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OFFSHORE

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A triplet report on hurricane awareness asking how prepared the platforms are & how big was the damages that katrina left behind, plus a hurricane forecast for 2006.

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Iran's Petropars to sign oil field development deal in Venezuela

Iran's Petropars will participate in the development project of an oil field in the Gulf of Venezuela once the related contract is finalized, noted here Asghar Ebrahimi-Asl, an official at Iran's South Pars Oil Co.

The agreement to carry out activities in the seventh block of Venezuela's giant oilfield will be signed during the Iranian minister of industries and mines upcoming visit to Venezuela, said Ebrahimi-Asl, the project manager of the South Pars oil field development phases 4, 5, and 12.

The official had said earlier that the block being 540 square meters contained up to 18 billion barrels of in-situ heavy oil.

The development contract had been officially given to the Petropars Co. at a session attended by Venezuelan President Hugo Chavez, the Venezuelan oil minister and the managing directors of Venezuela's major oil companies as well as the Iranian oil delegate dispatched by Petropars. It has been said that the Iranian delegation had been provided with a contract valued at least $2 billion.

Petropars and Petroleos de Venezuela (PDVSA) had in the early 2005, signed a pre-contract on an oil project in the Gulf of Venezuela, the offshore gas field of Mariscal and another oilfield with four blocks in the region.

BP gets Accused of Manipulating Crude Oil Futures Contracts

BP Plc, the world's third-biggest oil company by market value, has been accused in a lawsuit of manipulating prices of crude oil futures contracts. The suit, which was filed in Manhattan federal court, says London-based BP used its "dominant ownership" of oil pipeline connections in and out of Cushing, Oklahoma, to control how much crude may be delivered to "other market participants." Cushing is the most significant trading hub for crude oil in North America, the suit said. Because of BP's conduct, "the prices of NYMEX light, sweet crude oil futures contracts were manipulated to artificial levels," according to the suit by Richard Hershey, a St. Louis man who purchased and sold light, sweet crude oil futures contracts on the New York Mercantile Exchange. BP's motive was "to obtain trading profits on its NYMEX crude oil futures contract positions," the suit said. The case is the latest strike at BP, which is also defending a shareholder complaint that accused top executives, including Chief Executive Officer John Browne, of harming the company by allowing half of the Prudhoe Bay oil field, the largest in the U.S., to deteriorate. BP spokesman Steve Rinehart declined to comment. The company said last month that it will pump crude oil from only the western half of the Alaskan field while it replaces corroded pipe on the eastern half .

New oil treatment facility commissioned on Kumkol

A new oil treatment facility (OTF) has been commissioned on the Kumkol field in the Kyzylorda Region of the Republic of Kazakhstan.

The field is operated by Turgai Petroleum which is a joint venture between LUKOIL Overseas and PetroKazakhstan (a subsidiary of CNPC of China). The parties have equal shares in the joint venture.

The capacity of the OTF is 4 million tons of oil per year. The purpose of the new facility is to bring the produced hydrocarbons to the marketable quality and deliver them to the system of KazTransOil main pipelines as well as to treat water for the subsequent injection into the reservoir pressure maintenance system. The capacity of the formation water treatment unit exceeds 8 million tons per year.

Up till now, all operations on treatment and pumping of Turgai Petroleum`s crude were carried out at the facilities of PetroKazakhsyan Kumkol Resources. The startup of the OTF enables the venture to implement a very important processing cycle independently.

The OTF is characterized with the continuity and completeness of the processing cycle and compliance with the strict heath, safety and environment standards. The facility is equipped with the modern automated control and fire-fighting systems. The new facility is operated by about 30 specialists of Turgai Petroleum.

The OTF was designed by NIPInefetgaz Institute (Aktau, Kazakhstan) with MontazhSpetsStroy being the main work contractor of the construction project. Construction of the facility took 1.5 years, the total cost of work amounted to USD 17.2 million.

The Kumkol field was discovered in 1984, development started in 1990. Turgai Petroleum has been operating the field since 1995. Remaining proven reserves of the field amount to 177 million barrels of oil. More than 3 million tons of oil was produced on Kumkol in 2005, the plan for 2006 is to produce 3.5 million tons.

Pacific Stratus spuds Exploratory Well in Colombia

Pacific Stratus Energy Ltd.has spudded its La Creciente-1 exploratory well in Colombia's prolific Lower Magdalena Basin.

The company plans to begin testing the target located in Prospect A, the largest in the block, at a depth of 10,900 feet, with a final total measured depth of 11,600 feet to be reached within 45 days.

Marino Ostos, Chief Operating Officer, said: "We are all very excited about the potential of La Creciente-1. If this well is successful, we will move the rig immediately to commence drilling La Creciente-2".

Pacific Stratus holds a 100% interest in the La Creciente Block under its 2004 contract with Colombia's National Hydrocarbons Agency (ANH).

China to reduce reliance on oil imports

China will reduce its reliance on petroleum imports by basing its energy supply on coal and developing new and renewable energies, said a senior official of China's National Development and Reform Commission (NDRC) .

China has successfully reduced its net imports of petroleum last year, said Zhang Guobao, vice minister of the NDRC at the 7th Sino-U.S. Petroleum & Natural Gas Forum held in Hangzhou, capital of east China's Zhejiang Province.

According to Zhang, China's oil consumption was 317 million tons last year, down slightly from the previous year and its net imports of petroleum are 136 million tons, less than that of 2004.

The Chinese economy has maintained a growth of over 10 percent for three years running so it is normal for China to see a rise in its oil imports as well as its demand for energy, said Zhang.

But China has been trying to reduce its reliance on imports of petroleum, which has been over 40 percent, he said.

According to statistics of the NDRC, China's coal output reached 2.22 billion tons last year and coal supports 68.7 percent of China's consumption of non-renewable energies with petroleum and natural gas, 24 percent.

China is the second largest energy producer in the world and the top exporter of coal and coke.

China's imports of oil only accounted for six percent of the total world oil trade in 2005 and China has been playing a limited role in pushing up the oil price, said Zhang.

As China reduced its oil imports in 2005, the world still saw the oil price soar by 36.8 percent from the previous year, which "shows that China's effect on the soaring international oil price has been seriously overplayed," said Zhang Guobao.

Russia, Greece determined to build trans-Balkan pipeline

Russian President Vladimir Putin and Greek Prime Minister Konstandinos Karamanlis have reaffirmed their wish to build a trans-Balkan oil pipeline between Burgas and Alexandroupolis in a telephone conversation on Thursday, the Kremlin press service reports.

"The sides confirmed their determination to build the Burgas- Alexandroupolis trans-Balkan oil pipeline under an agreement reached at the recent summit in Athens," the press service said.

Seadrill wins two tender rig contracts

Seadrill has been awarded a contract by Chevron for extension of the production drilling assignment for the self-erecting tender rig T4. The contract extension has duration of five years. The estimated contract value is approximately US$ 156 million.

The commencement of the new contract is scheduled for second quarter 2008 following a five-year survey after completion of the current contract. T4 is currently operating offshore Thailand.

The self-erecting tender rig T11 currently under construction at MMHE in Malaysia has been awarded a five-year contract by Chevron for operations in Thailand. The contract is expected to commence in July 2008 following delivery from the yard. The estimated contract value is US$ 203 million.

BP and Gazprom sign LNG supply deal

BP and Gazprom Marketing & Trading, the UK subsidiary of energy giant OAO Gazprom, have reached an agreement for BP to supply a number of liquefied natural gas (LNG) cargoes which Gazprom Marketing & Trading will market in the Atlantic Basin.

The cargoes, which will be sourced from within BP's portfolio, will be supplied over the period 2006 and early 2007 and transported in LNG ships chartered by BP to Gazprom Marketing & Trading. Gazprom Marketing & Trading will specify the delivery points in accordance with its marketing needs.

The first cargo of 135,000m3 was loaded today on the British Merchant at Point Fortin, Trinidad & Tobago for delivery to Cove Point, Maryland, US.

BP's Anne Quinn, group vice president for gas, LNG and natural gas liquids said: "We are pleased to be working with Gazprom in the area of LNG. As the world's largest gas company, Gazprom is potentially also a major supplier of LNG to the Atlantic Basin. This agreement is a clear indication of the way our two companies can work together to their mutual advantage. We look forward to identifying further opportunities to deepen our relationship in the future."

Gazprom's Deputy Chairman Alexander Medvedev said: "We are pleased with this agreement with such a strong and well regarded partner as BP, as Gazprom is continuing to look at ways to increase its LNG portfolio for a successful development of its LNG strategy and the benefit of its customers".

Total Vows To Pursue Operation In Iran Despite US Pressure

Total SA will continue efforts to develop Iran's vast oil and gas reserves and will not have its hands tied by US attempts to isolate Iran by preventing international companies from investing there, said CEO Thierry Desmarest.

The French energy group will respect any decisions made by the its government, the EU and the UN regarding trade with Iran, but US regulations are the problem of US companies, Desmarest said in an interview.

Total, which has been active in Iran since the 1990s, is one of the companies involved in a 2 bln usd Azadegan oilfield development contract.

Exmar completes First LNG ship-to-ship transfer

Exmar NV, Antwerp, has completed the first commercial ship-to-ship (STS) transfer of LNG in the Gulf of Mexico.

Until recently, STS transfer of LNG was only performed between LNG carriers in emergency situations.

A total of 20,650 cu m of LNG was transferred from the LNGRV Excelsior, a 130,800 cu m vessel built in 2005, to the Excalibur, a 138,000 cu m vessel built in 2002, Exmar said. Exmar operates these vessels along with Excelerate Energy LLC.

Exmar said STS LNG transfer will enhance the operational flexibility of the regasification vessels. The process does not require the construction of an offshore platform.

Exxon Mobil considers plan for Pipeline to Australia

EXXON Mobil is due to meet Oil Search and AGL to consider a plan for a staged development of a gas pipeline from Papua New Guinea to Australia, JPMorgan Chase said.

The proposal was probably the "last hope" for the pipeline, JPMorgan said in a report.

While Oil Search and AGL supported the staged development plan, Exxon might not be willing to back it because rising construction costs had reduced its profitability, the report said. AGL, the operator of a venture to build the Australian part of the pipeline, said last month it would not proceed with engineering work because the project would not be economically viable unless more customers committed to buying gas.

The company has proposed an alternative route for the pipeline.It would

initially stop at Mt Isa in Queensland instead of going to central Australia, JPMorgan said. "The last hope for PNG Gas in its current incarnation is the Mt Isa option," JPMorgan oil and gas analysts Mark Greenwood and Ryan Martyn wrote in the report. "A meeting with Exxon is planned in Houston next week and we understand that either way we will know the fate of PNG Gas by around the end of September."Shares in Oil Search, which have fallen 20 per cent since AGL decided to stop engineering work on the project, rose 1c to $3.02.Oil Search, PNG's largest oil producer, is the biggest investor in the gasfields that will supply the pipeline. Estimates of the cost of the Australian part of the pipeline have risen to between $4 billion and $5.3 billion.

JPMorgan said Oil Search shares were a "buy" should Exxon support the staged project plan and it went ahead. Otherwise the project venture would be dissolved and Oil Search would pursue alternative options to develop the gas, including petrochemicals and liquefied

natural gas projects, it said.

East coast energy to expand activity in Tanzania

EastCoast Energy announces its intention to raise approximately Cdn$21.5 million through a rights issue

The funds will be primarily used to drill a development and exploration well on the Company's licence acreage in Tanzania during the first half of 2007 to meet the rapidly increasing demand for gas in the country.

Iraq plans Kirkuk pipelines

Iraq's Oil Minister Hussain Al Shahristani has revealed that the country is considering the construction of a new pipeline for exports from its northern Kirkuk oil field in order to lessen disruption caused by sabotage, reported Gulf News. A further pipeline is nearing completion and should be ready inside a month. This 500,000 bpd pipeline will link Kirkuk to the Baiji oil hub prior to flowing into Ceyhan in Turkey.

GOC urged to build refineries

Energy experts attending the Arab Oil and Gas Show in Dubai have urged GCC countries to increase their investment in oil and gas refineries, reported Gulf News. Analysts feel that the robust growth in the region can only be sustained if spiralling energy demands are met. Dubai's energy sector has been achieving an annual growth rate of 17%, slighter higher than the global average of around 15%.

Regional crude share to hit 44%

A report by the Organisation of Arab Petroleum Exporting Countries says the Middle East and North Africa will have a 44% share of the global crude supply market by 2030, compared to 35% in 2004, Gulf News reported. It predicts output from Saudi Arabia could double to 18m bpd, while production in Iraq could go to 8m bpd, and the UAE and Kuwait to around 5m bpd each.

Oil near six-month low

Oil prices hit near six month lows of around $60 a barrel , after OPEC agreed to keep production quotas unchanged at 28m bpd. The group is actually producing 500,000 bpd less than that figure because of a recent drop in demand for crude, news agencies reported. Worries over possible supply disruptions from Iran have eased for the time being.

Dewa reissues tenders

The Dubai Electricity and Water Authority has started a second round of bidding for the contract to build a $2bn power and desalination plant, reported Bloomberg. Despite receiving offers last month, the tender did not receive the minimum number of bids required by law. Companies now have until December to tender bids for the plant, which will produce 2,000 megawatts of power and purify 105m gallons of sea water every day.

Hydro reduces 2006 production target

Norsk Hydro ASA has revised its oil and gas production target for 2006 down with about 5 percent from 615,000 to 585,000 barrels of oil equivalents per day (boed). The reduction of 30,000 boed is equally divided between Hydro's Norwegian and international portfolio and is mainly due to unforeseen events in Norway, Canada and US Gulf of Mexico, and somewhat lower gas export from Norway than planned.

Hydro is experiencing production shortfall from the non-Hydro-operated fields in Norway, primarily due to the unplanned shutdown of the Visund field and delayed production build-up from new fields and delayed drilling of production wells at other fields.

Internationally, Hydro's short-term production outlook in the US Gulf of Mexico continues to be negatively impacted by the high demand for oil and gas services following hurricanes in 2005 resulting in lower production on the shelf. In addition, deepwater production has been lower than Hydro's initial projections. In Canada the Terra Nova field will be out of production until September due to mechanical problems and an extended maintenance shutdown.

Hydro-operated fields in Norway are producing according to plan. The Grane field continues to produce above planned levels, and compensates for somewhat reduced production from other fields.

Any negative consequences of the ongoing oil services strike on the Norwegian Continental Shelf have not been accounted for in the revised target.

Hydro's oil and gas production in the second quarter 2006 is estimated to be about 535,000 boed of which 32 percent is gas.

The revised production target for 2006 is a result of delayed production and has no impact on Hydro's oil and gas reserves.

IOC boosts crude imports by 14%

India's state-run refiner Indian Oil Corp. (IOC) expects to import 14% more oil during the current fiscal year than it did during 2005-06 in order to feed an expanded plant at Haryana. The company is building new plants and expanding existing operations to meet India's surging demand for fuels and chemicals.

IOC has doubled the capacity of its 120,000 b/d Panipat refinery, increasing its output to 12 million tonnes/year, equivalent to about 240,000 b/d.

"More crude will be required to keep it going," said S Narasimhan, IOC's finance director. "The import bill will be substantially higher than last year because crude prices have gone up so much."

Demand for gasoline and diesel is expected to rise further as India's Congress-led coalition government seeks to boost the economy's gross domestic product to more than 10% in the next decade, from an average 8% over the past 3 years.

Energy experts forecast that IOC and other state-owned refiners, including Hindustan Petroleum Corp. and Bharat Petroleum Corp., will import 110 million tonnes of oil during fiscal 2006-07, a 10% jump from fiscal 2005-06.

IOC's purchases from Saudi Arabia and other suppliers were slated to rise to 40 million tonnes/year Apr. 1, compared with 35 million tonnes/year imported a year earlier. This will increase the refiner's import bill by 25% to $20 billion this year.

Higher imports by India and China have kept oil prices near record levels as demand growth in the world's two most populous nations outpaced output. This year, India's demand is forecast to increase by 5%, while China will require 7.2% more oil than last year.

The seven IOC-operated refineries can now process an aggregate 47.3 million tonnes/year of oil, and IOC units, Bongaigaon Refinery & Petrochemicals Ltd. (27,110 b/d) and Chennai Petroleum Co. (130,000 b/d), have the capacity to process 12.85 million tonnes/year.

Oilex commences drilling in India

Oilex announces that the first well in the Cambay Field drilling programme was successfully spudded at 19:30 hours on Monday 11 September 2006. The well, Cambay-72, is located on the crest of the Western High block of the Cambay Field.

Drilling operations using the Dalma Energy MR 4 rig commenced today at 00:00 and the well is expected to take 9-12 days to reach the planned total depth (TD) of 1835m.

Current operations are drilling ahead at 108 metres prior to running 9 5 /8" casing at 600m. On reaching TD, the well will be logged and casing will be run if there are indications of oil and gas in the well. The rig will then move to the Cambay-71 location and testing of Cambay-72, if warranted, will be undertaken by a workover rig at a later date in October, to be confirmed.

The primary reservoir objective is the Oligocene sandstone (OS II) and the secondary objectives are at Miocene and Eocene levels. These sandstone reservoir units are proven producers in fields immediately to the north and south of Cambay Field. Oil is being produced on the Western High at low rates on an intermittent basis from wells that have suffered formation and well bore damage in the past.

Shell lets ethylene cracker contract in Singapore

Shell Eastern Petroleum Pte. Ltd. has awarded a contract to ABB Lummus Global and joint venture partner Toyo Engineering Corp. for the implementation phase of a world-scale 800,000 tonne/year ethylene cracker on Bukom Island, Singapore. The contract's value was not disclosed.

The contract's scope includes engineering, procurement, and construction management services for the cracker, which will use ABB Lummus's proprietary liquid feedstock steam cracking technology.

Engineering and procurement work on the unit has already begun with construction slated to begin in 2007. Start-up of the unit is scheduled for 2009-10.

Iran invests $4 bln in Venezuela oil

Iran's state-owned Petropars oil and gas company is investing around $4 billion in the explorations and developments of two oilfields in Venezuela, Iran's Oil Minister Kazem Vaziri Hamaneh said. "The level of investment in the two Venezuelan oil fields is estimated at $4 billion, which will amount to Petropars' largest investment outside the country," Vaziri said in Press briefing after negotiations with his Venezuelan counterpart, Rafael Ramirez, who arrived in Tehran.

Petropars, affiliated to the National Iranian Oil Co., was established in 1998 and is currently involved in a number of oil and gas projects in Iran. It is also intent on expanding its operations outside Iran.

GAIL allocates $2.59 billion for 5-Year plan

India's state-owned GAIL (India) Ltd. plans to invest about $2.59 billion on pipeline construction during 2007-12 as part of its eleventh 5-year plan.

About $216-259 million will be spent on overseas investments, which include a proposed gas cracker plant in Iran.

"We are laying about 9,000 km of pipeline," as part of a $3.87-4.3 billion national gas grid project, said GAIL's Chairman S.P. Rao. The company has completed about 20% of that work, having already invested $1.19 billion on pipelines from Dahej on the Gujarat coast to Uran in Maharashtra and from Uran to Dabhol.

Work on remaining sectors will be accomplished when gas became available. Rao said production from the Oil & Natural Gas Corp.'s wells is declining, and private player Reliance Industries Ltd. would not begin producing gas from the Krishna-Godavari basin until 2008 or later. Rao said GAIL also is attempting to import LNG from Myanmar and Iran.

During the current fiscal year, GAIL will spend $711 million laying 1,500 km of pipelines. "The Iran-India pipeline has run into difficulties due to geopolitical problems, since it has to run through Afghanistan and Pakistan," Rao said. "But we have not given up on it yet. The [Indian] government is still pursuing it."

Chennai invests $1 billion to upgrade refineries

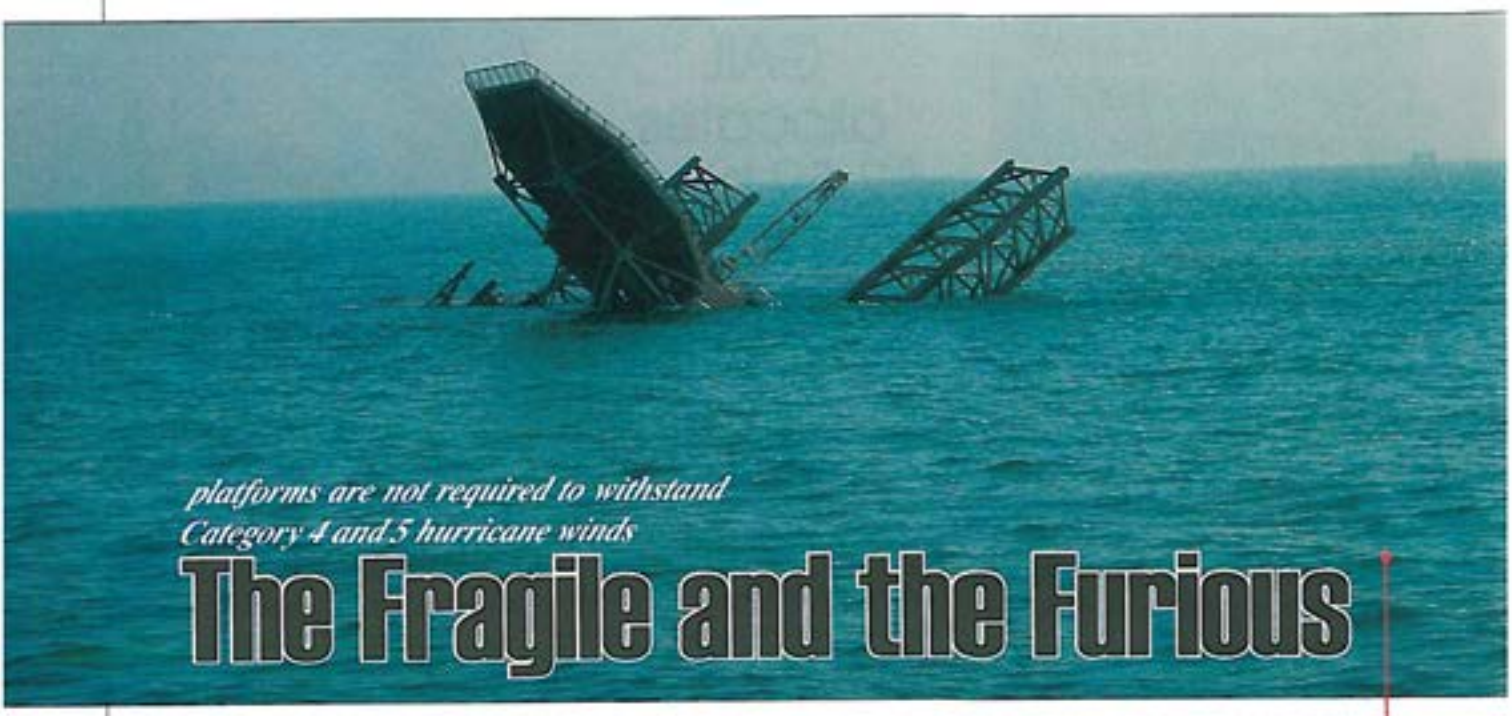
Chennai Petroleum Corp. Ltd. (CPCL), formerly known as Madras Refineries Ltd. and a subsidiary of India's state-owned refiner Indian Oil Corp. (IOC), has committed to invest more than $1 billion on various upgrading projects at its 130,660 (total) b/d refinery complex at Manali. The refineries produce fuel products, lubricants, and additives.

Planned Manali complex upgrade investments include a $647 million residue upgrade, and $61 million to expand Refinery I and Refinery III refining capacity to 11.2 million tonnes/year from 9.5 million tonnes/year.

IOC Chairman and Managing director Sarthak Behuria, who also is CPCL chairman, said the high-conversion residue upgrade will increase the distillate yield and reduce fuel oil production. The project is scheduled for completion in 2010.

CPCL also will expend $359 million for the addition of diesel and naphtha hydrotreating units and $18 million for a wind power program.

Another investment calls for a 1.5 million-tonne/year diesel hydrotreating unit and a 150,000-tonne naphtha hydrotreating unit and isomerization unit to meet European fuel standards. These projects are slated for completion by Dec. 31, 2009.



platforms are not required to withstand Category 4 and 5 hurricane winds

The Fragile and the Furious

In the days after Katrina, as hundreds of oil-producing platforms remained off line -- and some continued to leave a conspicuous trail of petroleum in the Gulf of Mexico -- federal officials insisted to Congress that they were doing everything they could to make this critical infrastructure stable during hurricanes, designing platforms to survive Category 5 storms.

But federal and industry documents obtained by the Mobile Register show that the latest design criteria for offshore oil and natural gas platforms require only that these structures withstand winds and seas typical of a borderline Category 2/Category 3 storm, well below the Category 4 and 5 winds that affected Gulf oil fields at least four times in the last five years.

By contrast, the latest International Building Code would require that houses on Dauphin Island be constructed to withstand stronger winds than the offshore platforms are built to withstand -- even though hurricane winds offshore are usually higher than winds near shore.

The implications of these design decisions extend far beyond the oil industry, and include the gasoline price spikes in the days after Katrina, and the spreading oil slicks emanating from multiple platforms in the Gulf.

The U.S. federal officials released reports of at least 64 spills associated with Gulf platforms following Katrina, which made landfall in Louisiana Aug. 29.

"For these platforms and other critical facilities, I'm really surprised that people would put that type of investment out there without more consideration," said Lawrence Twisdale, an expert in hurricane impacts and risk assessments for Applied Research Associates in Raleigh, N.C.

In the past year, three hurricanes -- Ivan, Dennis and Katrina -- with sustained winds 140 mph or greater have damaged platforms in the Gulf. According to a Shell Web site, Ivan destroyed seven platforms in September 2004 and damaged 26 others. Katrina destroyed at least 46 platforms last month and significantly damaged another 16, according to the American Petroleum Institute.

Even a Category 3 storm, can, under the right conditions, produce waves close to 100 feet

Many other platforms could not operate following Katrina because of pipeline ruptures and other problems throughout offshore oil fields. Subsequently, federal officials reported that Gulf oil production was at 44 percent of the pre-hurricane level.

On Sept. 6, Rebecca Watson, the Department of the Interior's assistant secretary for Land and Minerals Management, told members of Congress: "current design standards require industry to design facilities to Category 5 storm criteria."

But the Register has found that federal regulations require that facilities

be designed to withstand a 100-year storm as defined by the American Petroleum Institute, a nonprofit trade organization.

In the documents used to calculate design loads for offshore platforms -- API 2A-LRFD and API 2A-WSD -- the institute defines a 100-year storm in the northwestern Gulf of Mexico as having 80 knot one-hour average winds. According to Twisdale and wind engineers from Texas Tech University, that should be equivalent to about 115 mph in sustained one-minute winds, the scale used to gauge hurricane strength.

In wind estimates provided by ConocoPhillips Inc., 3-second wind gusts produced by API's 100-year-storm would be 134 mph. Such gusts are typically associated with one-minute sustained winds of about 109 mph, according to standard calculations used by the American Society of Civil Engineers.

This means that the wind design standards for the offshore structures approximate an upper Category 2 or lower Category 3 hurricane. (110 mph is the threshold between Category 2 and Category 3; 130 mph is the Category 3/Category 4 threshold.)

Though engineers working with industry and the U.S. Minerals Management Service have described Ivan and Katrina as once-in-a-thousand-year events, other engineers who have worked with hurricanes say that such storms are not so unusual.

Twisdale said that his researchers at Applied Research Associates are still analyzing the data, but their preliminary estimates indicate that the windfield associated with Katrina was not a once-in-a-thousand year event, but rather in the range of a once-in-a-hundred year event.

That's the kind of storm that the industry and federal officials say they are preparing for in the Gulf. But Katrina's Category 4 or 5 winds were far in excess of Petroleum Institute standards, and so were the waves produced by that storm.

Planning for high waves

The Petroleum Institute's standards require that platforms be built to survive waves of up to about 70 feet high.

During Katrina, one federal data buoy recorded a "significant wave height" of more than 55 feet about 80 miles east of the hurricane eye, according to Christopher Burr, chief of tropical analysis for the National Hurricane Center.

Significant wave height is a way of measuring the average of the highest waves, but Burr said it is safe to assume that some individual waves were more than 100 feet high.

Burr noted that researchers at the Naval Research Laboratory recorded a 91-foot wave over 100 miles from the eye of Hurricane Ivan. Those researchers estimated that waves closer to the eye were in the range of 131 feet high.

Minerals Management Service spokesman Gary Strasburg said the agency's view is that such waves are not typical. "My understanding with that is that is an anomaly," he said. "It is not something that would be expected, that high wave."

Burr said such waves are not out of the ordinary for major hurricanes. "It's been known for quite some time," he said. "It's just getting more press recently."

Even a Category 3 storm, can, under the right conditions, produce waves close to 100 feet, Burr said.

American Petroleum Institute officials said they couldn't comment on the standards, and referred reporters to the Minerals Management Service, the branch of the Interior Department charged with overseeing proper con-

the wind design standards for the offshore structures approximate an upper Category 2 or lower Category 3 hurricane

struction, maintenance and operation of offshore oil and gas platforms.

Minerals Management Service officials vigorously defended Rebecca Watson's assessment that the government requires that platforms be built to Category 5 standards.

"I'm confident that the Category 5 is the design criteria in our regulations," said Tom Readinger, an economist and associate director of the offshore minerals management program for the federal agency. "It's design, and you can quote me."

Standards in agency regulations "are based on a facility surviving a Category 5," Readinger said, adding that he would have to consult with engineers before he could find the specific reference to Category 5 conditions in the federal regulations.

In a subsequent interview, Strasburg said that the wording in the standards referred to a 100-year storm, not a Category 5 storm. He said the primary intent of the standards was to protect against large waves, not simply high winds.

"The reason we used the Cat 5 terminology is that a Category 5 storm could generate those waves," said Strasburg. But, he acknowledged, "so could a Category 3 or a Category 4."

Another document produced by the Minerals Management Service after Hurricane Ivan also indicated that the platforms were being designed to standards below a Category 5 storm.

On its Web site titled "Hurricane Ivan Research," the agency wrote that "Ivan, a full category-4 storm, moved through the U.S. Gulf of Mexico (GOM) with extreme winds and large waves exceeding or matching the 100-year design criteria of the facilities in its path."

Older platforms also an issue

Many of the more than 4,000 platforms now operating in the Gulf may

not have been built to the Petroleum Institute's current 100-year design criteria. That's because a large percentage of those platforms were built in the 1970s and early 1980s, before the latest Minerals Management Service regulations were passed by Congress in 1988, according to agency officials.

It's clear that not all the platforms damaged during Katrina were older-design platforms. A Helmerich & Payne Inc. platform built in 1996 lost its derrick and had "major damage" to the rig floor and substructure, according to the industry online magazine Rigzone. A Pride International platform built in 1989 is being inspected "to determine if rig will be scrapped," Rigzone wrote.

Some oil and gas companies have elected to build platforms to higher standards than those required by the federal agency.

For example, ConocoPhillips said its plans for an offshore Liquefied Natural Gas terminal about 12 miles south of Dauphin Island has been designed with a 150-year storm in mind. According to ConocoPhillips spokesman David Knox, such a storm would produce 3-second wind gusts of about 143 mph, which would typically be associated with 120-mph sustained winds during a mid-range Category 3 storm. The facility could simultaneously absorb waves of about 58 feet, he said.

Knox said company officials decided to build to the higher standard after looking at the damage done by Ivan's maximum sustained winds in the open Gulf, which were about 140 mph.

Still, the wind gusts ConocoPhillips is designing for are below the wind gusts that homebuilders on Dauphin Island are expected to build for. According to the American Society of Civil Engineers, residential construction on the sandy shores of Dauphin Island should be built to withstand a minimum of 150 mph 3-second gusts.

The industry has demonstrated that it may be possible to construct platforms to withstand Category 5 winds, and the waves and currents often associated with those winds. Officials with the BP energy company in Houston said that their state-of-the-art, $1 billion Thunderhorse platform, one of the newest in the Gulf, was designed to withstand 147 mph sustained winds and waves at least 100 feet. He described the design criteria as consistent with a 1,000-year storm.

The Thunderhorse platform, located about 150 miles south of New Orleans, listed 20 to 30 degrees earlier this year after Hurricane Dennis passed by. But industry officials said that the platform had not yet been placed in service when the damage occurred and may not have been damaged as a result of the hurricane.

BP spokesman Hugh Depland acknowledged that not all BP platforms are built to the same standards as Thunderhorse. He defended the Petroleum Institute's 100-year-storm design criteria, which BP engineers interpret as a storm with 120 mph sustained winds, a 74-foot wave and 5-knot currents occurring simultaneously.

When she's gone...

The devastation that hurricane Katrina left behind

The sea was anything but calm when Hurricane Katrina moved through here; it was a maelstrom. In parts of the gulf, the storm was a Category 5 when it arrived on the night of Aug. 28 and morning of Aug. 29, with sustained winds of 175 mph.

Waves; as high as 35 feet, locals say; pounded and demolished some oil platforms as the storm barreled through the offshore oil patch on its path to the coast. Water swept ashore, levees broke and key refineries were ravaged.

Within hours, drivers thousands of miles away felt the ripple effect, as waves of higher gas prices hit the pumps. Shortly after the storm, the average price of a gallon of gasoline in the United States was $1.22 higher than it had been a year earlier.

According to Oil Daily, a bible of the petroleum business, in the days after the deluge, processing of petroleum in the United States dropped by 2 million barrels per day; a total of 84 million gallons a day; about 12 percent of normal intake.

Some refineries have since returned to full or partial production, but four major facilities; three in Louisiana and one in Mississippi; are believed to be badly damaged and may not be online for weeks or months. Experts expect the price of gasoline to come down gradually, but it probably will be inflated by Katrina well into next year.

"There's plenty of damage out there to the platforms, but what makes this storm different is what happened to the refineries on shore," says Mark Pregeant, operations manager for Grand Isle Shipyards, a large maritime construction company that will help rebuild the rigs. "It's a mess."

A 60-mile boat tour through offshore oil- and gas-producing sectors reveals an abandoned seascape. Most rigs survived, especially the newer ones. But some of the older, smaller rigs have disappeared. The ones that are simply unmanned pumping stations are called "China rigs," because there are so many.

"That China rig broke right off," says Shook, pointing at a bare patch of water that has been marked by small caution buoys. "Divers will need to go down and cap those wells."

Pregeant talks about one drilling sector that was particularly hard hit.

"Out of 13 platforms, six were lost altogether and two more are leaning,"

he says. "I think they'll abandon that sector altogether."

Other platforms are still standing, but their enclosed structures have been ripped up as if they were made of paper. Metal piping is coiled up in balls, like string. Steel stanchions 24 to 36 inches wide are snapped in half.

The work crews on the rigs were evacuated before Katrina arrived, and in the sectors off Port Fourchon almost no one is back aboard those still standing. The rigs stand like empty gray metal watchtowers, one after the other.

In part, according to Shook, it is because they still don't have electrical power. But the main reason is what lies on the bottom of the gulf.

"There is a network of pipelines going every which way under here," Shook says.

Shut-off valves were closed before Katrina hit in order to avoid spills, "but (the lines) are gonna have to be checked for breaks before they start pumpin' again."

Dearth of trained workers

That work is already under way. A battered, rusting boat named the Sea Cat is anchored in about 35 feet next to a Chevron rig in the Grand Isle-25 drilling sector, about four miles out to sea.

Jeff Pogue, 37, a diver with Global Industries of New Orleans, pulls a bright yellow helmet over his wet suit and oxygen tank and jumps in. On board is a decompression chamber for deeper dives.

"We're doing inspections of lines and structures," says the boat captain, Ross Fengier, who, like so many captains here, is a Cajun. "We're looking for problems and reporting them. There are quite a few leaks all over."

Shook explains that while Pogue's equipment includes a digital camera on his helmet and a light, "a lot of it he has to do by touch because it's so muddy down there after the storm."

A distance away, in the Grand Isle-16 sector, welder Jimmy Kay, 41, of McComb, Miss., is already securing handrails ripped loose by the storm. Apart from that, the rig looks unscathed. The only sounds are that of his welding unit and the crackling radio of the boat.

Business owners here say it will be difficult to find the trained workers needed to inspect and rebuild the oil fields; divers, boat captains, welders.

"I figure I'll have to start looking overseas," says Pregeant, naming other oil-intensive areas around the globe where workers speak English ; such as Aberdeen, Scotland; and the Philippines.

Farther offshore, in deeper water, larger, more modern drilling and pumping facilities fared differently. About half of the crude pumped from the floor of the gulf is now produced by super rigs that can operate in thousands of feet of water.

6.7 million gallons of spillage

British Petroleum's Thunder Horse, the largest oil production platform in the world, due to start operation soon, escaped serious harm. It is the size of four football fields, stands 20 stories tall, floats on the surface of the sea and sits 150 miles southeast of New Orleans.

The rig was knocked off kilter by Hurricane Dennis earlier this year

Platforms' enclosed structures have been ripped up as if they were made of paper. Metal piping is coiled up in balls, like string. Steel stanchions 24 to 36 inches wide are snapped in half.

and had to be righted. This time, it fared better.

"The steps we took to make it safe were effective," said BP spokesman Ronnie Chappell. "It was standing straight and tall when we returned."

But Shell Oil's super-rig,Mars ; 162 feet high and 1.5 acres on its most spacious level; stationed about 130 miles southeast of New Orleans, took a harder hit and was badly damaged. Photos posted online show extensive damage.

Pregeant said he believed the platform would take months to repair.

The story inland was also stark. The Coast Guard reported that at least 6.7 million gallons of fuel had spilled from refineries or tank farms on the Gulf Coast. That compares with 11 million gallons that gushed into Alaskan waters when the Exxon Valdez ruptured in 1989.

In Port Fourchon, about 70 miles south of New Orleans, authorities implemented an air canon to keep water fowl from landing in waters laden with oil. Gulls, egrets and spoonbills stayed aloft, afraid to land, as the canon exploded with a loud pop every few seconds.

Travis Collins, 21, a worker for Source Environmental, a company participating in the cleanup, steered a launch within the boundaries of oil retention buoys and skimmed oil off the top.

"It isn't that bad a spill here," he said. "It shouldn't take that long to clean up."

Captain Shook disagreed. He pointed at a pile of dead oysters washed up on the shore and coated in oil. Foliage along the shore of the harbor was also contaminated."It's bad," he said.

Oil hands Southern, Cajun Up the highway, inland about 20 miles, offshore oil field workers who had been evacuated from rigs two days before Katrina hit were gathered at a helicopter port. They were packed and ready to return to certain rigs that had escaped harm and were back in operation.

The population of the rigs; thousands of workers; is almost exclusively male, largely Southern and particularly Cajun. The men usually work 14 days on, with seven or 14 days off in between shifts. They get on and off by boat or copter, landing on helipads built on the larger rigs.

No alcohol is allowed. Television and taped movies are the main distractions between long work shifts. The local stores onshore where they are most likely to stop before going offshore feature large supplies of Playboy and Penthouse, and tattoo and fitness magazines. Cosmopolitan is hard to find.

The rigs are isolated and exposed to the elements.

Dan "Tadpole" Dworaczyk, 37, of New Iberia, La., a veteran of more than 15 years of offshore work, says veteran rig workers didn't get too concerned about the coming of hurricanes.

He said oil and drilling companies got them off in time. He also said that everyone employed on the rigs received survival training. This includes drills in what to do in case of fire, an explosion and other emergencies. Then with a wry smile and a distinct Cajun accent, he says:
"But mainly, they teach you how to pray."

Hurricane Forecast 2006

The year 2006 will be an above average year for hurricanes

The aftermath of last year's US land-falling Hurricanes Dennis, Katrina, Rita, and Wilma still linger as we head into what most experts predict will be another active hurricane season.

This Year"s Hurricane Predictions According to the latest predictions from the Tropical Meteorology Project at Colorado State University, 2006 will be an above average year for Atlantic tropical storm activity. The research by Philip J. Klotzbach and William M. Gray predicts a total of 17 named storms for 2006, including 9 hurricanes. Those 9 hurricanes are expected to last an average of 5 days each for a combined total of 45 hurricane days this year. And among those hurricanes, 5 are predicted to reach winds of 111 mph or more.

These predictions follow closely with the 16 named storms and 6 major hurricanes predicted earlier this year by the NOAA.

The report also predicted a 52% chance of a hurricane-making landfall somewhere in the United States, with a 38% chance of a landfall in the Gulf of Mexico. As such, it is not likely that this year's hurricane season activity will reach the unprecedented level of activity for 2005. One of the report's authors, Philip Klotzbach noted: "Statistically, the odds of having four major storms make landfall this year are very small."

As a baseline for comparison, over the course of 1950 to 2000, the average number of named storms was 9.6 per year. Of those named storms, an average of 5.9 developed into hurricanes. So, the predictions for the current year are much lower that the number of storms seen last year, they still indicate a 77% increase in named storm activity and a 53% increase in hurricane activity over the 1950 to 2000 averages.

Last Year's Hurricanes

The 2005 hurricane season was the busiest Atlantic hurricane season on record. It resulted in a total of 28 named storms, 15 of which developed into hurricanes. And of those 15 hurricanes, 7 progressed into intense hurricanes with winds in excess of 111 mph.

For the Gulf of Mexico oil and gas industry, the most notable hurricanes were Katrina and Rita, which inflicted a great deal of damage to offshore infrastructure. The two hurricanes combined to destroy 115 offshore platforms, while damaging another 52 platforms and 183 undersea pipelines.

	Platforms		Pipelines	
Hurricane	Damaged	Destroyed	Large (10")	Total
Katrina	20	46	36	100
Rita	32	69	28	83
Total	52	115	64	183

As of May 3rd, a total of 324,445 barrels of oil per day were still shut-in, approximately 22% of the GOM's daily oil production of 1.5 million bar-

rels. A further 1.3 billion cubic feet of natural gas production was also still shut-in, approximately 13% of the GOM's daily gas production of 10 bcf.

Preparations PrAfter the damage inflicted by Hurricanes Ivan, Katrina, and Rita over the last two years, the MMS has worked with the Coast Guard and the oil & gas industry to issue new requirements for improving communications and safety.

In the three major hurricanes of the last two years, a total of 19 deepwater rigs and 9 jackups experienced complete mooring failures and were moved off location. As such, this has been a major area of focus for improvements. Operators and lessees will now be required to file information related to mooring systems when applying for drilling permits, and those applications will be reviewed for their compliance with two new API Recommended Practices, 95J and 95F. For jackups, this focuses mainly on the pre-loading process and the air-gap between the rig and water surface. For deepwater rigs, the new requirements focus on improved mooring design and mitigation of risk, but also require satellite tracking of rig positions.

The MMS has also worked to improve communications between itself, the Coast Guard, and industry companies. From the deployment of new electronic systems to more integration between government agencies, the MMS looks to make the communications during hurricane season run more smoothly.

Looking forward to this new hurricane season, the industry and the country can hope that 2006 will be in line with predicted levels of hurricane activity and not as overactive as 2005, a year in which 15 named storms were predicted but 28 actually occurred.

Oil heavy weights learn to play by new rules in Orinoco

Venezuela tightens the screws on foreign companies at a time when they're ever more eager to tap new oil.

The gently rolling grasslands of Venezuela's Orinoco belt are a frontier oil area in more ways than one.

Not only are international companies learning how to economically produce unconventional crude oil, they're dealing with a newly-empowered national government bent on more control of its resources.

As the balance of power shifts in favour of the latter, some analysts think the only option is surrender.

Only those firms willing to bend to increasingly draconian rules will manage to stay, not just in Venezuela, but in other major oil and gas producers like Russia which are also tightening the screws on foreign companies at a time when they're ever more eager to tap new oil.

One has to recognize that a country's natural resources belong to that country," said Enrique Sira, a Caracas-based analyst with Cambridge Energy Research Associates.

The ever more aggressive Venezuelan government is seeking to take a majority stake of the four multi-billion dollar Orinoco heavy crude projects --home to some of the largest oil reserves in the world. It's also increasing taxes and making companies renounce investment protection tools such as international arbitration. These measures seek to reverse contracts signed during the 1990s, under conditions the current government considers too advantageous to foreign companies. The open-door policy of the times -- when oil prices were low and Venezuela was desperate for foreign investment -- allowed "an assault on Venezuelan petroleum," oil minister Rafael Ramirez told the National Assembly in May 2005.

Orinoco stakeholders like ExxonMobil and Total, which have bristled at recent changes, may have to soften their approach in order to maintain access to these resources. Others like Chevron and Norwegian state oil producer Statoil seem happier to play by the government's rules -- but may end up with their assets exposed to further changes or the mercy of Venezuelan courts as they and others seek to keep their feet firmly planted in the Orinoco.

"It's a known and proven reserve," said Gero Farruggio, analyst at Wood Mackenzie in Edinburgh. "In such an opportunity constrained region, this will always attract attention from the major players simply because of the huge potential."

Venezuelan energy officials said in May that state-run Petroleos de Venezuela (PdVSA) sought to gain a 60 % stake in all existing joint ventures in the Orinoco, which Venezuela says is home to 1.3 tn barrels of oil, of which 235 bn can be recovered with existing technology. These projects consist of upstream fields where tar-like heavy crude is mixed with naphtha -- a light, gasoline-like fraction of crude oil -- and shipped out to coastal downstream facilities where it's transformed into lighter, more valuable crude.

"It's a bit like alchemy," said Jose Llanos, the French-born field manager for Sincor, a heavy crude consortium owned by Total, Statoil and

PdVSA. ConocoPhillips, Exxon and Chevron are present in three other projects.

Negotiations will focus on how PdVSA andits foreign partners will distribute control of upstream and downstream operations, Sira said.

Discussions are still in their early stages, but international oil companies had a taste of the government's stance during the recent transformation of 32 conventional oil-operating contracts into joint ventures run by PdVSA.

The new contracts didn't include provisions for international arbitration and officials for a US oil company told the Government Accountability Office that they were concerned about the "fairness" of Venezuelan courts, according to a recent report.

Firms seeking to keep arbitration on the agenda realized they were "facing an 800-pound gorilla," said a Caracas-based expert failiar with the negotiations who spoke on condition of anonymity. "There was no flexibility."

Exxon refused to sign the new contracts, opting instead to sell a stake in one of its two conventional oil fields to partner Repsol-YPF. France's Total and Italy's ENI had their fields seized by PdVSA after failing to reach an agreement. But most other operators were willing to sign the dotted line. "Reserves here are extraordinary," the expert said.

Big Oil companies who resist the most will fare the worst, as many competitors are eager to replace them in the Faja, analysts say.

Many look to Chevron's amiability to Venezuela's wishes as a recipe for success in the Orinoco, as the company has managed to secure potentially lucrative gas exploration contracts despite Venezuelan president Hugo Chavez's mounting rants against US imperialism.

Norway's Statoil is also publicly optimistic about the investment climate in Venezuela.

"So far we have had a very good return on our investment," said Helge Lund, Chief Executive recently.

But he added Statoil needs "to have a stable financial framework to operate there in the long term." In order to enhance their image, Chevron and others like Repsol and Royal Dutch Shell have emphasized their agreement with the government's social development goals, said IHS' Bello. "They do a lot of public relations," he said.

On the other hand, Exxon, the biggest of Big Oil, is a known hardliner. The Irving, TX-based firm was the only one of the five Orinoco companies to protest a 2004 royalty hike, and was booted out of a $ 2 bn petrochemical plant project in early 2006 after increasingly acrimonious exchanges with the Venezuelan government.

"ExxonMobil relies on a stable fiscal regime and sanctity of contracts when making investment decisions," an Exxon spokeswoman said.

Exxon's strategy may still reap fruit. Even though the petrodollar-laden Venezuelan government is confident in its negotiating stance, Big Oil still has bargaining chips.

International oil companies "hold the key to unlocking the full potential of the Faja, and PdVSA and the ministry are keen on doing that," said Wood Mackenzie's Farruggio.

The proof is the lack of growth in Venezuela's oil sector since Chavez took power in 1998.

Although changes in operating conditions are in line with historical trends and developments elsewhere, the heavy rhetoric that accompanies the transformation has discouraged companies from undertaking new investments.

"There has been no real growth, despite being one of the countries with the highest potential in the world," Sira said.

Dr. Elizabeth wishnick

Great powers compete for Kazakh energy

US companies, led by Chevron have invested mor than US$12 billion in Kazakhstan 1993, more than any other state

The world's great energy hungry powers have become extremely active in Kazakhstan lately.Motivated by concerns over diversification of supply routes as well as by geopolitics and instability in global energy markets, the US, China, and Russia have all accelerated their competition over energy resources in Kazakhstan. Each of the three great powers is seeking to assert its own interests in Kazakhstan in response to actions by the other two. Although cooperation is possible, and on the surface, already present in the case of Russia and China, each of the three is pursuing a distinct strategy in Kazakhstan.

On 25 May China received its first pipeline oil. It flowed from Atasu in Kazakhstan to Alashankou in China's Xinjiang Uighur Autonomous Region. The 962-kilometer pipeline - built by Kazakhstan's state oil company, KazMunaiGaz, and the Chinese National Petroleum Corporation (CNPC) - was completed in December at a cost of US$700 million. The pipeline will bring in up to 20 million tonnes of oil annually. As a result, Kazakhstan will quadruple its oil exports to China in 2006 - shipping 4.75 million tonnes by the new pipeline, and then 8 million tonnes in 2007. Ultimately, the pipeline will span some 3,000 kilometers to connect to Kazakhstan's Atyrau fields in the Caspian Sea. Kazakhstan currently produces 60 million tonnes of oil annually and is planning to double its production by 2015.

After more than a decade of difficult negotiations with Kazakhstan and Russia over pipeline projects, the Kazakhstan oil pipeline is the first to be built to China, though Russian oil will also be shipped along this route.

PetroKazakhstan, which CNPC purchased for US$4.2 billion in October 2005, will help supply the pipeline, but it cannot do so alone. Thus far, China has failed to purchase fields in western Kazakhstan where reserves are greater. Consequently, Kazakhstan has allowed Russia to ship up to five million tonnes of oil per year through the Atasu pipeline to China as well. In a 25 April agreement, Transneft, Russia's state-owned oil pipeline monopoly, agreed to send 1.3 million tonnes of oil through the pipeline in 2006. Both Rosneft and Lukoil have expressed interest in participating in the plan.

Once China became a net oil im-

porter in 1993, the Chinese government sought to diversify its supplies and supply routes. In 2003, China overtook Japan as the second largest importer of oil. In 2005, China imported 43 per cent of the 319 million tonnes of oil it consumed, according to the Chinese National Development and Reform Commission. Currently, more than half of the oil China imports comes from the Middle East and 80 per cent of those imports pass through the Malacca Straits.

Although Chinese officials initially pinned their hopes on a Siberian pipeline to Daqing in Northeast China, Sino-Russian differences over pricing, reserves estimates, and routing caused considerable delays.

The first spur, linking Siberian oilfields to Skovorodino near the Chinese border, only began construction on 28 April.

The new pipeline from Kazakhstan to Xinjiang also will help Chinese leaders address some of the regional

disparities presenting a fundamental challenge to Chinese energy policy. The Daqing field, in China's northeastern Heilongjiang province, once the center of Chinese heavy industry, has been producing oil since the 1960s and amounts to one-third of total Chinese output (46 million tonnes in 2004), but is now in decline. Today, the country's energy resources are located in less developed inland areas, while energy-intensive industries are concentrated in the northeast, and prosperous population centers with high rates of energy consumption and modern industrial complexes are found in coastal cities such as Shanghai, Guangzhou, and Beijing.

To respond to these disparities, the Chinese government announced a "Go West" policy at the March 2000 session of the National People's Congress. The policy aims to boost the development of the inland provinces by exploiting their resources, which will then be directed to population and industrial centers in need of energy. The centerpiece of the project is the US$5.2 billion 4,000-kilometer West-East gas pipeline project, connecting gas deposits in Xinjiang's Tarim basin with Shanghai. The project began supplying gas in September 2004 and has a capacity of 12 billion cubic meters per year.

Xinjiang is slated to replace China's northeast as the new center of petrochemical industry, as China receives energy resources from Kazakhstan and develops its own Tarim Basin. An oil refinery with an annual capacity of ten million tonnes is under construction in Dushanzi in Xinjiang and will be completed in 2008.

Xinjiang is also home to the Uighur population, one of China's Muslim minorities, and consolidating economic and social stability has also been a driving force behind China's western development strategy as well as its interest in promoting greater economic integration under the auspices of the Shanghai Cooperation Organization (SCO).

Although Russia and China both hail this organization as an alternative to Western-dominated regional security organizations such as NATO, Russian leaders have been more wary of Chinese efforts to expand its influence in areas of the former Soviet space that Moscow considers its traditional sphere.

Under Russian President Vladimir Putin, as energy has been renationalized, it has emerged as a powerful tool of state diplomacy and a means of reasserting Russian leverage over members of the Commonwealth of Independent States (CIS). Russian policymakers are much more intent

on creating a common economic space within the CIS than in the SCO, and have been using control over energy exports and prices to achieve that end.

At times, this leverage is used to reward cooperative partners like Kazakhstan's President Nursultan Nazarbaev, who highlights the constructive partnership with Russia as a key foreign policy priority.

In a meeting in the Russian port of Sochi on 20 May, Nazarbaev and Putin agreed that Russia would pay higher transit fees for gas from Kazakhstan that Gazprom exported to other states. This means that customers like Ukraine, where pro-Western political change incurred Russian wrath and a dispute over pricing led to a brief cut-off of gas supplies this winter, are likely to see their gas prices increase as a result.

The US Vice President Dick Cheney has paid a visit to Kazakhstan to urge President Nazarbaev to export oil westward through the Baku-Tbilisi-Ceyhan (BTC) pipeline that just began shipping Caspian oil to the Turkish port of Ceyhan on 28 May. Cheney's trip to Kazakhstan came the day after his 4 May speech in Vilnius, Lithuania in which he accused Russia of using energy exports to acquire political leverage.

After criticizing Russia for rolling back democratic freedoms, Cheney went on to praise the even more authoritarian Kazakhstan for its economic and political development. Kazakhstan has long been at the center of US policy towards central Asia, considering that US companies, led by Chevron, have invested more than US$12 billion in the country since 1993, more than any other state.

In the past year, as relations between Uzbekistan and the US have deteriorated, ties with Kyrgyzstan have become more complicated, and European anxiety about dependence on Russian gas exports has grown, US relations with Kazakhstan have become all the more important. Although US ambassador to Kazakhstan John Ordway claimed Washington supported the new Kazakh-Chinese pipeline, clearly the Cheney visit reflected Washington's effort to anchor Kazakhstan to European and US economic interests.

Officials in Kazakhstan, for their part, have been seeking to balance their good relations with Russia, which the Baku-Tbilisi-Ceyhan pipeline circumvents, with its own desire for export diversification and interest in achieving a "multi-vectored" foreign policy that also values good relations with the US and China.

After demurring for some time, Nazarbaev is slated to sign an agreement with Azerbaijan on 17 June, pledging that Kazakhstan will export 7.5 million tonnes of oil through the BTC pipeline.

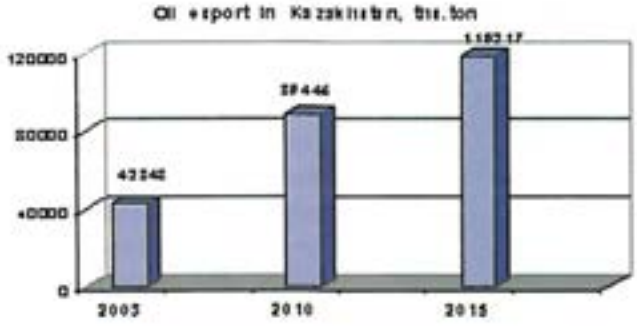
Kazakhstan is also considering participating in a Baku-Tbilisi-Erzerum gas pipeline that would ship gas from central Asia to Turkey, bypassing Russia. The perception of Russian unreliability as a gas supplier for Europe revived interest in the US$2.5 billion plan, which first came up in the early 1990s.

EU Energy Commissioner Andris Piebalgs, visiting Kazakhstan just before Cheney, expressed European support for the central Asia gas pipeline, although many economic and political questions remain concerning its feasibility.

Due to its geographic location at the juncture of Asia and Europe, squeezed between Russia and China, Kazakhstan has long been accustomed to delicate balancing acts.

To make matters more complicated, however, Azerbaijan, along with Ukraine, Georgia, and Moldova, announced on 24 May they would leave the CIS to form a new organization, the Organization for Democracy and Economic Development.

This means Kazakhstan will be a part of the CIS, yet joined to its pro-democratic rival through the BTC, as well as a member of the SCO and NATO's Partnership for Peace program, among other regional organizations. Such a multi-pronged foreign policy means that great power competition over Kazakh energy resources is only likely to continue in the future.



FPSO : A ship for all jobs

A Floating Production, Storage and Offloading vessel (FPSO; also called a "unit" and a "system") is a type of floating tank system used by the offshore oil and gas industry and designed to take all of the oil or gas produced from a nearby platform (s), process it, and store it until the oil or gas can be offloaded onto waiting tankers, or sent through a pipeline. A FSO is a similar system, but without the possibility to do any processing of the oil or gas.

Oil produced from offshore production platforms can be transported to the mainland either by pipeline or by tanker. When a tanker solution is chosen, it is necessary to accumulate oil in some form of tank such that an oil tanker is not continuously occupied whilst sufficient oil is produced to fill the tanker. Often the solution is a decommissioned oil tanker which has been stripped down and equipped with facilities to be connected to a mooring buoy. Oil is accumulated in the FPSO until there is sufficient amount to fill a transport tanker at which point the transport tanker connects to the stern of the floating storage unit and offloads the oil.

A FPSO have the capability to carry out some form of oil separation process obviating the need for such facilities to be located on an oil platform.

FPSO's are particularly effective in remote or deepwater locations where seabed pipelines are not cost effective.

The world's largest FPSO is the Kizomba A, it has a storage capacity of 2.2 million barrels. Built at a cost of over US$800 million by Hyundai Heavy Industries in Ulsan, Korea, it is operated by Esso Exploration Angola (ExxonMobil). Located in 1200 metres (3,940 ft) of water at Deepwater block 15,200 statute miles (320 km) offshore in the Atlantic Ocean from Angola, West Africa, it weighs 81,000 tonnes and is 285 metres long, 63 metres wide, and 32 metres high ((935 ft by 207 ft by 105 ft).

Current FPSO's

•SeaRose FPSO, on the White Rose oil field, offshore Newfoundland
Terra Nova FPSO, on the Terra Nova oil field, offshore Newfoundland
•Ramform Banff FPSO, in the North Sea
•Anasuria FPSO, on the Teal, Teal South and Guillemot A oil fields, North Sea
•Texaco (Now Chevron) Captain oil field FPSO December 1996 North Sea
•Shell Curlew oil field FPSO September 1997 North Sea
•BP Foinaven oil field FPSO November 1996 North Sea
•Maersk Oil Gryphon oil field FPSO September 1993 North Sea
•Maersk Oil Janice oil field FPS February 1999 North Sea (The Janice is a semi-sub).
•Maersk Oil GP3 to go to the Dumbarton Field late 2006.
•Conoco (Now ConocoPhillips) MacCulloch oil field FPSO April 1997 North Sea
•Enterprise (now Shell) Pierce oil field FPS February 1999 North Sea
•Talisman Energy Ross oil field FPSO March 1999 North Sea]
•Bluewater FPSO's Uisge Gorm (1995 Fife Field, North Sea), Bleo Holm (leased to Talisman on the Ross Field above), Glas Dowr (off Durban, South Africa) and Haewen Brim (North Sea), Munin (Lufeng Field, China Sea), Aoka Mizu (Ettrick Field), Jotun A (Norwegian sector, operated by ExxonMobil but 55% owned by Bluewater), Hanne Knutsen (a tanker awaiting conversion 2006).
•BP Schiehallion FPSO oil field July 1998 North Sea
•Shell Teal, Teal South and Guillemot A oil field FPSO August 1996 North Sea
•Amerada Hess Triton - Bittern, Guillemot West & North West oil fields FPSO March 2000 North Sea
•Norne FPSO, offshore Norway
•Sea Eagle FPSO, offshore Nigeria
•Bonga FPSO, 2005, off the coast of the Niger Delta, Africa
•Kizomba A, offshore Angola, West Africa
•Kizomba B, offshore Angola, West Africa
•Girassol, offshore Angola, West Africa
•Marlim Sul, offshore Brazil
•Capixaba, offshore brazil
•BHP Billiton Griffin FPSO , offshore northwest Australia
•Woodside Energy Northern Endeavour, Timor sea
•Woodside Energy Cossack Pioneer, Northwest Australia
•Woodside Energy Berge Helene (Bergesen offshore) Mauritania

FPSO builders

•Acergy
•Aker Kværner
•Bluewater
•Chicago Bridge & Iron
•Daewoo Shipbuilding & Marine Engineering (DSME)
•Hyundai Heavy Industries
•KBR (Halliburton)
•Keppel Shipyard
•Mitsubishi Heavy Industries
•Mitsui Engineering & Shipbuilding (Mitsui)
•NORTECHS FPSO
•Saipem
•SBM Offshore
•Samsung Heavy Industries (Samsung)
•Technip

Building a platform from scratch

Offshore oil was first explored and produced at Baku in the then Russian Empire at the beginning of the twentieth century. About the same time the discovery of onshore oil in Texas and Louisiana induced enormous changes in the economy of that region, making it not only a centre of oil production but also a centre for oil field services and equipment. The oilfield was and is a demanding environment for people and equipment, requiring extraordinary organisation of people and use of technology. We normally think of efforts such as the space programme spinning off technology, but the oilfield has done so as well, in ways that may not be as obvious to ordinary consumers but which are equally beneficial.

The move offshore in the Gulf of Mexico for the oil industry started after World War II. It started in the coastal areas of Louisiana, where land and sea tend to run together. The further out things went, the larger the platforms and the equipment needed to install them.

Conventional Platforms

When we speak of "conventional platforms" we mean those that have a continuous rigid structure from the seabed to the ocean surface. These were developed for water depths generally not exceeding 300 m, although a few exceed that in depth. These are generally tubular structures using large diameter pipe, much of which was rolled from plate at the yard and butt-welded before being welded into the platform. The coping and ocean floor, the platform itself being a giant cantilever.

Most barges--and the derrick barges themselves before they became self-propelled--were towed by ocean going tugboats. These workhorses were an essential part of any offshore construction operation, operating in all seasons and in all types of weather, fair and foul. In the Gulf of Mexico, construction generally tapered off during the winter months due to the winter storms from onshore. The North Sea had an even more restrictive construction season, which led to a "quantum leap" of offshore technology of its own.

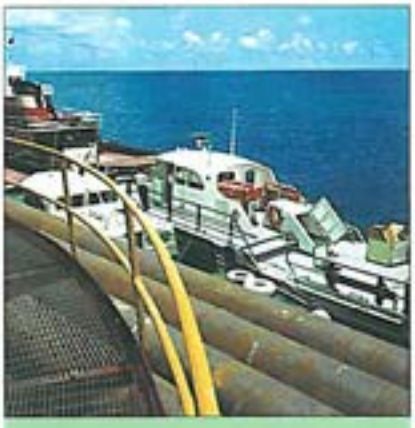
was centred in Morgan City, LA

Once the jacket was finished, it was placed on a barge and floated out to the spot in the ocean where it was intended to be installed. Below is a view of the jacket and barge below it as they approach the derrick barge (the construction barge used to actually complete the construction of the platform.) The triangular plates on the bottom of the platform are mud mats; they prevent the platform sinking into the soft ocean floor after it is upright and resting on the bottom. Virtually all platforms are tapered to the top, as the moments from wind and wave action are the greatest at the

sheer size of these structures--some of which were as tall as the original World Trade Centre in New York--required very specialised and competent fabrication capabilities.

The upper right inset above shows platforms being built in yards along the Bayou Boeuf south of Amelia, LA. Most conventional platforms were prefabricated onshore. They were then floated down the bayou and past Morgan City (shown in the lower middle inset above) into the Atchafalaya River and then into the Gulf. (Click here for information on how we got the chart.)

Much of the construction portion of the offshore oil industry in the Gulf



Once the jacket had arrived at the site, the legs were flooded and the jacket sank upright to the sea floor. Setting the jacket could be a trying task, as the photo below and the one to its right can attest. Sometimes

Platforms are in reality complexes of structures joined together into small offshore cities

it was necessary for the barge (or more than one) to pick up and move the jacket, as it would be "off station."

Once the jacket was set, pile driving could begin. The set platform became a template for the piles, which were driven through the legs. Below is a good view of a four-pile platform with two of its piles "stabbed" through the legs. Once driven, these would hold the platform to the sea bed.

Crew and supply boats were the only method of transporting personnel and small supplies in the early years of offshore exploration. For platforms near the shore, they were practical and economical, but as the work went further and further offshore, crew boat rides became longer and longer, something Vulcan's people found out the hard way.

Helicopters were indispensable in offshore exploration, drilling, construction and production, especially as platforms went further and further offshore. Like everyone else offshore, Vulcan personnel spent time in helicopters, enduring mechanical problems (which are potentially disastrous in a helicopter) and violent weather.

Offshore crews generally worked twelve-hour on/twelve hour off for two weeks at a stretch. There was thus some idle time offshore; one favourite pastime was fishing. Derrick barge crews discovered what environmentalists hate to admit: offshore platforms are natural habitats for all kinds of fish and other marine life, which made for good fishing. Welding wire was a favourite type of fishing line, though other materials would get the job

done too.

After the piling was complete and the piles grouted to the jacket, the actual superstructure of the platform was installed. With the long work season in the Gulf and other tropical and sub-tropical regions, the superstructure was brought out in modules and assembled as shown below. Again the North Sea's hurried schedules forced the development of bringing out the entire superstructure in one piece and setting it on the jacket; this more than anything drove the construction of the very large derrick barges by McDermott and Heerema in the late 1970's and early 1980's.

The superstructure had to be as light as possible, not only for lifting but for the structural economy of the platform. The question, "too much weight topsides?" was more than a personal one for designers of conventional platforms.

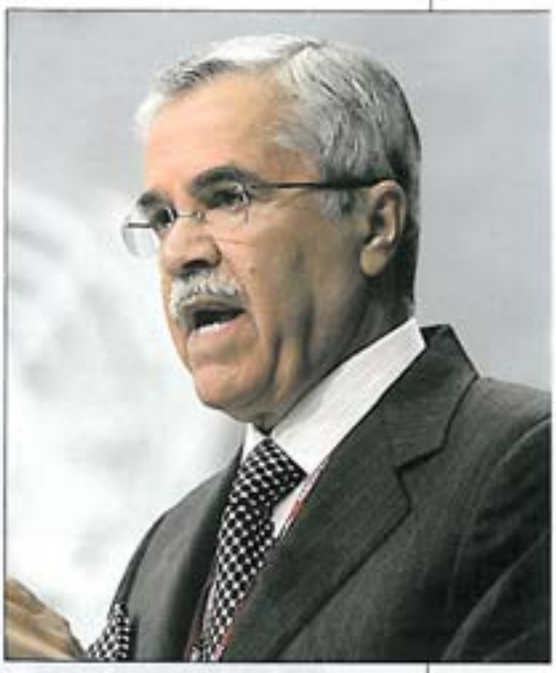
One important operation involving the piling separate from driving was the welding of add-ons. The literature tells us that adding on to steel piling is "easy" but with 1-2 metre diameter piles and up easy is a relative term. Even with a crew such an operation could take an entire shift, and the weld had to pass ultrasonic inspection or be done over. In cohesive soils, a big problem was that while the pile was being welded the soil would set up, making for harder driving for the next add on. Under pressure from the North Sea's short construction season, the process was shortened by the use of "breech block" technology by which an add on was threaded onto another like the closing of an artillery piece.

When we think of a platform, we usually think of a single structure, but many platforms were in reality complexes of structures joined together into small offshore cities. The 1968 photo below shows the last module for such a structure about to be placed on the deck of the platform. Such complexes were not unique to the Gulf of Mexico; they also appeared in the North Sea and other places around the world.

Floating the topsides out: as the Vulcan hammers install the piles, the next step waits on the barge. Installation by Global Marine in September 1996.

Supply barges were an essential element in the marine construction process, bringing materials and equipment to keep the process going. Both hammers and pipe loaded up this barge. In the centre is a Menck hammer; Menck was Vulcan's chief competitor for the offshore market. Since this was 1976, the Menck hammer was decorated in a patriotic way for the U.S. Bicentennial, but this could not change the fact that the Vulcan 3100 was the only American hammer on the barge.

Future demands force Oil Producers to huge investments



KSA oil minister says Middle East oil producers will spend $94bn in the oil and natural gas industries by 2011 to help meet future demands for energy.

Saudi Arabia will spend $18bn to add capacity and $70bn overall on its oil and natural gas operations by 2011, Naimi said. Naimi encouraged foreign investors to "build mutually beneficial, long-term relationships with Saudi enterprises."

Producers must carefully gauge future demand for crude when committing to long-term investments, Naimi told an Organisation of Petroleum Exporting Countries seminar in Vienna. Boosting Opec output capacity by 1mn bpd by 2010 requires $8bn in spending, Naimi said.

"By 2011, the countries of the Middle East will invest some $94bn in their oil and gas upstream sectors, more than half of which will go to expand oil-production capacity," Naimi said. "The assessment of market demand for our oil" is a key factor guiding expansion plans, he said.

The seminar, held in Vienna's Hofburg Palace, was attended by ministers from the world's top oil producers, including Venezuela and the United Arab Emirates. It followed an Opec meeting on Monday where Opec agreed to maintain the group's production target of 28mn bpd, brushing aside concern by Nigeria, Algeria and others that weaker demand could soon force prices lower. Oil futures in New York have declined 16% from a high July 14 of $78.40 a barrel as fuel stockpiles in the US, the world's largest energy consumer, remain above seasonal averages.

Naimi said he was happy with overall market conditions and called the recent slide in prices a "blip." Opec also declined to publicly discuss overproduction by some of its members, an issue that has generated heated debate in the past.

Opec President Edmund Daukoru said on Monday Opec was treating official output targets with "benign neglect."

Opec members excluding Iraq produced 27.92mn bpd in August according to Bloomberg data, 80,000 barrels below the official target.

Iraq is not bound by the group's quota system. "Our quota is 28mn barrels," Iran's Opec governor, Hossein Kazempour Ardebili, said .

How we distribute among ourselves is none of your business." Earlier , the International Monetary Fund said high oil prices and faster inflation are among the chief risks to financial markets. IMF Managing Director Rodrigo De Rato, who is attending the seminar, said producers must move ahead with investments to increase oil supply, ease prices and lower the risk of inflation. "There are clear signs of increasing risks," Rato said referring to global growth. "Adequate investment in the oil sector will help alleviate concern about future supply." Naimi outlined the kingdom's expansion plans, which call for an increase in production capacity to 12.5mn bpd by 2009. That is a net increase of about 1.5mn bpd, Naimi said.

Saudi Arabia will continue to maintain 1.5 mn bpd to 2mn bpd of spare output capacity, he said. Increases will come from seven oil fields, including the Haradh field, which when on line earlier this year with production capacity of 300,000 bpd. Such relations, while politically challenging, he said, are needed "for the health of the world economy, which relies so heavily on a stable, reliable supply of hydrocarbons"

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Though dependent on its oil exports and under pressure by the western world, Iran's superior geopolitical features and enormous natural and human resources give it more than enough winning cards in one hand.

Dealing with a Rising Iran

Persian Gulf Reserves It has been common knowledge for many years that the Middle East is home to the world's largest resource base of oil. With over 700 billion barrels of reserves, the Persian Gulf states of Bahrain, Iran, Iraq, Kuwait, Oman, Qatar, Saudi Arabia, and the UAE hold nearly 60% of the world's conventional oil. Between them, these countries pump close to one third of the oil produced in the world each day.

In addition to crude oil, the Persian Gulf states also hold about 40% of the world's conventional natural gas reserves with more than 2,500 tcf. With the massive amount of energy resources concentrated in these few countries, it is easy to see why they are so important to the entire world and why the world watches intently when conflicts brew in the Middle East.

Iranian Oil and Gas

Iran currently has the world's third largest proved oil reserves with 133 billion barrels, which is about half the reserves of the world leader, Saudi Arabia. Iranian oil reserves represents about 10% of all the oil in the world, a huge proportion for a country with less than 1% of the world's population.

As such, Iran is a major exporter of crude oil. Each day, the country produces just under 4 million barrels of oil. But, with consumption of just about 1.5 million bpd, Iran has the ability to export 2.5 million barrels of oil each day. This makes Iran the world's fourth largest oil producer and the world's 5th largest oil exporter.

In addition to oil, Iran also has the world's second largest natural gas reserves, with about 940 trillion cubic feet of gas. These reserves, which account for about 15% of the world's conventional natural gas, are largely concentrated in the offshore South Pars field. This one field alone contains as much as 500 trillion cubic feet of recoverable natural gas.

Given that 1 barrel of oil contains about as much energy as 5,400 cubic feet of natural gas, Iran's natural gas reserves account for the energy equivalent of about 175 billion barrels of oil. Combined with Iran's oil reserves of 133 billion barrels, Iran controls the energy equivalent of more than 300

billion barrels of oil. That puts Iran slightly ahead of Saudi Arabia's total hydrocarbon energy reserves, making it the most energy rich nation in the Middle East and second only to Russia in the entire world.

The majority of Iranian crude oil is produced from giant onshore fields near the Iraqi border. Most of these are older fields that have been producing for many years, and they are now in natural decline, with production rates dropping an estimated 8% to 13% per year. Those decline rates combined with the relatively low recovery rates in Iran, which range from 24% to 27% (compared to 35% worldwide), indicate that significant investments need to be made in order to maintain Iranian oil production.

The Iranian Oil Ministry has announced in recent years that it plans to increase its oil production to 5 million barrels per day by 2010. This feat may not be realizable, but with the help of foreign investors and oil companies, it could be a reachable goal. And while Iranian law does not allow foreign companies to have direct concessions, they are allowed to invest in field development via a "buyback" program in which the government buys the fields back from the operators at a fixed rate.

Thus far, foreign investment in Iranian oilfields has been primarily focused on offshore fields. Since 1998, when the first foreign operated field came online, Iran has seen foreign investments being used to develop several offshore fields and increase production by several hundred thousand barrels per day. However, of Iran's 40 producing fields, only 13 are offshore, and only about 15% of Iranian production comes from offshore fields. So, the impact on overall production is somewhat limited.

Iranian Exports

As mentioned above, Iran is a major exporter of oil, with approximately 2.5 million barrels of oil flowing from its oilfields to other nations each day. About one third of those exports head for Europe, while the lion's share heads to Asia. Japan, China, and South Korea are the leading Asian recipients of Iranian crude.

Iran is now China's second leading supplier of imported oil. In 2004, China and Iran signed two monumental energy accords, which will deliver close to $100 billion oil and natural gas to China in 25 years.

Historically, Japan has been Iran's leading oil export recipient, given Japan's large demands for oil and limited resources. Recently, however, China has begun to catch up with Japan in terms of oil use. China's daily oil usage now exceeds Japan's, and its oil imports are growing very rapidly and likely to surpass Japan's in the next few years.

As such, over the last two years, ties between Iran and China have grown increasingly close. Iran is now China's second leading supplier of imported oil. In 2004, China and Iran signed two monumental energy accords, which will deliver close to $100 billion dollars worth of Iranian oil and natural gas to China over the next 25 years.

Beyond hydrocarbons, China and Iran have also expanded their trade in other areas, with China selling electronics, consumer goods, and military technology to Iran. Politically, the two countries both share an interest in curbing Western involvement in Asia and the Middle East. And US foreign policy and sanctions have helped to drive these two nations closer together. These strengthening political ties and the growing military strength in Iran give the Iranian government more

leverage in choosing its own course even in the face of growing pressure from the United States and Europe to discontinue nuclear activities. With an ally like China, Iran need not overly concern itself with what the rest of the world thinks.

Oil Tankers and The Strait of Hormuz

Between one half and two thirds of the world's oil moves by tanker each day. With the world consuming about 85 million barrels of oil per day, that means that between 40 and 55 million barrels of oil per day are being carried by tankers around the globe.

Of all the world's waterways, the Strait of Hormuz that connects the Persian Gulf with the Arabian Sea is the single most important oil transportation way. This narrow waterway separates Oman from Iran by just 34 miles. Yet, it carries the majority of Persian Gulf oil exports to the rest of the world, with about 90% of the region's exports traveling through this vital route. As such, 16 to 17 million barrels of oil are carried through this region every day.

This is another key area where Iran exerts a great deal of control.

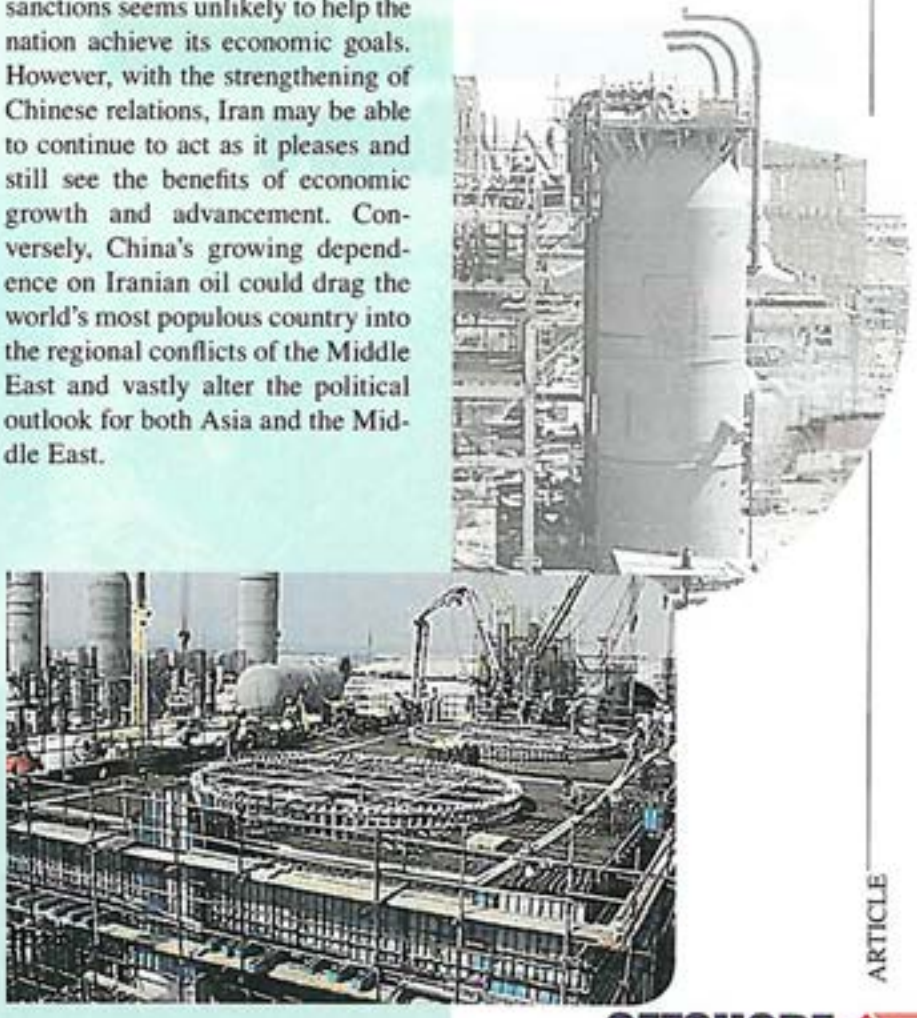
The country took control of three islands in the midst of the Strait in 1971 when its military forces invaded Abu Musa and the Greater and Lesser Tunb islands. The UAE and Iran held joint sovereignty of the islands until the early 1990s when Iran took control and claimed them as an "inseperable part of Iran." The Tunbs lie within 10 miles of the Hormuz shipping lanes, and as such, Iran has the ability to block shipping traffic from leaving or entering the Persian Gulf.

conclusion

In many ways, Iran holds an enviable position in the world. It has the world's second largest combined oil and natural gas reserves, serving to fuel its economy. It has a strong and growing relations with China, the world's fastest growing economy and a likely future world superpower, serving to give it increasing political and economic clout. It has the ability to control all of the oil flowing out of the Persian Gulf via tankers, serving as a major deterrent to any actions taken against the country.

At the same time, the country is extremely dependent on oil export revenues, which account for 80% to 90% of export revenue and almost 50% of government revenue. While the oil industry has helped the economy to grow about 5% per year, the country's inflation rate is near 15%. Iran is also suffering from high unemployment, which averages around 14%, and is much higher for young people.

With the need for investment to maintain and grow the country's oil production, it seems important that Iran be able to present a stable and investor-friendly image to the world. Acting as a pariah nation that boasts of nuclear advancements, sponsors insurgent and terrorist activities, and invites Western sanctions seems unlikely to help the nation achieve its economic goals. However, with the strengthening of Chinese relations, Iran may be able to continue to act as it pleases and still see the benefits of economic growth and advancement. Conversely, China's growing dependence on Iranian oil could drag the world's most populous country into the regional conflicts of the Middle East and vastly alter the political outlook for both Asia and the Middle East.

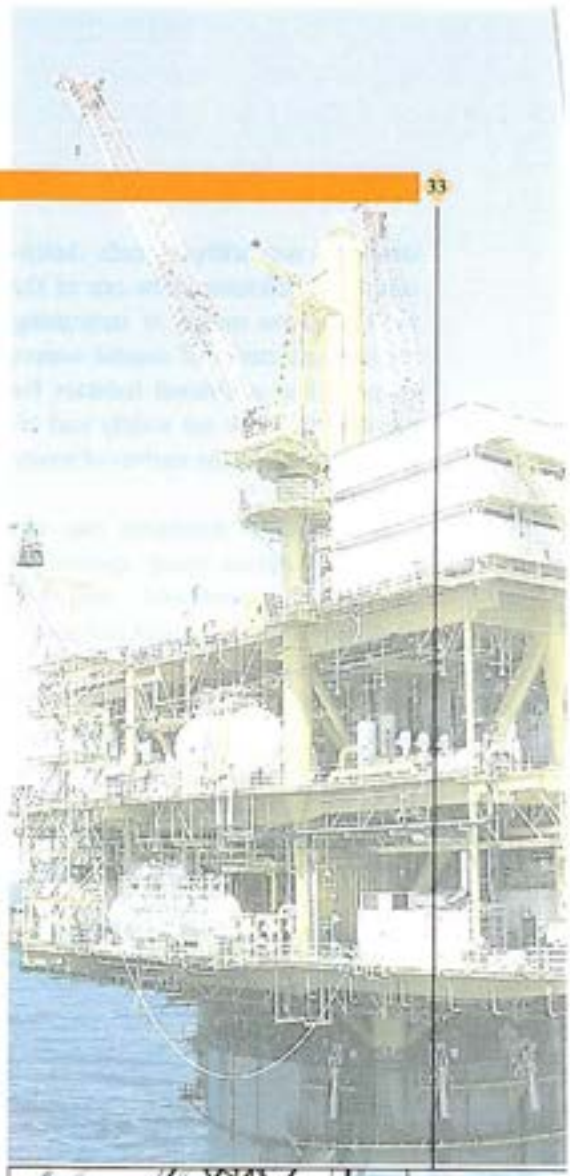


Decommissioning, abandonment and removal of obsolete offshore installations

Worn-out rigs, when discarded, may inflict unbearable damages on the marine life, but there are ways to prevent and minimize the effects.

Abandonment options

The extremely high cost of decommissioning and removal off offshore installations led to the need to revise some of the national and international regulations adopted about 40 years ago. Such a revision covered, in particular, the requirement set by the Convention on the Continental Shelf (Geneva, 1958) and the United Nations Convention on the Law of the Sea (Montego Bay, 1982) to remove abandoned offshore installations totally. At present, a more flexible and phased approach is used. It suggests immediate and total removal of offshore structures (mainly platforms) weighing up to 4,000 tons in the areas with depths less than 75 m and after 1998 - at depths less than 100 m. In deeper waters, removing only the upper parts from above the sea surface to 55 m deep and leaving the remaining structure in place is allowed. The removed fragments can be either transported to the shore or buried in the sea. This approach considers the possibility of secondary use of abandoned offshore platforms for other purposes.



From the technical-economic perspective, the larger the structures are and the deeper they are located, the more appropriate it is to leave them totally or partially intact. In shallow waters, in contrast, total or partial structure removal makes more sense. The fragments can be taken to the shore, buried, or reused for some other purposes.

From the fisheries perspective, any options when the structures or their fragments are left on the bottom may cause physical interference with fishing activities. In these cases, the possibility of vessel and gear damages and corresponding losses does not disappear with termination of production activities in the area. Instead, abandoned structures pose the threat to fishing for many decades after the oil and gas operators leave the site. The obsolete pipelines left on the bottom are especially dangerous in this respect. Their degradation and uncontrolled dissipation over wide areas may lead to the most unexpected situations occurring during bottom trawling in the most unexpected places. At the same time, national and international agreements about the decommissioning and abandonment of offshore installations refer mostly to large, fixed structures like drilling platforms. The fate of underwater pipelines is still not affected by clear regulations.

Secondary use of offshore fixed platforms

The options of reusing abandoned platforms, their foundations, and other structures that are out of service have been actively discussed for the last 10 years.

An analysis of scientific potential of research stations permanently based on abandoned oil platforms in the Gulf of Mexico revealed several promising directions of marine research at such stations [Dokken, 1993; Gardner, Wiebe, 1993]. These include studying regulation of the marine populations and coral reproduction, making underwater observations, monitoring the sea level, and collecting oceanographic and meteorological information within the framework of international projects. Some other suggestions consider transformation of abandoned platforms into places for power generation using wind/wave and thermal energy [Rowe, 1993]. These platforms also could be used as bases for search and rescue operations or centers for waste processing and disposal [Side, 1992].

From the fisheries perspective, the most interesting projects are the ones aimed at converting the fixed marine

structures into artificial reefs. Artificial reefs are known to be one of the most effective means of increasing the bioproductivity of coastal waters by providing additional habitats for marine life. They are widely and effectively used on the shelves of many countries.

The offshore structures can undoubtedly attract many species of migrating invertebrates and fish searching for food, shelter, and places to reproduce. In particular, observations in the Gulf of Mexico revealed a strong positive correlation between the amount of oil platforms, growing since the 1950s, and commercial fish catches in the region. It became one of the reasons to suggest the positive impact of offshore oil and gas developments on the fish populations and stock. Wide popularization of this fact led to the mass movement using the slogan "From rigs - to reefs" in the USA in the mid-1980s.

However, further analyses of the fishing situation in the Gulf of Mexico showed that the growth of the fish catch in this case was connected not with increasing the total stock and abundance of commercial species but with their redistribution due to the reef effect of the platforms. A critical point here was the use of static gear methods of fishing (e.g., lines and hooks) instead of trawl gears. Besides, the areas around the platforms became very popular places of recreational and sport fishing. This also made a significant contribution to the total catch volumes. Nothing similar was noted in the North Sea, where the number of oil platforms has also been growing since the 1960s. However, the total catch did not correlate with this growth at all and even decreased. This fact indicates the absence of any positive impact of the reef effect of oil platforms on the commercial fish catches in areas where the main way to fish is trawling.

At the same time, we should not forget about the danger that abandoned offshore oil platforms and their fragments pose to navigation and trawling fishing. With an abundance of such artificial reefs, this problem requires special regulations for negotiating the inevitable conflict of interests. One such regulatory program has been developed and applied in the USA in the Gulf of Mexico on the shelf of Louisiana [Pope et al., 1993]. It requires mapping the area to indicate the locations of platforms, underwater pipelines, and other structures left on the bottom. The program also includes monitoring, collecting data, developing a warning system, and other activities necessary to control the situation and ensure safety in the region.

Explosive activities

Complete or partial removal of steel or concrete fixed platforms that weigh thousands of tons is practically impossible without using explosive materials. Bulk explosive charges have been used in 90% of cases. This is very powerful, although short-term, impact on the marine environment and biota, which should not be neglected.

It is extremely difficult to get any reliable estimates of possible mortality of marine organisms, especially fish, during an explosive activity even if the initial data, such as the type of explosive, depth of the water, bottom relief, and others, are known. This large uncertainty is connected, in particular, with the high heterogeneity of fish distribution that strongly depends on specific features of fish schooling behavior. Calculations show that with a 2.5-ton (TNT equivalent) charge, the mass of killed fish will be about 20 tons during each explosion. At the same time, if, for example, a school of herring happens to get into that zone, the fish kill figure may be much higher [Side, Davies, 1989].

One of the few known observations of fish damage in zones of explosive activity was done in 1992 in the Gulf of Mexico near the shore of Louisiana and Texas [Gitschlag, Herczeg, 1994]. In order to remove over 100 fixed platforms and other structures, more than 12,000 kg of plastic charges were exploded. The amount of dead fish floating on the surface was visually recorded after the explosions. It totaled to about 51,000 specimens. The actual number of killed fish was undoubtedly higher because many specimens could not float to the surface or did not get in the zone of visual observation.

Whatever number of adult fish actually died during the explosions, it will hardly influence the total abundance of commercial species. Much more hazardous for the fish stock are explosive impacts on fish larvae and juveniles. The threshold of lethal impacts for the younger organisms weighing up to several grams is tens of times lower than that for adult specimens [Yelverton et al., 1975; Side, 1992]. Thus, the zone of mortality of fish at the early stages of development is respectively wider. The quantitative estimates of possible effects at the population level are even more complicated because of the absence of corresponding data and methods. Nevertheless, enough evidence exists to enforce strict regulations of explosive activities and to forbid them in areas and in seasons of spawning and fry development of commercial fish.

Removal of the offshore structures also decreases the number of habitats for structure-related fish. For example, in the mostly soft-bottom environment of the Gulf of Mexico, these structures provide hard substrates for marine organisms. The decline of stocks of reef fish observed in this region within the past decade can be connected, in particular, with elimination of over 400 oil-related structures that had served as an artificial habitat for marine life [MMS, 1995].

America's interests in offshore oil and gas

U.S. offshore development accounts for more than 25 percent of the country's natural gas and more than 30 percent of its oil.

U.S. offshore energy production is an essential component of the nation's energy and economic security. U.S. offshore development accounts for more than 25 percent of the country's natural gas and more than 30 percent of its oil.

1- each year, offshore energy development contributes between $4 and 6 billion in revenues to the federal Treasury.

2- Millions are also paid to states and local communities. The federal offshore produces approximately 600 million barrels of oil and about 4.5 trillion cubic feet of natural gas annually.

3- The U.S. offshore industry leads the world in developing and commercializing advanced technologies that protect sensitive environments and improve the quality of life for all Americans.

The U.S. offshore energy industry operates in accordance with the world's most stringent standards for human safety and environmental protection. Since 1985, more than 7 billion barrels of oil were produced in federal offshore waters with less than 0.001 percent spilled a 99.999 percent record for clean operations.

4- Government statistics show that

ARTICLE

the injury and illness rate for offshore workers is about 70 percent lower than for all of private industry.

5- Thirty percent of the 15 million fish caught by recreational fishermen annually off the coasts of Texas and Louisiana are caught near platforms. Conservative estimates show annual catches of approximately 450,000 pounds of reef fish annually, valued at approximately $2 million.

6- NOIA's mission is to secure reliable access to the nation's valuable offshore energy resources in order that they may be developed, produced and supplied in an environmentally responsible manner.

National Benefits, safe production since 1953, OCS development as produced more than 14 billion barrels of oil and 160 trillion cubic feet of natural gas. Currently, about 25 percent of the natural gas and 30 percent of the oil produced in the United States comes from the federally managed OCS.

NATIONAL BENEFITS

The submerged lands of the Outer Continental Shelf (OCS) of the United States have proved to be one of the most bountiful sources of offshore oil and natural gas in the world.

On a per-day basis, the OCS currently produces about 13.9 billion cubic feet of natural gas and about 1.3 million barrels of oil. The federally managed OCS provides the bulk—about 89 percent—of all U.S. offshore production. Five coastal states—Alaska, Alabama, California,

Louisiana and Texas—make up the remaining 11 percent. Between 1953 and 2002, the offshore energy industry has contributed more than $145 billion to federal revenues.

Ten of these revenues were derived from royalty payments that are assessed on oil and natural gas produced from federal lands — typically one-eighth or one sixth of oil and natural gas' market value.

Royalties, rents and bonus payments are collected by the Minerals Management Service (MMS) — which often results in that agency serving as the second largest collector of federal revenues after the Internal Revenue Service.

Although most the revenues derived from offshore energy activity are deposited directly into the federal Treasury, these revenues are also the source of funds for the Land and Water Conservation Fund and the National Historic Preservation Fund. State and federal agencies use the Land and Water Conservation Fund Act to buy parks and recreation areas.

Annually nearly $1 billion dollars in OCS revenues flow to this program.

Likewise, the National Trust for Historic Preservation has received more than $2.5 billon in offshore energy proceeds to help preserve historic legacies since 1982.11 Like the Land and Water Conservation Fund, money from the National Historic Preservation Fund is distributed to states whether or not they have any offshore leasing or production seaward of their coasts.

Coastal states in producing areas also have a direct claim on OCS revenues under Section 8(g) of the Outer Continental Shelf Lands Act For leases on the submerged lands lying outside the 3-mile state zone and as far as 10 miles offshore, 27 percent of the royalty, rent and bonus revenues are since 1982, $16 billion in OCS revenues have been paid into the land and Water conservation fund. The national historic preservation fund receives about $150 million annually in OCS revenues national Benefits, safe production paid directly to the adjacent states. States have used these funds for a variety of programs. Alabama established the "Forever Wild Program" with offshore leasing and production money to acquire, maintain, and protect unique habitats. Mississippi has a similar "Gulf and Wildlife Protection Fund" and Louisiana uses its money for education.

Employment

The Gulf coast of Texas, Louisiana, Mississippi and Alabama is the

birthplace of offshore prospecting for oil and natural gas, and the economic benefits of that development continues to accrue to that region to the present day. There are more than 85,000 jobs that are directly related to the industry, and an equal number of workers employed in supporting jobs indirectly related to OCS activity.

The average salary and benefits for workers of producing companies employed as a direct result of activity in the Gulf of Mexico was estimated to be $52,580 in 1992. (The last year for which statistics are available.)

Since then, a shortage of skilled

labor due to the recent boom in industry activity has pushed earnings even higher. In addition to payroll expenditures, producers pay several billion dollars each year to vendors and contractors who support OCS activities.

Safety and environmental performance

The National Academy of Science's National Research Council recently released the results of a comprehensive study entitled, Oil in the Sea III: Inputs, Fates, and Effects. The report finds that although the amount of oil produced and transported on the sea continues to rise, improved production technology and safety training of personnel have significantly reduced both blowouts and daily operational spills. In fact, the report states, today, accidental spills from platforms represent only 2 percent of petroleum inputs in U.S. waters and about 4 percent worldwide.

Furthermore, the MMS has found that most spills are quite small — with the median being three barrels or less. Between 1971 and 2000, 41 percent of all spills were less than three barrels in size, 81 percent were less than 10 barrels, and 96 percent were less than 100 barrels.

The industry remains under intense scrutiny by its two primary regulators — the MMS and the U.S. Coast Guard— as well as a host of other governmental the 8 (g) revenue sharing agreement has distributed more than$3 billion to coastal states since 1986, and$108 million in 2000alone.

Offshore development accounts for some 170,000 jobs! Since 1985, more than 7 billion barrels of oil were produced in federal offshore waters with less than 0.001percent spilled— a 99.999 percent record for clean operations.

Safe production

It is the MMS that regulates all exploration, development, and production activities on about 8,000 active leases to ensure that these activities are conducted safely and in an environmentally sound manner. The MMS reviews and approves industry exploration and development plans before allowing any operations to commence, monitors all lease operations to ensure that industry is in compliance with relevant requirements, and conducts scheduled and unscheduled inspections. In 1997, MMS conducted over 12,000 inspections of OCS facilities.

Innovation Boosts U.S. energy

Between 1996 and 1999, technological advances coupled with economic incentives passed by Congress under the 1995 Deepwater Royalty Relief Act, encouraged energy companies to acquire more than 2,600 leases in waters 800 meters or greater pushing the total number of leases in the Gulf of Mexico to more than 7,000.

The number of deepwater exploratory wells drilled more than doubled from 1996 to 1998, despite the limited number of rigs that can work at such water depths and the decline in crude oil prices during this time period. During that same period, production from deepwater wells jumped 50 million barrels, bringing total Gulf of Mexico deepwater oil production to more than 570 million barrels in 2001— nearly a 535 percent increase from 1995. By 2002, deepwater activity contributed 959,000 barrels of oil and 3.6 billion

cubic feet of natural gas per day to U.S. energy supplies — approximately 61 percent of the Gulf's total production.

Innovative technological leaps have enabled this thrust into ever-deeper waters. Floating drilling rigs and production platforms are now able to maintain position over top of a well thousands of feet below without the need to moor a fixed structure to the ground. Dynamic positioning systems use computer-controlled directional propellers compensate for wind, wave or current to keep the vessel stationary relative to the seabed, while innovative hull design maintain stability even in "hundred–year" storms.

As a result, drilling is now taking place in waters more than 10,000 feet deep, an accomplishment that would have been unimaginable just 20 years ago. Since 2001, industry has announced 11 major discoveries in waters exceeding 7,000 feet.

The deep shelf trapped more than 15,000 feet within the earth's crust; so-called "deep natural gas" represents a tremendous untapped domestic energy resource. Government studies estimate that there could be more than 20 trillion cubic feet of untapped deep natural gas deposits in the Gulf of Mexico— about as much as is currently being produced from all areas in North America on an annual basis! Annual gas production from Federal waters of the Gulf of Mexico has exceeded additions to proved gas reserves every year since 1984, causing a decreasing trend in remaining proved gas reserves. New discoveries of deep gas on the OCS offer the best short-term opportunity for achieving the large reserve additions and necessary high flow rates to offset declining gas production, which has been falling since 1997.

Recent deep gas discoveries on the OCS have shown these new completions can produce as much 20 to 80 million cubic feet per day.

Unfortunately, despite significant advances in deep gas technology, these prospects remain very challenging to find and develop successfully. Since 2001, Gulf natural gas production has decreased from 5,128 BCF to 4,175 BCF in 2003. Deep gas discoveries may help reverse this trend however: deep gas production increased from a relatively low 284 billion cubic feet in 2000 to 421 billion cubic feet in 2002.

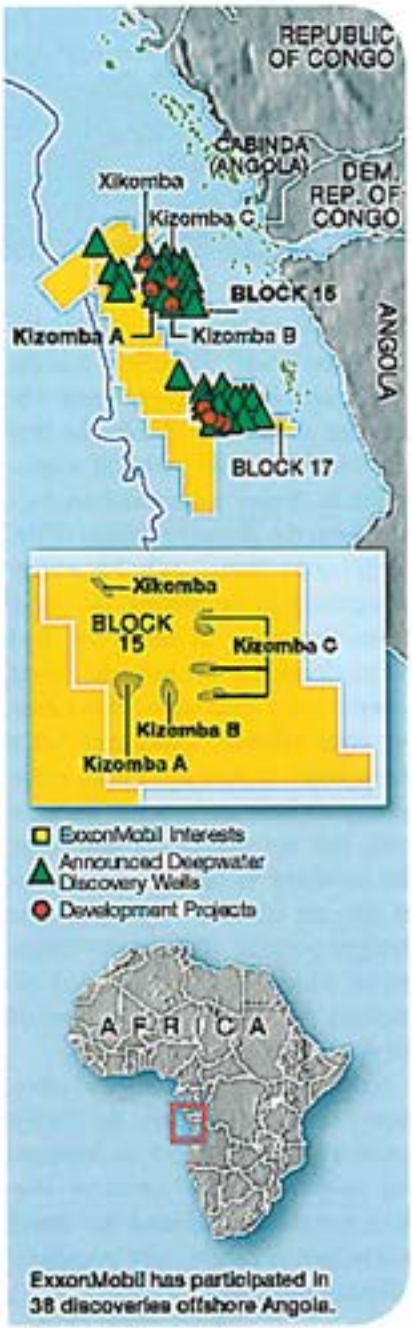
New life for the "dead sea"

As recently as the late 1980s, many experts agreed that oil reservoirs in the Gulf were drying up. With oil and natural gas output slackening, since the deep Water royalty relief act passed in1995, more than 2,600 tracts have been leased in water depths of 800 meters and greater.

Innovation Boosts U.S. energy national Benefits, safe production some dubbed the Gulf of Mexico the "Dead Sea". However, leading edge technologies breathed new life into the Gulf — technologies that have enabled more efficient exploration in deeper waters and production from the deepest recesses of the earth's crust. Now the Gulf is widely recognized to be among the most promising areas in the world and oil production levels have increased sharply every year since 1996.Leading edge offshore technology helps the country to find and produce the energy to heat our homes, fuel our cars, run our computers and drive the economy in faster, safer, cleaner and ore efficient ways than ever thought possible. These innovations began with the natural gas and oil industry but they enrich the lives of all Americans.

As the leading technological laboratory in the oil industry, the Gulf's transformation provides an interesting snapshot of the advances that have reverberated around the world and helped to keep energy abundant, affordable and clean.

The Kizomba-A oil project offers better economy for Angola



ExxonMobil has participated in 38 discoveries offshore Angola.

The project has already brought jobs, technology, infrastructure and hope for a higher standard of living in Angola.

Tankers plying the seven seas to feed an energy-hungry world have a new stop some 200 miles offshore Angola.

The Kizomba A project, with recoverable resources of about 1 billion barrels of oil (gross) (ExxonMobil interest, 40 percent), began producing more than 130,000 barrels of oil a day in August. Current rates are averaging 200,000 barrels a day and are expected to reach 250,000 barrels a day during 2005.

Kizomba A, in water 3,300 to 4,200 feet deep and representing an investment of nearly $3.5 billion, is the largest deepwater energy development in West Africa. Indeed, it's the first of three world-class projects in Angola's offshore Block 15 that collectively are expected to develop more than 2.5 billion barrels of oil at an investment of some $10 billion.

The project has already brought jobs, technology, infrastructure and hope for a higher standard of living in Angola.

"The start-up represents a milestone for Angola," says Harry Longwell, Exxon Mobil Corporation director and executive vice president. "As planned, our projects are employing leading-edge deepwater technology to develop significant new oil-production capacity. They demonstrate our commitment to the long-term development of Angola's hydrocarbon and human resources."

Indeed, with ExxonMobil as the region's largest producer in deepwater tracts, Angola and West Africa will assume a growing share of the world's crude oil production over the next 10 years. By 2030, the region is expected to account for approximately 7 percent of global oil supplies.

A giant jigsaw puzzle

With only the beginnings of an oil industry in West Africa, components of Kizomba A had to be built elsewhere and delivered to Angola, ready for use.

"It required major construction projects on four continents and unique applications of deepwater technology," says Dave Marchak, project executive. "Like a giant jigsaw puzzle, pieces were built in South Korea, the United States, Malaysia, the Netherlands and Angola, with at least a dozen nationalities on the project team."

Kizomba A consists of three main components. The drilling center is a tension leg platform (TLP) that includes a rig and 36 slots for drilling the project's planned oil and gas wells.

Moored nearby is a floating production, storage and offloading (FPSO) vessel designed to take all of the oil produced from the platform, process it

Kizomba A field operations in 3,300 to 4,200 feet of water feature a floating, production, storage and offloading (FPSO) vessel that's about 300 yards long. Shown to the left is a tension leg platform that contains 36 well slots for drilling. A semisubmersible rig visible on the horizon drills additional wells.

and store it until the oil can be offloaded onto waiting tankers.

The third main component of Kizomba A is a series of 26 subsea wells. Unlike the surface wellheads on the production platform, these are installed on the ocean floor. It is unique that all of the subsea wells are injectors. These injectors take water and gas that have been separated from the oil and pump them back downhole to maintain pressure in the oil-bearing reservoir. Nearly three soccer fields long

The largest of Kizomba A's four main contracts covered construction of the FPSO. The production vessel, almost the length of three soccer fields, holds 2.2 million barrels of oil.

Lisa Waters managed its design and construction. She and her engineering team lived in South Korea near the Hyundai shipyard for two years while the vessel was being built. The shipyard — the largest in the world — is also building the FPSO for Kizomba B, which will be installed in 2005.

"Kizomba A and B are as close as you can get to the concept we call 'Design One, Build Two,'" says Waters. "The hull and marine systems for the two vessels are identical. The topsides are nearly identical. We transferred what we learned on Kizomba A. As a result, the construction of Kizomba B is well ahead of schedule. We're one of the few oil companies that has the global reach and technology strengths to be able to pursue this concept."

A 40,000-mile journey

For the TLP, engineers knew that what they wanted was possible, but it had never been done before: build a complete tension-leg platform, pick it up and deliver it thousands of miles by sea.

One of the early decisions was how to handle all the interfaces between various contractors regarding design, hardware and delivery times. The hull was built in South Korea. Topside modules were built in North America, and the platform was assembled in the Netherlands.

"Timing was critical," says Brian Boles, project manager. "In a global effort like Kizomba, each component must arrive on time, or we risk delaying the entire job."

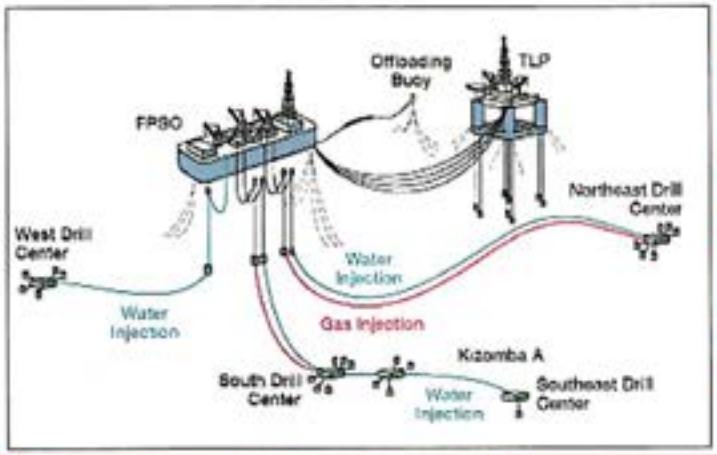
By the time the TLP was delivered to Block 15 in October 2003, its major components had traveled more than 40,000 miles on some of the largest transport vessels in the world.

The excitement is still building

Esso Exploration Angola has about 580 employees, 65 percent of whom are Angolans working in their own country. That percentage will continue to grow as more workers are trained.

Workers inspect some of the massive suction piles that help stabilize the FPSO.

Laurindo Pemba (left) and Guilherme Pascoal perform maintenance aboard the FPSO, center of Kizomba A's production operations



The center of production operations at Kizomba A is a 2.2 million-barrel floating production, storage and offloading vessel (FPSO). Development drilling is conducted with a tension leg platform (TLP) secured to the seafloor by eight long tendons that attach to the hull and "pull down." The tendons are secured by piles the height of a 30-story building.

"The focus on local workers is essential to our success in Angola and to the country's growing economy," says Terry McPhail, Esso's lead country manager. "An even larger economic impact comes from the estimated 3,500 contractors and subcontractors in Angola who work to support our ongoing operations."

To train the workers it needed, Esso spent $400,000 upgrading the National Institute of Petroleum in Sumbe, a coastal town about 160 miles (260 kilometers) south of Luanda.

Esso and its partners also spent $10 million to upgrade the Lobito fabrication yard and training facility owned by Sonangol, Angola's national oil company. Another $10 million went to upgrade Sonangol's offshore supply base in the town of Soyo.

Meanwhile, ExxonMobil and its co-venturers have announced 38 discoveries in Angola. ExxonMobil holds interests in five offshore deepwater blocks covering 4.5 million gross acres. Those blocks contain a resource base now estimated at more than 11.5 billion oil-equivalent barrels (gross).

"This is an exciting time for Angola and for ExxonMobil,"says Tim Bryan, business manager for Kizomba A and B. "and you can look for a lot more excitement as more of these world-scale oil and gas developments become realities.

ExxonMobil and its partners invested more than $10 million to upgrade the fabrication yard at Lobito, Angola, including this pipe rack for assembling piles for the TLP. Other infrastructure improvements are planned.

Note: Estimates, expectations, and business plans in this article are forward-looking statements. Actual future results, including resource recoveries, production rates, and project plans, schedules and costs, could differ materially due to changes in long-term oil and gas price levels or other market conditions affecting the oil and gas industry; political or regulatory developments; reservoir performance; timely completion of development projects; technical or operating factors; and other factors discussed under the heading "Factors Affecting Future Results" included in Item 1 of ExxonMobil's most recent Form 10-K and posted on exxonmobil.com. References to recoverable resources, the resource base and expected development or recovery amounts include quantities of oil and gas that are not yet classified as proved reserves but that we believe will be produced in the future.

Avoiding Costly Downtime and Delays in Offshore Electrical Operations

In offshore oil and gas operations, downtime and delay can cost millions of dollars, especially at today's record oil prices. Any number of systems and components can impact operations, but among the most critical and often overlooked are the wire and cable used for power, control, instrumentation, and emergency systems for offshore operations.

Each one of these systems must meet a variety of stringent standards, and choosing the wrong wire and cable could lead to loss time and more importantly lost revenue to operators who are down due to un-planned maintenance. So choosing wire and cable is more complicated than simply complying with regulations or meeting specifications. Simply put, there is more to consider than what comes on the spool.

Initially supply and availability is a critical component of selecting wire and cables. Can the partner you're relying on really deliver what is needed during the construction phase or do they have it in stock for routing maintenance? With oil at record levels, how long can a company afford to wait for wire and cable? Every day of delay can cost millions which can easily pay for the entire wire and cable needed for a rig.

Product breadth is also a key factor in selecting a wire and cable supplier. Can the supplier offer you a full range of wire and cables that are certified for use in all major global offshore markets? Or are you forced to source from more than one company that can add to compatibility, delivery and installation issues? More importantly, do they have a global distribution system in place to deliver the right wire & cables regardless of your location?

Is there a trained and globally accessible technical staff available to advise you on using the proper wire & cable regardless of where you're operating? An experienced engineer knows that cost is more than a function of price. Sourcing from a single source can greatly simplify the entire process and reduce purchasing, engineering and installation costs.

Tracking down the rigs

Where the rigs have been moving in the last six years.

Rig utilization impacts the distribution of the rig fleet around the globe. As demand grows in one area, it may decline in another and rigs move to new markets.

Moving On Up All around the world, rigs are moving into developing regions, pushing the offshore rig counts higher than they have ever been in these areas.

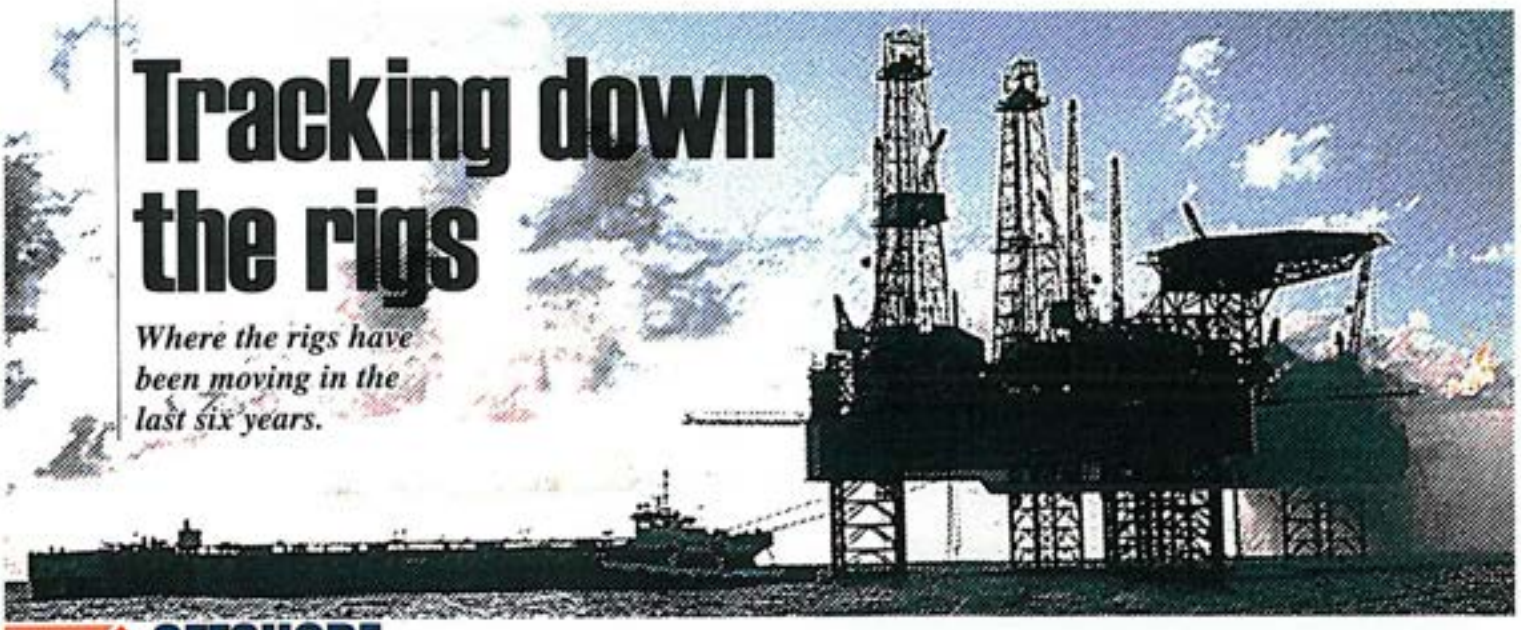
Mexico has seen the largest increase in the number of rigs working its waters. In July 2000, there were only 5 rigs offshore Mexico, 4 of which were under contract. That number fluctuated somewhat through 2001 and into 2002, when the rig count began to take off. At the start of 2002, there were 10 rigs in Mexico and by the end of 2002 there were 26 rigs, a 160% increase in 1 year. The growth continued as Pemex increased its exploration budget on into 2004, when the Mexican rig count peaked at 45 rigs and held at that level for 10 months. From the initial level of just 5 rigs to 45 rigs is an increase of 40 rigs, an 800% increase. Since the start of 2005, the rig count has fallen back to a current count of 37 rigs.

The Persian Gulf has been another area that has benefited from a growing rig fleet over the last 6 years. In July 2000, there were 44 rigs in the region, working at just 66% utilization. That number started to grow in early 2001, and since that time, a total of 28 rigs have moved into the region pushing the overall rig count up to a current total of 72 rigs. That's an increase of 28 rigs, which equals 64% growth over 6 years. That growth was fairly steady over that time frame, although there was a large growth spurt of about 10 rigs in 2001 and another spurt of 8 new rigs over the last year.

In the Far East and Australia, there has been a slow and steady growth in the rig count, with an average of 4 to 5 new rigs entering the region each year. In July 2000, there were 59 rigs in the area, of which 47 were contracted. By July 2005, 18 new rigs had entered the market. But within the last 12 months alone, a total of 10 more new rigs have come into the area, pushing the total rig count up to 87 rigs. That marks a 47% increase over the last six years.

Southern Asia, for which India accounts for almost all-offshore activity, has seen significant growth in its rig count since July of 2000. At that time, there were only 12 offshore rigs working in the region. That number grew steadily over the next 5 years to a peak of 38 rigs working at 100% utilization in early 2005. Since that time, the number has come down slightly and held near the mid-30s, with a current rig count of 36 rigs. That is a 200% increase caused by 24 new rigs entering the region over 6 years.

The Mediterranean, Black Sea, and Red Sea taken as a group has also seen their overall rig count in-



crease over the last six years. In July of 2000, there were 21 rigs working in these waters, which declined to just 20 rigs in 2001. From 2001, the number of rigs in the region has grown steadily until the end of 2005, when the rig count peaked at 36 rigs with 90% utilization. In the last 7 months, the number of rigs has fallen to 31 rigs. But, for the last 6 years, the region shows a net gain of 10 rigs, a 48% increase.

Steady as They Go A few regions of the world have had fairly consistent rig counts over the course of the last six years. Of course, none of these regions was perfectly static, but overall, the rig counts did not vary more than about 10 percent from the 6-year average number of rigs.

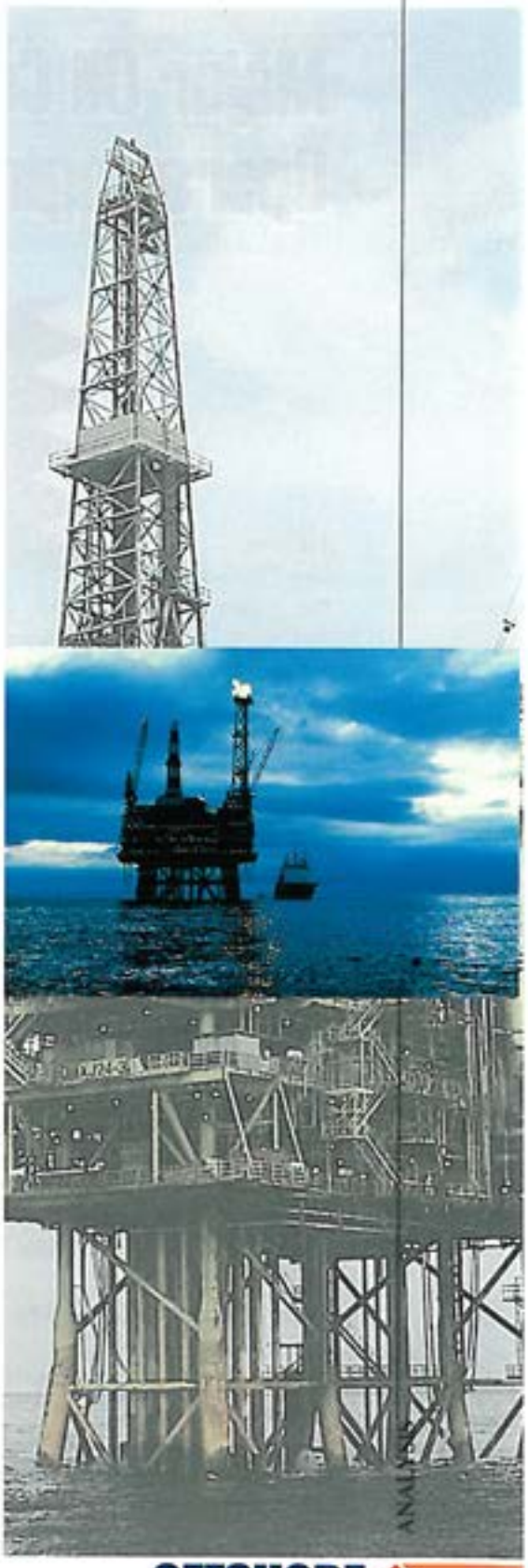
South America has remained-steady for most of the last 6 years. During late 2000 and early 2001, the rig count varied from 40 rigs up to 57 rigs. The rig count slowly declined over the course of 2002 and 2003, steadying at about 50 rigs, which the rig count has remained near until the last 18 months, when it declined by a few more rigs to its current count of 47 rigs. With the decline in overall rig count, South American rig utilization has pushed upwards above 90% for the first time in the last 6 years, holding about 90% for the last 10 months.

West Africa has also held a consitent rig fleet over most of the last 6 years. The rig count stood at 40 rigs, of which 32 were contracted, in July 2000. By early 2001 that number had grown 12% to 45 rigs. Since that time, the number of rigs in the region has remained between 42 and 52 rigs, varying only about 5% from the average of 45 rigs. There are currently 48 rigs in the region, and 47 of those are contracted, for a very high utilization rate of 97%.

Emptying Out With quite a few regions experiencing significant growth in the size of their offshore rig fleets, most of those rigs had to come from some other region. At the same time, not all of the rigs moving into these growing areas were rigs moving from other patrs of the world; a portion of the additions in these regions were newbuilds, which accounted for 24 new jackups, 18 new semisubs, and 5 new drillships that joined the fleet from July 2000 to today.

The North Sea rig fleet has seen a small decline in its overall size over the last 6 years. In July 2000, there were 80 rigs in the North Sea. By late 2001, that number had grown to 87 rigs. After the start of 2002, the fleet size dropped by 18 rigs to just 69 rigs in September 2004. It has since begun to recover, and the North Sea fleet now stands at 77 rigs. Overall, that is just 4% (3 rigs) below its level of 6 years ago and 12% (10 rigs) below its 2001 peak.

The Gulf of Mexico experienced by far the biggest loss in total fleet size over the last 6 years. Like the North Sea, the region experienced some growth and peaked in 2001, rising from 193 rigs July 2000 to a maximum of 206 rigs in September 2001. In the nearly 5 years since that time, the Gulf of Mexico has lost an average of more than 1 rig per month every month. The only exception to this trend was the 9 month period from January to September 2005, when the decline stopped near 150 rigs and pulled back up to 158 rigs before continuing its decline to just 140 rigs today. Over the last 5 years, the GOM has lost 64 rigs, more than 30% of its overall fleet of jackups, semis and drillships.



Major Oil Companies Operating In The Persian Gulf

Bahrain:

State Companies:

The Bahrain National Oil Company (BANOCO), wholly owned by the Bahrain Government, and is the holding company for the Bahrain Petroleum Company (BAPCO)

Joint Ventures:

Bahrain National Gas Co. (Banagas) is owned 75% by the government of Bahrain, 12.5% by Caltex, and 12.5% by the Arab Petroleum Investment Corp.

Bahrain Aviation Fueling Co. (Bafco) is the aviation refueling service at Bahrain International Airport. It is owned by Banoco, 60%; Caltex 27%; BP, 13%

Original Concession Holders:

Bahrain Petroleum Co. Ltd., an equal partnership of Texas Oil Co. and Socal, also offshore concession granted to Continental Oil Co.

Continental Oil Co. of Bahrain, Continental Oil Co., Pure Oil Middle East Inc. (Union Oil of California)

Major Foreign Oil Company Involvement:

Harken Oil, of Grand Prairie, Texas, who is backed in part by Bass Enterprise Production Company of Fort Worth, Texas Harvard University, a major shareholder in Harken through an affiliate, and George W. Bush

Iran:

State companies:

National Iranian Oil Company (NIOC) - oil and gas exploration and production, refining and oil transportation; National Iranian Gas Company (NIGC) ,manages gathering, treatment, processing, transmission, distribution, and exports of gas and gas liquids; National Petrochemical Company (NPC) - handles petrochemical production, distribution, and exports.

Original Concession Holders:

Anglo Persian Oil Company, replaced in 1954 by Iranian Oil Participants Limited, a joint venture of British Petroleum, Jersey, Socony, Texaco and Socal, Gulf, Royal Dutch/Shell Group, Iricon Agency Ltd., Richfield Oil Corp., Signal Oil and Gas, Aminoil, Sohio, Getty, Atlantic Oil, Tidewater Oil, San Jacinto Petroleum Corp., and CFP

Iran Pan American Oil Co., American International Oil Co. (Standard Oil of Indiana)

Iranian Offshore Petroleum Co., Tidewater Oil, Superior Oil, Sunray DX, Cities Service, Kerr-McGee, Atlantic Richfield, Skelly Oil

Lavan Petroleum Co., Atlantic Richfield, Murphy Oil, Sun Oil Co., Union Oil of California

Major Foreign Oil Company Involvement:

Gazprom
Petronas
Shell
Total

Recent Developments:

(Concluded at least negotiations with):

Elf Aquitaine
Japex, the state-owned Japanese Exploration and Production Co.,
PetroCanada
Ultramar (Canada)

The U.S. Treasury has allowed two American companies (Chevron, Coastal) to import Iranian crude

Iraq:

State companies:

The Oil Ministry oversees the nationalized oil industry through the Iraq National Oil Company (INOC). Autonomous companies under INOC include: State Company for Oil Projects (SCOP) - design and engineering of upstream and downstream projects; Oil Exploration Company (OEC) - exploration; Northern Oil Company (NOC) and Southern Oil Company (SOC) - upstream activities in northern/central and southern Iraq, respectively; State Organization for Oil Marketing (SOMO) - crude oil sales and OPEC relations; Iraqi Oil Tankers Company (IOTC)

Original Concession Holders:

Iraq Petroleum Company (Mosul Oil Company and Basrah Oil Company), Royal Dutch/Shell, Anglo-Persian, CFP, Exxon, Mobil, Atlantic Richfield, Gulf Oil Corporation, Standard Oil of Indiana [Amoco], and Participations and Explorations Corp., under auspices of the Near East Development Company.

Recent Developments:

U.S. previously operating in Iraq include Haliburton, Howe-Baker Engineering Inc., Mobil Oil, and Pullman-Kellogg.

Iraq's State Oil Marketing Organization (SOMO), -- pending U.N. approval --is in discussions with: U.S. companies Coastal Corp., Phoenix, Chevron Corp. and Mobil Corp.

Iraq has current contracts with Coastal, Russian Sidanco and France's Total S.A.

The Oil Daily reports that Shell, BP, Chevron, and Coastal are among the companies interested in buying Iraqi crude

Kuwait:

State Companies:

Subsidiaries of Kuwait Petroleum Corp. include: Kuwait Oil Co. (KOC), Kuwait National Petroleum Co., Petrochemical Industries Co. (PIC), Kuwait Oil Tanker Co., Kuwait Foreign Petroleum Exploration Co. (Kufpec), and Kuwait Petroleum International (KPI, London)

Original Concession Holders:

Kuwait Oil Co. Ltd., subsidiary of BO (Kuwait) Ltd., and Gulf Kuwait Co., Kuwait Shell Development Co. Ltd., owned by Royal Dutch/Shell Group

For Kuwaiti portion of Neutral Zone:

Offshore: Arabian Oil Company Limited, Japan Petroleum Trading Co. Ltd.

Onshore: American Independent Oil Co., joint venture of Phillips Petroleum, Signal Oil and Gas, Ashland, J.S. Abercrombie, Sunray Mid-Continent Oil Co., Globe Oil and Refining Co., and Pauley Petroleum Inc.

Major Foreign Oil Company Involvement:

British Petroleum Co. Plc
Chevron
Getty Oil Co.
Gulf Oil
Japan's Arabian Oil Co. (AOC)
Mobil Corp.
Royal Dutch/Shell,
Shell International Petroleum Co. Ltd.
Texaco
Total

Oman:

State companies:

Petroleum Development Oman Ltd. (PDO) controls all oil resources. Oman Oil Company (OOC) is the overseas investment arm of the Ministry of Petroleum, until recently headquartered in Houston and headed by John Deuss

Joint Ventures:

Petroleum Development Oman Ltd. (PDO) controls all oil resources. PDO is a partnership between the Omani government (60%), Shell Petroleum Co. Ltd. (34%), Total-CFP (4%), and Partex (Oman) Corp. (2%)

CXO Ltd. Is a joint venture of Oman Oil Co. Ltd. and Caltex

Original Concession Holders:

Petroleum Development (Oman) Ltd., Shell Group, CFP, Participations and Explorations Corp., and John W. Mecom

Mecom-Pure-Conoco, John W. Mecom, Pure Oil, Continental Oil

Major Foreign Oil Company Involvement:

There are two American concessionaires: Occidental/Gulf and Amoco. Ashland Oil manages Oman's sole refinery, and U.S. firms lift Oman's crude.

Qatar:

State Companies:

The Qatar General Petroleum Corporation (QGPC)

Joint Ventures:

QGPC owns 65% of Qatar Liquefied Gas Co. (QatarGas) the rest of the interest is divided among France's Total SA. (10%), Mobil Qatar Gas Inc. (10%), Mitsui & Co. Ltd. (7.5%), and Marubeni Corp. (7.5%)

QatarGas Upstream, partners are Total, 20%, Mobil 10%, and Mitsui and Marubeni, 2.5 each

QGPC holds 66.5% of Ras Laffan LNG Co. (RasGas); Mobil 26.5 ; the Japanese companies Itochu Corp. and Nissho Iwai, respectively, 4% and 3%

Qatar Vinyl Co. (25.5% QGPC, 31.9% Qapco, 29.7% Norsk Hydro, and 12.9% Elf Atochem)

Qatar Fuel Additives Co. (50% QGPC, 20% Chinese Petroleum Corp., 15% Lee Chang Yung Chemical Industry Corp., and 15% International Octane Ltd.)

Original Concession Holders:

Continental Oil Co. of Qatar, Continental Oil Co., Pure Oil Middle East Inc. (Union Oil of California)

Anglo Saxon Petroleum Company, Shell

Major Foreign Oil Company Involvement:

ARCO Qatar Inc., (as operator for a consortium of Germany's Wintershall A.G. and Preussag A.G., British Gas Co., and Gulfstream Resources Canada Ltd. of Calgary)

Chevron Over-seas Petroleum (Qatar) Ltd. and its partner Magyar Olaj Gazi (MOL), the Hungarian Oil & Gas Co. Ltd.

Elf Petroleum Qatar.

Enron

Maersk Oil Qatar Co.

Marubeni

Methanex Corp. (Vancouver)

Mitsui

Mobil Oil Qatar

Mobil, MOL

Occidental Petroleum of Qatar Ltd..

Pennzoil Qatar Oil Co.

Phillips Petroleum Co.

Royal Dutch Shell

Wintershall

Saudi Arabia:

State Companies:

Saudi Aramco

Samarec

Petromin

Petromin Lubricating Oil Refining Co. (Luberef), [Mobil Oil Corp. holds a minority interest in this company]

Petromin Lubricating Oil Co.,

Saudi Arabian Basic Industries (Sabic)

Original Concession Holders:

Arabian American Oil Company, Socal, Texas Oil, Jersey, Socony-Vacuum

For Saudi portion of Neutral Zone: Getty Oil Co., Japan Petroleum Trading Co.

Joint Ventures:

Star Enterprise (U.S.) Saudi Refining Inc. (50%), Texaco (50%);

Ssangyong Oil Refining Co. (S. Korea) Saudi Aramco (35%), Ssangyong (65%); Luberef - Mobil (30%) and Petrolube - Mobil (29%)

Samref, an export fuels company- Mobil is a 50% shareholder

Subsidiaries: Aramco Services Co. (Houston), Aramco Overseas Co. (Netherlands), Saudi Petroleum International Inc. (New York), Saudi Petroleum Overseas Ltd. (London/Tokyo)

Major Foreign Oil Company Involvement:

Mobil

Shell

UAE:

State Companies:

Abu Dhabi National Oil Company (ADNOC) has controlling interest in 21 domestic oil and natural gas companies.

Joint Ventures:

Abu Dhabi Co. for Onshore Oil Operations (ADCO) is held by ADNOC (60%) and a consortium comprising British Petroleum (BP) (9.5%), Shell (9.5%), Total (9.5%), Exxon (4.75%), Mobil (4.75%), and Partex (2%).

Abu Dhabi Marine Operating Company (ADMAOPCO) is held by ADNOC (60%) and a consortium comprising BP (14.7%), Total (13.3%), and Japan's Jodco (12%).

Zakum Development Company (ZADCO) is operated by ADNOC (88%) and a consortium (12%) comprising BP, Jodco, and Total

Original Concession Holders:

Union Oil Co., venture of Union Oil Co. and Southern Natural Gas Co.

Abu Dhabi Marine Areas Ltd., BP, CFP, Continental

Dubai Marine Areas Ltd., Continental Oil, BP, CFP, Deutche Erdol AG, Sun Oil Co.

Phillips-AGIP-Aminoil, joint venture of Phillips, AGIP, and Aminoil

Major Foreign Oil Company Involvement:

BP

Caltex Petroleum Corp.,

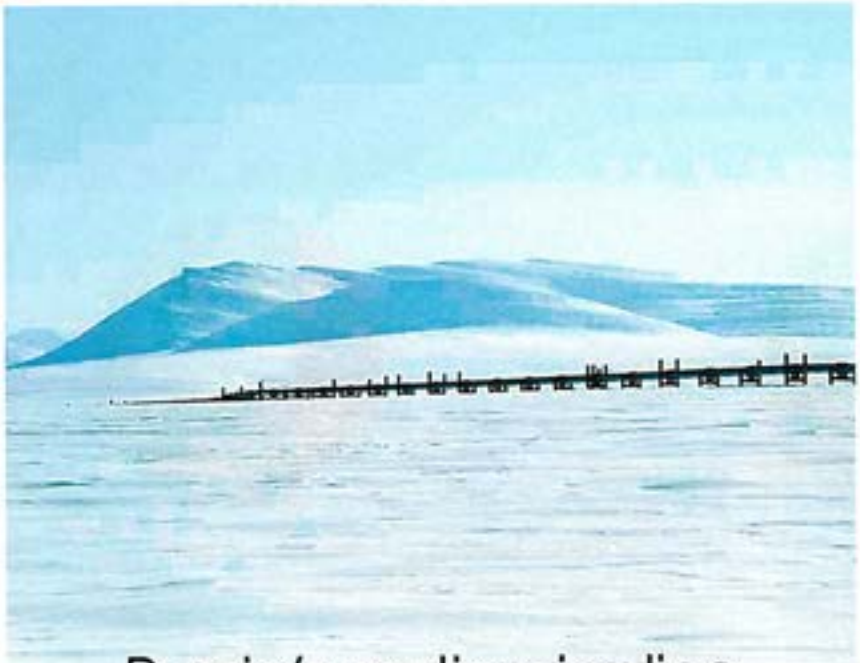
Miutsui & Co. Ltd.

Parrex

Pennzoil

Shell Gas BV

Total



Russia's arctic pipeline under feasibility study

An investment feasibility study for the construction of an Arctic oil pipeline has been turned over to the government for analysis, an oil pipeline company's vice president said Wednesday.

The proposed $2.2-billion Kharyaga-Indiga pipeline will stretch more than 450 kilometers (280 miles) and is designed to pump 12 million metric tons per year (240,000 bbl/d) of oil from a major deposit in northwestern Russia to the country's Arctic coast.

Under existing plans, the crude will then be loaded onto tankers and shipped to Europe and North America.

"We have held public hearings and the feasibility study on investments has been turned over for a state expertise," Yevgeny Astafyev, a vice president of the Transneft oil pipeline company, said, adding that a government resolution is needed to begin construction.

He added that guarantees from domestic crude suppliers and foreign customers were also needed for work to begin.

In April, the chief executive of Transneft said a feasibility study for the pipeline, which would source oil from the Timan-Pechora basin, could be completed in November.

He said once the Kharyaga-Indiga oil pipeline went online, higher-grade Timan-Pechora crude would not have to be mixed with Russia's standard Urals blend, which has a higher sulfur content.

The Timan-Pechora field's recoverable reserves have been reported at 20 billion barrels of oil equivalent, with crude accounting for 66%, natural gas for 30%, and condensate for 4%.

IOEC wins four rig-building contracts

IOEC, Iran offshore engineering construction company, secured one build and lease contract for two rigs thought negotiation with Pars Oil & Gas Company (POGC).

It also won a second build and lease contract for two rigs in partnership with National Iranian Drilling company (NIDC) via an international tender Bids are also due on 15 October for a separate POGC contract to construct another two rigs.

Engineering procurement and construction (EPC) cost on each of the rigs in the region of $150 million-$180 million. POGC will rent the build and lease rigs for five years at a rate of $85,000 a day-about $31 million a year.

The rigs are to be delivered in 24 months.

Tehran has placed contracts worth up to $600 million for four offshore rigs for use in the south pars gas fields.

Potential Iranian bidders include IOEC, NIDC, Iran shipbuilding & Offshore Industries Company, Iran Marin Industries Company (Sadra), Dana, Sadid and Momsaz. Possible foreign bidders are understood to include two UK companies, Noble Denton and Swan Hunter, as well as Chinese and Italian companies. The rigs are to be used for south Pars phases9-10 onward.

Iran's development of offshore gas has been hampered by the scarcity of rigs in the Gulf.

Newfield and Sojitz agree upon U.K. Southern Gas Basin

Newfield Exploration Company, through its wholly owned subsidiary, Newfield Petroleum U.K. Limited, announced an agreement with Sojitz Energy Project Limited, a wholly owned subsidiary of Sojitz Corporation, relating to Newfield's Southern Gas Basin exploration and development program.

Under the agreement, Sojitz will participate in the ongoing development of the Grove Field and the 2007 exploration and appraisal drilling program which consists of the West Cutter Prospect, the Seven Seas Discovery and two wells planned in the West Sole Area under the existing Exploration and Development Agreement between BP Exploration Operating Company Limited and Newfield. Sojitz will earn 15% of Newfield's interest in the Grove Field and 20% of Newfield's interest in the West Cutter, Seven Seas and West Sole Area Prospects.

This transaction is valued at approximately $100 million and is subject to the necessary U.K. government approvals.

A production platform for the Grove development was recently installed in the field. The platform has production capacity of approximately 100 MMcf/d of gas and 2,000 BCPD. Newfield is currently drilling the Grove #5 well as a horizontal producer in the central and western fault blocks. Newfield anticipates that the field will be on-line in December 2006. Production is expected to ramp up to approximately 60 MMcf/d and 1,000 BCPD in early 2007.

The recent #6 exploration well was drilled from a remote surface location into the western fault block approximately 2.1 km west of the Grove platform. The well found approximately 40' of net gas pay and was temporarily abandoned with a subsea production tree installed. Final plans for the #6 well will be determined once the information obtained from the platform development wells has been integrated into the overall field development plan.

Aker Kvaerner wins Petrobras' subsea contract

Aker Kvaerner has been awarded a contract to supply subsea trees to Brazil's national oil company Petrobras. The contract has a value of approximately USD 12 million.

The scope of work comprises three mudline dual-bore christmas trees designed to 250 metres (820 feet) water depth, with associated tools. The christmas trees will be deployed in the Peroá phase II field, located in Espírito Santo basin offshore Brazil. The engineering phase of this contract starts immediately in Houston. Deliveries are to be completed from Aker Kvaerner's facility in Curitiba, Brazil, for delivery in the next 12 months.

"This award sets a new path for close cooperation with Petrobras in the mudline christmas trees segment, enhancing Aker Kvaerner's established position as a of strong supplier of christmas trees in Brazil," says Marcelo Taulois, President Aker Kvaerner Subsea in Brazil.

Aker Kvaerner has extensive experience delivering subsea trees in Brazil, having delivered more than 130 subsea christmas trees to Petrobras since the start of operations in Brazil.

The agreement is signed between Aker Kvaerner Subsea Brazil and Petróleo Brasileiro S.A.

Oman plans to improve Gas Supply

Oman is banking on new discoveries as well as supplies from Qatar to boost its gas supply position soon,Omani Commerce and Industry Minister Maqbool Ali Sultan indicated here Monday.

Oman is currently not in a position to meet the demands of gas-based industries but it might be in a better position in a few years, said Maqbool.

'For small industries gas will be available, but not for big gas-based industries. We hope to find more gas to meet the needs of more industries,' Maqbool told IANS.

Oman is currently exporting 9 million tonnes of liquefied natural gas (LNG) to countries like South Korea and Japan among others.

Besides banking on new discoveries, Oman is also looking at gas supplies from Qatar under a gas sales agreement signed last year by Oman Oil Company (OOC) with Dolphin Energy Ltd, which has promised to deliver an average 200 million standard cubic feet of gas per day (mmcmd) to Oman from early 2008.

'Only when more gas becomes available would Oman be in a position to go in for expansion of existing projects and undertaking more projects in fertiliser and other sectors,' said Mohammed Hassan Al-Theeb, deputy chief executive officer of Salalah Free Zone.

Al-Theeb said in the first phase the government proposed to invest $15 million in development of infrastructure including warehouses and port connectivity for the free zone covering 19 million square metres.

The second phase of the free zone would be developed depending on demand.

'The aim of the free zone is to promote both heavy as well as small and medium industries and logistics operations. While we would like to provide water and gas, the latter is not available as yet. But within next three to four years it will be available,' the official said.

Indian Ambassador to Oman Ashok Kumar Attre said Oman is keen to build another fertiliser plant at the Sohar Industrial Port though on a smaller scale than the Oman India Fertiliser Company, a joint venture that will be supplying India 1.68 million tonnes of urea and 255,000 tonnes of ammonia under a long-term buyback arrangement.

The project, currently on hold, is expected to take off once gas becomes available in a couple of years.

'Oman is looking at India for investments in areas like plastics, steel, power generation and other spin- off industries using feedstock from its oil refinery, aluminium smelter, and polypropylene plants in the Sohar Industrial Port,' said Attre.

The projects in the Sohar Industrial Port, which has already witnessed investments worth $12 billion in little over a year, 'is tailored to provide feedstock for steel plants, petrochemical and fertiliser projects,' said Attre.

Through these mega projects Oman is striving to increase its non-oil revenue, which registered a 9.2 percent increase in 2005.

Whittier Energy announces updates

Whittier Energy Corporation announced that a drilling and operations update and the final adjusted closing prices and estimated proved reserves associated with the two acquisitions completed on June 1, 2006 and August 9, 2006 respectively.

Drilling and Operations Update

Whittier Energy remains on-track to participate in 46 new wells in 2006, a record number for the Company. Through September 8, 2006 the Company has participated in 28 wells with 24 of them successful, for an 85% success rate. This drilling program has been largely responsible for the growth in current daily production to 20 Mmcfe (million cubic feet equivalent), an increase of 42% over year-end 2005.

The Company currently has two operated and two non-operated drilling rigs running including one drilling the Rebel #5 located in the Windham Field in the Permian Basin which spudded September 9, 2006 and the non-operated Diamond Development #1 located in Gillis English Bayou. The Company intends to test the recently drilled Westhoff #A-1 this week. The Duhon #1 well, located in Lafayette Parish, Louisiana has been returned to production.

The well, which was shut-in by the operator in July of this year to repair casing, is currently producing at approximately 6 Mmcfe per day; however volumes will be monitored over the next few weeks to ensure the well is producing at optimum levels. The Company owns a 9.75% working interest in the well.

Acquisition Update

The net acquisition price after customary closing and post-closing adjustments for the previously announced acquisitions of Westhoff Ranch located in South Texas and certain Imperial Petroleum properties located in Mississippi and East Texas is approximately $28.1 million with total proved reserves for the two acquisitions after closing adjustments estimated at 15.9 Bcfe (Billion cubic feet equivalent). The Company estimates that it paid an average of $1.77 per Mcfe (Thousand cubic feet equivalent) of estimated proved reserves.

In the Westhoff Ranch acquisition the final closing price of $17.9 million reflects purchase price adjustments for revenue and expenses attributed to the Company during the period from the February 1, 2006 effective date of the acquisition through the May 31, 2006 closing date. The Company elected not to close on certain Imperial Petroleum properties resulting in a final closing price of approximately $10.2 million.

Offshore E-fever

by : D. Ramasubramanian

The marine industry is a global market worth over $150bn, where speed and efficiency are crucial. Recently, e-procurement has emerged as an important tool that can give operators and oil companies a competitive edge. D Ramasubramanian, project manager at Wipro Technologies, reports.

Over the last two years, e-procurement for marine purchasing has gone from a faddish curiosity to a business tool that mainstream operators are willing to invest in. Several oil and gas companies are also using e-procurement for supply and services to their offshore rigs situated in international waters.

The web has become a ubiquitous tool for enhancing all aspects of day-to-day marine business.

The buyer usually aggregates the needs of several offshore oil rigs,either those owned by a single large company or as a collective function for a number of smaller companies. The buying agent sometimes splits the requisition by category of items needed into several requests for quote (RFQs), each targeted at vendors that supply that category.

Vendors may be ship chandlers who manage general kinds of supplies for a given port or specific manufacturers for spare parts and other oil rig components.

In case expensive or complex technical services are required, the technical superintendent of the oil exploration company must have the expertise and authority to request, review and approve the purchasing decision.

In this case, the RFQ is communicated to that individual and may either

be approved outright, changed accordingly or rejected/sent back to the ship/oil rig for revision. A vendor may decide to respond to an RFQ by generating a quote for goods and services from their offerings, and fully specifying pricing for these items.

The quote is then communicated back to the buying agent. The buying agent reviews all quotes received for a specific RFQ and orders according to the oil rig's needs. This involves regrouping items from several quotes to receive the best quality, pricing and delivery terms.

An order is then sent to the vendor, who reviews and determines if the order can be fulfilled. If not, an order response and a revised quote are prepared and sent to the buying agent for review and reorder. If the order is acceptable, the vendor completes the order. On the receipt of the ordered items, payment is made.

THE RISE OF E-SELLING

This whole process for procurement of supplies and services to offshore oil rigs can be automated using the internet, web services and integration between oil rig owners, buyers, oil rig officers, vendors and any other intermediates.

The reliability, scalability, ease of use and administration, and cost-effectiveness of this kind of web-based platform, in terms of supporting process-intensive business operations such as global procurement from a single window, are well documented, and have helped oil rig owners realise tremendous savings through efficient paper-less work management with trading partners.

"The reliability, scalability, ease of use and administration, and cost-effectiveness of this kind of web-based platform are well documented."Many of these innovations are taking place in the marine fuel procurement business, with several companies forming internet portals such as OceanConnect and efuel with a view to changing the basic relationship between buyers and sellers of fuels. This ensures a hitherto unimaginable amount of information on pricing levels and product availability.

Since its inception in 2000, OceanConnect.com has also aggressively expanded into other marine products and services. The major players in the industry clearly consider this serious business.

Some fuel and product suppliers have gone a step further with value-added offerings for their customers using the power of the internet.

One example is testing and advisory services that are provided post-procurement of fuel/lubricating oil. In the case of fuel oil, the testing service is provided mainly by classification societies such as Lloyds and DNV, to ensure neutrality in analysis.

Marine lubricating oil suppliers use web-based software applications as an advisory service, to give their customers a better understanding of the machinery and their associated fuel/lubricant performance.

The process is initiated by the suppliers' designated labs receiving the used lubricant samples from the vessels subscribing to the suppliers' advisory service.

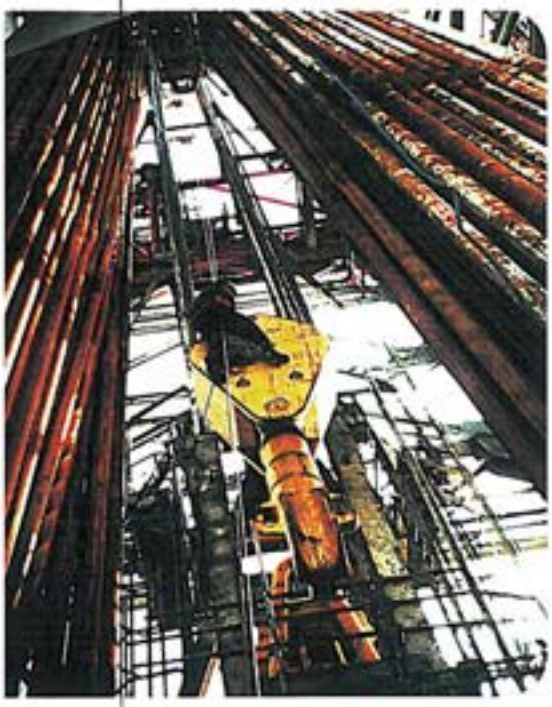
The sample is then reviewed and analysed by the suppliers' lab technicians, who then interpret the results and electronically transmit their comments to the suppliers' central systems.

Innovative use of the web has thus enabled company-specific business operations and processes to be e-enabled, resulting in improved productivity, a rise in collaboration between partners, a strong customer base, improved services to customers, and reduced procurement costs and times.

This 'e-fever' has caught on in the tanker trading market as well. Tanker transportation has always been an epicentre of global attention through its links with oil trading. Tankers are vital for the movement in bulk of oil, petroleum products, chemicals and liquefied gas products from their politically sensitive origins to multiple destinations around the globe.

Tankers are a cost-efficient and extremely flexible mode of transport, nd have made global transport of oil possible. This key segment of the maritime industry today is the largest component of sea-borne cargo movements; more than a third of all cargoes routed through sea.

Sales activities are now more and more prevalent through the internet in the shipping business area. Today, cargo booking sites, scheduling portals and auction sites have



become important e-selling channels for shipping companies and are decreasing the marketing and distribution costs of information-centric services.

For example, e-B/L (Bill of Lading) is now a key component of the entire shipping processes documentation. This contains proof copies, which can be checked prior to issuance of the original Bill of Lading, and minimises re-processing time, reduces paper flow and eliminates faxing.

All this cuts costs and processing time between carriers and shippers when changes occur.

The networks between shipping companies and their agents allow both sides to monitor the bookings from online and offline marketing efforts in a single database. Bookings are entered directly onto the systems, posted to centralised databases and collected, allowing shipping companies and their territorial sales forces to operate efficiently.

The intra-firm networks and intranets also enhance the total shipping service processes from production to distribution by linking up all related departments and reaching the pool databases.

Information-centric services before and after the sales processes in shipping are delivered directly and indirectly using secure XML messages and documentation. Typically, this involves registration of a shipper/cargo owner/charterer in a shipping line's web application, issue of digital certificates by shipping line and website personalisation for the shipper by the shipping company. This enables the shipper/cargo owner/charterer to receive information related to shipment in a customised and secure way.

Ship charter is a contract by which a ship is hired or leased for he transportation of cargo by sea. Ship chartering deals with cargo and vessel matching. Success in ship chartering largely depends on the ship owner-shipper relationship and the trust and confidence that exists between the two. This means a greater degree of face-to-face interaction, something the internet cannot provide and exchanges such as Baltic Exchange, NYMEX and Singapore Mercantile Exchange claim as a competitive advantage.

However, with web applications becoming more common and user-friendly, future maritime exchanges need not be in cities where brokers operate.

ONLINE INFORMATION

Charterers have their own complex systems (many automated) of actually assessing the ship from the data available and determining whether or not it is suitable. The charterer's decision to charter the vessel depends on a variety of different criteria, of which vessel inspection is just one element. Charterers review information from numerous sources, including SIRE (a tanker's latest inspection report), uploaded onto OCIMF1's online database.

"With web applications becoming more common and user-friendly, future maritime exchanges need not be in cities where brokers operate."Because of the internet, the SIRE program database is now available online to all participating companies, accredited inspectors, ship owners and oil terminal operators. SIRE2 participants and government organisations can access all current online reports of required vessels, including the vessel's detention and casualty record, its past experience with the vessel and its management. This is of tremendous importance to oil trading and scheduling companies, which can use the web to access this data in real time to help them make decisions about logistics and supply.

A number of private portals such as the RightShip & Equasis have also been developed to provide accurate and reliable information on vessels, owners and managers. On the commercial side, a large number of portals have also sprung up to help shippers and shipping companies enter into contract management.

This is particularly useful with spot market contracts.

Another e-community builtaround cargo movements within the petroleum industry is ShipIQ.com, a tanker-chartering portal. The portal has successfully attracted oil traders, charterers and tanker operators by providing quality information, control

of the chartering process, control of confidentiality, flexibility in terms of business processes, and efficient documentation generation and handling. ShipIQ also offers news and market reports.

These 'shared industry' electronic platforms provide their users with many additional advantages, such as real-time market intelligence, pre- and post-fixture voyage management applications, freight futures trading, and risk management tools. These exchanges have enabled their users to increase their operating efficiencies and reduce costs through a simpler, quicker and more automated transaction process, improved communication flows, reduced paperwork and duplication, collaborative systems, reduced management time, and reduced IT operating costs.

WORKING TOGETHER

Crucial to the availability of this information is that oil companies, traders, brokers, schedulers and carriers interface their internal systems with these portals, agencies and exchanges in real time for direct information access. The critical issue is that, with many such exchanges or their associated applications in the market, how can such disparate technologies talk to each other and relay information?

"The nature of shipping is to operate in an open and highly competitive market, so it is inevitable that the web is playing an increasingly prominent role in shaping more efficient markets."One noteworthy response has been that of the Maritime Electronic Commerce Association (MECA),

which enjoyed some early success with an XML schema for procurement and has recently launched Maritime Chartering Mark-up Language (MCML), a data scheme for organising ship descriptions, voyage files and post fixture information. Standards such as MCML are a great advantage to the tanker industry, which is a fertile breeding ground for the new XML chartering protocol.

On the commercial side, a large number of portals have also sprung up to help shippers and shipping companies enter into contract management. This is particularly useful with spot market contracts.

The nature of shipping is to operate in an open and highly competitive market, so it is inevitable that the web is playing an increasingly prominent role in shaping more efficient markets. With the global online logistics market slated for significant growth over the coming years, it is time that maritime players grabbed their rightful share of the pie.

The web has become a ubiquitous tool for enhancing all aspects of day-to-day marine business. Maritime players have to embrace the web, incorporating the logical connectivity to move shipping data from application to application at speeds and volumes that result in greater visibility in supply chains.

Ultimately, the success of e-business rests on the ability of buyers, suppliers and IT service providers to work together to develop easy-to-use operational web technology solutions for the benefit of all parties.


James L. Williams

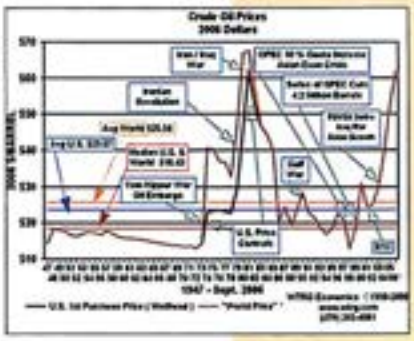
Oil Prices: a historical review

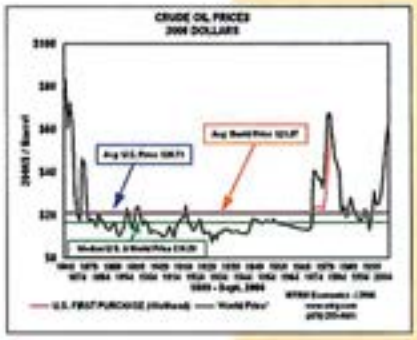
Introduction

Crude oil prices behave much as any other commodity with wide price swings in times of shortage or oversupply. The crude oil price cycle may extend over several years responding to changes in demand as well as OPEC and non-OPEC supply.

The U.S. petroleum industry's price has been heavily regulated through production or price controls throughout much of the twentieth century. In the post World War II era U.S. oil prices at the wellhead have averaged $23.57 per barrel adjusted for inflation to 2006 dollars. In the absence of price controls the U.S. price would have tracked the world price averaging $25.56. Over the same post war period the median for the domestic and the adjusted world price of crude oil was $18.43 in 2006 prices. That means that only fifty percent of the time from 1947 to 2006 have oil prices exceeded $18.43 per barrel. (See note in box on right.)

Until the March 28, 2000 adoption of the $22-$28 price band for the OPEC basket of crude, oil prices only exceeded $23.00 per barrel in response to war or conflict in the Middle East. With limited spare production capacity OPEC has abandoned its price band and for close to three years was powerless to stem a surge in oil prices which was reminiscent of the late 1970s.



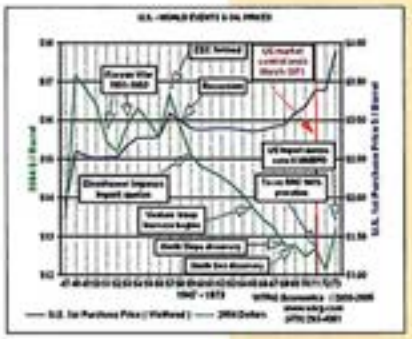


The Very Long Term View

The very long term view is much the same. Since 1869 US crude oil prices adjusted for inflation have averaged $20.71 per barrel compared to $21.57 for world oil prices.

Fifty percent of the time prices were U.S. and world prices were below the median oil price of $16.59 per barrel.

If long term history is a guide, those in the upstream segment of the crude oil industry should structure their business to be able to operate with a profit, below $16.59 per barrel half of the time.



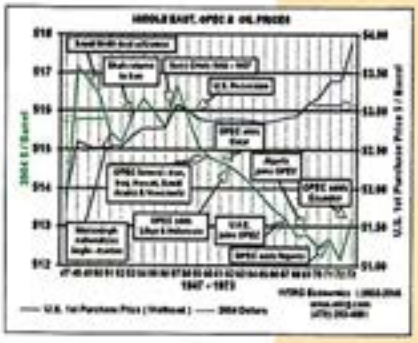
Post World War II
Pre Embargo Period

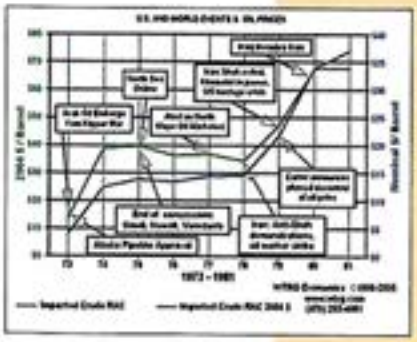
Crude Oil prices ranged between $2.50 and $3.00 from 1948 through the end of the 1960s. The price oil rose from $2.50 in 1948 to about $3.00 in 1957. When viewed in 2004 dollars an entirely different story emerges with crude oil prices fluctuating between $15 - $17 during the same period. The apparent 20% price increase was just keeping up with inflation.

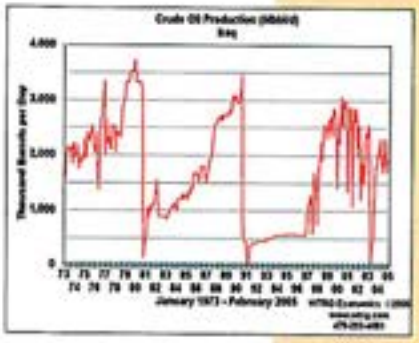
From 1958 to 1970 prices were stable at about $3.00 per barrel, but in real terms the price of crude oil declined from above $16 to below $13 per barrel. The decline in the price of crude when adjusted for inflation was amplified for the international producer in 1971 and 1972 by the weakness of the US dollar.

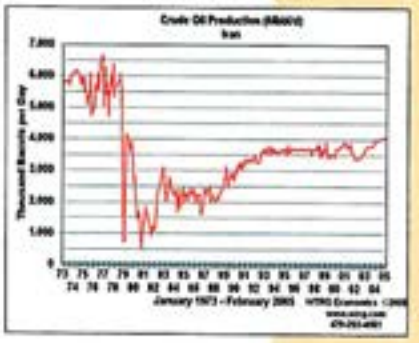
OPEC was formed in 1960 with five founding members Iran, Iraq, Kuwait, Saudi Arabia and Venezuela. By the end of 1971 six other nations had joined the group: Qatar, Indonesia, Libya, United Arab Emirates, Algeria and Nigeria. From the foundation of the Organization of Petroleum Exporting Countries through 1972 member countries experienced steady decline in the purchasing power of a barrel of oil.

Throughout the post war period exporting countries found increasing demand for their crude oil but a 40% decline in the purchasing power of a barrel of crude. In March 1971, the balance of power shifted. That month the Texas Railroad Commission set proration at 100 percent for the first time. This meant that Texas producers were no longer limited in the amount of oil that they could produce. More importantly, it meant that the power to control crude oil prices shifted from the United States (Texas, Oklahoma and Louisiana) to OPEC. A little over two years later OPEC would through the unintended consequence of war get a glimpse at the extent of its ability to influence prices.









Middle East Supply Interruptions

Yom Kippur War - Arab Oil Embargo

In 1972 the price of crude oil was about $3.00 per barrel and by the end of 1974 the price of oil had quadrupled to over $12.00. The Yom Kippur War started with an attack on Israel by Syria and Egypt on October 5, 1973. The United States and many countries in the western world showed strong support for Israel. As a result of this support several Arab exporting nations imposed an embargo on the countries supporting Israel. Arab nations curtailed production by 5 million barrels per day (MMBPD) about 1 MMBPD was made up by increased production in other countries. The net loss of 4 MMBPD extended through March of 1974 and represented 7 percent of the free world production.

If there was any doubt that the ability to control crude oil prices had passed from the United States to OPEC it was removed during the Arab Oil Embargo. The extreme sensitivity of prices to supply shortages became all too apparent when prices increased 400 percent in six short months.

From 1974 to 1978 world crude oil prices were relatively flat ranging from $12.21 per barrel to $13.55 per barrel. When adjusted for inflation the price over that period of time exhibited a moderate decline.

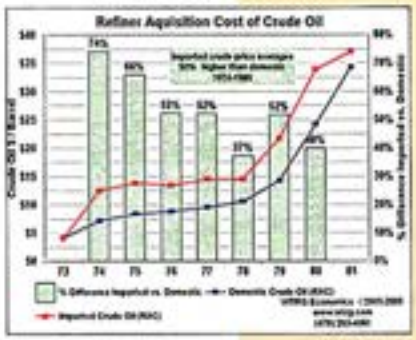
Crises in Iran and Iraq

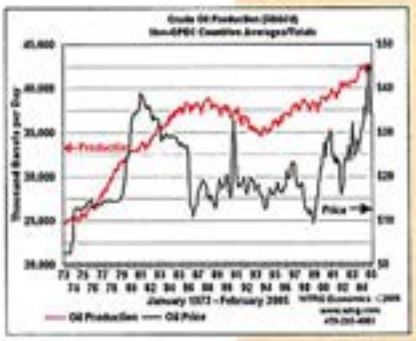
Events in Iran and Iraq led to another round of crude oil price increases in 1979 and 1980. The Iranian revolution resulted in the loss of 2 to 2.5 million barrels of oil per day between November, 1978 and June, 1979. At one point production almost halted.

Iraq invaded Iran in September, 1980 by November the combined production

of both countries was only a million barrels per day and 6.5 million barrels per day less than a year before. Worldwide crude oil production was 10 percent lower than in 1979.

The combination of the Iranian revolution and the Iraq/Iran War resulted in crude oil prices more than doubling from $14 in 1978 to $35 per barrel in 1981. Twenty-five years later Iran's production is only two-thirds of the level reached under the government of Reza Pahlavi the former Shah of Iran.





US Oil Price Controls - Bad Policy?

The rapid increase in crude prices from 1973 to 1981 would have been much less were it not for United States energy policy during the post Embargo period. The US imposed price controls on domestically produced oil in an attempt to lessen the impact of the 1973-74 price increase. The obvious result of the price controls was that U.S. consumers of crude oil paid about 50 percent more for imports than domestic production. Put another way U.S producers received less than world market price.

Did the policy achieve its goal? In the short term the recession induced by the 1973-1974 crude oil price rise was less because U.S. consumers faced lower prices. However, it had other effects as well. In the absence of price controls U.S. exploration and production would certainly have been significantly greater. The higher prices faced by consumers would have resulted in lower rates of consumption: automobiles would have had higher mileage sooner, homes and commercial buildings would have been better insulated and improvements in industrial energy efficiency would have been greater than they were during this period. As a consequence, the United States would have been less dependent on imports in 1979-1980 and the price increase in response to Iranian and Iraqi supply interruptions would have been significantly less.

OPEC's Failure to Control Crude Oil Prices

OPEC has seldom been effective at controlling prices. While often referred to as one OPEC does not satisfy the definition of a cartel. One of the primary requirements is a mechanism to enforce member quotas. During the 1979-1980 period of rapidly increasing prices, Saudi Arabia's oil minister Ahmed Yamani repeatedly warned other members of OPEC that high prices would lead to a reduction in demand. His warnings fell on deaf ears.

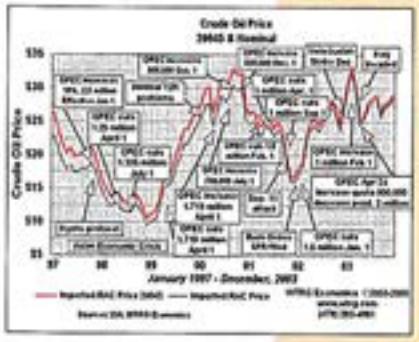
Surging prices caused several reactions among consumers: better insulation in new homes, increased insulation in many older homes, more energy efficiency in industrial processes, and automobiles with higher mileage. These factors along with a global recession caused a reduction in demand which led to falling crude prices. Unfortunately for OPEC only the global recession was temporary. Nobody rushed to remove insulation from their homes or to replace energy efficient plants and equipment -- much of the reaction to the oil price increase of the end of the decade was permanent and would not respond to lower prices with increased demand for oil.

The higher prices also resulted in increased exploration and production out-

side of OPEC. From 1980 to 1986 non-OPEC production increased 10 million barrels per day. OPEC was faced with lower demand and higher supply from outside the organization.

From 1982 to 1985 OPEC attempted to set production quotas low enough to stabilize prices. These attempts met with repeated failure as various members of OPEC would produce beyond their quotas. During most of this period Saudi Arabia acted as the swing producer cutting its production to stem the free falling prices. In August of 1985, the Saudis tired of this role. They linked their oil prices to the spot market for crude and by early 1986 increased production from 2 MMBPD to 5 MMBPD. Crude oil prices plummeted below $10 per barrel by mid-1986.

A December 1986 OPEC price accord set to target $18 per barrel was already breaking down by January of 1987. Prices remained weak. The price of crude oil spiked in 1990 with the uncertainty associated Iraqi invasion of Kuwait and the ensuing Gulf War, but following the war crude oil prices entered a steady decline until in 1994 inflation adjusted prices attained their lowest level since 1973



OPEC had mixed success at controlling prices. There were mistakes in timing of quota changes as well as the usual problems in maintaining production discipline among its member countries.

The price cycle then turned up. The United States economy was strong and the Asian Pacific region was booming. From 1990 to 1997 world oil consumption increased 6.2 million barrels per day. Asian consumption accounted for all but 300,000 barrels per day of that gain and contributed to a price recovery that extended into 1997.

The price increases came to a rapid end when the impact of the economic crisis in Asia was either ignored or severely underestimated by OPEC. In December, 1997 OPEC increased its quota by 2.5 million barrels per day (10 percent) to 27.5 MMBPD effective January 1, 1998. The rapid growth in Asian economies had come to a halt and in 1998 Asian Pacific oil consumption declined for the first time since 1982. The combination of lower consumption and higher OPEC production sent prices into a downward spiral In response, OPEC cut quotas by 1.25 million b/d in April and 1.335 million in July. Price continued down through December 1998. Prices began to recover in early 1999 and OPEC reduced production another 1.719 million barrels in April 1999. As usual not all of the quotas were observed but between early 1999 and the middle of 1999 OPEC production dropped by about 3 million barrels per day and was sufficient to move prices above $25 per barrel.

With minimal Y2K problems and growing US and world economies the price continued to rise throughout 2000 to a post 1981 high. Between April and October three successive quota increases totaling 3.2 million barrels per day were not able to stem the price increases. Prices finally started down following another quota increase of 500,000 effective November 1, 2000.

Russian production increases dominated non-OPEC production growth from 2000 forward and was responsible for most of the non-OPEC increases since the turn of the century.

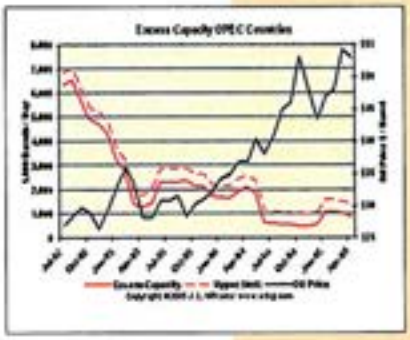
Once again it appeared that OPEC overshot the mark. In 2001 a weakening US economy and increases in non-OPEC production put downward pressure on prices. In response OPEC once again entered into a series of reductions in member quotas cutting 3.5 million barrels by September 1, 2001. In the absence of the September 11, 2001 terrorist attack this would have been sufficient to moderate or even reverse the trend. In the wake of the attack the crude oil price plummeted. Spot prices for the U.S. benchmark West Texas Intermediate were down 35 percent by the middle of November. Under normal circumstances a drop in price of this magnitude would have resulted an another round of quota reductions but given the political climate OPEC delayed additional cuts until January 2002 when it reduced its quota by 1.5 million barrels per day and was joined by several non-OPEC producers including Russia who promised combined production cuts of an additional 462,500 barrels. This had the desired effect with oil prices moving into the $25 range by March, 2002. By mid-year the non-OPEC members were restoring their production cuts but prices continue to rise and U.S. inventories reached a 20-year low later in the year.

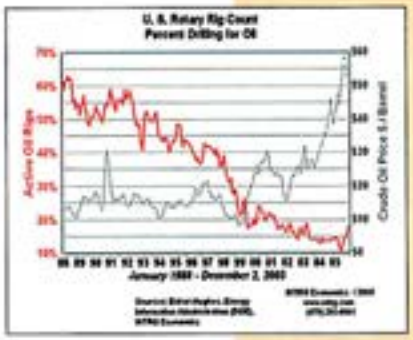
By year end oversupply was not a problem. Problems in Venezuela led to a strike at PDVSA causing Venezuelan production to plummet. In the wake of the strike Venezuela was never able to restore capacity to its previous level and is still about 900,000 barrels per day below its peak capacity of 3.5 million barrels per day. OPEC increased quotas by 2.8 million barrels per day in January and February, 2003.

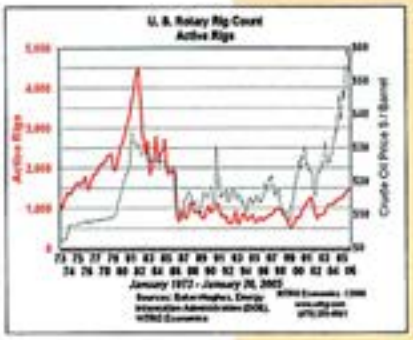
On March 19, 2003, just as some Venezuelan production was beginning to return, military action commenced in Iraq. Meanwhile, inventories remained low in the U.S. and other OECD countries. With an improving economy U.S. demand was increasing and Asian demand for crude oil was growing at a rapid pace. The loss of production capacity in Iraq and Venezuela combined with increased production to meet growing international demand led to the erosion of excess oil production capacity. In mid 2002, there was over 6 million barrels per day of excess production capacity, but by mid 2003 the excess was below 2 million. During much of 2004 and 2005 the spare capacity to produce oil has been under one million barrels per day. A million barrels per day is not enough spare capacity to cover an interruption of supply from almost any OPEC producer. In a world that consumes over 80 million barrels per day of petroleum products that adds a significant risk premium to crude oil price and is largely responsible for prices in excess of $40 per barrel.

Impact of Prices on Industry Segments Drilling and Exploration

Boom and Bust The Rotary Rig Count is the average number of drilling rigs actively exploring for oil and gas. Drilling an oil or gas well is a capital investment in the expectation of returns from the production and sale of crude oil or natural gas. Rig count is one of the primary measures of the health of the explo-



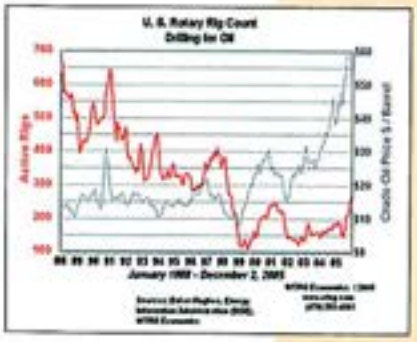


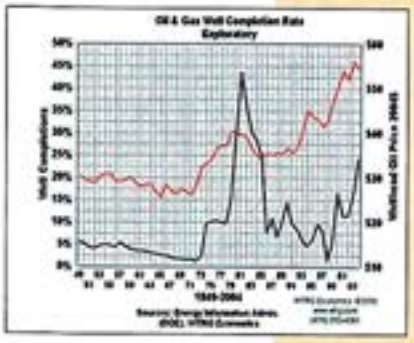


ration segment of the oil and gas industry. In a very real sense it is a measure of the oil and gas industry's confidence in its own future.

At the end of the Arab Oil Embargo in 1974 rig count was below 1500. It rose steadily with regulated crude oil prices to over 2000 in 1979. From 1978 to the beginning of 1981 domestic crude oil prices exploded from a combination of the the rapid growth in world energy prices and deregulation of domestic prices. At that time high prices and forecasts of crude oil prices in excess of $100 per barrel fueled a drilling frenzy. By 1982 the number of rotary rigs running had more than doubled.

It is important to note that the peak in drilling occurred over a year after oil prices had entered a steep decline which continued until the 1986 price collapse. The one year lag between crude prices and rig count disappeared in the 1986 price collapse. For the next few years the economy of the towns and cities in the oil patch was characterized by bankruptcy, bank failures and high unemployment.





After the Collapse

Several trends established were established in the wake of the collapse in crude prices. The lag of over a year for drilling to respond to crude prices is now reduced to a matter of months. (Note that the graph on the right is limited to rigs involved in exploration for crude oil as compared to the previous graph which also included rigs involved in gas exploration.) Like any other industry that goes through hard times the oil business emerged smarter, leaner and more conservative. Industry participants, bankers and investors were far more aware of the risk of price movements. Companies long familiar with accessing geologic, production and management risk added price risk to their decision criteria.

Technological improvements were incorporated:

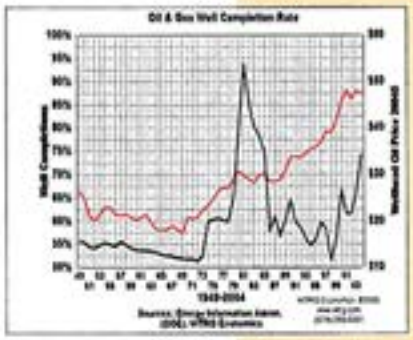
- Increased use of 3-D seismic data reduced drilling risk.
- Directional and horizontal drilling led to improved production in many reservoirs.
- Financial instruments were used to limit exposure to price movements.
- Increased use of CO2 floods and improved recovery methods to improve production in existing wells.

In spite of all of these efforts the percentage of rigs employed in drilling for crude oil decreased from over 60 percent of total rigs at the beginning of 1988 to under 15 percent until a recent resurgence.

Well Completions - A measure of success? Rig count does not tell the whole story of oil and gas exploration and development. It is certainly a good measure of activity, but it is not a measure of success.

After a well is drilled it is either classified as an oil well, natural gas well or dry hole. The percentage of wells completed as oil or gas wells is frequently used as a measure of success. In fact, this percentage is often referred to as the success rate. Immediately after World War II 65 percent of the wells drilled were completed as oil or gas wells. This percentage declined to about

57 percent by the end of the 1960s. It rose steadily during the 1970s to reach 70 percent at the end of that decade. This was followed by a plateau or modest decline through most of the 1980s. Beginning in 1990 shortly after the harsh lessons of the price collapse completion rates increased dramatically to 77 percent. What was the reason for the dramatic increase? For that matter, what was the cause of the steady drop in the 1950s and 1960s or the reversal in the 1970s? Since the percentage completion rates are much lower for the more risky exploratory wells, a shift in emphasis away from development would result in lower overall completion rates. This, however, was not the case. An examination of completion rates for development and exploratory wells shows the same general pattern. The decline was price related as we will explain later. Some would argue that the periods of decline were a result of the fact that every year there is less oil to find. If the industry does not develop better technology and expertise every year, oil and gas completion rates should decline. However, this does will not explain the periods of increase. The increases of the seventies were more related to price than technology. When a well is drilled, the fact that oil or gas is found does not mean that the well will be completed as a producing well. The determining factor is economics. If the well can produce enough oil or gas to cover the additional cost of completion and the ongoing production costs it will be put into production. Otherwise, its a dry hole even if crude oil or natural gas is found. The conclusion is that if real prices are increasing we can expect a higher percentage of successful wells. Conversely if prices are declining the opposite is true. The increases of the 1990s, however, cannot be explained by higher prices. These increases are the result of improved technology and the shift to a higher percentage of natural gas drilling activity. The increased use of and improvements to 3-D seismic data and analysis combined with horizontal and and directional drilling improve prospects for successful completions. The fact that natural gas is easier to see in the seismic data adds to that success rate. Most dramatic is the improvement in the the percentage exploratory wells completed. In the 1990s completion rates for exploratory wells have soared from 25 to 45 percent.



Workover Rigs - Maintenance Workover rig count is a measure of the industry's investment in the maintenance of oil and gas wells. The Baker-Hughes workover rig count includes rigs involved in pulling production tubing, sucker rods and pumps from a well that is 1,500 feet or more in depth. Workover rig count is another measure of the health of the oil and gas industry. A disproportionate percentage of workovers are associated with oil wells. Workover rigs are used to pull tubing for repair or replacement of rods, pumps and tubular goods which are subject to wear and corrosion. A low level of workover activity is particularly worrisome because it is indicative of deferred maintenance. The situation is similar to the aging apartment building that no longer justifies major renovations and is milked as long as it produces a positive cash flow. When operators are in a weak cash position workovers are delayed as long as possible. Workover activity impacts manufacturers of tubing, rods and pumps. Service companies coating pipe and other tubular goods are heavily affected.

WHO IS WHO

Guenov holds

Prof. Guenov holds MEng degree in Mechanical Engineering and PhD in Operations Research. He has acquired research and industrial experience from a variety of fields, including the Design and Discrete Optimisation of Materials Handling Systems and Equipment, Integrated Design and Cost Estimating of Large Marine Made-to-Order Products, and Multidisciplinary Design, Analysis and Optimisation in the Aerospace sector. He has made a significant contribution to the MDO field, especially the field of design tool integration and design change propagation modelling. In the early 1990s he led one of the first successful multidisciplinary research projects in geographically distributed design, including the integration of Parametric CAD systems, Knowledge Based Systems, Object Oriented Databases and middleware. The results were fed back into the aerospace, shipbuilding and offshore industry.

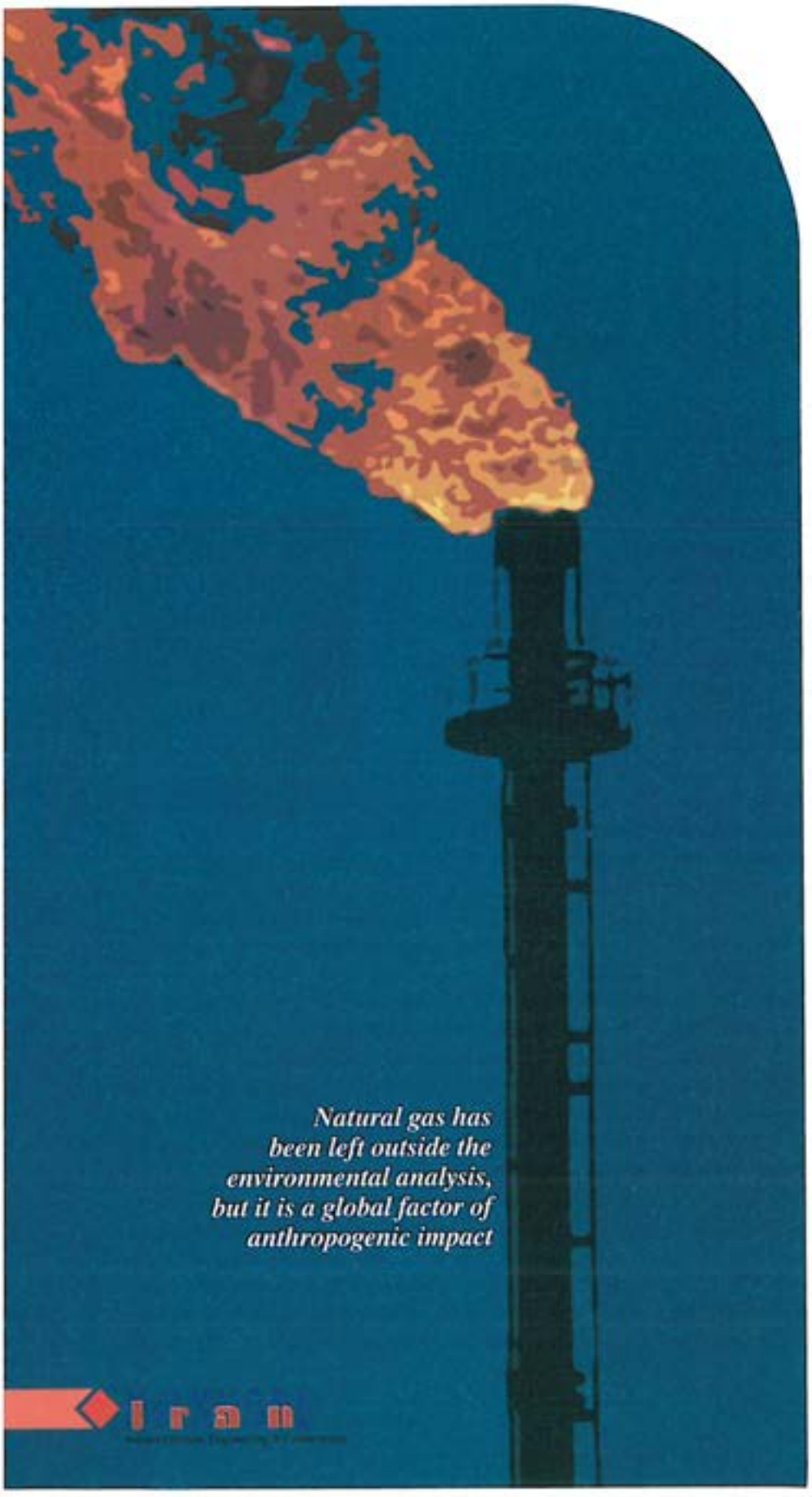
Prof. Guenov's current activities are also interdisciplinary. He has been the Principal Investigator of EPSRC funded projects on decomposition of complex systems as well as research funded by BAE SYSTEMS in modelling and simulation for Synthetic Environments. Prof Guenov also leads Cranfield's €1.6M participation in a €70M FP6 European project VIVACE – "Value Improvement through a Virtual Aeronautical Collaborative Enterprise" where he directs research into Multidisciplinary Design Optimisation, Design to Design Objectives and Distributed Information Systems Infrastructure for Large Enterprises.

Prof. Guenov is a Fellow of the Institute of Mechanical Engineers, a Member of the Royal Aeronautical Society and The Association of Cost Engineers, and is a Chartered Engineer

James Jenkins

James Jenkins has over 35 years experience in metallurgical engineering and corrosion control. In addition to working for the US Navy from 1966-1995, Mr. Jenkins has been an independent consultant since 1972. His duties for the Navy included research and development in the areas of metallurgy and corrosion control technology for the Naval Shore Establishment. He was involved in development of technology for design, construction, operation and maintenance of facilities and equipment, as well as direct field activities. For his consulting clients, Mr. Jenkins has acted as investigator and expert witness in cases involving equipment failures due to corrosion, as well as providing expertise on a variety of subjects such as wastewater treatment plant equipment, a propulsion pump for oceangoing hydrofoils and construction of offshore oil drilling platforms.

Mr. Jenkins is active in several technical societies and has presented many articles and papers. He has taught seminars for the US Navy, the National Association of Corrosion Engineers and the Nickel Development Institute. Mr. Jenkins received his B.S. in Metallurgical Engineering from the University of Arizona School of Mines in 1966.



Natural gas has been left outside the environmental analysis, but it is a global factor of anthropogenic impact

by : Stanislav Patin

Natural gas in the marine environment

In contrast with oil hydrocarbons, which have been an object of wide and detailed ecotoxicological studies worldwide, natural gas and its components have been left outside the sphere of environmental analysis, control, and regulation. At the same time, the input of natural gas and products of its combustion into the biosphere is one of the typical and global factors of anthropogenic impact.

Below you will find information on sources and composition of natural gas in the marine environment

Composition and sources of natural gas in the water

Natural gas is closely related to crude oil. Both substances are thought to have formed in the earth's crust as a result of transformation of organic matter due to the heat and pressure of the overlying rock. All oil deposits contain natural gas, although natural gas is often found without oil. Gas hydrocarbons can also be produced as a result of microbial decomposition of organic substances and, less often, due to reduction of mineral salts. Many of these gases are released into the atmosphere or hydrosphere, or they accumulate in the upper layers of the earth's crust.

The composition of natural gas varies. It depends on the origin, type, genesis, and location of the deposit, geological structure of the region, and other factors. Natural gas chiefly con-

sists of saturated aliphatic hydrocarbons, i.e., methane and its homologues. The deeper the location of gas deposit, the higher the number of methane homologues. In gas condensate fields, the content of methane homologues is usually considerably higher than the level of methane. In gases associated with oil, the content of methane homologues is comparable with the content of methane. Large amount of gases associated with oil is dissolved in this oil. During oil extraction, as the pressure goes down, gases come to the surface of the oil. They are released in the environment in volumes of 30-300 m3 for every ton of extracted oil. These gases give about 30% of the gross total production of combustible gases in the world. However, over 25% of this amount are flared off because of the absence of the needed capacities and equipment for gas collection and processing.

Other components commonly found in natural gas are carbon dioxide, hydrogen sulfide, nitrogen, and helium. Usually, they constitute an insignificant proportion of natural gas composition. However, in some areas, their concentrations can be considerably higher.

Besides the previously mentioned sources of natural gas (transformations of organic matter in the earth's crust, microbial decomposition of organic substances, and reduction of mineral salts), gas hydrates are another extremely promising source of gas hydrocarbons on the sea bottom. According to some estimates [Zubova et al., 1990; Kellard, 1994], the reserves of gas hydrates are an order of magnitude higher than potential recoverable gas resources of all conventional fields in the world.

From the physicochemical point of view, gas hydrates can be considered as a modification of ice that has a high content of gas. They are solid crystallized substances that look like compressed snow. Hydrates form during the interaction of many components of natural gas (methane, ethane, propane, isobutane, carbon dioxide, and hydrogen sulfide) with water under certain combinations of high pressure and relatively low temperature.

Hydrate formation usually accompanies and complicates gas and oil extraction and transportation because hydrates can accumulate on the sides of wells and pipelines and thus plug them. The methods used to overcome these difficulties include pumping different inhibitors (methanol, glycol, and solutions of potassium chloride) into the wells and pipelines, dehydrating the gas, and heating it up to temperatures higher than the temperature of hydrate formation.

over 25% of associated gases are flared off due to lack of capacities for gas collection and processing.

Similar to oil, gas enters the environment due to both natural and anthropogenic processes. Among the major mechanisms of methane natural production in the biosphere, the decomposition of organic matter by methane-producing bacteria (e.g., Methanococcus, Methanosarica) deserves a special mention. These bacteria are able to get the energy by reducing carbon dioxide in accordance with $CO2 + 4H2 = CH4 + 2H2O$ reaction. These processes are typical for the silt deposits of lakes and marshes and for marine sediments that are lacking in oxygen and rich in organic matter.

Microbial methane formation in the oceans is usually accompanied by sulfur reduction and the release of hydrogen sulfide. These take place inside the upper part of sediments from the seafloor surface to tens and even hundreds of meters deep. In regions with a cold and moderate climate at depths of over 500 m, methane can accumulate in a form of crystal gas hydrates. In areas with a warmer climate, some methane from shallow formations is often released from the sediments into the water column and then into the atmosphere.

Methane can appear in the marine environment not only due to microbial and biochemical decomposition of the organic substance in bottom sediments. It can also occur as a result of the natural bottom seepage of combustible gases from shallow oil- and gas-bearing structures. Such seeping has been found in the Gulf of Mexico, North Sea, Black Sea, Sea of Okhotsk, and other marine areas. This process can lead to intensive vertical flows of hydrocarbon gases from the bottom to the sea surface. Sometimes it is accompanied by gas hydrate decomposition.

Over the last 100 years, the natural processes of biogeochemical production and distribution of methane in the biosphere are under large-scale anthropogenic impact. According to some estimates, anthropogenic sources contribute as much as 40-70% of methane into the global atmospheric flow of this gas [Novozhevnikova, 1995]. Large quantities of hydrocarbon gases are released during many kinds of anthropogenic activity. These include oil, gas, and coal production and transportation, burning of fossil fuels, intensive rice cultivation, animal farming, and garbage dumping.

Lately, the increased levels of methane have been found even in areas of intensive aquaculture in the coastal

waters. In these areas, methane could be formed as a result of decomposition of food residuals and metabolites of cultivated water organisms.

The global consequence of all these anthropogenic impacts is the gradual increase of methane concentration in the atmosphere over the last 100 years - from 0.7x10-4% to 1.7x10-4% (in volume). Many scientists believe that gases released due to human activities have already begun to affect the earth's overall temperature and the methane anthropogenic emission is responsible for about 30% of the total warming effect. If the concentrations of methane and other greenhouse gases in the atmosphere keep increasing, global changes in climatic conditions on the earth will be noticeable in the near future.

Another component of natural gas - hydrogen sulfide - is water soluble in contrast with methane. It can cause hazardous pollution situations in both the atmosphere and the water environment. Its proportion in the composition of natural gas and gas condensate, as previously mentioned, sometimes reaches more than 20%. Pollution by hydrogen sulfide can lead to disturbances in the chemical composition of surface waters. This gas belongs to the group of poisons with acute effects. Its appearance in the atmosphere and hydrosphere can cause serious economic damage and medical problems among local population. Unfortunately, in Russia, air, soil, and water pollution by hydrogen sulfide and sulfur dioxide has been reported in a number of regions. Especially severe consequences for human health and biota have been observed in the basin of the low Volga River in the zone of development of the Astrakhanskoe gas condensate field [Ecology and impact of natural gas on organisms, 1989].

The sources of atmospheric pollution also include flaring of natural gas on the offshore platforms and onland terminals. Some estimates [Cairns, 1992] show that about 10% of total gas production and up to 30% of associated gases are burned here. The behavior and distribution of the products of natural gas flaring in the atmosphere, their removal by precipitation, and the impact on the water environment have not been studied. The same situation is true regarding gas emissions at different stages of its production, transportation, and processing.

An important anthropogenic source of gas hydrocarbons in the water environment is the offshore drilling accidents. Their environmental consequences can be very hazardous. Especially dramatic situations developed in the Sea of Asov as a result of two large accidents on drilling rigs in the summer-autumn of 1982 and 1985. These accidents caused long-term releases of large amounts of natural gas into the water accompanied by self-inflaming of the gas. During these events, the levels of methane in surface waters exceeded the background concentrations up to 10-100 times. The air samples also showed very high concentrations of methane. These accidents drastically disturbed the composition and biomass of the water fauna and caused mass mortality of many organisms, including fish and benthic mollusks. Similar incidents probably took place in other regions of the world as well. However, there are no publications on this topic available.

Another potential source of gas in the hydrosphere is damaged gas pipelines, both on the seafloor and on land where they cross over rivers and other water bodies. The causes of such damage can vary from corrosion processes to natural disasters (severe ice

conditions, seismic activity, and earthquakes). It should be noted that hydrocarbon gases are piped over great distances totaling many thousands of kilometers. These pipelines cross hundreds of water bodies. Possible pipeline damages can lead to hazardous impacts on water ecosystems. The negative fisheries consequences in such cases may go beyond the limits of local scale. Regional problems can emerge if, for example, an accidental gas blowout or leakage blocks the spawning migration of anadromous fish.

Methane impact on water organisms and communities

Water toxicology of saturated aliphatic hydrocarbons of the methane series has not been developed thus far. This gap cannot be filled by available materials on the toxicity of other gaseous poisons (e.g., carbon oxide, hydrogen sulfide, and ammonia) for fish. Clear behavioral specifics of each of these gases in the water environment do not allow us to extrapolate these data to predict the biological effects of methane and other saturated hydrocarbons. However, the toxicity data on different gaseous poisons can help to reveal some general features of interaction between gaseous traces and

marine organisms [Patin, 1993].

The first important feature is the quick fish response to a toxic gas as compared with fish response to other dissolved or suspended toxicants. Gas rapidly penetrates into the organism (especially through the gills) and disturbs the main functional systems (respiration, nervous system, blood formation, enzyme activity, and others). External evidence of these disturbances includes a number of common symptoms mainly of behavioral nature (e.g., fish excitement, increased activity, scattering in the water). The interval between the moment of fish contact with the gas and the first symptoms of poisoning (latent period) is relatively short.

Further exposure leads to chronic poisoning. At this stage, cumulative effects at the biochemical and physiological levels occur. These effects depend on the nature of the toxicant, exposure time, and environmental conditions. A general effect typical for all fish is gas emboli. These emerge when different gases (including the inert ones) oversaturate water. The symptoms of gas emboli include the rupture of tissues (especially in fins and eyes), enlarging of swim bladder, disturbances of circulatory system, and a number of other pathological changes.

These general features of fish response observed in the presence of any gas in the water environment are likely to be found for saturated gas hydrocarbons as well. Available materials derived from the medical toxicology of methane and its homologues support this suggestion.

Medical toxicology distinguishes between three main types of intoxication by methane:

light, results in reversible, quickly disappearing effects on the functions of central nervous and cardiovascular systems;

medium, manifests itself in deeper functional changes in the central nervous and cardiovascular systems and increase in the number of leukocytes in the peripheral blood; and

-heavy, results in irreversible disturbances of the cerebrum, heart tissues, and alimentary canal as well as acute form of leukocytosis.

These types most likely adequately describe the general patterns of methane effects in vertebrates. However, its features in respect to ichthyofauna remain to be studied. Fish resistance to the presence of gas at different life stages is of special interest. With most toxicants, the most vulnerable periods are the early life stages. The question of whether this general pattern is typical for saturated hydrocarbons still remains open. The importance of this issue in assessing biological effects of natural gas in the water environment is quite obvious.

toxicant concentrations that do not cause any effect under low temperatures can become lethal with increasing water temperature.

During toxicological studies of different gases, including methane and its derivatives, one must take into consideration the influence of other factors (especially temperature and oxygen regime) that can radically change the direction and symptoms of the effect. In particular, increasing temperature usually intensifies the toxic effect of practically all substances on fish because of the direct correlation between the level of fish metabolism and water temperature. From the physiological perspective, this can be explained not only by the general intensification of fish metabolism but also by the increased permeability of the tissues for the poisons and increased oxygen consumption under high temperatures. Thus, toxicant concentrations that do not cause any effect under low temperatures can become lethal with increasing water temperature. This circumstance should be taken into consideration during ecotoxicological assessment of the potential impact of natural gas and other toxicants, especially when studies are conducted in high latitudes. In such regions, methane hydrates may be accumulated during the winter and dissociate during the increased temperatures in the summer. This may be followed by the releasing of free methane with corresponding environmental consequences.

Another critical environmental factor that directly influences the gas impact on water organisms is the concentration of dissolved oxygen. Numerous studies show that the oxygen deficit directly controls the rate of fish metabolism and decreases their resistance to many organic and inorganic poisons. This decrease sometimes depends more on the species characteristics and the rate of their gas metabolism rather than on the nature of the poison. From the physiological perspective, such a phenomenon is explained by the fact that the level of hemoglobin in fish blood and the rate of blood circulation through the gills increase under oxygen deficit. Clearly, such effects are of special interest when interpreting the data on fish response to natural gas in situations of significant change in the oxygen regime (e.g., during eutrophication of water bodies or seasonal and weather variations of the oxygen content).

The European gas supply is threatened by the lack of security on various Eastern European pipelines.

Eastern Europ's gas supply remains uncertain

The stability of gas supply has become an issue of increased importance in Europe of late. While Russia and the former Soviet states are embroiled in disagreements over gas prices, questions are being asked concerning the stability of several pipelines in Europe.

The unexpectedly cold weather at the beginning of the year took Georgia by surprise and demand for gas rose to unprecedented levels. A spokesman for Ukraine's state-owned energy firm Naftogaz said that the extra gas the country consumed was needed to cope with the especially cold January weather.

In response, Russia's gas monopoly Gazprom, which supplies over a quarter of Europe's gas, mainly via the Ukraine, commented that the Ukraine was preventing Russia from meeting its international obligations.

The Ukrainian Prime Minister, Yuri Yekhanurov, said his country's consumption of gas had exceeded 400 million cubic metres in a 24-hour period ; a record level, amounting to about 43% more than during an average winter day. Temperatures fell lower than -30°C in Ukraine during January, severely straining its energy infrastructure.

"The countries of Central and Eastern Europe are among the most dependent on Russian gas."Gazprom implemented emergency measures to compensate for the missing volumes by using underground storage facilities in European countries. The energy giant said it was extracting nearly 85 million cubic metres of gas above-plan daily to meet the demand.

ONGOING DISPUTES

Tension has been mounting between Russia and Ukraine recently over a new gas pricing deal which doubles the amount Kiev has to pay for its gas.

The signing of the deal, which was agreed on 4 January 2006, has been postponed until various issues have been resolved, not least the issue of ensured supply highlighted above. Under the five-year deal, Ukraine will buy Russian and Central Asian gas for $95 per 1,000m^3 on average.

The dispute led to Gazprom temporarily turning off Ukraine's supply, which in turn disrupted supplies to a swathe of European countries. Western and Central European countries produced about 60% of the gas they needed in 2004. The biggest producers were the UK, the Netherlands and Norway.

Of the gas imported from outside the region, two-thirds came from Gazprom.

The Ukrainian pipeline network carried approximately 80% of this supply with the rest travelling through a smaller pipeline crossing into Poland and Germany via Belarus. Most of the rest of the gas imported into Europe comes from Algeria.

PIPELINE SECURITY

Another major factor concerning European gas supply is the apparent lack of security on various Eastern European pipelines.

The political volatility of these areas is affecting confidence in the supply chain originating in Russia. For example, the suspected sabotage of the Mozdok-Tbilisi pipeline on the Georgian border throws the outlook for a trans-Caucasus pipeline into doubt.

Georgia's President, Mikhail Saakashvili, accused Moscow of serious acts of sabotage in January after gas blasts on Russian pipelines cut off supplies to Georgia and Armenia.

The two explosions occurred on the main branch and a reserve branch of the Mozdok-Tbilisi pipeline in the Russian border region of North Ossetia at around 0300 local time (2400 GMT).

The electricity transmission line in Russia's southern region of Karachayevo-Cherkessiya, also near the Georgian border, was brought down by an explosion just hours later.

Mr Saakashvili commented that the near simultaneous attacks close to Georgia's border were pre-planned actions orchestrated by Russia.

Russia's foreign ministry dismissed the Georgian President's remarks as 'hysteria'.

"Germany, Italy and the Ukraine are the biggest importers of Russian gas."Relations between Georgia and Russia have been tense since Saakashvili was handed power during the 'Rose Revolution' in 2003, pledging to lead his nation on a pro-Western course.

Saakashvili said the gas pipeline was blown up in "an area fully under Russian control", where there were no local insurgents.

"They happened at the same time, and basically they didn't affect supplies to Russia proper, so we can conclude that it was a very well-organised and very well-coordinated act," said the Georgian President. "We've received numerous threats by Russian politicians and officials at different levels to punish us for basically for not giving them pipelines."

A spokesman for Russia's gas monopoly Gazprom argued that the company was doing all it could to restore gas supplies. "We believe this situation should not be politicised," Sergei Kuprianov was quoted as saying by the Russian Interfax news agency.

FOCUS OF ATTENTION

Although no single party has claimed responsibility for the attacks, the threat of continued security problems has forced Europe to take notice of the integrity of its gas pipelines.

With an intricate supply chain network relying on Russian gas via various pipelines, many countries will be monitoring the situation very carefully over the coming months.

Turning off Russian supplies of gas to Eastern Europe is a bold assertion of political power - with major consequences for some energy-hungry countries in the west of the continent.

Dr. Jonathan Wills

Minimising Waste Discharges and Their Effects

There are several ways to reduce the volume of drilling waste produced and to minimise its effects on the sea

Using less toxic alternatives is a favoured solution in both Europe and North America, where governments and industry are continually searching for improved and less harmful offshore drilling fluids. SBMs, most of which failed to satisfy European standards, were such an attempt to deal with the problem at source and the US may yet prove that some forms of SBMs really are an environmentally acceptable alternative to OBMs. For WBMs, improvements to the purity of stock chemicals, and measurement of their toxicity prior to mixing into the drilling fluid, are among the most promising prospects for environmental improvement in cases where waste discharge is unavoidable.

Cleaning onboard prior to discharge is also a rapidly developing technology. The crude shale-shakers and sieves once employed to separate solids from drilling fluids after use have been superseded by much more efficient equipment that can greatly improve the separation of mud from cuttings and oil from produced water. Technology exists, but has not yet been widely adopted offshore, that can very largely remove the residual pollutants in cuttings and, particularly, in produced water. The obstacles are financial rather than technical. Whether such equipment is installed and used offshore is, of course, a matter for government enforcement.

Shipment of wastes ashore for recycling, landfill and/or incineration is one of the options being considered for dealing with the very large accumulations of contaminated drill cuttings in the North Sea. It is already used to dispose of some ongoing waste streams and thus prevent the build-up of new drill cuttings piles on the seabed. While making a contribution to both the environment and the local economies of North Sea coastal regions, (In the UK, for example, new equipment to process cuttings and other wastes shipped ashore from North Sea fields has recently been installed in Peterhead, Aberdeen and Shetland (where one firm has been handling contaminated cuttings waste for over 10 years). See, for example: Burgess & Garrick. 2000. Waste Management.

Website: http://www.burgess-garrick.co.uk/about.htm Lerwick) the air pollution, landfill space demands and energy costs associated with transporting, processing and disposing of the material seem likely to influence governments in favour onsite re-injection technology as a more practical and cost-effective method - wherever geological conditions are suitable.

Re-injection Offshore

Cuttings re-injection (CRI) is a waste disposal technique where drill cuttings and other oilfield wastes are mixed into slurry with water and

pumped at high pressure down an injection well. Sometimes it is necessary to grind up the particles in the slurry to make them finer. The hydraulic pressure can also be used to break open layers in the rock to make subsequent injection easier and to contain the wastes in a defined area - hence the term slurry fracture injection commonly used in the US and Canada, where the technique was pioneeredOne of the clearest explanations of CRI is by the British company Gidatec which describes it as "a cost effective means of complying with environmental legislation concerning discharges of oily wastes" and says it has "proven to be viable in many different areas and formations around the world, with the most activity in the North Sea, Alaska, Gulf of Mexico and Venezuela":

Re-injection of drill cuttings normally involves collection of the waste from solids control equipment on the rig, followed by transportation to a cuttings processing station.

Cuttings are slurried in this unit by being milled and sheared in the presence of water, usually seawater.

The resulting slurry is then disposed of by pumping it into a dedicated disposal well, or through the open annulus of a previous well into a fracture created at the casing shoe set in a suitable formation. Operations are usually batch by nature and carried out at low pump rates (2.0 - 8.0 bpm). These kinds of operations have been carried out all over the world, with disposal into many different types of strata.

On logistical and cost grounds the means of disposing of waste cuttings from [offshore] platform based operations can usually be narrowed down to one of two choices. These are either re-injection into a dedicated disposal well, which if newly drilled can be re-completed as a producer at a later date, or re-injection through the annulus of a well drilled prior to the current live well. Drilling and cuttings disposal into the same well is possible but to date, because of well control concerns, it is not a preferred option with operators.

Sequential annulus injection is invariably the preferred means of disposing of cuttings, particularly in offshore locations. This is because of its flexibility and that it avoids the cost of drilling a dedicated disposal well. For cost reasons, dedicated re-injection wells are usually only practical on land or in shallow water. They do have advantages, however, including ease of cleaning out with coiled tubing in the event of plugging, can be designed to accommodate high volumes of waste, the ability to inject larger sized solids and a reduced risk of tubing plugging. Even so, unless annular cuttings re-injection is not viable, for example because of lack

Drilling and cuttings disposal into the same well is possible but to date, because of well control concerns, it is not a preferred option with operators.

of annular access to a suitable deposition horizon, drilling a dedicated disposal well is usually ruled out on cost grounds. Thus, annular re-injection of waste cuttings is invariably the method of choice. Typically the 13 3/8" by 9 5/8" annulus is selected as the disposal location.

One of the first oil companies to make extensive use of cuttings re-injection was BP. The company had opened up its Alaska North Slope oilfields by using "reserve pits" - a euphemism for holes in the ground where drillers dumped almost anything. Within a few years BP had a serious environmental problem on its hands, as poisonous wastes began to leach out of the pits and spread across the tundra on top of the permafrost. Although it was out of sight from most people, the pollution in the Arctic wilderness north of the Brooks Range was not out of mind. As controversy grew about the oil industry's plans to drill in the Arctic National Wildlife Refuge (ANWR) critics pointed to the mess at the reserve pits as evidence that BP's environmental credentials were suspect. This caused serious public relations problems for BP and its compradors in the Alaska State Legislature and business community. During the late 1980s and early 1990s the company cleaned up the pits, volunteered its services to deal with other organisations' waste dumps (some dating from World War II and earlier) and, to some extent, salvaged its reputation among American environmentalists.

The results certainly looked impressive and showed what an organisation like BP could achieve when management and workers were given the resources to do a thorough job.

(1. Taylor, S. 1998. Status of North Slope Environmental Protection (video presentation), BP Exploration, Anchorage. 2. Minton, R. C. and Secoy, B. 1992. Annular Re-injection of Drilling Wastes. IADC/SPE Paper 25042. Society of Petroleum Engineers, Richardson, Texas.

3.Brasier, F. 1992. Injection Control Regulations - Federal Framework and Alaska Regulations.

Proceedings of a Seminar on Subterranean Disposal of Drill Cuttings and Produced Water. Stavanger). By 1993 the E&P Forum could boast: "In Alaska the injection of cuttings and waste fluids has led to much smaller drilling pads, and therefore less impact from the rig rites, and less heavy traffic transporting materials across the tundra. (E&P Forum. 1993. Guidelines for the Planning of Downhole Injection Programmes for Oil Based Mud Wastes and Associated Cuttings from Offshore Wells.

Report No. 2.56/187. E&P Forum, London) There were also economic

benefits because the reserve pits had been costing about $2,000,000 per well, whereas grinding and down-hole injection cost about $500,000 per well thereby saving about $1,500,000 per well. (ADEC informant, pers. comm., 2000.)

BP was also in the forefront with CRI offshore. In January 1991 BP engineers injected 5,700 barrels of drilling wastes 5,100 feet below the bottom of the Gulf of Mexico, in tests at the Ewings Bank platform. In the Norwegian sector of the North Sea, BP was involved in a case study on the Gyda oilfield from July 1991 (Molland, G. 1992. Re-injection of Cuttings on Gyda. Proceedings of a Seminar on Subterranean Disposal of Drill Cuttings and Produced Water. Stavanger). In September that year BP did a test injection of 1,500 barrels of waste from the Clyde platform in the UK sector. Other case studies on CRI were carried out in the early 1990s by Conoco in the southern North Sea (January - March 1992) and the Gulf of Mexico (Block EC56, December 1991 - January 1992), by Statoil on the Norwegian Gullfaks field (October 1991) and by Amoco, also in the Norwegian sector, on the Valhall oilfield (January 1992). (E&P Forum. 1993. op. cit.) These, however, were all described as case studies, tests or experiments.

By 1993 CRI was such a well-established technique offshore that the E&P Forum produced detailed guidelines (Ibid) for operators planning to use it for OBM wastes and oil-contaminated drill cuttings. The document gave examples of the kinds of problems staff might encounter and, in addition to practical advice, laid down recommended procedures for monitoring and reporting re-injection work. The working group that drew up the guidelines included two representative of Exxon, alongside experts from Agip, Amoco, BP, Chevron, Elf, Enterprise Oil, Statoil, Texaco and Total.

They agreed that re-injection had "a successful history to date, particularly in Alaska and the Gulf of Mexico" but in Europe it had "only recently been evaluated". They described a Drilling Engineering Association project, with 12 operator sponsors, that had "been involved in developing the concept" between 1990 and 1993 and added:

Injection has been adopted by operators in the Norwegian and UK sectors of the North Sea, and is seen as a viable route to oily waste disposal.

The adoption of this approach to the disposal of oilfield wastes is particularly attractive since it means that the overall environmental impact of operations is minimised. Injection offers a cost effective disposal option with minimal energy utilisation.

This view is confirmed by a review of the extensive literature on the subject in the public domain. (For example, see the following: 1. Lal, M. and Thurber, N. 1989. Drilling Wastes Management and Closed-Loop Systems. In Engelhardt, F. R. et al. (eds). 1989. Drilling Wastes. pp. 213-228. Elsevier Science Publishers

Injection has been adopted by operators in the Norwegian and UK sectors of the North Sea, and is seen as a viable route to oily waste disposal.

Ltd, Barking, England. 2. Dusseault, M.B., Bilak, R.A., and Rodwell, G.L. 1997. Disposal of dirty liquids using Slurry Fracture Injection, SPE 37907, Proc. 1997 SPE/EPA Expl. and Prod. Env. Conf., Dallas, TX, March 3-5, 1997, pp. 193-202. 3. Dusseault, M.B., Bilak, R.A., Bruno, M.S. and Rothenburg, L., 1995. Disposal of granular solid wastes in the Western Canadian sedimentary basin by Slurry Fracture Injection, Paper presented at the International Symposium of Scientific and Engineering Aspects of Deep Injection Disposal of Hazardous and Industrial Wastes, Berkeley, CA, May 10-13, 1994. 4. Dusseault, M.B. and Bilak, R.A., 1993. Disposal of Produced Solids by Slurry Fracture Injection, Paper presented at the 4th Pet. Conf. of the S. Saskatch. Sec., Pet. Soc. of CIM,, Regina, Sask., Oct 18-20, 1993. 5. Sipple-Srinivasan, M.1998,

U.S. Regulatory Considerations in the Application of Slurry Fracture Injection for Oil Field Waste Disposal. International Petroleum Environmental Conference (IPEC) '98 , Albuquerque, N.M. 6. Sipple-Srinivasan, M., Bruno, M., Bilak, R., and Danyluk, P. 1997. Website: Field experiences with oilfield waste disposal through Slurry Fracture Injection. SPE 38254, Society of Petroleum Engineers' 67th Annual Western Regional Meeting, Long Beach, CA.)

(For accounts of early work on re-injection, see: 1. Beak Consultants and Imperial Oil Limited 1974. Disposal of waste drilling fluids in the Canadian Arctic. APOA project no.73. APOA, Calgary. 2. Dome Petroleum Limited 1974. Interim guidelines for waste management in exploratory drilling in the Canadian north. Dome Petroleum Ltd., Calgary. 3. French, H. M. 1980. Terrain, Land Use and Waste Drilling Fluid Disposal Problems, Arctic Canada.

Arctic 33:794-806. 4. Friesen, G. 1980. Drilling Fluids and Disposal Methods Employed by Esso Resources Canada Limited to Drill in the Canadian Arctic. Proceedings of a Symposium: Research on Environmental Fate and Effects of Drilling Fluids and Cuttings, Lake Buena Vista, Fla.: pp. 53-69. American Petroleum Institute. Washington, DC.

5. Lam, L. 1982. Report on Offshore Oil and Gas Drilling Fluid Disposal in the Canadian North Technical Report No. 3.6. A Survey of Methods of Waste Fluid Treatment and Disposal for Canadian Offshore Drilling. Canadian Superior Oil Ltd. 6. Canada Dept. of Indian Affairs and Northern Development, Environment Canada, Canada Dept. of Fisheries and Oceans, Industry/Government Working Group on Disposal of Waste Fluids from Petroleum Exploratory Drilling in the Canadian North, and Arctic Petroleum Operators Association. 1982. Report on offshore oil & gas drilling fluid disposal in the Canadian North. Yellowknife, N.W.T. 7. Hillman, S.O. 1983. Drilling Fluids: Disposal in the Alaskan Beaufort Sea. Issues of the 80's: Twelfth Annual Arctic Environmental Workshop held at Fairmont, British Columbia, May 8th-11th, 1983, p.162-166.)

(United States Department of the Interior (DOI), Fish and Wildlife Service (FWS). 1987. Effects of Prudhoe Bay Reserve Pit Fluids on Water Quality and Macroinvertebrates of Arctic Tundra Ponds in Alaska. US DOI Biological Report 87(7). Washington D.C.)

In the 1980s the consensus among Western scientists studying the environmental effects of drilling waste discharges was that effects were mainly local and minor. This view was summarised by the American researcher Jerry Neff of the Battelle Research Laboratory in Duxbury, Massachusetts, with an authoritative paper (Neff, J. M. 1987. Biological Effects of Drilling Fluids, Drill Cuttings and Produced Waters, in Boesch, D. F. and Rabalais N. N.

(eds.). 1987. Long-Term Environmental Effects of Offshore Oil and Gas Development, pp. 469-538.

Elsevier Applied Science Publishers, London) in Donald Boesch and Nancy Rabelais' influential book, Long-Term Environmental Effects of Offshore Oil and Gas Development, published in 1987:

Most of the major ingredients of drilling fluids have a low toxicity to marine organisms. Only chrome and ferrochrome lignosulphates and sodium hydroxide are slightly toxic. A few specialty chemicals sometimes added to drilling fluids to solve certain problems are toxic.

These include diesel fuel, chromate salts, surfactants and paraformaldehyde biocide [tests for] chronic and/or sub-lethal effects of drilling fluids have been performed with at least 40 species of marine animals. In most cases, sublethal responses in marine animals were observed at drilling mud concentrations only slightly lower than those that were acutely lethal. In some species, sublethal responses were observed at drilling fluid concentrations up to two orders of magnitude lower than acutely lethal concentrations. Sensitive species included reef corals, lobster larvae and scallop embryos and larvae. Recruitment of planktonic larvae to sandy sediments in laboratory microcosms was decreased by high concentrations of drilling mud mixed with or layered on the sediments. Based on laboratory studies of acute and chronic/sublethal toxicity of drilling muds and field observations of rates of dilution of drilling muds in the water column, it is concluded that water column organisms will never be exposed to drilling fluids long enough and at sufficiently high concentrations to elicit any acute or sublethal responses. Where drilling fluid solids settle on the bottom, there could be localised adverse impacts on the benthos, through chemical toxicity, change in sediment texture, or burial... [emphases added. JWGW]

...The severity of the impact of drilling fluids and cuttings on the benthos is directly related to the amount of material accumulating on the substrate, which in turn is related to the amount and physical characteristics of the materials being discharged, and to the environmental conditions at the time and site of discharge, such as current speed and water depth. In high energy environments, little mud and cuttings accumulate and impacts on the benthos are minimal and of short duration. In low energy and depositional environments, more material accumulates and there may be reduction in abundance of some benthic species.

Most of the major ingredients of drilling fluids have a low toxicity to marine organisms. Only chrome and ferrochrome lignosulphates and sodium hydroxide are slightly toxic. A few specialty chemicals sometimes added to drilling fluids to solve certain problems are toxic.

IOEC to possess a yard in Venezuela

Iran's Offshore Engineering and Construction Company (IOEC) has announced its plans to own yard in Venezuela jointly with the Spain's Dragados and Venezuelan Cameron companies.

Mojtaba Emam-Mousavi, the IOEC marketing and development director, said in a report following his trip to Venezuela that the Spanish Company had a long standing back ground in Venezuela as it has had the advantage of the Spanish language, which is the common language spoken both in Spain and Venezuela.

"Founding a joint yard and building the capacities for oil and gas activities in Venezuela are the main purposes of our becoming partners with Dragados," Emam-Mousavi said.

Hamid Reza Zamani, IOEC regional manager for Venezuela, said that a Venezuelan company named Cameron was to be a partner in the project as well as Dragados.

"Dragados and Cameron will form a company named 'Tec Offshore', which will create the consortium with IOEC in order to shape the joint yard and the consortium will own the yard," Zamani said.

Zamani also said that a team of IOEC experts was to be dispatched to Venezuela to find the appropriate location for the joint yard, however he said the scheme of partnership in the consortium had not yet been defined.

"The coasts of four Venezuelan cities have been inspected so far as potential locations of the yard, Barcelona, Cumana, Guiria and PuertoCaubeillo, non of which have been definitely selected yet," Zamani said, adding that Cumana and Puerto Caubeillo seem to be the better options among the four.

Emam-Mousavi announced the formation of another consortium made of Iranian IOEC, Sadra and ICON along with the Venezuelan state oil company PDVSA, where the Iranian firms own a 49 percent stake and the Venezuelan party own 51 percent of the consortium.

"The consortium will be able to carry out all of PDVSA's project in the sea and land," Emam-Mousavi said.

Zamanin added that the Iran-PDVSA consortium was supposed to be formed within 90 days and added that the consortium would only be acting in the Hydrocarbon fields' development.

IOEC officials Emam-Mousavi and Zamani were among the delegation that accompanied President Mahmoud Ahmadinejad on his trip to Venezuela in September.

REPORT

HERE'S THE PUZZLE,

GOOD LUCK !

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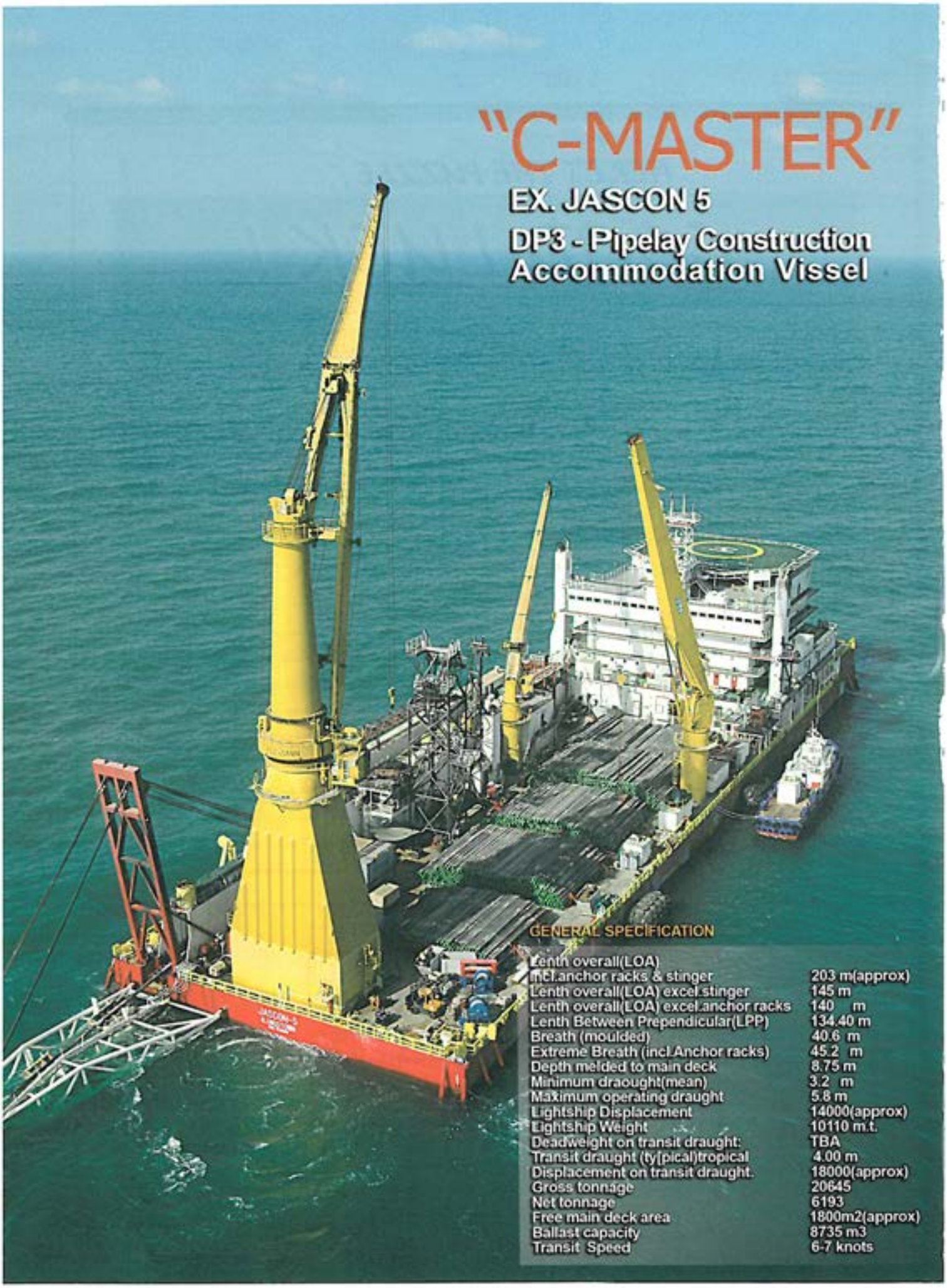

"C-MASTER"

EX. JASCON 5

DP3 - Pipelay Construction Accommodation Vissel

GENERAL SPECIFICATION

Lenth overall(LOA) incl.anchor racks & stinger	203 m(approx)
Lenth overall(LOA) excel.stinger	145 m
Lenth overall(LOA) excel.anchor racks	140 m
Lenth Between Prependicular(LPP)	134.40 m
Breath (moulded)	40.6 m
Extreme Breath (incl.Anchor racks)	45.2 m
Depth melded to main deck	8.75 m
Minimum draought(mean)	3.2 m
Maximum operating draught	5.8 m
Lightship Displacement	14000(approx)
Lightship Weight	10110 m.t.
Deadweight on transit draught:	TBA
Transit draught (ty[pical)tropical	4.00 m
Displacement on transit draught.	18000(approx)
Gross tonnage	20645
Net tonnage	6193
Free main deck area	1800m2(approx)
Ballast capacity	8735 m3
Transit Speed	6-7 knots

KITO

KITO Enterprises (L.L.C)

- Fleets Operation
- Taking and Extension International Certificates (I.M.S. / I.S.P.S. / H.S.E.)
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