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Deepwater Investment

August 2002


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Hart Publications,
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4545 Post Oak Place, Suite 210
Houston, Texas 77027-3105
713-993-9320
Fax: 713-840-8585
www.OilandGasInvestor.com

Publisher
Brad Holmes
bholmes@chemweek.com
Ext. 140

Editor
Leslie Haines
lhaines@chemweek.com
Ext. 151

Contributing Editors:
Karl Lang, Gary Clouser

Art Director
Marc Conly

Graphic Artist
Jennifer Paniagua

Regional Sales Manager
Bob McGarr
bmcgarr@chemweek.com
Ext. 144

Regional Sales Manager
Shelley Lamb
slamb@chemweek.com
Ext. 118

Vice President, Hart Publications, and Group Publisher, Finance & Power Publications
Bob Jarvis
bjarvis@chemweek.com
Ext. 130

Managing Editor
Nissa Darbonne
ndarbonne@chemweek.com
Ext. 165

BPA International

Chemical Week Associates

Richard A. Eichler, President Hart Publications

Mario G. Di Ubaldi, Executive VP ChemWeek Group

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Deepwater Investment

In 2003, TotalFinaElf's Canyon Express project will go on production in the deepwater Gulf of Mexico. When it does, it will break the world production record for water depth. The massive project involves the subsea tieback of three producing fields—Aconcagua, King's Peak and Camden Hills—to a fixed production platform in shallower water some 56 miles away.

With advances like this paving the way, no wonder deepwater oil and gas production is estimated to grow significantly in the next five years. There were 51 deepwater projects onstream by year-end 2001, more than triple the amount four years ago. Some 59% of oil and about 24% of gas production in the Gulf now comes from deep water.

"A certain level of maturity has now been reached," says Chris Oynes, regional director of the Minerals Management Service in New Orleans. "I am very optimistic that production will continue to rise."

Many discoveries have been made and their development sanctioned by the industry. Now there is a flurry of activity in evaluation, conceptual design and engineering under way to determine the most effective way to bring these finds to full production.

Once again, technology and innovation are helping to make oil and gas dreams come true. This special report focuses on the amount of deepwater production that is coming soon to the Gulf, and the production systems and pipeline infrastructure needed to handle it.

The federal government is encouraging more exploration through its Deepwater Royalty Relief Act. It also has joined with numerous universities and companies involved in all sorts of research groups. For example, begun in 1992, the DeepStar research consortium is now in its 10th year and Phase VI. Its gap analysis program has indicated where a systems approach needs to be taken—what good is it to have an umbilical system that operates in 10,000 feet of water if the flowlines do not function well, or the subsea wellheads do not? Or the risers from the production platform to the sea floor are not tenable?

The challenges are huge. But operators and service companies and manufacturers are willing to take up these challenges.

—Leslie Haines

contents

ON THE COVER: Pipe is being laid in the Gulf of Mexico for El Paso Energy Partners.

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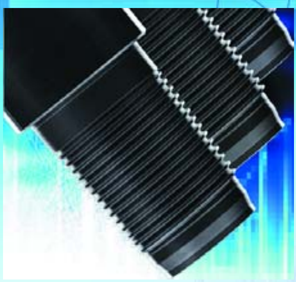

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MINERALS MANAGEMENT SERVICE
Gulf of Mexico OCS Region
1201 Elmwood Park Boulevard
New Orleans, Louisiana 70123-2394

July 15, 2002

Since 1996, Minerals Management Service (MMS) has overseen astonishing levels of deepwater (greater than or equal to 1,000-foot depths) oil and gas activity in the Gulf of Mexico (GOM). After the emergence of massive exploration and development in the GOM, a certain level of maturity has now been reached--the deepwater GOM is an expanding frontier.

While only 16 deepwater projects were on production in early 1997, this number grew to 51 by the end of 2001. A record 14 deepwater projects initiated production during 2001, and another 13 are projected to begin in 2002. The MMS estimates that, by the end of 2001, deepwater oil production had risen 500 percent and gas production had risen 550 percent since 1995. Fifty-nine percent of all oil production in the Gulf now comes from the deepwater.

Many different types of production-system technologies are now in use. There is a strong reliance on subsea tiebacks in deepwater and, surprisingly, in shallow water, with 38 subsea projects now producing throughout the GOM and more than 200 wells installed to date. With this reliance on subsea production technology and a growth of the pipeline infrastructure, operators have established numerous production hubs to support this expanding frontier. The Auger tension-leg platform (TLP), installed in 1994, now supports 3 separate subsea tieback developments - Macaroni (1999), Serrano (2001) and Oregano (2001). Shell began production from Brutus in 2001, the seventh TLP in the GOM. Installation of the unique class of small TLP's at the Typhoon and Prince fields shows the continued progression of floating production-system technology. The installation of the world's first truss spars at the Boomvang and Nansen fields, and the ongoing construction of five more, further demonstrates this progression.

In a sense, production of oil and gas is only now hitting its stride, and large increases in production are on the horizon for 2004-2006. Estimates by MMS of the substantial resource potential in deepwater will likely grow again when a new resource assessment is released.

Ultra-deepwater activity (greater than or equal to 5,000-foot depths) continues to accelerate; Unocal's announcement of a significant discovery at their world-record well on the Trident project (9,727 feet of water) serves to accentuate the unfolding potential of the deepwater GOM.

Chris C. Oynes

Chris C. Oynes
Regional Director
Minerals Management Service

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Deepwater Promise Keeps Unfolding

Through 2000, up to 9 billion barrels of new reserves were discovered in the deepwater Gulf of Mexico. Much more is on the way.

Article by Karl Lang

With a combination of a large active lease inventory, an increased drilling program and a growing pipeline and facility infrastructure, the deepwater Gulf of Mexico will play an increasing role in the U.S. energy-supply picture, according to the Department of Interior's Minerals Management Service (MMS).

A new publication, "Deepwater Gulf of Mexico 2002: America's Expanding Frontier," released at the Offshore Technology Conference in Houston in May, highlights the history of industry activity in deep water (1,000 feet of water or more) during the past seven years.

Key indicators of success, according to the MMS, include the following:

- A total of 59% of Gulf of Mexico oil production now comes from deep water.
- The number of rigs working in deep water has increased to an all-time high of 45.
- A record number of wells, 225, were drilled in the deepwater Gulf in 2000.
- The number of ultradeepwater-capable rigs (5,000 feet or greater) in the Gulf has increased from 18 to 26, and the number of ultradeepwater wells drilled has increased from 37 to 59. Currently 10 wells are being drilled in water depths of 5,000 feet or greater.
- A record 14 deepwater projects began production in 2001, and another 13 are expected to begin during 2002.

A second report, "Gulf of Mexico OCS Daily Oil and Gas Production Rate Projections from 2002 through 2006," forecasts shallow and deepwater oil and gas production rates through the next five years. The following material includes highlights from these two publications.

Transocean's *Discoverer Spirit* held the world water-depth drilling record at 9,727 feet, in the Gulf of Mexico. (*Photo by Mieko Mahi.*)

Reserves Additions

Beginning in 1975, the deepwater area of the Gulf of Mexico began contributing significant new volumes to the nation's oil reserves. Between 1975 and 2000, an estimated 8- to 9 billion barrels of new reserves were discovered, nearly as much oil as was produced during the first 70 years of commercial oil production in the U.S.

Those large numbers don't tell the whole story, because of the time lag between a discovery and when it becomes clear that a field will be produced—and reserves thus can be considered proved. For example, reserve additions associated with the large number of discoveries made during 1984-87 were not accounted for until 1987-90. (*See Figure 1.*)

Similarly, much of the oil associated with discoveries made during the late 1990s has not yet been booked as reserves. Accordingly, the true impact of relatively recent large deepwater exploratory successes is not yet reflected in MMS proved and unproved reserve estimates.

One of the important features of deepwater field discoveries is that the average size of deepwater fields is many times larger than the average size of shallow-water fields. During the 1990s the average shallow-water field added approximately 5 million barrels of oil equivalent (BOE) of proved and unproved reserves. In contrast, the average deepwater field during this period added more than 47 million BOE of proved and unproved reserves—more than nine times the shallow-water average.

In the most active deepwater exploration zone—water depths between 1,500 and 7,499

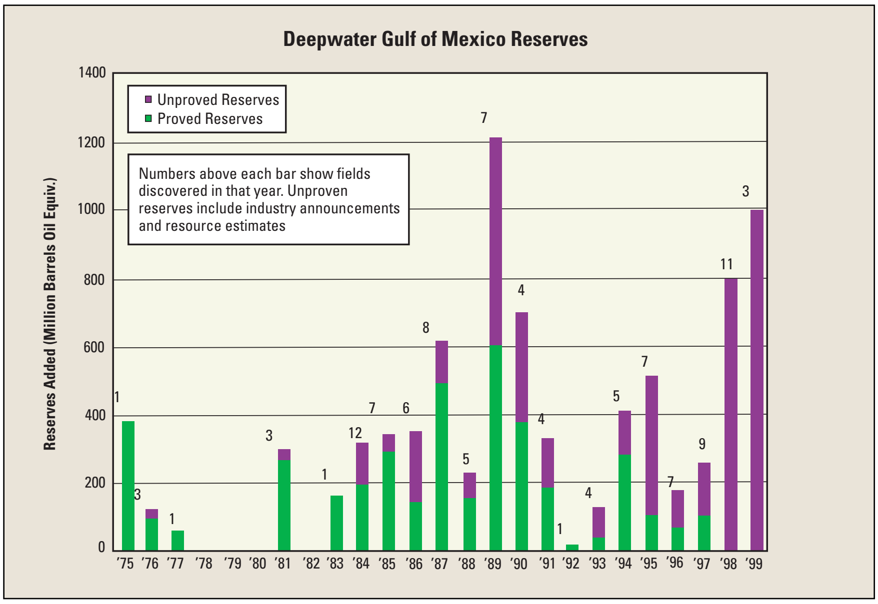

Fig. 1. The time lag between discovery and first production makes it tough to keep up with reserve statistics.

feet—the average field contributed more than 60 million BOE—12 times the average shallow-water field addition. This is typical of frontier areas where exploration strategies target large accumulations necessary to justify large capital investments. It also highlights the enormous potential of the Gulf of Mexico deepwater region, much of which has yet to be fully explored.

Production Trends

Oil-production data from deepwater leases in 2001, which is still being compiled, is expected to show total production of more than 900,000 barrels per day, including condensate. Deepwater gas production is projected at more than 3 billion cubic feet (Bcf) per day for 2001.

Oil and gas production data during the past decade show clearly that as the contribution of oil from shallow water leases has declined, the contribution from the deepwater has grown significantly. Since late 1999, more than 50% of the Gulf's oil production has come from deepwater projects. (*See Figure 2.*)

The MMS expects the trend will continue during the next five years, with deepwater oil production projected to comprise about three-quarters of the Gulf total by 2006.

Deepwater gas production, which has more than tripled since 1996, will amount to about a quarter of total Gulf gas production in 2001. (*See Figure 3.*) Shallow-water gas production has been relatively stable during the past 15 years, with only a slight decline.

The steady increase in deepwater gas production that has occurred during the past few years has offset the decline in shallow-water gas output. The MMS expects total Gulf gas production and relative contributions of deep- and shallow-water areas remaining at roughly the same levels during the next five years.

These forecasts were compiled from data on 86 deepwater fields, 56 of which have begun production and 30 of which are projected to begin producing before the end of 2006.

Currently undiscovered, or discovered but unreported fields that come on production before 2007, would further increase the outlook. Eleven of the 30 fields not yet on production are discoveries on unnamed deepwater blocks scheduled to come onstream in 2004-05.

About 25% of deepwater oil and about 40% of deepwater gas—a significant portion—comes from subsea completions. There are now 82 subsea completions in the deepwater Gulf, with 30 deepwater projects relying solely on a subsea completion tied back to some other facility. The larger percentage for gas is as might be expected, since subsea wells tied back to a central producing facility are one way of developing gas reserves that might not otherwise meet economic criteria. The growing share of production for subsea wells in general is also expected, as development moves into deeper water depths and the reliability of subsea equipment grows.

The Independents' Surge

Deepwater oil and gas production was confined almost entirely to major E&P companies from the first barrel of oil produced by Shell's Cognac platform in 1979, until production came onstream from Kerr McGee's Neptune/Thor, Marathon's Arnold and Amerada Hess' Baldpate projects in 1997-98.

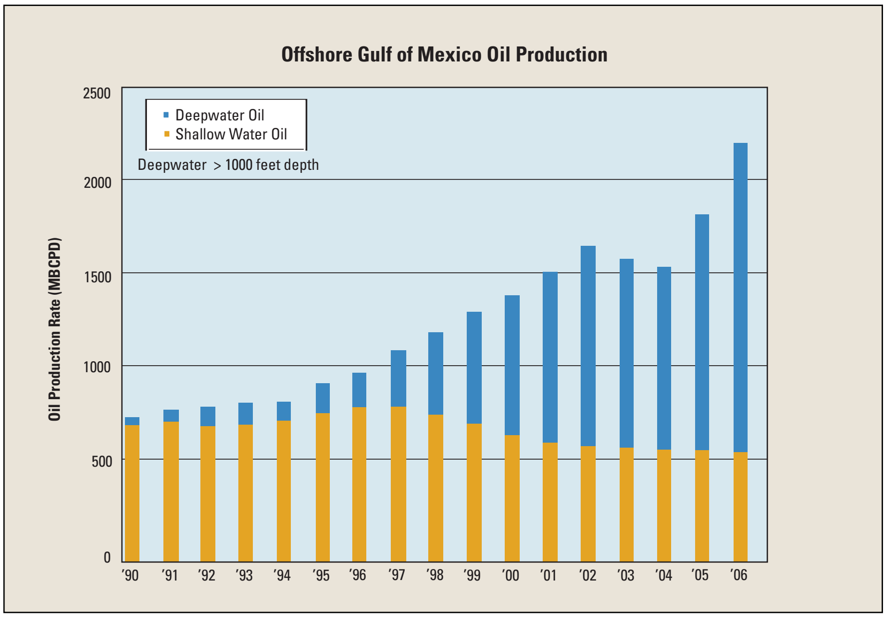

Fig. 2. Since 1999, more than 50% of the Gulf's oil production has come from deep water.

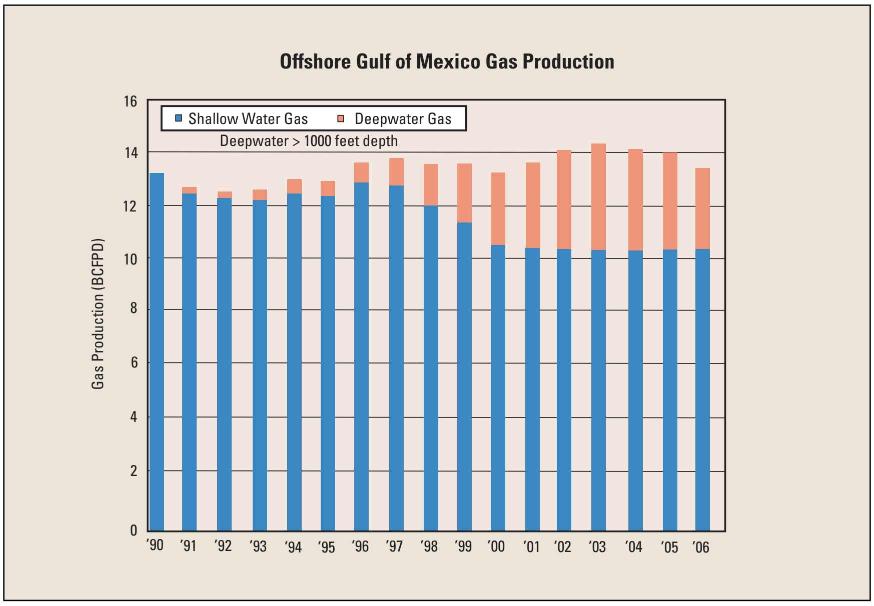

Fig. 3. More gas output from deep water offsets shallow-production declines.

In 1999, nonmajor companies owned about 25% of deepwater Gulf of Mexico oil production and about 20% of deepwater gas production. Since there are significant lag times between leasing and production, and since nonmajors did not gain a leasing foothold until about 1996, a surge of production from nonmajors is likely to be observed during the next several years.

Of the majors, Shell and BP Amoco were the driving forces behind the increase in deepwater production during 1995-99, with Shell the clear leader in both oil and gas production.

High individual well production rates have been a driving force behind the success of deepwater operations, providing the rapid cash flow necessary to support the massive capital investments that deepwater development requires. Many of the major incremental step changes in per-well oil rates have been a result of Shell development projects: Bullwinkle (1992) at 5,000 barrels per day; Auger (1994) at 10,000; Mars (1996) at 20,000; and Troika (1997) at 27,000 barrels per day. Ursa (1999) is the current record-holder, producing 36,520 barrels per day per well.

Similarly, a gas well in Shell's Mensa project (1997) holds the record for deepwater per-well gas—196 million cubic feet per day.

While not record-holders, many deepwater fields produce at rates much higher than those ever encountered in the shallow-water areas of the Gulf. The trend in deepwater production has been for maximum oil rates to be significantly higher off the southeast Louisiana coast than off the Texas coast. This may change as projects such as ExxonMobil's Hoover and Diana fields begin to be developed in the western portion of the Gulf's deepwater area.

Leasing, Evaluation Trends

There has been a six-year average lag time between leasing and initial drilling, according to analysis of deepwater activity by the MMS. On leases that later become productive, the average lag time between leasing and initial drilling is about four years. There is an additional two-year average lag before the well is qualified. (Operators must request MMS qualify a lease as capable of production after drilling a discovery well and before beginning production.)

Overall, history has shown that for deepwater leases, a total of 10 to 11 years elapses from lease issuance to production.

The combination of huge deepwater lease inventories and limited drilling capabilities means numerous leases remain untested when their terms expire. For example, more than 90% of deepwater leases acquired in 1974-75 and 1978-79 were drilled. About 70% of leases acquired in 1974-75 contained producible hydrocarbons, and about half came on production.

The percentage of leases drilled decreased rapidly throughout the 1980s as lease inventories swelled. By the late 1980s, less than 10% of issued deepwater leases were drilled and less than 5% produced, due primarily to the fact that drilling limitations mean only a finite number of leases can be evaluated in a given period of time. However, although the percentage of leases drilled declined, the actual number of leases drilled generally increased along with the number of leases issued. This eventually resulted in higher numbers of discoveries and producing leases.

About 10% of existing deepwater leases will be evaluated, given lease terms, operator behavior and rig constraints, according to MMS analyses of historic data. Operators may evaluate more than 10% of their deepwater lease inventory by spreading out their drilling programs wisely or bringing additional rigs into the Gulf.

Despite the difficulty evaluating deepwater leases, the future of deepwater Gulf exploration and production is very promising. Deepwater economics are more attractive than ever, with technology improvements having lowered costs and elevated production rates.

Although the traditional deepwater minibasin plays are far from mature, new plays near and beyond the Sigsbee Escarpment show that the deepwater Gulf is still an emerging frontier. Several recent deepwater discoveries are in very lightly tested plays, including the first significant discovery in the Perdido Foldbelt play of Alaminos Canyon.

Access Remains Critical

The Deepwater Royalty Relief Act of 1995 was very successful in catalyzing leasing and production activity throughout the deepwater frontier and reversing what was a declining production trend in the Gulf, according to the MMS.

However, while royalty relief has helped to mitigate the tremendous up-front financial risks faced by deepwater exploration companies and new technology has transformed the capabilities of operators, access to acreage in other promising offshore regions will be important if production growth is to continue.

There is strong evidence to suggest that large undiscovered fields remain in areas of the Gulf not available to industry. The eastern Gulf lease sale in December 2001, while it opened deepwater acreage in that area for the first time since 1988, was significantly scaled back by the federal government due to protests from Florida. If the incredible growth in production from deepwater development is to continue, industry must be allowed to apply the same technological and financial tools to as wide an area as possible. ✺

Perspective

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Transforming Discoveries into Production

Semi, spar, TLP, FPSO? As explorers succeed in deeper water in the Gulf, the production side of the business is following close behind.

Article by Leslie Haines

Imagine you've found an oil reservoir 150 miles from shore in 3,600 feet of water. It looks like it holds 200 million barrels of recoverable reserves. You estimate it will support eight wells producing a total of 50,000 barrels a day. Do you use a floating production platform or use subsea tiebacks to an existing facility? How many manifolds are needed? How many miles of flow lines? What about reservoir depth and pressure? Ocean floor currents?

These questions and more (some not technical, such as a company's budget, experience and time constraints), figure into transforming a deepwater discovery into an economically sound producing field. Fortunately, the production options available are more varied than ever before, thanks to learning from recent experience, continuing research and even government rules.

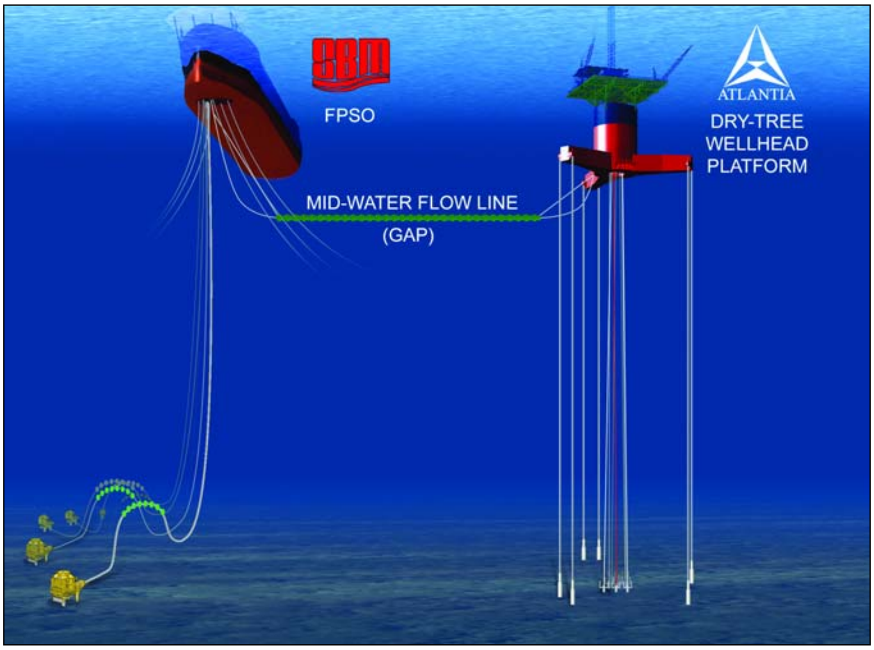
To optimize production, many decisions must be made. Drilling locations, topsides facilities, dry trees or wet, whether to move production by pipeline or shuttle tanker—these all enter the equation. In general, a fixed platform is economically feasible up to about 1,500 feet and a compliant tower can be used to about 3,000 feet of water. A floating solution such as a spar or TLP can be used to about 5,000 feet. Semis and FPSOs look to be an answer in the deepest waters—beyond 6,500 feet.

The two biggest drivers still are the size of a field's reserves and the depth of water it is in, when deciding whether to use a semisubmersible production platform or "floater," a spar, tension leg platform (TLP) or a floating production, storage and offloading vessel (FPSO).

The latter was only recently approved by the Minerals Management Service (MMS) for use in the Gulf. No company has stepped forward for permits, yet. Observers speculate Unocal's Trident find, in 9,687 feet of water in Alaminos Canyon, may be the first. It is the deepest-water discovery yet.

Notes Allan Millmaker, general manager of Bluewater Offshore Production Systems (USA), "FPSOs are certainly not new. The critical path for them has nothing to do with technology. It's the bottleneck of transporting oil to market from the FPSO—the Gulf lacks a U.S.-built shuttle tanker fleet." Bluewater, a Dutch firm, recently increased its Houston presence. It designs single-point mooring systems, and it designs, leases and operates FPSOs. At press time, Conoco announced plans to build a new shuttle fleet for the Gulf. The major has many deepwater fields in development.

There's a general question of costs versus experience, says Sandeep Khurana, principal facility engineer for Granherne, a Halliburton company that offers engineering consulting and decision software for these matters. "For example, use a spar that has a rig on it, so you can drill and produce from the same facility, or bring a semi that drills the additional wells instead. But,



Atlantia Offshore thinks a mid-water flow line will reduce deepwater flow assurance problems.

you have to look at technical as well as business aspects to make a decision." (*See chart.*)

"Subsea wells are becoming more popular, but you still have issues related to wellhead intervention, and that is expensive to perform in deep water. Every well is going to need some help eventually. Subsea flow assurance is also a huge issue—that's a reason people like a dry tree [at the surface on a production facility, as opposed to subsea]."

Other than deepwater royalty relief from the MMS, the type of technology one chooses makes a big difference on costs, which affects what size field is considered economic to develop. "Future well intervention needs dictate a lot. If a field can be developed with four wells or less, subsea trees are feasible. If a field will need more wells, companies tend to choose a dry tree configuration above water, on a spar, a semi or TLP."

"One big difficulty is in knowing when commodity prices will allow a company to sanction development of a field," says Tim Juran, regional manager, North America, for Transocean, one of the largest offshore drilling contractors. The company's fifth-generation semi rigs and dual-activity deepwater drillships can drill in 10,000 feet of water. The latter can drill two wells at a time, or drill one while servicing the other.

In the next three to five years, Transocean may go further by offering more to customers, such as the ability to lay pipeline and perform well services from its drill ships or semis. "We would provide the service company with our 'real estate' and the water needed for services, and support necessary for them to do what they need to do," Juran says. Rather than the service company bringing a semi of its own to the location, which would add considerable cost to any well intervention job, this could save money and time.

Research Challenges

The deeper the water, the riskier the project, due to distance from shore, ocean currents found on the sea floor, temperatures and pressures, as well as other factors.

As risers get longer their weight increases. As water gets colder, flow through subsea lines slows down or ceases. Hydrate blockage can occur rapidly whereas wax build-up occurs more gradually.

There is a high price paid for wrong assumptions and poor planning. But research continues at a fast pace. The well-known, 10-year-old DeepStar project, a consortium of 20-plus companies led by Paul Hays of ChevronTexaco, is now on Phase VI. Its original goals to achieve production in 6,000 feet of water and enable subsea tiebacks up to 60 miles away have been reached. Now it is studying what needs to be ready for production to occur in 10,000 feet of water.

The Southwest Research Institute in San Antonio, Texas, just built a deepwater simulation chamber that tests the collapse limits of drilling and subsea equipment in water depths up to 25,000 feet. Texas A&M, already active in deepwater and marine research, just formed a new alliance with the Gas Technology Institute to do more specific research on deepwater applications. A lab in Wyoming takes advantage of the natural cold weather there to test flow line assurance issues—in deepwater, the colder temperatures cause subsea flow lines to plug up by wax or paraffin build-up or gas hydrates.

Spars are currently installed in waters as deep as ExxonMobil's Hoover-Diana Field in 4,800 feet of water. Dominion E&P's Devils Tower Field in 5,610 feet of water will be the world's deepest-water dry-tree spar.

Hubs and Spokes

Industry is expending a lot of effort figuring out how to make smaller fields economic, mostly through subsea tiebacks to their larger brothers in the deep. New techniques are making development of these small fields more feasible, opening up a host of new opportunities.

"We think you'll see more operators offering their production-facility capacity to third parties, to justify those large investments [in offshore platforms]," says Transocean's Juran. "The Gulf is now a pipeline-driven environment and those lines are being extended deeper and deeper, but you start to get into these subsea canyons where the topography makes it difficult to construct a pipeline." So, subsea flowlines tied to another platform in shallower water make sense.

Shell's Auger TLP platform, for example, receives production from nearby subsea wells owned by other companies, although Shell informed them recently that it is now out of capacity.

In addition to major producers offering hub space, pipeline and service companies are doing so. El Paso Energy Partners and Cal

WEIGHING THE FACTORS

Technical issues	Business drivers
Reservoir characteristics	Net present value (NPV)
Ocean conditions	Scheduling
Drilling & completion plan	Capex limitations vs. costs
Facilities	Risk-reward
Transportation	Comparison to other corporate projects
Operations	Operating costs

Sourcce: Granherre, a Halliburton company.

RECENT DEEPWATER CHOICES

Company	Field	Water depth/ft.	Production Facility
ExxonMobil	Hoover-Diana	4,700-5,000	Deep-draft caisson (spar) with dry trees & subsea wells
Dominion E&P	Devils Tower	5,610	Dry-tree spar
Agip/Mariner	King Kong/Yosemite	3,800	Subsea wells connected to Allegheny TLP
BP	Thunder Horse	6,640	Semisubmersible
Conoco	Magnolia	4,700	4-column TLP with subsea tiebacks to a Shell hub platform
BP	Atlantis	6,683	Moored semi
Anadarko Petroleum	Marco Polo	4,300	TLP
BP	Mad Dog	7,137	Spar
Kerr-McGee	Red Hawk	5,300	Mini floating production platform

To be produced from a spar, the Devils Tower project has reserves of 75- to 100 million BOE. (*Photo by Lowell Georgia.*)

Dive International will own and operate the platform under construction now for Anadarko Petroleum's Marco Polo Field in Green Canyon. This allows Anadarko to spend its capital on drilling instead of building a platform. El Paso and Cal Dive are marketing unused capacity on the new facility to other producers in the area. Some of those fields may not be economic on a stand-alone basis.

The business of handling smaller deepwater fields economically will no doubt get bigger. Atlantia Offshore Ltd.'s mono-column TLP, the SeaStar, was developed specifically to handle fields smaller than 75 million barrels of oil. In 1996 it was awarded the first job for "an economically challenged" deepwater field, Morpeth, operated by British Borneo in 1,960 feet of water.

Other players such as ChevronTexaco watched this with interest, as they discovered smaller fields that in the past they would have deemed uneconomic to develop, such as that company's Typhoon Field, a 40-million-barrel-of-oil-equivalent (BOE) accumulation that will use another of Atlantia's TLPs.

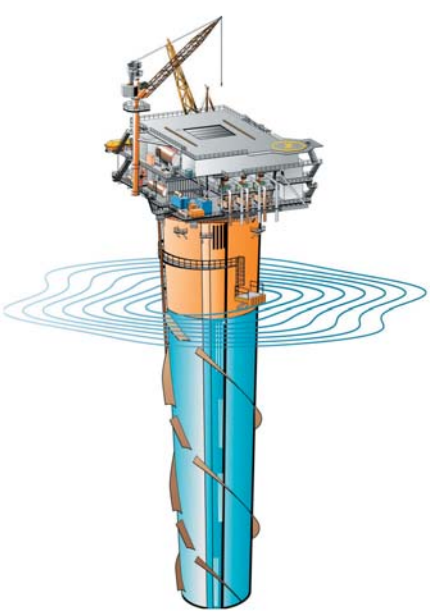
"For a major to develop a field of that size with its own host facility is rare," says David Snell, Atlantia vice president.

"We are trying to get away from the term 'mini-TLP' because in fact, we have already built one that is three times the size of Morpeth. We started with a smaller TLP concept and slowly scaled up in size and capacity, whereas other contractors started with very large solutions and are now scaling down.

"I guess the race is on to see who can scale these facilities most efficiently. The MMS says 80% of the deepwater fields that have been discovered in the Gulf are less than 125- or 135 million BOE and 50% are less than 60 million BOE. It is painfully obvious that development scenarios and economic models of the past will have to change in order to exploit these fields."

The Majors' Research

The major oil companies are as involved in deepwater research as the vendors. Conoco, for one, participates to some degree in about 150 joint-interest groups involving E&P companies, universities and vendors. It also has an in-house lab and research group. A company technology publication says that last year, Conoco drilled an appraisal well at its Magnolia Field for $23 million less than the industry average for a well



The classic spar design, which is constantly being improved.

of that depth and complexity. "That's almost enough savings to drill an entirely new well," says Gerry Cooper, supervising drilling engineer for the Gulf of Mexico business unit.

Also last year the company made headlines when it installed the world's first composite drilling riser joint at its Heidrun Field in the Norwegian North Sea. Using composites in drilling and production is a step-change attracting a lot of attention today. They enable operators to go into deeper water yet burden their drilling and production facilities with half the weight of steel alternatives and half the cost of titanium risers, says Glenn Schaaf, deepwater development manager.

"Magnolia, being located in 4,700 feet of water, is at the economic crossover point between a TLP and a spar. As the water depth increases, the viability of the TLP concept diminishes without new technology to reduce the buoyancy requirements. Lighter weight risers made of composites or the use of tubing risers may push the depth at which the two concepts are equivalent in cost closer to 7,000 feet."

"Where rig intervention is not critical, an FPS or FPSO provides the least expensive real estate option for processing equipment. These solutions are only water depth sensitive in the areas of risers and mooring systems. The further development of alternative, lighter weight materials like composites for risers and polyester for moorings is ongoing."

Conoco has participated in the world's first dual-gradient well, which was drilled in the Gulf using the Subsea Mudlift Drilling System. This resulted from research that took five years, millions of dollars and about 20 companies working together, led by Conoco and Hydril Co. The system enables drilling in ultradeepwater by simulating conditions found on land. It replaces the mud in the risers with seawater, greatly reducing both pressure on the riser and stress on the well bore.

In addition to the deepwater-niche vendors, all the big service companies offer technology specifically for deep water. "One of the important drivers for development is a good understanding of reservoir size and any potential 'compartmentalization.' Are there faults present? Will they divide up the field into separate blocks, which drives the location of the development wells?" says Jeremy Walker, testing and completions marketing manager for Schlumberger.

Deepwater well testing is key, but this is an art in itself, as the tests need to be run from dynamically positioned rigs that will not drift off the exact location. A couple of years ago Schlumberger introduced SenTREE3, a subsea test tree with a special electrohydraulic control and monitoring system that enables a fast disconnect—less than 10 seconds at depths to 10,000 feet. It allows the operator to test wells in deep water from all rig types.

One technology that continues to be developed is tubing risers and use of composites to reduce the weight of the risers.

The company also developed SenTREE7 and Commander telemetry that enables an operator to safely run and then flow the well back to the rig when a horizontal Christmas tree is being used, as is quite common, where the completion is run through the tree rather than separately.

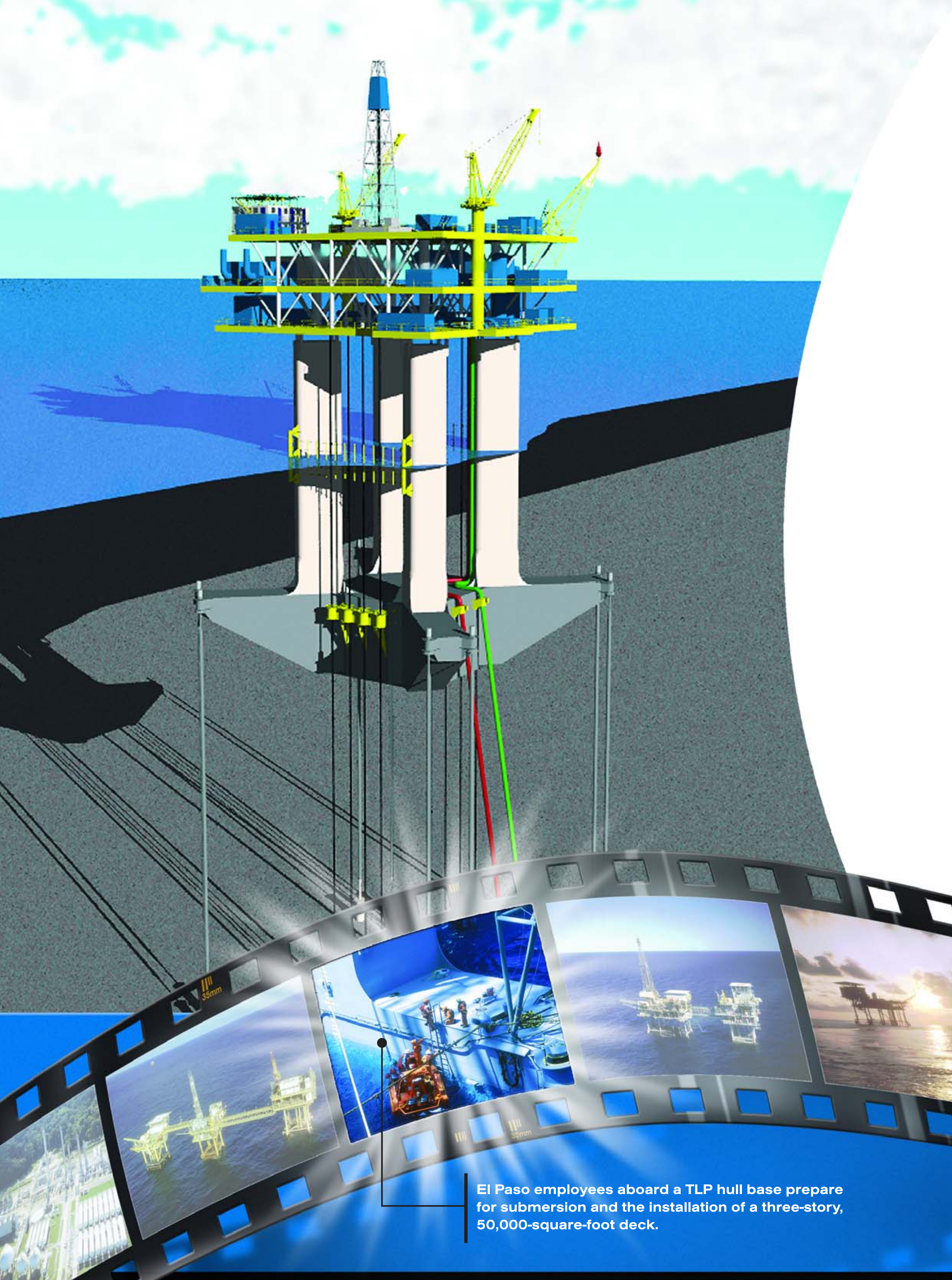
The truss spar provides greater vertical stability over the classic spar.

"We are still in the early stages of deepwater development and certainly very early in the ultradeep," says Knut Eriksen, senior vice president, Aker Kvaerner. The company, which has projects in 60 countries, was formed through a March 2002 merger. Headquarters are in Oslo and Houston. From its predecessors, the new firm combines design and shipbuilding skills for semis and FPSOs with engineering and manufacturing of subsea wellheads, moorings, umbilicals and other subsea hardware.

Aker Kvaerner is building a new umbilical manufacturing facility in Mobile, Alabama, because its existing one in Norway can't keep up with increasing demand. It is marketing a new concept, a heated flowline and riser with umbilical functions into one line.

And it also is involved in developing a deep-draft, "mini-semi" platform that would handle smaller fields in up to 5,000 feet of water or more. "If we can put in a simple floater with first-stage separation for the oil, gas, water and condensate, then you can ship these in pipelines. There are lots of smaller fields in the deep and that's a real challenge."

"It's evolving rapidly," says Transocean's Juran. "We'll soon be able to produce in water depths to 7,500 feet. The next challenge is what happens when we get out to 10,000." ❋



El Paso employees aboard a TLP hull base prepare for submersion and the installation of a three-story, 50,000-square-foot deck.

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El Paso Energy Partners, L.P. is committed to building critical infrastructure for the development of new energy supplies from the Deepwater Gulf of Mexico. Planned for 4,300 feet of water nearly 160 miles south of New Orleans, Louisiana, the Marco Polo Tension Leg Platform (TLP) will provide comprehensive Deepwater solutions and cost-effective capacity for Anadarko Petroleum Corporation's Marco Polo oil field. The Marco Polo TLP will be owned by Deepwater Gateway, L.L.C., a joint venture between El Paso Energy Partners and Cal Dive International Inc., and when installed will become the world's deepest TLP. The Marco Polo TLP is designed to handle up to 100,000 barrels per day (Bbls/d) of oil and 250 million cubic feet per day (MMcf/d) of natural gas.

In addition to serving Anadarko's development of the Marco Polo oil field, the Marco Polo TLP will serve as a delivery point for future oil and gas development in an area surrounded by significant reserve potential. Anadarko will have rights to a capacity of 50,000 Bbls/d of oil and 150 MMcf/d of natural gas. The remaining capacity will be marketed to encourage the development of oil and gas reserves in smaller Deepwater fields that cannot support their own platform infrastructure.

El Paso Energy Partners will also provide the oil and gas export pipelines for the Marco Polo TLP. The oil from the Marco Polo TLP will be gathered through a new 37-mile pipeline and the Allegheny pipeline for delivery to the Poseidon Oil Pipeline System and the recently announced Cameron Highway Oil Pipeline System. The gas from the Marco Polo TLP will be gathered through a new 75-mile pipeline and the Typhoon pipeline for delivery to the ANR Patterson Pipeline System. The gas will be processed at El Paso Field Services' Pelican Plant.

The Marco Polo TLP is an example of El Paso Energy Partners' Deepwater development strategy to serve the nation's energy needs by providing cost-effective infrastructure and premium connections to downstream oil and gas markets. By providing capital for platform and pipeline infrastructure, El Paso Energy Partners frees up the producer's capital for exploration, development drilling, and completion. Learn more at www.elpaso.com.

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Accessing Markets

As production moves to deeper water, infrastructure follows. For gas pipelines alone, the industry may spend up to $7.8 billion during the next 20 years.

Article by Gary Clouser

As U.S. reliance on oil and gas from the Gulf of Mexico increases, so too does the need to build additional infrastructure—pipelines, gathering lines and processing facilities—in areas farther from shore and in ever-increasing water depths. The go-ahead to develop any discovery must be weighed in terms of the size of recoverable reserves, expected commodity prices—and the cost of access to markets.

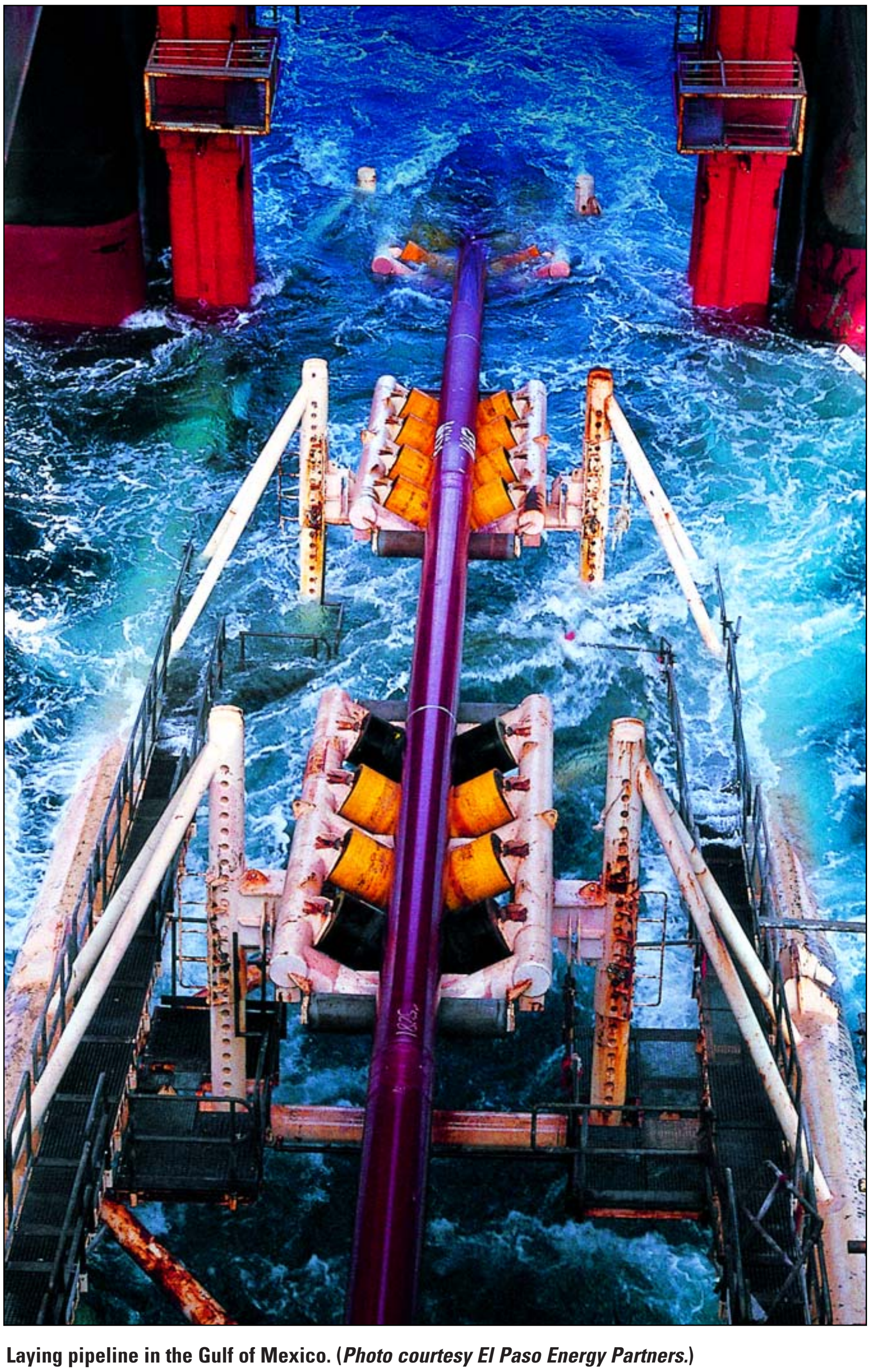
The Minerals Management Service (MMS) is forecasting daily production of 2- to 2.47 million barrels of oil and 10.97- to 16.39 billion cubic feet (Bcf) of gas by year-end 2006. How much infrastructure capacity will be needed?

The gas industry already proposes 1,676 miles of new pipe at a total cost of $1.1 billion. The Interstate Natural Gas Association of America, a pipeline and producer trade group, predicts another 11,000 miles of pipe will be needed in the region during the next 20 years, at a cost of $6.7 billion, for a total of $7.8 billion.

"Producers indicated they face several impediments to deepwater development," says an INGAA report on a study's results. "These include higher development costs, lack of deepwater pipeline infrastructures and supporting facilities…and onshore take-away capacity. A number of producers are investing in deepwater pipelines to overcome some of these obstacles."

That investment is needed. The MMS reported in June, "Should the high case estimates be reached in 2006, we will see a 10% increase in oil production from the Gulf in the period 1995-2006." It forecasts that as much as 77% of daily oil production and 26% of gas production from the Gulf could come from deep water by 2006. "Meanwhile, deepwater oil production surpassed shallow-water oil production in 2000."

David Pursell, director of upstream research for investment-banking firm Simmons & Co. International, Houston, says the infrastructure needed for deep water would be even greater,



Laying pipeline in the Gulf of Mexico. (*Photo courtesy El Paso Energy Partners.*)

were it not for a corresponding decline in shallow-water production. Much of the infrastructure originally built for Gulf Shelf production would be underutilized without the increased activity from deep water, Pursell says. The challenge is to find ways to get production from deep water to the existing overcapacity on the Shelf.

It is the nation's insatiable appetite for gas that accounts for a dominant portion of the new or announced deepwater infrastructure projects. Even though about two-thirds of the reserves found in deep water are oil, 67% of the pipeline mileage approved in deep water since 1990 is for moving gas, according to the MMS.

Jerald Halvorsen, president of INGAA, says, "Clearly, gas-resource development is driving pipeline development." Citing a study conducted by Foster Associates Inc. on behalf of the INGAA Foundation, Halvorsen says the gas industry could spend as much as $7.8 billion during the next 20 years to accommodate offshore Gulf production. Over time, these investments will be in deepwater areas, particularly in the eastern portions of the Gulf, according to the INGAA.

Pipelines or Shuttle Tankers?

Rory Miller, director of deepwater services for Williams Energy Services, says the INGAA's 20-year projection for additional gas infrastructure looks conservative. Typically, three- to five-year projections are overly optimistic, because field development takes longer than original estimates. But, the amount of drillable reserves in deep water will ultimately result in massive additional gas infrastructure, he says.

Williams Energy Services is focused on gas and "is opportunistic" regarding oil projects, Miller says, noting there are numerous gas-only plays being developed, or at least reserves where gas is the primary objective.

Projections for oil pipelines are far less certain because of the unknown long-term impact of tanker shuttle services that will compete against pipelines, and maybe supplant them. (At press time, Conoco announced it will build a new deepwater shuttle fleet.)

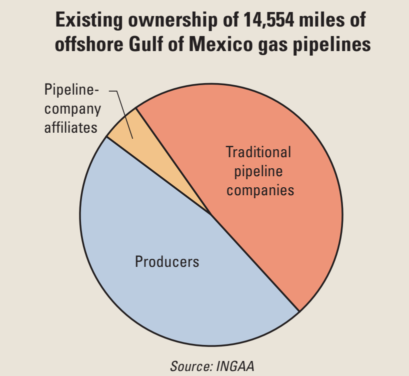
Miller thinks tankers will have a significant impact on the amount of additional oil pipelines that will be needed, "causing pause" among potential pipeline developers. Williams Energy Services is not planning to enter the shuttle business, as it is far removed from its core skills set, he says.

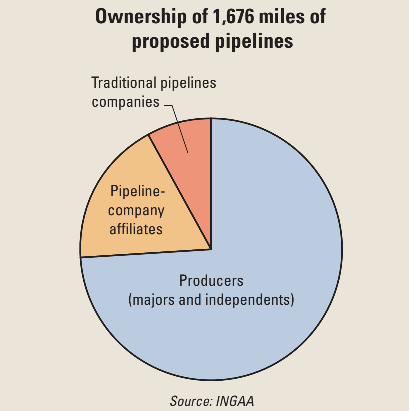
DID YOU KNOW?

Offshore Gulf of Mexico production is approximately 14.5 billion cubic feet (Bcf) per day. Pipeline capacity to transport it onshore is about 28 Bcf per day. About 73% of leases are not producing, indicating substantial growth opportunity. Most of those are in deep water.

Fifty-one onshore gas plants are identified as processors of offshore production. Located in Alabama, Louisiana and Texas, they have a combined capacity of more than 20 Bcf per day.

There is a 14,554-mile gas pipeline network offshore to bring supplies to processing plants, market hubs and downstream pipeline interconnections onshore. These pipelines are owned by 157 companies, ranging from traditional interstate pipeline firms and their affiliates to producers themselves.





More producers have taken charge of their destiny. They own 73% of the pipelines built since 1995, compared with 38% of the mileage built before then.

Who Will Build?

An understanding of the regulatory history of interstate gas pipelines lends perspective to the trend of pipeline companies owning a declining percentage of recently added Gulf mileage.

"The Shelf's infrastructure was developed largely by regulated interstate pipeline companies looking to extend lines to new production to ensure the pipelines, which still had a merchant function, had security of supply," Miller explains. "By the time infrastructure began in the deep water, pipelines no longer had a merchant function and were simply transporters. The attitude of most was to let someone else build the deepwater pipelines. Meanwhile, producers were building up deepwater reserves so fast they needed new infrastructure, so the major players built their own infrastructure."

This is changing again. Integrated pipeline and gas marketing companies are now offering third-party infrastructure services such as pipelines, tiebacks and floating production systems. Williams will have spent about $700 million in recently completed and soon-to-be-completed Gulf infrastructure. El Paso Energy Partners has developed more than $800 million of deepwater-related infrastructure during the last 12 months.

Third-party infrastructure providers will focus on using their integrated position to add value through aggregation and economies of scale to aid producers of any size smaller than the big three—Shell, BP and ExxonMobil—Miller says.

Since the early 1990s, El Paso Energy Partners has viewed the deepwater Gulf as a strategic investment area, as well as a means to maintain volumes on its existing pipeline systems, says Bart Heijermans, El Paso Energy Partners vice president of deepwater project development. It's much too soon to quantify deepwater reserves, let alone compare them to the Shelf, but from development thus far the deepwater appears to be more oil-prone than the Shelf, he notes.

During the past 10 years, El Paso has developed approximately $2 billion of projects to serve producers in the deep. With the development of these new projects it will have increased gas pipeline capacity by 2.5 Bcf per day and oil pipeline capacity by more than 1 million barrels per day. It has hiked oil and gas processing capacity by 200,000 barrels and 1 Bcf per day, respectively. It now ranks second to

Industry proposes 1,600 miles of new gas pipeline alone. (*Photo courtesy El Paso Energy Partners.*)

Shell Oil in the number of deepwater pipelines it owns.

Shell announced in May two pipelines, one for oil, the other for gas, totaling $87 million, to be completed by 2004. "This project is a strategic extension of our existing deepwater oil transportation system into the deeper waters of the Garden Banks area…," says John Hollowell, general manager of the crude-oil business unit for Shell Pipeline Co.

Ocean Energy is a 25% stakeholder in Magnolia Field with Conoco holding the remaining 75%. The field begins producing in late 2004 in nearly 4,700 feet of water. The partners will ship production through Shell. The gas line will tie back to Shell's Enchilada platform in somewhat shallower water; the oil pipeline will tie back to Shell's Auger pipeline system.

Independents' Views Vary

Rusty Walter, chief executive officer of Walter Oil & Gas, a privately held E&P company, did not wait for infrastructure to be built by others. The Houston independent ranks 16th among the top 20 Gulf pipeline owners with 206 miles of pipeline. Years ago when the company began exploring offshore, it realized that it would have to build its own infrastructure if it was to be a real player and control its own destiny, Walter says.

"If you have the reserves to justify it, third parties will lay pipeline and assume capital risks."

Now, the company has developed some expertise and a niche, and is likely to continue to build its own pipelines, regardless of third-party services' offerings.

Doss Bourgeois, Ocean Energy vice president of production, Gulf of Mexico, says it was the independents' plunge into offshore production that prompted an increase of infrastructure and services offered by third parties. The megamajor producers did not want, or need, third-party involvement, but independents did, as most did not want to be pipeline owners, if there was a suitable alternative.

The presence of third-party infrastructure providers has allowed Ocean Energy to develop reserves it probably would not have, if the company had to first incur the infrastructure expense. "If you have the reserves to justify it, third parties will lay pipeline and assume capital risks," Bourgeois says. Still, there are regions of the Gulf where the infrastructure is not yet adequate, which is a factor in determining the timing and selection of reserve development, he adds.

Mike Radabaugh, Ocean Energy vice president of planning, says that whatever the magnitude of gas pipelines that will be needed, the oil-pipeline need will track closely. The impact of shuttle tankers versus pipelines will be a matter of pricing, he says.

Existing infrastructure, particularly in deep water, is just one of the considerations in managing a company's portfolio, based on the anticipated timeframe from discovery to production, says Roger Jarvis, chief executive officer of Spinnaker Exploration.

Partially because of the existence of infrastructure, a discovery on the Shelf can be turned around in six months to a year; one on the deep Shelf in a year to 18 months, and one in deep water in three to four years.

Spinnaker for the past several years has built an average of 100 miles of pipeline per year, spending $50- to $60 million annually. These are mainly gathering lines to serve its own production. But owning a pipeline is not the business the company wants to be in. Although the company has not yet taken the plunge to having third parties provide its deepwater infrastructure, it is increasingly considering this, on a deal-by-deal basis.

Jarvis says it was natural that producers, with the greatest motivation to see infrastructure built and maintained, would initially build and own more of the pipelines. Now that deepwater Gulf production is a reality, and growing, integrated companies whose businesses include pipeline transportation would also become involved in processing, and commodity resale.

Capital Required

It is difficult to pin down an estimate of total pipeline infrastructure needs, much less their costs. Mark Ammerman, managing director and head of U.S. energy for investment-banking firm Scotia Capital, Houston, thinks the estimates by INGAA are high, noting that past experience shows a lot of duplication in long-range energy infrastructure projects, with subsequent cancellations and consolidations.

"By the time spending for infrastructure is sought, they are real confident that the assets are there to support the project."

James Allred, Scotia Capital team leader, oil and gas producers, says that as pipelines are built in deeper water, the costs increase dramatically, so only the bigger players have the financial wherewithal to build infrastructure. Producers, particularly independents, do not want to tie up large amounts of capital in ownership of pipelines, he notes, so construction is more likely by third-party experts and the megamajors.

"Before seeking capital for infrastructure, producers have done extensive due diligence, spending tens, maybe even hundreds of millions of dollars to determine the size of the reserves of a given field. By the time spending for infrastructure is sought, they are real confident that the assets are there to support the project," says Joseph Lattanzi, Scotia Capital team leader, project financing. "Generally, for such projects, you are dealing with the big boys, the right companies, that do things in the right way." He estimated that in the next 18 months Scotia Capital will spend about $3 billion financing Gulf projects, including financing platforms and pipelines.

Most infrastructure will be project-financed. Typically, a producer or team of developers would have to put up 30% of the capital, while seeking up to 70% from capital providers. Ammerman says it is unlikely any single capital provider would provide more than $80 million per project.

Using floating production, storage and offloading systems (FPSOs) could speed the initial production for a specific deepwater field, in that producers could begin generating cash flow from the first well instead of having to wait until infrastructure is built. But Ammerman doesn't think that in the long-term, their use will have much of an impact on ultimate production from deep water.

He notes that FPSOs make the most sense when the oil is to be exported, rather than in the case of the Gulf, where it will be transported ashore for domestic use. There is also the risk that any shuttle tanker accident could dramatically sway political sentiment away from its use, he says. Floating storage vessels and crude-oil shuttle tankers will likely be required in deepwater areas that are far beyond the reach of subsea pipelines.

Carolita Kallaur, MMS associate director, offshore minerals management, says, "Industry is encountering a variety of situations in the more than 100 discoveries of oil and gas in the deep waters of the central and western Gulf of Mexico. Sometimes these discoveries are small and sometimes they are distant from existing infrastructure. These represent potential use of FPSOs to produce resources that would not be developed using current technology and infrastructure." ❋

Shuttle tankers and FPS or FPSOs are an option to building pipelines.
(*Photo courtesy El Paso Energy Partners.*)

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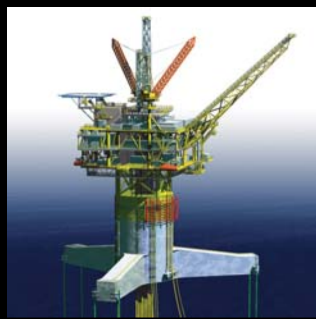

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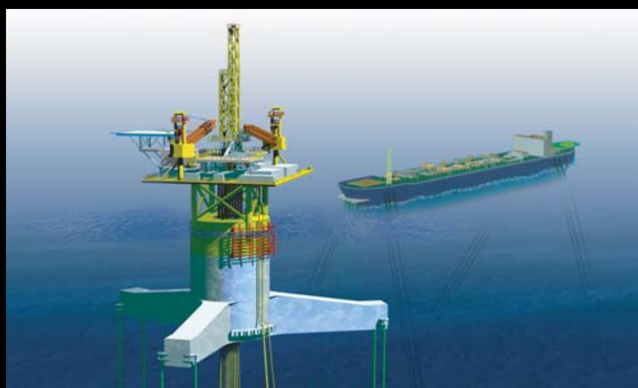

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