owned energy company Petrotrin says its refinery needs a \$1bn upgrade if it is to remain competitive. Petrotrin is searching for potential joint-venture partners who would be able to help fund the upgrade and open new markets for oil product exports. Petrotrin has opted to upgrade the 90 year old refinery to reduce fuel oil production rather than construct a new facility, which would have cost more than \$3bn. The 160,000 b/d Point a Pierre refinery has seen its financial performance improve since a previous \$360mn upgrade in 1997 improved its product slate. However, the Petrotrin management is struggling to maintain the plant's profitability amid tight refining margins and high labour costs.

The proposed US\$1 billion upgrade of Petrotrin's refinery at Point-a-Pierre is not about increasing the throughput capacity of the plant but essentially the conversion of fuel oil into higher value products for local and foreign markets.

But even in the midst of a second upgrade Petrotrin has not fully repaid the loan for the first upgrade which was completed just six years ago.

The 90-year-old refinery was upgraded between 1991 to 1997 at a cost of US\$360 million to improve product quality by reducing the sulphur content and increasing octane. That upgrade increased the refining from 100,000 to 160,000 barrels per day throughput, and also upgraded the infrastructure, instrumentation and environmental systems of the refinery.

At one time Trinidad had three oil refineries—at Pointe-a-Pierre, Point Fortin, and Brighton. Brighton shut down in 1978 and the one at Point Fortin closed in 1995.

At the lone refinery at Pointe a Pierre, there are eight products currently being manufactured: low propane gas, aviation fuel, motor gasoline, kerosene, gas oil, fuel oil, bitumen and sulphur. The Trinidad market consumes 20,000 barrels a



day of the fuel that is refined. Fifty thousand barrels are exported to the Eastern Caribbean, Guyana and French Guyana, another 50,000 barrel go to the Northern Caribbean and Central and South America while the United States imports 50,000.

Of the total throughput figure, 65,000 barrels per day comes from locally produced crude and 95,000 imported from Brazil, Venezuela, Colombia, and West Africa.

Petrotrin's decision to upgrade the refinery was examined alongside the possibility of building a new refinery at a cost of some US \$ 3-5 billion. The three options were to discontinue refining operations, construct a new refinery or upgrade the present one.

Cuba

Cuban oil production has more than doubled since 1991. In 2002, Cuban oil production averaged 49,300 bpd while oil consumption averaged 157,000 bpd. Most domestic crude oil production consists of a heavy, sulphur-laden oil, which is converted into usable fuel. Refineries process imported crude oil, mainly from Venezuela and Mexico.

Cuba has a financial arrangement with Venezuela, allowing for the sale of oil under preferential conditions. Cuba imports 53,000 bpd of crude oil and refined products from Venezuela, representing approximately a third of the island's oil demand. The contract, which was signed in October 2000, is set to expire in 2005. Natural gas production has also increased significantly in Cuba since the early 1990s. As of January 2003, proven natural gas reserves stood at 2.5 tcf.

Exploration and production

The Cuban government plans has set a goal to generate all of its electricity demand from domestic crude oil resources, making the island self-sufficient in energy. Increases in oil and natural gas production already fulfill more than 50 %



of domestic energy demand, according to the Cuban government. The government has forecasted that the combined oil and natural gas production will increase by 17 % in 2003.

Cuba's territorial waters in the Gulf of Mexico are expected to hold the most promising oil prospects. In early 2000, Cuba offered 59 offshore blocks in its deepwater economic exclusive zone (EEZ) for oil exploration by international oil companies. The Cuban government has awarded Repsol-YPF (Spain) and Sherrit International (Canada) blocks in the EEZ. The United States maintains an economic embargo against Cuba, and oil companies from other countries may be subject to US sanctions under the Helms-Burton Act of 1996 if they conduct significant transactions in Cuba.

New developments

Sherrit International announced in March 2003 that it plans to invest \$ 110 mm in its oil and gas operations in Cuba. Petrobras of Brazil expressed interest in restarting oil exploration in Cuba after the Cuban government offered Petrobras a deep-water exploration block in Gulf of Mexico.

In 2001, Petrobras abandoned exploration efforts in Cuba following disappointing results. Pebercan (Canada) doubled crude oil production at its Block 7 joint-venture (Sherrit) in 2002. Pebercan expects to increase its production as it brings more wells online.

Barbados

Oil production for 2002 totalled 1,200 bpd. Oil production has declined slightly since 2001 despite efforts of Barbados National Oil Company (BNOC) to expand oil production. BNOC contracts with a consortium led by Triassic.

As Barbados has no refining capacity, its oil is refined in Trinidad, and then returned for domestic consumption.



Other regional developments

Jamaica announced in the summer of 2003 that it plans to restart exploration efforts off its southern coast.

In the Bahamas, US companies AES Ocean LNG and El Paso and Belgium's Tractebel have plans to build regasification terminals, from where it would be piped to Florida. This will start with an analysis of previous exploration data over the period 1956-1986.

If approved, **AES** would construct a **regasification terminal at Ocean Cay in the Bahamas, along with a 54.3-mile pipeline to Florida**. The pipeline would have a capacity of 842 mm cfpd. AES has already received provisional permission from both the US Federal Energy Regulatory Commission (FERC) and the Bahamian government. Environmental impact assessments will determine whether the project will be able to proceed.

Tractebel, which also received approval from FERC but is still awaiting approval from Bahamian authorities, **would build a LNG regasification terminal in Freeport, on Grand Bahama Island, as well as a 54-mile pipeline (Calypso), with a capacity of 832 mm cfpd.**

El Paso has already received provisional approval from the Bahamian government but not yet from FERC. El Paso also plans to build its terminal on Grand Bahama Island. The pipeline (Seafarer) would have a capacity of 1 bn cfpd. The Bahamian government indicated, however, that it would only accept two of the three proposed projects.

In November 2002, the Bahamian government granted the oil company Kerr McGee a licence to drill oil in Bahamian waters.

Refining



Crude oil refining capacity in the Caribbean exceeds 1.7 mm bpd. Smaller refineries are geared towards meeting local demand, while the larger refineries in Aruba, the Netherlands Antilles, Trinidad and Tobago, and the US Virgin Islands serve both local and export markets.

The Hovensa refinery of St Croix, owned by Hess and the Venezuelan state oil company, PDVSA, is among the largest in the Western Hemisphere. PDVSA also operates the Curacao Isla refinery, which the company is in the process of expanding. PDVSA is investigating the possibility of building two new refineries in the Dominican Republic, as well as reactivating the Cienfuegos refinery in Cuba.

In August 2002, the Trinidad and Tobago government granted Soreco approval for the construction of a 224,000-bpd refinery. The refinery, the Sabaneta Refinery Project, was expected to be completed in 2005. However, it remains unclear whether the project will move forward due to difficulties of securing \$ 2 bn in loans for the project.

US energy company El Paso plans to sell its 280,000 b/d refinery on Aruba, Coastal Aruba Refining Company, in 2003/4. Both Valers and PDVSA have expressed interest.

Colombia

Crude Refining Capacity: 285,850 bbl/d

Refineries: 285,850 bbl/d, all run by state owned Ecopetrol. Two main refineries, Barrancabermeja - Santander (205,000 bbl/d) and Cartagena - Bolivar (75,000 bbl/d). Other refineries: Tibu - N. de Santander (1,800 bbl/d), Orito - Putumayo (1,800 bbl/d), and Apiay (2,250 bbl/d).

Refining

Colombia's current refining capacity is about 285,850 bbl/d, and all refineries are 100% owned and operated by Ecopetrol. Although Colombia is a net oil exporter, it imports gasoline to meet domestic product demand. **The government has**



stated that it will not construct new refineries, and any new construction must be undertaken by the private sector. In October 2000, Ecopetrol selected Shell Global Solutions, an affiliate of Royal Dutch/Shell, to provide technical assistance in a \$22-million program to modernize Colombia's two largest refineries, Cartagena and Barrancabermeja. The modernization program is intended to raise Cartagena's and Barrancabermeja's total gasoline production by 26% to 350,000 bbl/d in anticipation of domestic demand growth and plans for significant exports.

In August 2000, Ecopetrol designed a short-term plan to import heavy oil from neighbors Venezuela and Ecuador, in order to produce lower cost derivatives, such as diesel, solvents and jet fuel at its Cartagena refinery. This would allow the company to export more of its light, sweet crude

Costa Rica

Crude Refining Capacity: 25,000 bbl/d. The refinery has large available land space and is in need of upgrading.

Ecuador

Crude oil Refining Capacity: 176,000 bbl/d

Guatemala

Guatemala's current refining capacity stands at 20,000 bbl/d. The country aims to encourage private investment in refinery construction to augment its total refinery capacity, in anticipation of future increased crude production.

Mexico

Total Refinery Capacity: 1,525,000 bbl/d.



Major Refineries : Salina Cruz (330,000 bbl/d), Tula Hidalgo (320,000 bbl/d), Salamanca (245,000 bbl/d), Cadereyta (235,000 bbl/d), Minatitlan (200,000 bbl/d), Ciudad Madero (195,000 bbl/d), total of 1,525,000 bbl/d.

Mexico's downstream oil sector was nationalized in the 1950s, and privatization is not planned. Although Mexico is one of the world's largest oil producers, about a quarter of gasoline consumption is imported due to insufficient refinery capacity. The country has six refineries, with a total throughput capacity of 1.5 million bbl/d. Major upgrades on the refineries begun in 1998 aim to: increase the percentage of gasoline and light products; allow refineries to process heavier crudes, such as Mexican Maya; meet clean fuel specification; and increase overall refining capacity by 690,000 bbl/d. Work is underway at four refineries, while contracts for work at the two remaining refineries remain in the bidding process. All work is expected to be completed by early 2005.

Panama

Crude Refining Capacity: 60,000 bbl/d

Peru

Crude Oil Refining Capacity: 182,250 bbl/d

Refineries: La Pampilla Lima (100,000 bbl/d); Talara (62,000 bbl/d); Iquitos Loreto (10,500 bbl/d); Conchan (6,500 bbl/d); Pucallpa (3,250 bbl/d)

Peru has five main active refineries. The largest, La Pampilla, with a capacity of 100,000 bbl/d, underwent a 60% privatization in 1996 and is now controlled by Repsol-YPF and others. It handles over half the total production of refined products. Petroperu owns the other major refineries: the 62,000 bbl/d-capacity (about 35% of total production) Talara refinery, located in the region of Piura on Peru's northwest coast, as well as the Iquitos Loreto (10,500 bbl/d) refinery in the



northeast, the Conchan refinery (6,500 bbl/d), and the Pucallpa refinery (3,250 bbl/d). The state-owned refineries had been slated to be privatized from the late 1990s. Despite considerable interest from international companies, privatization of the refineries has been put on hold indefinitely.

Regional Crude Oil Refining Capacity (January 1, 2001)		
	Company/Location	Capacity (barrels/day)
Aruba (NETH)	Coastal Aruba Refining Co./San Nicolas	225,000
Cuba	Cienfuegos	76,000
	Ermonos Dias/Santiago	101,500
	Niko Lopes/Habana	121,800
	Serhio Soto/Cabaiguan	2,100
	Subtotal, Cuba	301,400
Dominican Republic	Falconbridge Dominicana/Bonao	16,000
	Refineria Dominicana de Petroleo/Haina	33,250
	Subtotal, Dominican Republic	49,250
Jamaica	Petrojam/Kingston	34,200
Martinique (FR)	Societe Anonyme de la Raffinerie des Antilles/Fort-de-France	16,090
Netherlands Antilles (NETH)	Refineria Isla Curazao/Emmastad	320,000
Puerto Rico (US)	Caribbean Petroleum Corp./Bayamon	49,000
Surinam	Staatolie	7,500
Trinidad & Tobago	Petroleum Co. of Trinidad & Tobago/Pointe-a-Pierre	160,000
U.S. Virgin Islands	Hovensa/St. Croix	525,000
TOTAL	14 Plants	1,687,240



Venezuela

In addition to the Jose industrial complex, which is not, strictly speaking, a petroleum refinery, PDVSA operates one of the Western Hemisphere's largest refining systems and is one of the world's largest oil refiners. Domestic refinery capacity presently stands at about 1.3 million b/d, with significant additional holdings in Curacao, the United States, and Europe (Germany, Sweden, Belgium, and the United Kingdom). In the United States, PDVSA owns 100% of the 320,000 b/d Lake Charles, Louisiana, the 167,000 b/d Lemont, Illinois, the 150,000 b/d Corpus Christi, Texas, the 84,000 b/d Paulsboro, New Jersey, and the 28,000 b/d Savannah, Georgia refineries, plus 41% of the 265,000 b/d Houston, Texas refinery and 50% of the 184,000 b/d Chalmette, Louisiana refinery. The Refinería Isla facility in Curacao is 100% leased by PDVSA, and because of its closeness to mainland Venezuela, it is, in effect, part of its domestic-sited refining capacity. The Refinería Isla facility has a crude oil capacity of 335,000 b/d, which would rank it second-largest of the refineries if it were instead located in Venezuela.

The largest refining complex in Venezuela itself, and one of the largest in the world, is located on the Península de Paraguaná in northwest Venezuela, near the city of Punta Fijo. PDVSA has integrated the Amuay and Cardón refineries there to create the Paraguaná refining centre, which has a total crude oil refining capacity of 940,000 b/d. This represents nearly 75% of Venezuela's total refining capacity. In 1997, a joint venture between BOC Gases and Foster Wheeler brought online a \$50 million, 50 million cubic feet per day hydrogen production facility (the largest in South America) next to the Amuay refinery which allowed that refinery to produce higher-value and higher-quality refined products.



At the other extreme, Venezuela's smallest refinery, San Roque, is of strategic importance as it is the country's sole production facility for paraffin, with daily rates of about 75-80 metric tons. In 2000, a modernization was completed to the control systems for this refinery that allowed an increase in annual paraffin production of about 2,250 metric tons, worth about \$1.2 million annually.

Besides San Roque, PDVSA is also working to upgrade its other refineries. In 2002, a contract was awarded to a joint venture led by Japan's Toyo to upgrade and expand the El Palito Refinery; planning is also underway to upgrade the Puerto La Cruz refinery.

A summary of Diva's Venezuela-sited petroleum refineries is shown on the table below:

PDVSA'S Venezuela-sited Petroleum Refineries

Refinery	Location		Crude Oil Capacity (thousand b/d)
	City	Estado	
Amuay	Amuay	Falcón	635
Cardón	Punto Fijo	Falcón	305
Puerto La Cruz	Puerto La Cruz	Anzoátegui	203
El Palito	Puerto Cabello	Carabobo	130
Bajo Grande	Maracaibo	Zulia	16
San Roque	Santa Ana	Anzoátegui	5



Total	1,294
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Source: PDVSA

Storage

The Caribbean region has a number of independent petroleum storage facilities, with the capacity to store approximately 100 mm barrels of crude oil and petroleum products. In addition to long-term storage arrangements, these facilities offer logistical options for petroleum shipments.

Islands with storage facilities include: Bahamas, Trinidad, Puerto Rico, Saint Lucia, Aruba, and St Eustatius, Curacao, and Bonaire of the Netherlands Antilles.

Exports to the United States

In 2002, the continental United States imported about 390,000 bpd of petroleum from the Caribbean, of which about 83 % were petroleum products. The US Virgin Islands was the largest single regional exporter to the United States (about 236,000 bpd of petroleum products), followed by The Netherlands Antilles (about 74,000 bpd of petroleum products), and Trinidad and Tobago (80,000 bpd of total crude and petroleum products). Trinidad and Tobago is the only exporter of crude oil (68,000 bpd) from the region.

Electricity

Installed electric generating capacity in the Caribbean exceeds 17 GW. In general, the region needs additional capacity. Several countries (including the Dominican Republic, Haiti, and Cuba) experience power outages on a regular basis. Electricity demand in the region is expected to grow substantially in the coming decade.

The Dominican Republic

Dominican Republic has been plagued by electricity blackouts for many years. In 1999, the former President Leonel Fernandez privatized parts of the state-owned



Dominican Electricity Corporation (CDE) in the hope of eliminating the country's power outage problems. However, privatisation has yet to assure a steady supply of electricity to the population.

A dispute between the Dominican government and the private companies which acquired parts of CDE in 1999 reportedly is partly responsible for the blackouts. When CDE was split up, Union Fenosa (Edenorte and Edesur subsidiaries) and AES (Edeeste subsidiary) bought into the distribution network. In September 2002, the government and customers began falling behind on their payments, leaving the private companies without enough money to pay generators.

The distributors periodically stopped supplying electricity, resulting in blackouts. Although current President Hipolito Mejia renegotiated contracts between the government and private power companies in an effort to solve the country's power supply problems in September 2002, the situation has not improved.

Despite the need for further structural reform, foreign firms continue to invest in the Dominican Republic's power infrastructure. AES Andres, a subsidiary of AES, has invested \$ 400 mm to construct an LNG import terminal, a regasification facility, a pipeline and a 300-MW combined cycle power plant, located outside of Santo Domingo.

The LNG terminal received its first shipment in February 2003. However, since the 300-MW power plant will not be completed until summer 2003, the imported natural gas has been going to the Los Mina power plant in Santo Domingo, which AES converted from fuel oil to natural gas. In April 2003, Canada signed two \$ 35 mm agreements with the Dominican government to build hydroelectric and renewable energy projects.

Jamaica

In April 2001, the US-based utility Mirant, acquired 80 % of the formerly government-owned Jamaica Public Service Company, the island's main power



provider. Mirant has indicated that it is making progress in reducing the number of blackouts currently affecting Jamaica due to lack of capacity.

Including independent producers, installed capacity is approximately 780 MW, and Mirant expects to add another 2000MW to the system in 2004/5 at a cost of US\$200 million. Jamaica is now weighing replacing fuel oil with natural gas for its power plants and bauxite and aluminum sectors. The Jamaican government plans to import LNG to meet natural gas demand by 2008.

Puerto Rico

In January 2000, Puerto Rico's primary electric power producer and grid operator, publicly-owned Puerto Rico Electrical Power Authority (PREPA), initiated a \$ 2.4 bn program to increase the country's electric generation capacity. Economic growth in the late 1990s averaged 3 %, resulting in concerns that electricity demands associated with economic growth would exceed generation capacity. In response, PREPA began signing contracts with independent power producers (IPPs) to increase generation capacity from about 4.9 GW to 5.2 GW by end 2003.

A new 454-MW power station, built by US-based AES, is the first coal-fired plant in Puerto Rico. The plant has the additional benefit of being able to sell its steam to Phillips Petroleum's Puerto Rico subsidiary. The EcoElectrica and AES facilities are part of a general plan to reduce Puerto Rico's dependence on oil for electricity generation. In August 2000, the first shipment of LNG from Trinidad and Tobago arrived at Punta Guayanilla, near Ponce, where there is an LNG receiving terminal used to supply gas to the plant.



Only Jamaica, Guadeloupe, and Cuba have significant amounts of power generated from non-hydro renewable (geothermal, solar, wind, wood and waste) electric sources in 2003. Cuba produced approximately 0.8 bn kWh of renewable power while Jamaica generated approximately 0.1 bn kWh. Information on the geothermal production in Guadeloupe was not available at the time of writing.

The Dominican Republic was the largest producer of hydroelectricity in the Caribbean, with 0.7 bn kWh. This was greater than the hydropower produced by Cuba, Haiti, Jamaica, and Puerto Rico combined.

Jamaica is building a 20.7 MW wind farm at Wigton in Manchester (central Jamaica) which should be commissioned in May 2004. It will use twenty three 900kw NEG-Micon turbines.

25. OIL PRICE OUTLOOK

Western crude benchmarks have moved over the past month by nearly \$3/bl, particularly in expectation of a cold winter. Strong demand in the Asia Pacific region is adding to the bullish outlook.

OPEC's plan to cut output by 900,000 b/d from 1 November looks likely to keep prices well above the group's \$22-28/bl target, but at the expense of market share, which is steadily being eroded by non-OPEC suppliers, particularly from Russia.

Demand for crude in the USA has also been temporarily cut by a heavy refinery maintenance programme, which will be completed by December, just as the OPEC cuts start to affect the market.



Demand in Asia Pacific is already very strong. Consumer fears that cuts in Mideast Gulf supply will leave the region short at the height of winter, has sucked in oil from elsewhere, including west Africa and South America. Saudi Arabia is expected to cut allocations to Asia Pacific by fully 9% in November, just as the region struggles to replace Abu Dhabi production lost to maintenance. Abu Dhabi crudes are rich in distillates used for heating and are attracting ever higher prices going into the winter season.

Traditionally, it is heating oil demand that principally drives prices in the European, Asian and US winter prices. The severity of the winter will be a huge factor for prices in the medium term. Mediterranean gas oil prices have been climbing steadily for the last three weeks.

The portents appear almost exclusively bullish heading into the winter season. High prices will obtain for another 6 months, or even longer if Iraq does not reenter the market in a significant way.

