CEE CENTER FOR ENERGY ECONOMICS

Bureau of Economic Geology, Jackson School of Geosciences
The University of Texas at Austin

Case Study From

NEW ERA IN OIL, GAS & POWER VALUE CREATION

ESTABLISHING A VIABLE DEEP WATER GULF OF MEXICO FRONTIER IN THE U.S.[1]

As the U.S. offshore Gulf of Mexico (GOM) oil and gas province has matured, the exploration and production industry has pushed into deeper waters supported by technology advances and the growing awareness that the GOM represents one of the most important supply areas for hydrocarbons. This case presents an analysis of GOM deepwater development from the perspective of our virtual company, "Energy Inc.," a company that was faced with developing an entry strategy for the GOM deepwater in 1998. It includes an overview of GOM trends and incorporates specific U.S. energy policy questions, as outlined below.

- *Should the U.S., through its federal Minerals Management Service (MMS), an agency of the Department of Interior, provide incentives for risk taking in GOM deepwater blocks through royalty relief?*
- *How should expensive transportation infrastructure investments be made to deliver GOM production to shore and under what policy and regulatory framework?*

CONFIDENTIAL INTERNAL MANAGEMENT MEMO
NOT FOR CIRCULATION OUTSIDE OF ENERGY INC.

TO: Energy Inc. Senior Officers and CEO
FROM: North American E&P New Ventures Team
DATE: December 10, 1998

The North American New Ventures team was asked to develop a strategy for Energy Inc.'s potential entry into the deepwater Gulf of Mexico. The results of our analysis are contained in this internal memo.

EXECUTIVE SUMMARY: AN ENERGY INC. INVESTMENT STRATEGY

In an effort to expand Energy Inc.'s asset base and build on its commitment to increasing shareholder wealth, the North America New Ventures team has evaluated the viability of a deepwater Gulf of Mexico exploration and development project. The deepwater GOM represents an important growth opportunity for Energy Inc. because of the potential for a significant discovery. Advances in technology and infrastructure have increased the accessibility of deepwater and have reduced capital and operating costs. In addition, the U.S. Minerals Management Service has already granted royalty relief for the area (blocks) included in the upcoming lease sale.

[1] This case study was prepared by an MBA student team in the C.T. Bauer College of Business, University of Houston as part of their requirements for International Business 7397, "Energy: Industries, Policy, Strategy" instructed by Dr. Michelle Michot Foss.

Based on the analysis contained in this proposal, it is recommended that Energy Inc. include a deepwater exploration and development project in its 1999 business plan. To finance this development, it is proposed that Energy Inc. utilize internal resources. Additional capital can also be generated by the disposal of some of Energy Inc.'s non-core assets. The following summary outlines the entry strategy and financial justification for the project.

Because of the North America E&P Division's lack of experience in deepwater drilling and production, the following entry strategy is recommended.

Short Term: Minority partnership with one of the following major operators: Supermajor Company B, Supermajor Company D, or Major Company E.

Participate in March 1999 Eastern Gulf of Mexico Lease sale. Estimated total signatory bonus – $3.6 million.

Long Term: Acquire additional leases at future lease sales with the objectives of growing position in the deepwater Gulf of Mexico and increasing levels of equity participation.

In order to determine the potential economic impact for Energy Inc. of a deepwater strategy, two scenarios were developed, one for oil and one for gas. For the oil development scenario, a four-well SPAR drilling and production platform was evaluated with a total capital investment of $332.6 million. For the gas development scenario, a four-well subsea system was evaluated with a total capital investment of $181.2 million.

Key drivers to the financial success of a deepwater development include oil and gas prices and reserves. Oil and gas prices were forecast for three scenarios: low, mid (base case) and high. Additionally, a probability distribution of potential proved reserves was developed in order to generate a low, mid (base), and high case. Using the base case for prices and reserves, along with other key assumption, the NPVs calculated for the oil and gas development scenarios were **$13.4 million** and **$103.7 million**, respectively. Both sets of data were then incorporated into a sensitivity analysis to evaluate the impact of these variables on the profitability of the project. The results of the sensitivity study concluded that, over the range of prices and reserves evaluated, *the gas case yields a positive NPV in all situations*. For the oil case, *the project yields a positive NPV when the price of oil is at the mid or high level*. However, the NPV becomes negative at the low price of oil over the range of reserves evaluated. Given that the NPV of the two cases was more sensitive to price variability, a break-even analysis was performed to determine the minimum price levels required for each development scenario. Holding all other factors constant, the resulting break-even prices are as follows.

Oil Case: $13.07/barrel and $2.26/mcf
Gas Case: $7.12/barrel and $1.23/mcf

INTRODUCTION

The North America New Ventures team recommends that Energy Inc. incorporate a deepwater Gulf of Mexico exploration and development project into its 1999 business plan. Our primary focus in evaluating potential projects for 1999 was to identify those opportunities that can best increase shareholder wealth, while continuing to provide for the long-term viability of Energy Inc.'s North American upstream operations through reserve replacement. While our existing asset base in North America offers healthy production and revenue streams over the short term, it consists of relatively mature properties with limited potential for growth. Therefore, we must look outside these core areas of operation for new opportunities to grow our reserve base. The deepwater Gulf of Mexico represents one of the few remaining frontier areas in North America that offers the potential for significant discoveries. Furthermore, the industry has seen substantial changes with regard to competition, technology, suppliers and infrastructure that have created a window of opportunity for investment in this area.

Due to Energy Inc.'s lack of experience in the deep Gulf of Mexico, we recommend pursuing this opportunity by securing a joint venture partner with a significant amount of deepwater expertise and jointly participating in the March 1999 Eastern Gulf of Mexico Lease Sale. This arrangement offers the benefits of reduced capital and risk exposures, the ability to leverage resources, the opportunity to share technical capabilities and the ability to accelerate activity.

Two significant advantages to this proposal exist, as compared to other global alternatives:

- The relatively stable business environment that exists in the U.S.; and
- Incentives provided by the federal government for investment in the deepwater Gulf of Mexico.

Primary lease terms, as governed by the U.S. Department of Interior's Minerals Management Service, are ten years for deepwater leases rather than the conventional five years. This is a significant provision in that it affords Energy Inc. and its partner(s) an additional five years in which to evaluate, plan and initiate an exploratory and development program (our shallow water projects typically require five years to plan and drill; we expect deep water opportunities to at least double that time horizon based on experiences of other operators). Another incentive supporting a deepwater Gulf of Mexico business plan is royalty suspension. Based on water depth, this provision provides a direct economic benefit to Energy Inc.

While a project of this type has many variables that influence its outcome, nothing is more critical to the success of exploratory and development projects than oil and gas prices. At present conditions, depressed oil and gas prices are creating a severe strain on the economic viability of deepwater exploration and development projects. However, given the amount of time required to evaluate and implement a project of this magnitude, we do not anticipate establishing production any sooner than mid-2001. This allows the global energy market over two years to recover to a level more consistent with the historical average of $14.00 to $17.00 per barrel.

Finally, it is important to recognize the substantial return that a project of this magnitude can provide to Energy Inc.'s shareholders. Ultimately, providing for increased long-term value to Energy Inc.'s shareholders is given the highest consideration when allocating capital resources. The North America New Ventures team is confident that this opportunity can provide a significant contribution to that objective and will add an important element of growth to the E&P Division's strategic objectives.

ENTRY STRATEGY

Our proposed entry strategy consists of two parts. First, based on our analysis, we are recommending that Energy Inc. obtain a joint venture partner for a majority participation in the proposed deepwater project. Second, we are recommending that Energy Inc., through the joint venture partnership, acquire a deepwater lease in the March 1999 Eastern Gulf of Mexico Lease Sale for subsequent exploration and development. We note that the next Eastern Gulf of Mexico Lease Sale (OCS Sale 181) is not scheduled until 2001. However, for the purpose of this analysis, we have assumed that this sale will occur next year, as this area brings to light certain issues that are not as critical in other, more heavily developed, GOM deepwater blocks. Regardless, the analysis and recommendations presented herein are applicable for any deepwater area being considered for exploration and development. The following sections discuss our entry strategy analysis and the lease sale process.

Joint Venture Analysis

Some of the major obstacles facing Energy Inc. as we attempt to enter the deepwater Gulf of Mexico include our lack of experience in deepwater drilling and production and the significant costs and risks associated with undertaking a deepwater project. In an effort to share technical capabilities and minimize these risks, we recommend that Energy Inc., as part of our entry strategy, look for one or more joint venture partners with deepwater Gulf of Mexico experience. Joint ventures have several advantages as compared with other forms of collaboration such as M&As (Mergers and Acquisitions) and Cooperative Agreements.

Advantages of Joint Ventures To Other Forms of Inter-firm Collaboration

Mergers and Acquisitions

The joint venture concept offers several advantages to Energy Inc. as compared to a merger or acquisition. First, a joint venture can be established for a finite time span (i.e. for the duration of a specific project). A second advantage specific to joint ventures is the ability to focus the partners on those areas in which cooperation is appropriate and beneficial, leaving the other business lines unaffected. Also, the financial risk associated with a merger or acquisition is significant as compared with a joint venture. This is because acquiring companies historically have paid premiums for their acquisitions and are also responsible for assuming the debt of the target firm. In a joint venture, assets are contributed at fair market value and therefore are not subject to the same type of speculative premium. Finally, joint ventures are better equipped to take advantage of the shield of corporate limited liability, should it be required. All of these advantages work together to make joint ventures the most common form of cooperation used for deepwater exploration and development (Carter, Cushman, and Hartz, 1988).

Cooperative Agreements

The primary drawback to a cooperative agreement, as compared with a joint venture, is that it does not offer the same types of incentives to promote collaboration and resource commitment. This is due to the lack of a binding legal commitment. The risks associated with this type of arrangement do not make it suitable for a deepwater exploration and development project.

Disadvantages of Joint Ventures

The joint venture concept offers several advantages to Energy Inc. and is particularly well suited for a deepwater project. There are, however, several drawbacks to joint ventures that must be considered when negotiating and drafting such an agreement. These include the following.

- *Sharing Control*. A balance must be reached between the financial incentives offered by a joint venture and the amount of control that must be yielded by each of the partners. Proper joint venture management is critical to the success of a project.

- *Conflicting Corporate Cultures*. In order for two or more partners participating in a joint venture to work effectively together, their corporate cultures must be compatible.

- *Company Management*. The management of each of the participating companies must be willing to work towards removing barriers to cooperation and information exchange.

To minimize and/or eliminate these potential disadvantages it is very important to address these issues during joint venture contract negotiations. A clear understanding of the roles and responsibilities of each venture partner can facilitate the effective integration of the inter-company team. Additional issues that should be addressed in these negotiations include technology sharing, financing, and project execution.

Joint Venture Partner Selection – Decision Matrix Method

There are currently a large number of oil and gas companies working in the Gulf of Mexico. In order to select the best possible partner for Energy Inc. the *Decision Matrix Method* was utilized. This process makes it possible to objectively weigh and select potential partners based on a set of key measures of upstream performance and experience.

Based on the specific situation for which a joint venture is being evaluated, the key performance measures must first be identified. Each criterion is then individually weighted to reflect its respective importance in the overall total score received by each potential partner. To begin the partner selection process, each potential company is added to the decision matrix and is individually scored from 1 to 10 in each selection category. The score given is then multiplied by the corresponding selection criteria weight and added to the other score/selection criteria products. The company with the highest cumulative score is the preferred partner for the joint venture. The set of key measures used for this analysis are described below.

1. *Finding and Development Costs* [weight = 7]. In order for Energy Inc. to have the best chance of achieving a positive return on our Gulf of Mexico venture, we need to find partners that not only have operational experience, but have demonstrated a history of developing fields cost-effectively.

2. *Net Income and Stockholders' Equity* [weight = 3]. The financial strength of a potential partner is important to the success of the venture. If a partner encounters financial difficulty during the project it could significantly affect Energy Inc.'s return.

3. *Spending and U.S. Net Wells Drilled* [weight = 5]. The amount of money an oil and gas company invests is an indication of both its commitment to the region as well as a relative measure of its financial strength.

4. *Net BOE produced in Gulf of Mexico (601 to 1,499 ft)* [weight = 8]. This is an important measure for a potential partner because what Energy Inc. lack of comparative advantage in the GOM deepwater. Companies with experience in deepwater blocks are given additional emphasis because of particular strategic focus.

5. *Net BOE produced in Gulf of Mexico (>1,500 ft)* [weight = 10]. Because Energy Inc. is targeting the purchase of a lease in a water depth greater than 1,500 ft., oil and gas companies with ultra-deepwater experience have been given the most weight.

Joint Venture Candidates

Based on our decision matrix, five (5) potential joint venture candidates, along with their cumulative scores, were identified.

1. Supermajor Company A[2] (330 pts)
2. Supermajor Company B (320 pts)
3. Supermajor Company C (310 pts)
4. Supermajor Company D (303 pts)
5. Major Company E (293 pts)

Joint Venture Recommendations

Short Term Strategy

To gain entry into the deepwater Gulf of Mexico, Energy Inc. should first look to partner with Supermajor Company B, Supermajor Company D, or Major Company E. Although Supermajor Company A scored the highest in the Decision Matrix, they were ruled out for the short-term strategy primarily because of the additional difficulties that could arise due to their recent merger. Supermajor Company C was also dropped as a primary venture partner target because of the secondary focus they seem to give to this region. In contrast, the other three firms cite the Gulf of Mexico as a primary target for future development.

Our strategy in the short-term should be to enter as a minority partner. This is prudent for two reasons. First, there is a significant reduction in project risk. As a minority partner, Energy Inc. will have an opportunity to gain experience from the other venture partner(s) without undertaking a majority of the responsibility for running the project. Second, it would be very difficult for Energy Inc. to persuade other firms to become minority partners given our lack of a previous deepwater GOM track record.

Long Term Strategy

As a long-term strategy Energy Inc. should look to acquire additional leases for future exploration and development projects. If the price of oil increases in the future, Energy Inc.

[2] Actual names of companies evaluated, and details from our evaluation, are kept anonymous for confidentiality purposes.

will be poised to take advantage of a majority ownership position with its newly acquired deepwater experience. In this scenario the choice of joint venture partners would also be broadened to include strong independent oil companies. Should the price of oil remain depressed for an extended period of time, the downside risk of simply letting the leases expire would be relatively small.

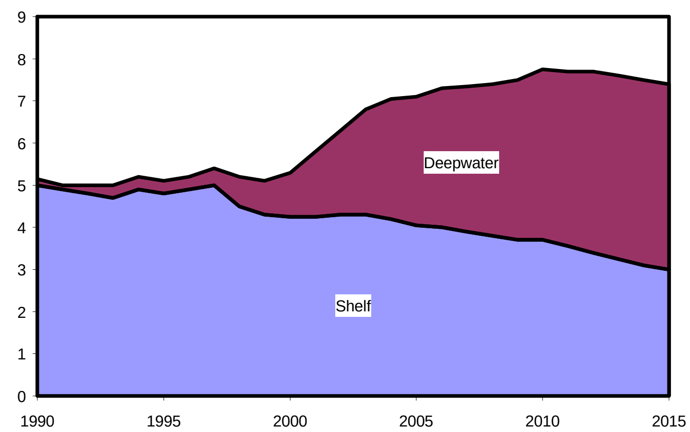
Lease Acquisition

The second phase of our entry strategy is the acquisition of a deepwater offshore lease in the Gulf of Mexico. Specifically, we plan on participating, through the negotiated joint venture, in the proposed sale of OCS Area 181 currently scheduled for March 1999.

BACKGROUND

The offshore Gulf of Mexico has become an increasingly important source of natural gas, especially after the 1980s. It now provides about 25 to 30 percent of dry natural gas production in the United States. Chart 1 reproduces Figure 6 from the recent National Petroleum Council (NPC) study on natural gas (December 15, 1999). The chart shows that natural gas production (especially deepwater) from the GOM is expected to remain significant.

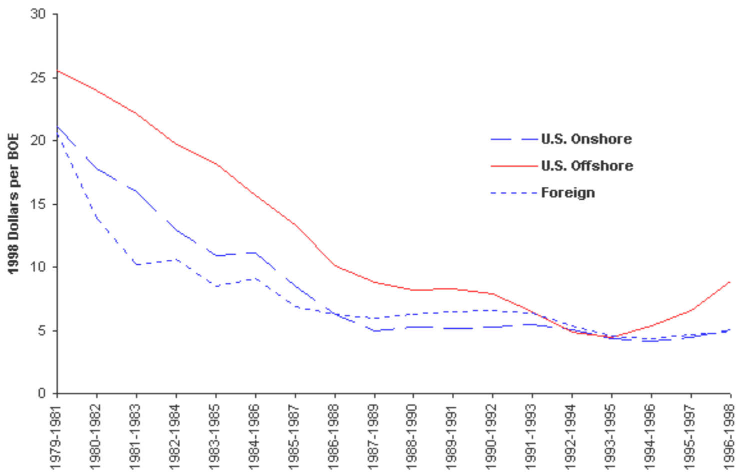
Chart 1
Natural gas production from the GOM (tcf)
(Source: www.npc.org)



Moreover, technological advances that lower the cost of deepwater operations, coupled with royalty relief legislation (The Outer Continental Shelf Deep Water Royalty Relief Act of 1995 – DWRRA) for deepwater production, indicate the possibility of increased oil and gas production from this region. Recently, Supermajor Company A discovered a potentially sizeable oil field in deepwater GOM. Many other companies, with Supermajor Company D the acknowledged deepwater leader, are quite active in this area as well. Based on press releases and annual reports, the Energy Information Administration (EIA) estimated the ultimate recovery from about ten current major projects at around 2 billion barrels of oil equivalent (boe).

Chart 2 shows the historical downward trend of the cost of finding oil and gas in different areas of the world for companies who comply with the EIA's FRS reporting.

CHART 2
FINDING COSTS FOR FRS COMPANIES (THREE-YEAR MOVING AVERAGE)



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

It is worthwhile to note the recent upward turn in finding costs for the U.S. offshore, which reflects the higher costs associated with developing and testing deeper-water technologies and strategies. Generally, industry sources expect finding costs to trend back down as experience with deep water plays accumulates and an increasing amount of technology becomes available "off the shelf." Persistently high finding costs would have a significant impact on the future of the GOM region.

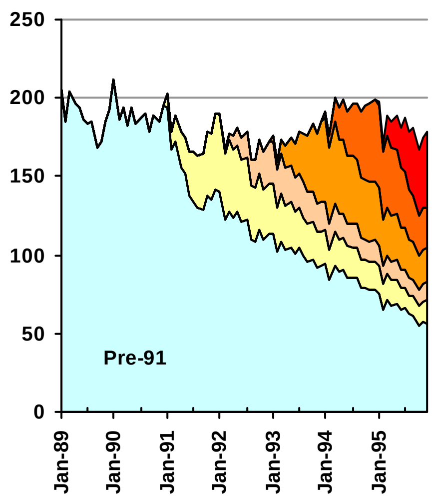
Chart 3 shows that, since the mid-1990s, GOM shelf oil and gas production is of younger vintages. This implies that more drilling activity has been necessary just to keep GOM output constant, especially for natural gas, and that drilling activity is yielding relatively small pools of hydrocarbons. When considered together with the projected downward trend of gas production from the shelf depicted in Chart 1, this combination of increased drilling activity to yield relatively small pools plus initially high finding costs as activity moves to deeper waters means that U.S. offshore finding costs could remain high. The discovery of relatively large pools of hydrocarbons in deeper water blocks would work to lower finding costs, as expenses are spread over more barrels of oil equivalent. Likewise, as more deepwater technology is proven out and becomes available "off the shelf," lower finding costs should result.

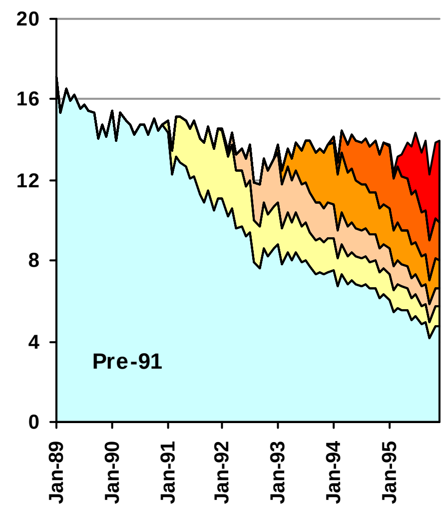
However, a scenario of upward pressure on finding costs for a prolonged period of time also introduces the question of whether independents, who have been so successful in shallow waters, can be viable competitors in deepwater GOM given capital constraints for the industry. The success or failure of independents, whose local base is much stronger than that of majors, will also have a significant impact on the GOM economy.

Chart 3

Top 11 GOM shelf producers
(*Source: Chevron Corp.*)

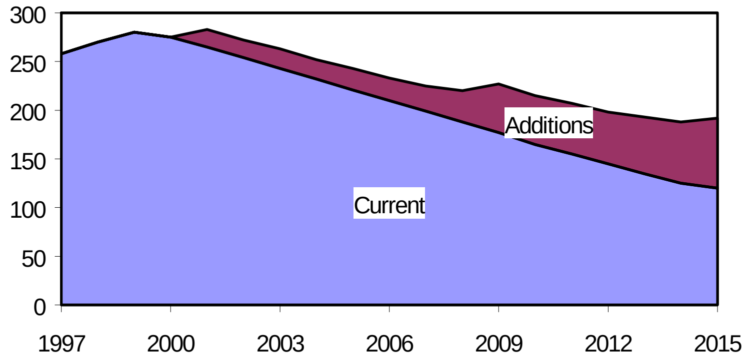
Gas (bcf/mo) **Oil (mb/mo)**





Obviously, the GOM region will remain crucial from the perspective of supplying the United States with domestic oil and gas for some time to come. Unfortunately, the short-term development of offshore projects (especially those in deepwater) is limited by the availability and utilization of drilling rigs and a trained workforce. Available equipment and personnel are not sufficient to meet the requirements of the existing inventory of offshore prospects, much less new ones. Chart 4 reproduces Figure 11 from the NPC study. Clearly, the current and on-order offshore fleet, net of attrition, will not be sufficient as early as the 2000-2001 period. Significant rig fleet additions must be made before 2010 in order to reach the levels of production predicted in Chart 1. Finding the sources of capital funding to build these rigs will become very important for the health of the GOM offshore industry.

CHART 4
OFFSHORE DRILLING RIG FLEET
(*SOURCE: WWW.NPC.ORG)*

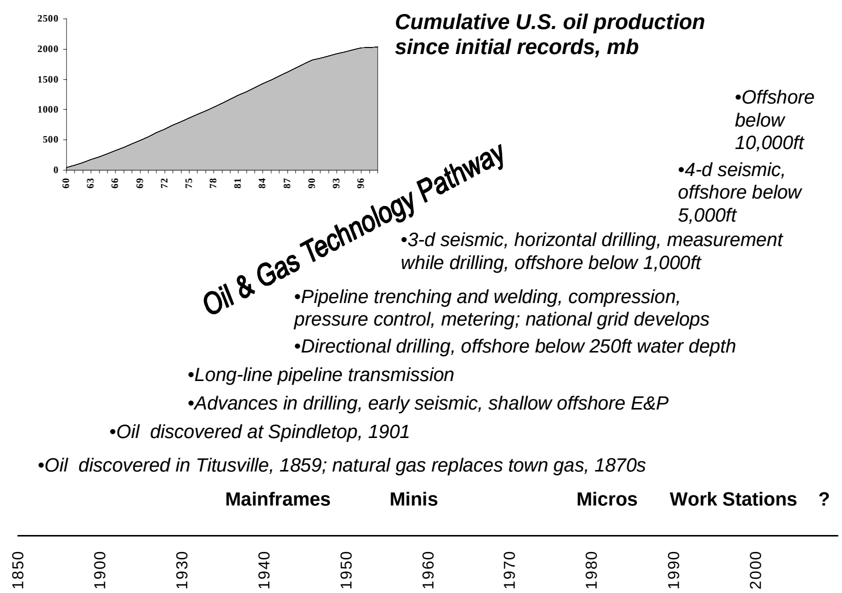


The lack of resources is the legacy of persistent boom-and-bust cycles in the oil and gas industries and the impact these cycles had on the socioeconomic structures of the region's producing states. Many companies reacted to the 1986 oil price collapse by downsizing. Some non-majors went out of business, while majors concentrated on foreign investments in parts of the world where development costs were much lower than in the GOM area.

The industry consolidation and restructuring that have taken place since 1986 almost seems to be a permanent feature. The emergence of supermajors has created a new class of enterprise. Surviving independents, especially mid-size companies, have become important players in the industry, but consolidation activity is high for this group as well. According to the EIA, investment by non-majors increased from about 33 percent of total U.S. exploration and development expenditures in 1988-90 to about 50 percent in recent years. Non-majors' share of U.S. oil and gas production has increased from less than 40 percent in the late 1980s to about 48 percent in the late 1990s, while the majors' share declined from above 60 percent to about 52 percent over the same period. Independents' reserve replacement cost was about equal to that of the majors (around $5 per barrel). Non-majors played an especially significant role in offshore gas developments (mostly shallow water) and have become fairly competitive with majors as they adopted new technologies such as 3-D seismic, directional drilling, and subsea completion methods.

Technology is a leading factor in explaining the resilience of the oil and gas industry in general, and the ability of the industry to continue to advance in spite of market adversity. Chart 5, developed by the Energy Institute, highlights technology achievements including the advent of deepwater exploration and production and their importance in sustaining the U.S. oil and gas resource base. In all likelihood, technology advances will help to offset increasing costs for the industry. However, the time frame during which the industry can continue to achieve technology gains before alternative energy fuels and/or technologies displace oil and gas is difficult to predict.

Chart 5
Oil and gas technology development
(*Source: Energy Institute, University of Houston*)



With regard to the region, state and city governments reacted to the 1986 oil price collapse and subsequent commodity business cycles by diversifying their economies, albeit to varying degrees. For example, Texas is much less dependent on the oil and gas industry today as compared to 20 years ago, while Louisiana still relies heavily on this industry. Since hitting the trough of a recession in 1986, the Texas economy has been steadily diversifying. Its service sector's share of Gross State Product (GSP) increased from 14.6 percent in 1986 to a projected 19.4 percent in 1999, while manufacturing grew from 14.5 percent of the economy in 1986 to a forecast 15.3 percent in 1999. By contrast, the portion of the Texas economy in mining (primarily oil and gas extraction) declined from 8.5 percent in 1986 to an estimated 6.1 percent for 1999 (mining's share of Texas GSP was as high as 19.5 percent in 1981).

In comparison, the offshore oil and gas operations in the GOM alone have an annual $3 billion positive impact on the Louisiana economy. More than $500 million of this impact is in the form of salaries and wages paid to offshore workers. The remainder results from the business the offshore industry does with onshore vendors in Louisiana. Approximately 45 percent of the Louisiana vendors derive more than half of their income from OCS activities in the GOM. In 1992, Louisiana's oil and gas extraction sector produced over $14.6 billion in total income. That figure exceeds the sum of all the state's manufacturing sectors except chemicals and allied products. In 1995, through both their direct and multiplier effects, the oil and gas extraction, refining and pipeline industries supported $65.2 billion in sales to Louisiana firms, nearly $8.1 billion in household earnings, and 296,966 jobs in the state. The $8.1 billion in earnings represented 18 percent of total earnings in Louisiana in that year. These three industries directly paid about 13.8 percent of total taxes, licenses, and fees collected in Louisiana in 1994-95.

As a result of this dependence on the oil and gas sector, Louisiana suffered to a wider extent than Texas during the 1997-98 period of low oil prices. However, in recognition of this problem, the Louisiana Department of Economic Development's *Vision 2020* program calls for a major effort to lessen the dependence of the state on the oil and gas sector.

Since the late 1980's, a limited amount of activity has taken place in the Eastern Gulf because of administrative deferrals and annual congressional moratoria. This area has historically been protected from exploration and development activities. However, this area is not effected by the State of Florida's opposition to offshore oil and gas activities being conducted within 100 miles of its coast, and it satisfies similar concerns raised by the Governor of Alabama. Therefore, Energy Inc. has an excellent opportunity to be one of the "first movers" in this area. The MMS estimates that between 7.5 and 8.7 trillion cubic feet of natural gas and between 1.6 and 2.5 trillion barrels of oil and condensate are contained in the Eastern Gulf of Mexico. (MMS – Eastern Gulf of Mexico Program Overview).

OCS Sale 181

The proposed sale will consist of leases located in the western 1/6th of Destin Dome and a majority of Desoto Canyon and Lloyd tracts. The water depth in this area ranges from 1,000 ft to 8,000 ft deep. As part of the preliminary regional lease evaluation process, we recommend focusing attention on the blocks in Destin Dome and the western portion of Desoto Canyon. These blocks are within a reasonable amount of distance to existing wells with substantial oil and gas discoveries and will allow Energy Inc. to take advantage of the existing infrastructure in the area. For example, Amoco submitted a plan of development to the MMS back in October of 1997 to conduct production operations on its King's Peak field, which is located in this area. This field consists of four contiguous blocks located at Desoto Canyon Blocks 133 and 177 and Mississippi Canyon Blocks 217 and 173. Amoco has plans to complete seven subsea wells to develop this gas field. It may make sense to examine nearby blocks since substantial gas finds have been made in this area (Hart's, April 1998).

Acquisition Costs

For economic evaluation purposes, we have analyzed historical lease sale activity in order to estimate what we might be required to invest in order to acquire a deepwater lease. The weighted-average high bid for the two lease sales in 1998 was almost $1.7 million. However, as an indicator of the level of competition, the weighted-average high bid for leases receiving multiple bids was almost $3.6 million. Overall, bid prices in 1998 varied from a low of $200,000 to as high as $28 million. Statoil Exploration and Sun Operating Ltd. Partnership bid $28 million, the highest bid ever made, to acquire Green Canyon Block 955 at the Central Gulf of Mexico Lease Sale in March 1998. The data from 1998 indicates that bid prices have increased significantly over the past couple of years. We believe this to be representative of an increase in the amount of competition, as more and more companies look for opportunities in the deepwater Gulf of Mexico.

Due to the increased level of competition in the deepwater Gulf of Mexico, we have elected to use the 1998 weighted-average high bid of $3,568,275 for those blocks receiving multiple bids for our estimate of lease acquisition cost. We believe this to be more representative of what bid prices will do in 1999. However, a factor that could work in our favor is the downward trend in oil prices over the past year. This may tend to keep some of the competition out of the bidding process, thereby lowering the overall average bid prices. In addition to the bid price, the joint venture partnership will also be liable for the first year's lease rental. At present, annual lease rentals are $43,200. Therefore, total gross anticipated signature bonus due in 1999 will be $3,611,475.

Lease Term and Annual Rental

Primary lease terms, as governed by the MMS, depend on the average water depth of the lease. At present, an operator(s) may hold a lease under primary term for up to five years for blocks in water depths of less than 400 meters, eight years for blocks in water depths between 400 and 800 meters, and ten years for blocks in water depths greater than 800 meters. If exploration and/or development activities are not initiated, or production established, within these time periods, the lease expires. Based on the range of water depths over Area 181, we have assumed a water depth of 6,000 ft (~ 1,830 meters) to work with in our exploration and development scenario. Therefore, we anticipate qualifying for a ten-year primary term. Although we currently plan on moving forward with exploration and development plans as soon as we acquire the lease, the ten-year primary term will give Energy Inc. and its partner(s) the flexibility to defer plans for exploration and development if oil prices remain deflated.

The annual rental rate or production bonus for a lease is $5 per acre for blocks in water depths of less than 200 meters and $7.50 per acre for blocks in water depths of 200 meters or greater. Our assumption of a water depth of 6,000 ft will result in a yearly rental rate, as indicated above, of $43,200 that will continue until production is established and royalties, if any, are due. We are not obligated to pay any further production bonuses, unless the amount paid out in royalties drops below the minimum amount of $43,200. Once production ceases, no further payments are due and the lease is relinquished (MMS – Proposed Notice of Sale 172).

PROSPECT EVALUATION

The next phase of this analysis includes a discussion concerning the prospect evaluation process. Prior to participating in OCS Lease Sale 181, we recommend that Energy Inc. form an internal multi-discipline work team to conduct a regional evaluation of the focus area defined above. This regional evaluation should, as a minimum, include an analysis of reserves and production potential, possible exploration and development scenarios, and the associated capital investment and operating expenses for each prospective lease. This will enable Energy Inc. and its joint venture partner(s) to focus attention on those leases that offer the most significant growth potential as well as to determine a competitive bid price. To illustrate this process and, more importantly, provide an indication of the growth potential offered by a deepwater development, the following sections present a typical scoping analysis that is performed prior to participating in a lease sale. It should be noted that all values quoted for reserves, production, and costs are on a gross basis. The net amount to Energy Inc. will depend upon our eventual level of equity participation in the joint venture.

Reserves Analysis

While hard data (i.e. 2-D and 3-D seismic, subsurface structure maps, and well logs) is traditionally used for this technical evaluation, we have, for the purpose of this scoping analysis, estimated a "most likely" reserve case for a typical deepwater project utilizing the following method. We first compiled a list of existing deepwater developments for which gross proved reserve estimates were available. Of the forty-one developments, the lowest and highest reserve estimates quoted are 4.5 MMBOE for the Walter Oil & Gas development at Viosca Knoll 986 and 500 MMBOE for Shell's Mars development at Mississippi Canyon 807. These two data points serve to bracket a range over which a typical commercial reserves case can be approximated. While we do not presume there to be any correlation between water depth and reserves, we have only included deepwater developments in our analysis in order to define an economically viable distribution of reserves.

The next step in our process was to determine an expected value by plotting the above two data points on log-log probability paper to form a reserves distribution. The 4.5 MMBOE reserve estimate was plotted at the P90 level. This indicates that, assuming geologic success, there is a 90 percent probability that at least 4.5 MMBOE will be discovered. The 500 MMBOE reserve estimate was plotted at the P10 level. This indicates that, assuming geologic success, there is only a 10 percent probability that reserves equal to or greater than 500 MMBOE will be discovered. From these two points, a straight line was plotted to form the reserves distribution. From this distribution, a value of 48 MMBOE is approximated at the P50 level. This represents the expected value of proved, recoverable reserves we subsequently utilized to generate production profiles.

Production Profiles

Given the base case of 48 MMBOE proved reserves, we have assumed that a total of four producing wells, each recovering 12 MMBOE, will be required. The basis for this assumption is that there is only one contiguous pay sand and that the geologic structure is relatively simple. Given these conditions, four producing wells will serve to accelerate the recovery of reserves while minimizing the level of initial capital investment and the potential for future well intervention requirements due to a long producing life.

We have generated base case production profiles for two cases. The first case assumes an oil discovery with associated gas. The second case assumes a gas discovery with associated condensate. For the oil case, we used an initial production rate of 6,500 BOPD per well and a typical gas-oil ratio of 1,200 scf/bbl to determine the amount of associated gas. Following a period of flat production, we have assumed an annual effective decline rate of 25 percent for the remaining life of the field. Based on these assumptions, we have estimated total reserves for the oil case to be 40 MMBO and 48 BCF, with each well recovering 10 MMBO and 12 BCF over a producing life of approximately 10 years.

For the gas case, we used an initial production rate of 40 MMCFD per well and a typical condensate yield of 33 bbl/mmcf to determine the amount of associated condensate. Following a relatively longer period of flat production, we have assumed an annual effective decline rate of 45 percent for the remaining life of the field. Based on these assumptions, we have estimated total reserves for the gas case of 240 BCF and 8 MMBO, with each well recovering 60 BCF and 2 MBO over a producing life of approximately 7.5 years.

Transportation Issues

Before proceeding with the evaluation of potential development scenarios, an important issue to be addressed is the means and cost of transportation of the oil and gas from the wellhead to onshore facilities. There currently exists a complex network of more than 23,000 miles of subsea pipelines in the Gulf of Mexico. However, this infrastructure exists in and around those areas that have been heavily developed. As we mentioned previously, the majority of the area that has been technically approved for release at the next lease sale is relatively undeveloped. This may present a potential obstacle in that it may be some time before infrastructure extends to this region.

It is for these reasons that we have recommended focusing attention on the areas that lie closest to existing infrastructure. Accordingly, we have made the assumptions for our development scenarios that a viable tie-in point will exist within a 15-20 mile radius of our discovery and that typical transportation fees will apply. However, if the lease acquired exists in a relatively remote area, development plans may have to be deferred until such time as the above assumptions are applicable. As more wells are drilled and discoveries are made in this undeveloped area, infrastructure will eventually be built to reach this new market of oil and gas reserves. At the same time, technology is addressing the problems of deepwater development and making it more technically feasible and economically affordable with continued advances in subsea completions and flexible flowlines that can route oil and gas back to facilities in shallower waters.

Exploration, Appraisal, & Development Scenarios

Using the above reserves and production information, along with our assumption regarding the availability of infrastructure, we have generated two different scenarios. Case 1 is based on an oil development in 6,000 feet of water. This eliminates the possibility, based on structural limitations, of using a fixed platform, compliant tower, or mini tension leg platform. Furthermore, due to our assumption of a 15-20 mile tie-in, and due to the greater sensitivity to fluid characteristics in an oil development, we have eliminated a subsea development as a potential option. Therefore, the most feasible development option, given the limited number of producing wells, would be to install a SPAR structure with a drilling and production deck rather than a typical tension leg platform. This would provide the most economic development option, given the water depth, and could potentially establish a facilities hub for future developments.

Based on these conditions, a typical exploration, appraisal, and development scenario for the oil case was developed. Once a prospective lease has been acquired, we have assumed that we could be ready to spud the initial exploratory well by March 2000. Based on the earlier assumptions of there being only one pay sand and having a relatively simple geologic structure, we would recommend drilling a vertical exploratory well and proceeding immediately to an appraisal sidetrack. This wellbore would then be permanently plugged and abandoned. The total time estimated for this phase is 75 days. We have then allocated a period of 8 months for evaluation and preparation of a development recommendation. This amount of time should allow for a thorough prospect analysis, as well as any further re-processing and analysis of seismic data. We would then be ready to approve and commit funds for development by February 2001. The next phase of the program is driven by the amount of time necessary for design and construction of the SPAR structure and production facilities. Following approval of the plan of development by the MMS, we have allocated a period of 12 months for this process. This would establish April 2002 as the earliest possible date for structure installation, which coincides with a good “weather window” for the Gulf of Mexico. Stepping back from this date, drilling of the four development wells would, therefore, need to begin no later than August 2001, with each well requiring 60 days to drill, log, set casing, and temporarily abandon. Concurrent to the development drilling phase, oil and gas sales subsea pipelines would be run to the closest viable tie-in point. Once the structure has been set, and the export risers run, tie-back and completion operations on the first well would be initiated in June 2002. Finally, first production, from one well, would be anticipated by July 2002. Production is then expected to ramp up over the next three months as subsequent wells are tied back and completed.

Case 2 of our analysis assumes a gas development. For this case, a four-well subsea development represents the most feasible option. Although we are still working with the assumption that the gas and oil (condensate) must be transported 15-20 miles for processing and sales, a subsea development is much more technically feasible with gas. Furthermore, given the base case reserve estimate of 48 MMBOE, a subsea development is also the most economically attractive option due to the limited initial investment. Finally, a subsea development allows for first production much sooner than a traditional development in which a structure and facilities must be installed.

Based on these conditions, a typical exploration, appraisal, and development scenario for the gas case was developed. This scenario is identical to the oil case up to the point at which a formal development recommendation has been made. As in the oil case, we would be ready to approve and commit funds for development by February 2001. However, once the plan of development has been approved by the MMS, there is no structure that needs to be designed and fabricated. Therefore, we would anticipate being ready to begin development drilling by April 2001. We have also assumed that, through proper planning, the pipeline could be laid and the subsea manifold could be fabricated and installed concurrent to drilling operations on the first development well. This would allow for production from the first well in June 2001, over one year earlier than the oil case, with production ramping up to a peak over the next six months as subsequent wells are drilled and completed.

Capital Investment and Operating Expenses

The following tables give our assumptions for initial capital investments and operating expenses required for each of the two cases. Each of these estimates, with the exception of lease acquisition cost, which was described earlier, is based on personal experience with modifications made, where appropriate, for a development in 6,000 feet of water.

Table 1: Four Well Oil Development
SPAR Structure with full processing facilities

Capital Investment	U.S. $ (Million)
Lease Acquisition	3.6
Drill Exploratory Well	25.0
Drill Appraisal Sidetrack	5.0
Drill 4 Development Wells	104.0
Design, Construct, & Install SPAR [1]	180.0
Tie-back & Complete 4 Dev. Wells [2]	15.0
Total Capital	332.6

[1] Includes cost of processing facilities with two 8" export lines and a 15-mile-tie-in to pipelines
[2] Includes cost of riser with dry tree for four wells

Expenses	U.S. $
Fixed Operating Cost	150,000 per month
Transportation Fees	0.75 per bbl & 0.10 per mcf
Well Intervention [1]	4,500,000
Plug & Abandonment [2]	2,000,000

[1] Includes cost of three workovers @ $1.5MM per well in years 3, 5, and 7 of production
[2] Includes cost of four P&A's @ $0.5MM per well at end of producing life

A final assumption made in regard to future cash items in the oil development case is an end of life net salvage value of $4 million.

Table 2: Four Well Gas Development Subsea

Capital Investment	U.S. $ (Million)
Lease Acquisition	3.6
Drill Exploratory Well	25.0
Drill Appraisal Sidetrack	5.0
Drill & Complete 4 Dev. Wells	110.0
Install Subsea Manifold / Pipeline [1]	37.6
Total Capital	181.2

[1] Includes cost of subsea wellheads, jumper lines, manifold, and a 20-mile-tie-in to facilities

Expenses	U.S. $
3rd Party Operating Fee	12,000 per month
3rd Party Processing Fee	1.05 per bbl & 0.12 per mcf
Transportation Fees	0.75 per bbl & 0.10 per mcf
Well Intervention [1]	8,000,000
Plug & Abandonment [2]	8,000,000

[1] Includes cost of two workovers @ $4.0MM per well in years 3 and 5 of production
[2] Includes cost of four P&A's @ $2.0MM per well at end of producing life

FINANCIAL ANALYSIS

Once the technical evaluation has been completed and a set of "most likely" (i.e. risked) numbers have been generated for reserves, production, and costs, a thorough financial analysis should be completed. This process will enable Energy Inc. to determine the potential financial impact of a deepwater development and to determine how this type of investment compares to other opportunities in the portfolio. Included in the following sections are a discussion of oil and gas price forecasts, royalties, and the financial (NPV) analysis performed.

Oil and Gas Prices

Worldwide energy prices have been falling over the last year. Recently, however, they have stabilized somewhat around $12.00 per barrel. By adjusting to 1996 dollars, current oil prices are below the post World War II average price of $19.27 per barrel and below the median price of $15.27. What this means is that between 1947 and 1997, oil prices were below $15.27 almost 50 percent of the time. Furthermore, it has only exceeded $22.00 during a war or conflict in the Middle East. This type of price volatility has forced the upstream energy industry to re-structure its business to be able to profitably operate at an oil price level of $15.00 per barrel.

In the short term, we believe that oil prices are going to continue falling, to perhaps as low as $10.00 per barrel, before they begin rising back up to the historical average of $16.00 to $21.00. While this has a negative impact on Energy Inc.'s existing portfolio of producing properties, it has a less significant impact on our proposed deepwater development project. In fact, as stated in conjunction with the lease acquisition discussion, deflated prices, over the short term, can actually offer a few advantages. In addition to the potential for reduced competition and lower overall bid prices at the lease sale, depressed oil and gas prices can also have a "trickle down" effect on the capital investment. We have already seen a decrease in exploratory and development activities over the last several months in the Gulf of Mexico. This decrease in activity increases the level of competition among service companies and contractors which manifests itself in decreased prices.

Under the two development scenarios presented, we do not expect to begin production any sooner than June 2001 for a subsea development scenario or July 2002 for a development with a structure and facilities. Therefore, it is our long-term price forecasts and, more importantly, the sensitivity of the proposed development to price risk that bears the greatest significance on the financial analysis. Just as with the discussion concerning infrastructure issues, if our forecasts are wrong and prices continue at depressed levels for the next several years, exploration and development plans may be deferred until prices recover to a more economically attractive level. In the worst case scenario, where prices do not recover during the ten-year primary term, our only financial exposure will have been the acquisition cost and annual rentals for the lease.

Price Forecasts

A model was prepared to forecast the price of oil and gas beginning in January 1999 through January 2010. The key assumptions and methodology for these price forecasts are as follows:

- *Natural gas prices will move up and down with crude oil prices* – While this may not be completely accurate, assuming a positive correlation between the two commodities provides an elementary method for forecasting energy prices.

- *Prices as of November 19, 1998 were used as a starting point for the model* – From this point, we have assumed prices will continue to decrease until January 2000. Beginning in 2000, prices will increase, through 2010, at a modest rate. Prices have been forecast over semi-annual periods.

- *A Low State and a High State were calculated* - A 15 percent variance from the forecasted price estimates was used to create a low case and a high case for use in the sensitivity analysis.

Due to existing low energy prices and an inability to accurately forecast oil and gas prices in the future, it is imperative that Energy Inc. not enter into any exploration and development efforts that are not profitable at modest energy prices. It is for this reason that we have used historical price levels as a ceiling over which our forecasts cannot exceed. While there are an unlimited number of variables that could dramatically increase or decrease world energy prices in the future, we believe that, on average, oil and gas prices will continue to remain at or around historical levels.

Royalties

For producing properties in federal waters of the Gulf of Mexico, an operator and its partners are obligated to pay royalties to the MMS. This amount represents the percentage of production, on a revenue-equivalent basis, that is owed to the federal government. At present, this rate varies from 16.67 percent for blocks in water depths less than 400 meters to 12.5 percent for blocks in water depths greater than 400 meters. There have been some recent discussions, as well as pilot projects in shallow water leases, concerning a conversion from the present royalty payment system to a royalty-in-kind system. Under this system, the MMS would take physical ownership of their share of production and become responsible for marketing their volumes. However, this system presents a number of administrative difficulties that neither operators nor the MMS are presently equipped to handle. Therefore, we do not believe that any changes will be made to the present guidelines until such time as the royalty-in-kind system can be implemented without any unnecessary financial or administrative burden on producers.

Additional provisions have been made governing royalty payments for deepwater leases. In November 1995, President Clinton signed the Outer Continental Shelf (OCS) Deep Water Royalty Relief Act (attached following case). Under this legislation, the Secretary of the Interior granted royalty suspension volumes on both producing and non-producing fields in waters deeper than 200 meters. The purpose of this law is to promote development of and increase production from marginal leases in the deepwater Gulf of Mexico. For leases acquired prior to this legislation, the Secretary determined the appropriate royalty-suspension volume on a case-by-case basis. However, for new leases in greater than 200 meters of water the following minimum volumes of production are not subject to a royalty obligation:

- 17.5 million barrels of oil equivalent (MMBOE) for leases in 200 to 400 meters of water
- 52.5 MMBOE for leases in 400 to 800 meters of water
- 87.5 MMBOE for leases in more than 800 meters of water

Since the proposed project we are evaluating is in 6,000 feet (~1,830 meters) of water, and our base case reserves are 48 MMBOE, royalties will be suspended for the life of the project. Therefore, as discussed in the Lease Term and Annual Rental section, Energy Inc. and its partner will only be obligated to make the minimum production payment of $43,200 annually. (MMS - 30 CFR Part 260).

Economic Analysis - Introduction and Model Explanation

The discussion of our financial analysis will consist of five parts: introduction and model explanation, key assumptions, financial results and sensitivity analysis, breakeven analysis, and financing alternatives. We utilized a Microsoft Excel spreadsheet to model our financial calculations. The purpose of the model is to calculate critical economic measures based on the input information we have outlined thus far. Furthermore, this model serves as a flexible tool for conducting a sensitivity analysis, in which we can vary key input information to determine their impact on the economic results. The key benchmark we used to evaluate our proposal was net present value (NPV). A positive NPV indicates a project that Energy Inc. should consider for investment, based on funds availability, other investment opportunities, other economic benchmarks, and certainty of the input. Additional economic benchmarks that should be evaluated include internal rate-of-return (ROR), finding and development cost per BOE, and return on average capital employed (ROACE). We used this model to evaluate both scenarios (oil and gas) presented in our discussion.

Key Assumptions

The quality of output is only as good as the quality of input. With that said, we'll discuss some of the important input assumptions of the model.

- *Discount rate*: we used 12% as the cost of capital for this evaluation based on Energy Inc.'s perceived risk factors and an evaluation of competitive costs of capital. Shell Oil Company uses 11% as its discount rate while Major Company E uses 11.5% and Kerr-McGee uses 11%.

- *Inflation rate*: we used 3% as the annual inflation rate to inflate certain costs and prices that we projected would be subject to inflationary pressures. For example, after projecting operating expenses at the beginning of production, we used the 3% inflation rate to project expenses for the balance of the project.

- *DD&A rate*: we calculated the DD&A rate on a unit of production bases by dividing the capital expenditure by total reserves and amortizing the depreciation as production occurs. For example, if the depreciation rate was $6.58 per barrel, and the production for the year was 5 MMBO, then we depreciated $32.9MM ($6.58 x 5MM) for that year.

- *Cash flows*: for the purposes of this model, cash flows for each year occur at the end of the year, and are discounted back to Year 0. Year 0 cash outlays occur at the beginning of the project life.

Financial Results and Sensitivity Analysis

We conducted our initial financial analysis using our most likely projections for prices and reserves. These initial projections are as follows:

- Price of oil in mid-year 2001 = $13.00/bbl
- Price of oil in mid-year 2002 = $14.00/bbl
- Price of gas in mid-year 2001 = $2.25/mcf
- Price of gas in mid-year 2002 = $2.42/mcf
- Reserves for oil case = 40 MMBO and 48 BCF (48MMBOE)
- Reserves for gas case = 240 BCF and 8 MMBO (48MMBOE)
- Production begins for oil case in mid-year 2002
- Production begins for gas case in mid-year 2001

Based on these projections the financial results for each scenario are summarized in Table 3.

Table 3 – NPV Summary

Case	Prod. Starts	Oil Price	Oil Reserves	Gas Price	Gas Reserve	NPV
Oil	2002	$14.00	40 MMBO	$2.42	48 BCF	$13.38 MM
Gas	2001	$13.00	8 MMBO	$2.25	240 BCF	$103.74 MM

Realizing that our price and reserve projections represent most likely estimates, they are subject to outside influences and can vary. With this in mind, we conducted a sensitivity analysis varying the prices and reserves to determine the impact on the NPV. Oil and gas prices were tested at +/- 15 percent from the projected (mid) prices, and reserves were tested at +/- 10 percent of the projected (mid) amounts. We realize that varying the reserve amounts by a significant amount could impact the amount of capital required for the project. Therefore, we chose to vary the amount by only +/- 10 percent for the purpose of minimizing its impact on capital investment.

For terminology purposes, low, mid, and high will be used in the sensitivity analysis to reflect low, mid, and high values for prices and reserves. A summary of the financial sensitivity analysis for the oil and gas cases can be found in Tables 4 and 5.

Table 4 – Oil Case Sensitivity Analysis

Oil and Gas Prices ($/bbl, mcf)	Reserves (MMBOE)	NPV (MM $)
Low (11.90, 2.06)	Mid (48)	(16.78)
Mid (14.00, 2.42)	Mid (48)	13.38
High (16.10, 2.79)	Mid (48)	38.40
Low (11.90, 2.06)	Low (43.2)	(22.90)
Mid (14.00, 2.42)	Low (43.2)	5.34
High (16.10, 2.79)	Low (43.2)	33.71
Low (11.90, 2.06)	High (52.8)	(9.56)
Mid (14.00, 2.42)	High (52.8)	22.37
High (16.10, 2.79)	High (52.8)	54.44

Table 5 – Gas Case Sensitivity Analysis

Oil and Gas Prices ($/bbl, mcf)	Reserves (BCFE)	NPV (MM $)
Low (11.05, 1.91)	Mid (288)	69.39
Mid (13.00, 2.25)	Mid (288)	103.74
High (14.95, 2.59)	Mid (288)	138.71
Low (11.05, 1.91)	Low (259.2)	57.83
Mid (13.00, 2.25)	Low (259.2)	89.70
High (14.95, 2.59)	Low (259.2)	122.14
Low (11.05, 1.91)	High (316.8)	80.08
Mid (13.00, 2.25)	High (316.8)	116.73
High (14.95, 2.59)	High (316.8)	154.06

Based on the sensitivity analysis, the two scenarios we have outlined will yield a positive net present value in almost all situations. In the gas case (Table 5), the project yields a positive NPV for all combinations of prices and reserves. In the oil case (Table 4), it yields a positive NPV, for each reserves scenario, when the price of oil is at the mid or high level. It yields a negative NPV at the low price. It appears, therefore, that price variability has a greater impact on NPV than reserves variability. For example, in the oil case, when the prices and reserves are both at mid levels, the calculated NPV is $13.38 MM. When the price is decreased to the low level (-15%), the NPV declines by $30.16 MM. However, when the reserves are decreased to the low level (-10%), the NPV declines by only $8.04 MM. Similarly, in the gas case, the price reduction resulted in a NPV decline of $34.39 MM while the reserves reduction resulted in a NPV decline of only $14.04 MM. Based on these findings, we conducted a breakeven analysis using the price of oil and gas as the critical risk factor.

Breakeven Analysis

We conducted a breakeven analysis to determine at what price levels of oil and gas the project will break even. We kept all factors constant, including reserves at 48MMBOE, and fluctuated the prices of oil and gas until the NPV = 0. For the purpose of this analysis, we fluctuated gas and oil prices in the same proportion. For example, in the oil case we were mainly interested in what the price of oil would need to be for the project to break even. However, since the production flow stream also includes gas, we varied the gas price proportionately. Since our projected oil price in 2002 is $14.00 and our projected gas price is $2.42, we reduced the gas price by $0.1729 (2.42/14.00), for every dollar reduction in the oil price. We conducted a similar proportional relationship in the gas case.

The analysis yielded the following prices for the two scenarios to breakeven:

Oil Case: $13.07/bbl and $2.26/mcf
Gas Case: $7.12/bbl and $1.23/mcf

Financing Options

Having determined that a deepwater development represents a viable investment opportunity for Energy Inc., several methods may be utilized to finance a project of this scale. The financing options are listed below, and are ranked in order of priority.

1. *Joint Venture* – This option would still require Energy Inc. to finance a portion of the project. However, it reduces the amount of capital outlay and reduces financial risk. For further discussion of this option, see the Joint Venture section of this proposal.

2. *Internal Financing* – The preferred method of financing Energy Inc.'s portion of the project is through internal means. Financing internally can be from either cash reserves or from internal cash flow. The advantage of internal financing is that Energy Inc. would not have to go to capital markets to raise monies. Internal financing however should not come at the expense of cutting dividends. Empirical data suggests that cutting dividends sends a negative signal to the market and reduces stock prices.

3. *Sale of Assets* – This option could be used if some of Energy Inc.'s assets are not earning a sufficient return. The advantage of this method is that the value of these assets could be re-deployed to earn an improved return. Additionally, this option holds the same advantages as internal financing.

4. *Debt Financing* – The advantage of debt financing is that the interest expense on the debt is not subject to corporate income tax. However, increasing debt generally increases bankruptcy risks for a firm. Energy Inc.'s debt ratio should be reviewed before it decides on additional debt obligations.

5. *Equity Financing* – Equity financing refers to issuing new shares of Energy Inc. stock. Empirical evidence suggests that issuing new shares of common equity sends a negative signal to the market, and reduces stock prices. Therefore, this method should only be used as a last resort.

CONCLUSIONS AND RECOMMENDATIONS

The analysis provided in this study indicates that a deepwater Gulf of Mexico exploration and development project represents a viable growth opportunity for Energy Inc.'s upstream operations and is one that will increase shareholder wealth as well as significantly contribute to the company's goal of reserve replacement. The base case financial analysis yielded a positive net present value (NPV) for both the oil development scenario and the gas development scenario. The sensitivity analysis yielded a positive NPV for all scenarios except for an oil development with the given reserve range and the forecasted low state oil prices. Therefore, the new ventures team recommends that this proposal be approved and incorporated into the 1999 Energy Inc. business plan.

The first phase of our recommended entry strategy is to secure a joint venture partner for a majority participation in the proposed deepwater project. The three recommended candidates identified from our analysis are Supermajor Company B, Supermajor Company D, and Major Company E. Due to Energy Inc.'s lack of experience in deepwater exploration and development operations, it is essential that we take advantage of the expertise of others in this area. Furthermore, holding only a minority interest in this partnership will enable Energy Inc. to minimize the costs and the risks associated with a project of this magnitude. The knowledge gained during this partnership will be critical for future projects where Energy Inc. elects to take on either a majority or full ownership.

The second phase of our recommended entry strategy is to participate, through the joint venture partnership, in the March 1999 sale of OCS Area 181[3] in the Eastern Gulf of Mexico. Internal multi-discipline teams should be charged with conducting a regional evaluation of the acreage included in the lease sale in order to prioritize those prospects that hold the most growth potential for Energy Inc. and its partner(s). Based on 1998 lease sale date, we have estimated a lease acquisition cost of $3.6 million. Following a successful lease acquisition, we recommend forming inter-company teams to begin the prospect evaluation process. As illustrated herein, these teams should be charged with conducting a thorough geologic and engineering evaluation of the prospect utilizing appropriate risking methodology. Once the possible exploration and development scenarios have been

[3] An important footnote to this case is that OCS 181 fell victim to presidential election politics in 2000 (see attached article following case study).

identified, a thorough economic analysis should be performed to evaluate the project versus Energy Inc.'s stated financial metrics as well as other opportunities in the portfolio.

Having determined that the project meets or exceeds all economic hurdles, we recommend that funding be provided either through internal financing or the sale of non-essential assets. The specific amount of capital and future operating budget requirements will be determined by Energy Inc.'s level of participation in the joint venture.

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APPENDIX

Exploration & Development
Oil&Gas Journal
December 17, 2001

Some see eastern gulf Sale 181 as missed opportunity

Oil and gas companies bid on 95 of 233 tracts far off Alabama in the eastern Gulf of Mexico in early December, but some said the federal lease sale was a missed opportunity for industry.

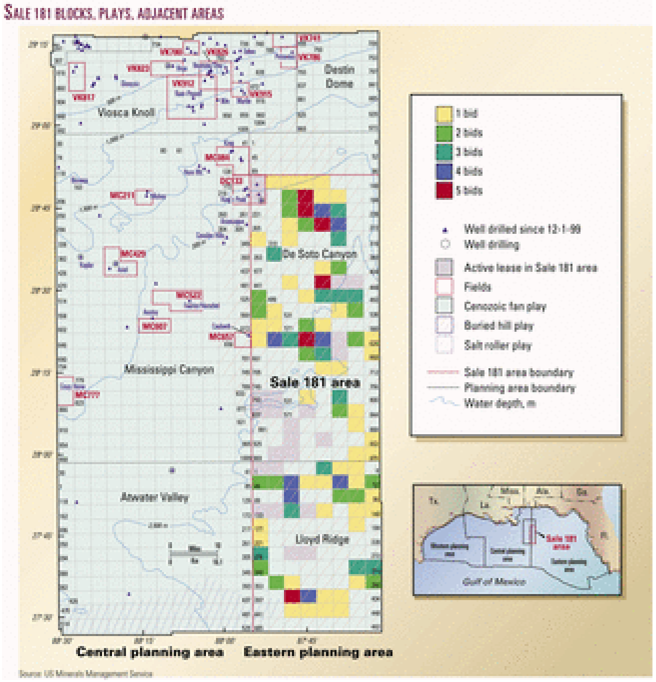
Seventeen companies bid a total $458.9 million at the sale, OGJ Online reported Dec. 5.

TOP 10 TRACTS

Company	Block	Water depth, m	High bid, $
1. *Anadarko Petroleum Corp.	Lloyd Ridge 91	1,600+	26,015,040
2. *Shell Offshore Inc.	Lloyd Ridge 399	1,600+	22,135,759
3. *Shell Offshore Inc.	Lloyd Ridge 446	1,600+	21,111,888
4. *Anadarko Petroleum Corp.	Lloyd Ridge 316	1,600+	18,025,440
5. *Anadarko Petroleum Corp.	De Soto Canyon 621	1,600+	18,017,280
6. *Anadarko Petroleum Corp.	Lloyd Ridge 50	1,600+	15,058,080
7. *Anadarko Petroleum Corp.	Lloyd Ridge 309	1,600+	13,024,800
8. *Shell Offshore Inc.	Lloyd Ridge 400	1,600+	11,117,500
9. *Marathon Oil Co. Kerr-McGee Oil & Gas Corp.	De Soto Canyon 491	1,600+	10,241,280
10. *Marathon Oil Co. Kerr-McGee Oil & Gas Corp.	De Soto Canyon 490	1,600+	9,924,480

*Denotes the submitter.
Source: US Minerals Management Service

SALE 181 BLOCKS, PLAYS, ADJACENT AREAS



Blocks offered were no closer than 100 miles from shore and no more than 24 miles east of the eastern boundary of the Central Planning Area (see map).

Some industry observers were scratching their heads over several established deepwater stars that either were underachievers or did not bid in the first lease sale in those waters since 1988. All of the blocks that drew bids in the sale are in 1,600 m of water or more, which qualify for a 10-year lease term at 12.5% royalty.

"ExxonMobil Corp. and BP PLC didn't even participate, despite their sizeable expertise in deepwater operations," noted Joel L. Riddle with Arthur Andersen LLP.

Before the sale, the Interior Department estimated that the sale area contained 1.25 tcf of gas and 185 million bbl of oil (OGJ, June 11, 2001, p. 41).

Bid highlight

The sum of the high bids was $340.5 million.

The blocks received an average of two bids each, though six received five bids each. All but one of those were in the De Soto Canyon area.

The deepest block to receive an offer was Lloyd Ridge 446 in 2,908 m of water. Anadarko Petroleum Corp., Houston, bid $26,015,040 for Lloyd Ridge Block 91, the highest bid of the sale. The bid was $4,516.50/acre.

Shell Offshore Inc., New Orleans, was the most active bidder, making offers for 48 blocks. It was highest bidder for 28. Anadarko was a close second in success rate. It bid for 33 blocks and was high on 26 of them.

Spinnaker Exploration Co., Houston, was third most active bidder.

The other companies participating were Kerr-McGee Oil & Gas Corp., Dominion Exploration & Production Inc., Amerada Hess Corp., Chevron USA Inc., Petrobras America Inc., Phillips Petroleum Co., Murphy Exploration & Production Co., EOG Resources Inc., Devon Energy Production Co. LP, Unocal Corp., Pioneer Natural Resources USA Inc., Ocean Energy Inc., and Conoco Inc.

Key players

Three active participants-Anadarko, Shell Offshore, and Kerr-McGee-accounted for 70 of the sale's high bids.

Anadarko was the sale's biggest spender. It submitted 33 bids totaling $167.4 million, including $136 million in its 26 high bids for blocks in 7,000 to 9,500 ft of water.

Anadarko Chairman Robert J. Allison Jr. said, "We have gathered and interpreted an extensive amount of information about these (East Gulf) blocks, and we're convinced they hold substantial oil and gas reserves with relatively low geologic risk. Since a lot of the preliminary work has already been completed, the prospects can be drilled ... as soon as late 2002, which makes this addition a good complement to Anadarko's portfolio."

Before this sale, Anadarko had 351 gulf leases, including 109 in deep water. The company also has a partnership with BP to explore 95 deepwater blocks held by BP in the Garden Banks and Keathley Canyon areas of the Central Gulf.

Shell Offshore's 48 bids totaled $127.9 million. Among those were 28 high bids-20 of them uncontested-exceeding $109.6 million.

Shell submitted the second-highest single bid in the sale, more than $22.1 million for Lloyd Ridge Block 399. That block was one of six that drew five bids each, including an offer from Anadarko of more than $21 million for Block 399.

Shell also had the sale's third highest bid, an uncontested offering of $21.1 million for Lloyd Ridge Block 446.

Kerr-McGee, the Oklahoma City company that drilled the first offshore well out of sight of land on Ship Shoal Block 32 in the gulf in November 1947, was still going strong at the sale. It submitted 22 bids, some with partners, that exposed more than $43.4 million. It was apparent high bidder in 16 of those attempts, totaling more than $34.7 million.

That will "give us a presence in new plays that complement our already outstanding deepwater gulf portfolio," said Luke R. Corbett, chairman and CEO of Kerr-McGee.

Assuming the company is successful in obtaining those 16 leases, Corbett said, "We will operate 60% of these high-bid blocks with an average working interest of about 63%, allowing us to continue to enhance our successful exploration and development program in the gulf."

Kerr-McGee is the gulf's largest independent leaseholder, with the largest number of deepwater gulf blocks among its peers. With the 16 new blocks, the company will have interests in 372 deepwater gulf blocks and operate more than 70% of those leases with an average working interest of 50%, officials said. It will increase its gulf leaseholdings by more than 92,000 gross acres to 3 million gross acres.

On sale day, Kerr-McGee noted that it spudded the 100%-owned Hornet prospect in late November in 3,700 ft of water on Green Canyon Block 379.

It is also drilling the Merganser prospect in 7,800 ft of water on Atwater Valley Block 36 (see map). If successful, the well will provide a hub for the Atwater Valley area, where the company has more than 25 blocks.

The company said the South Titan prospect, in 6,300 ft of water on a six-block cluster in the northeastern Walker Ridge area, was to spud in December. Its interest is 50%.

Other bidders

Spinnaker submitted 26 bids totaling $9 million and was apparent top bidder for only 8 for $3.4 million. Dominion made 22 bids for a total $17 million, coming out on top in only 5 for $6.3 million.

Amerada Hess submitted 20 bids for almost $13.8 million, but was high in only 8 for $6.8 million. Chevron USA Inc. made 12 bids totaling nearly $10 million, with only one apparent success of $237,643. Petrobras America made 11 attempts totaling $6 million, with only 4 high bids of $1.8 million.

Phillips didn't register a single top bid out of 10 offerings totaling $12 million. Conoco also was unsuccessful with its two bids totaling $450,400.

Some of those companies are among the most experienced deepwater operators. An earlier study by energy analysts Douglas-Westwood Ltd. and offshore data specialists Infield Systems reported that Petroleo Brasileiro SA (Petrobras) and Royal Dutch/Shell Group have brought more than 1 billion boe of deepwater reserves on stream during the last 5 years.

Within the next 5 years, it said, Petrobras has 3.3 billion boe of prospects expected to come on stream; BP, 2.5 billion boe; ExxonMobil, 2.4 billion boe; Royal Dutch/Shell, 2.3 billion boe; and ChevronTexaco Corp., 1.5 billion boe (OGJ Online, June 11, 2001).

Marathon registered 14 top offers totaling $28.3 million at Lease Sale **181**, out of 16 total bids for a combined $33.4 million.

EOG and Devon were among the most focused participants in the sale, with each registering three top bids out of four offerings. EOG's top bids totaled $8.3 million out of a cumulative offering of $8.5 million. Devon's top bids amounted to $2.77 million out of total bids of $2.8 million.

Final results of the sale will be announced after the US Minerals Management Service reviews the bids. The agency can reject bids that it deems too low.

Lost opportunity

The National Ocean Industries Association criticized a decision earlier this year by the Interior Department to pare back acreage in Sale **181**. "The acreage that was to be included in Lease Sale **181** was cut by nearly 75% earlier this year, even though the deleted tracts were specifically identified for leasing by the previous two administrations because of their importance to the national energy supply," said NOIA.

The White House decided to cut back the sale after the governor of Florida, the president's brother Jeb Bush, and Florida lawmakers in Congress said they feared the original parameters of the sale might pose an environmental risk to their coast. Lease sale proponents said the sale would not incur any environmental risk because it was at least 100 miles off Florida and was in federal waters.

Even more troubling to NOIA is the fact the area originally designated for leasing is not included in the current administration's Draft Proposed 5-Year Plan for offshore leasing for 2002-07.

Tom Fry, president of the National Ocean Industries Association, said, "Energy is the oxygen that our economy breathes, and it is the fundamental underpinning of the high quality of American life. By removing key resource areas, which can be rapidly integrated into already existing infrastructure from the 5-Year Plan, the administration is denying itself the flexibility necessary to effectively plan for and manage our energy future."

He warned that if the current draft plan is approved, producers could not access the disputed area until 2008 at the earliest.

"Placing energy resources off limits at this crucial time of economic and geopolitical uncertainty is tantamount to planning a crisis," Fry said.

American Petroleum Institute said holding the sale showed the US commitment to developing secure domestic energy sources. "We are pleased by the robust interest in this sale demonstrated by the oil and natural gas industry," said Betty Anthony, API's upstream general manager.

Sen. Breaux predicts eastern Gulf of Mexico sale won't be expanded

By the OGJ Online Staff

WASHINGTON, DC, Oct. 18 -- Sen. John Breaux (D-La.) predicted Thursday that the Bush administration would not expand an eastern Gulf of Mexico offshore lease sale planned for Dec. 5, although a Senate bill would allow it.

A provision in a Senate appropriations bill would permit the originally planned acreage to be offered in Sale **181** (OGJ Online, July 13, 2001) although the House spending bill would postpone the sale.

The administration of President George W. Bush has taken the middle ground: Interior Sec. Gale Norton said acreage in the sale would be reduced to 1.5 million acres from the 5.9 million acres originally planned (OGJ Online, July 2, 2001).

A House-Senate conference committee is due to reconcile the two versions.

Breaux told a meeting of the Schwab Capital Markets Washington research group that there is not enough political pressure being applied to persuade the administration to expand Sale

181 at this point. Also, the Minerals Management Service already has issued a notice for the reduced sale (OGJ Online, July 12, 2001).

The opposition to the sale has come from Florida politicians concerned about the potential of pollution from drilling and exploration. Breaux said Sale **181** would be more than 100 miles from the Florida coast, but "a bunch of folks living in the lap of luxury want [the oil industry] to drill somewhere else. But I'm getting tired of Florida always saying, 'Not off my shore.'"

On other issues, Breaux said the pending economic stimulus legislation in the Senate will not be industry specific, dimming chances that oil and gas producers will get some long-sought tax reform measures (OGJ Online, July 27, 2001).

However, he said Congress might approve an extension of existing tax measures such as the Sec. 29 tax credit for unconventional production.

Breaux said an effort might be made to amend the economic bill to allow exploration and production on the coastal plain of the Arctic National Wildlife Refuge.

"There are ways to bring this up (ANWR). The risk of something happening [an oil spill] is greatly offset by the need to be energy self sufficient."

Breaux predicted Congress would not pass an energy policy reform bill before it recesses for the year, probably just before Thanksgiving. He said many congressmen "are not willing to face up to what's happening" to the nation's energy security.