



## North Slope Drilling Practices – Ever Adapting to New Challenges

M. D. Dunn, Pioneer Natural Resources Alaska Inc. L. R. Crane, BP Alaska; R. L. Thomas, ConocoPhillips Alaska Inc.

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### Abstract

The North Slope Basin is in the midst of a transition from large, high margin fields such as Prudhoe Bay and Kuparuk, to fields that are more technically and financially challenged. The two main operators, BP and ConocoPhillips, have been working on ways to increase the profitability of viscous oil accumulations like West Sak and Schrader Bluff, as well as the eventual development of known gas resources. Smaller Independents are investigating ways to reduce the minimum economic size of satellite fields, while explorers are looking for ways to reduce the cost of exploration wells.

This paper focuses on three themes that command the attention of the drilling professionals in Alaska: downhole technology, surface (drilling hardware) technology, and work processes. The paper also includes a discussion of the following topics:

- The impact of drilling and completion technologies on the development of North Slope viscous oil resources.
- The role of through tubing work, particularly coiled tubing sidetracks, in redeveloping patterns.
- Monetizing smaller fields – strategies that Independents are using to reduce full cycle development costs.
- Growing the pie – ongoing work to reduce the cost of exploration wells with a purpose-built rig.
- Work processes required to adequately plan and execute complex well designs.

### Introduction

Depending on a company's perspective and/or position in the basin, the North Slope could be considered either a mature basin or an immature basin. For new entrants that are working to commercialize smaller more conventional resources, efficiency and simplicity are important drivers of profitability. These companies are attempting to apply approaches that are common of typical land rig basins. For the Majors who are working to commercialize huge, heavy oil accumulations, there is a strong focus on technology

improvement. Both approaches are necessary to monetize as much of the resource as possible and extend the life of the basin well beyond that of the Prudhoe Bay and Kuparuk oilfields.

The history of well construction on the North Slope of Alaska began with relatively simple slant wells in the main fields. Recently, well designs have become much more complex. Extended reach drilling is being used to extend the drainage area of a drillsite. Multilateral and horizontal well designs are becoming much more common. Future developments will include known and yet to be discovered gas fields. As the well designs evolve, there is a realization that technology alone will not achieve the necessary financial results. Consequently, work processes are constantly being adjusted to adequately address these challenges.

Specific technical areas that operators are working include viscous oil developments, multilateral completions, extended reach and long lateral wells, through tubing sidetracks, fit-for-purpose exploration rigs, low impact drillsites, and the optimization of on-pad drilling and production facilities. The non-technical issues that are being worked include the planning process, staffing levels, knowledge sharing, risk management, and integrated services. All of these subjects are briefly discussed in the following sections.

### North Slope Viscous Oil

Viscous oil on the North Slope represents a significant portion of the three Major's (BP, ConocoPhillips, Exxon) reserve base in Alaska, and provides the opportunity of sustained production for years to come. As Figure 1 shows, the viscous oil developments of West Sak in the Kuparuk River Unit, Schrader Bluff in the Milne Pt. Unit, and Orion and Polaris in the Prudhoe Bay Unit are targeting a resource close to 20 billion barrels in place. Similarities, synergies, and differences within these fields have spawned a number of new technologies and several very sophisticated approaches to completion design and sand control.

Although the existence of this resource has been known for several decades, the viscous nature of the oil, coupled with segmentation within the thin sand bodies has made recovery problematic. Attempts to monetize this resource have been marked by starts and stops as the two main operators, BP and ConocoPhillips (formerly ARCO Alaska) have developed their expertise. Early attempts found that conventional wells would not produce above the economic limit for a North Slope well. Later attempts focused on frac-packs and sophisticated sand control schemes. Recent attempts have focused on maximizing the exposure of reservoir to the wellbore and controlling pressure drop at the sandface.

This resource is challenged by low to moderate API gravity ( $14^{\circ}$  -  $22^{\circ}$ ) and cold temperatures, as it is within 2500' of the base of the permafrost. The in-situ viscosity is in the range of 20 – 200 cps. Consequently, as with most viscous oil waterfloods, the poor mobility ratio usually leads to early breakthrough and then steep oil decline rate. On top of these fluid challenges, the sand is friable and unconsolidated and the reservoir is compartmentalized in some areas.

To overcome these challenges, horizontal wells are being constructed with as many as four laterals as long as 7000' each. These wells have demonstrated that economic rates can be achieved and large scale developments can attract the capital needed to convert oil-in-place resources to reserves.

### **Multi-Lateral Well Technology**

Multi-lateral well technology is a powerful technique to develop viscous oil by lowering access costs, increasing production rates, and reducing environmental impacts. Multi-lateral horizontal wells now have a proven track record of being the most efficient well design for accessing these difficult reserves. Successful implementation of a multi-lateral well program not only provides cost and production benefits that could not have been realized with traditional well designs, it also yields significant environmental benefits, minimizing the footprint on the sensitive North Slope landscape.

In 2003, BP drilled the first tri-lateral multi-lateral on the North Slope. By November 2004, a number of tri-lateral wells had been drilled at the Orion, Schrader Bluff and West Sak fields. Shown in Figure 2 is a typical tri-lateral completion in the Orion field. These wells have been able to achieve selective access to the lateral sections. Efforts to isolate selective laterals are being developed. The goal is a modified Level 3 system that delivers TAML Level 5 junction capability at a fraction of the cost and complexity.

In late 2004, BP drilled the world's first Level 3 quad-lateral well at Orion. This well drilled a total of 34,798', with total high-angle footage of 27,743'. The well exposed over 17,000' MD of reservoir in four wellbores.

The future designs are expected to continue to push the envelope of completion designs. The focus continues to be on maximizing reservoir contact with the horizontal laterals. Figure 3 represents a recent well that ConocoPhillips drilled at West Sak, that includes an undulating wellbore as the lower lateral. Figure 4 represents BP's plan for the first penta-lateral well.

### **Drilling Challenges of ERD and Long Lateral Wells**

As the need for extended reach and long horizontal sections increases, the technical challenges of drilling the wells also increase. As Figure 5 highlights, extended reach wells are becoming the norm, including recent wells at Alpine and West Sak, and previously drilled wells at Niakuk. The importance of optimizing drilling mechanics, maintaining proper mud properties, and managing drilling hydraulics becomes critical to the overall success and value of the program. Several of the technology needs for these types of wells are described below.

#### Engineering Software

Torque, drag, and hydraulics modeling has become an important part of the planning and execution phases of many wells. With total horizontal displacement between 10,000' and 15,000' at TVD's of 3300' to 3500', prediction of torque and drag to stay the directional course and optimize downhole equipment is critical. Detailed modeling is done in the planning stages of the well. The models are then constantly and consistently calibrated using actual torque/drag and pressure-while-drilling (PWD) measurements from the rig site. The models are then used to look ahead and adjust the BHA or directional plan as needed.

#### Torque/Drag Reducing BHA Components

Several non-conventional approaches and BHA components are incorporated in the drilling of ERD and horizontal wells on the Slope. Placing heavier pipe in the more vertical hole sections of the hole to push pipe out the horizontal sections has become a common practice. Another practice uses roller subs in drill strings and in liner running strings for drag reduction. Rotary steerable directional systems have become the norm. The rotary steerable systems are run in the surface and/or intermediate hole to achieve a smooth wellbore to minimize torque/drag. Steerable systems are also run in the long horizontal sections to improve directional control over systems that require sliding, and, to extend the

departure limit compared to sliding systems that may leave multiple small doglegs.

### Mud Properties

Maintaining clean mud systems with good rheology is vital to the success of drilling ERD and long horizontal wells. ECD management is particularly important for the shallow TVD horizontal holes due to the lower fracture gradient. Lubricity of mud for torque/drag reduction is a particular area of attention. Water based muds have been historically used on the Slope with good success, utilizing lubricant “cocktails” to minimize friction. There has recently been a move toward oil-based mud systems to improve well productivity. New oil-based lubricants to drive friction factors down even further are currently being investigated.

### Rig Upgrades

The rig equipment that is most commonly upgraded to address the needs of current well designs includes top drive systems, solids control systems, waste handling systems, and rig pumps. Top drives are standard for most rigs on the North Slope. These units are used to better manage torque/drag and hole cleaning issues. Backreaming from TD to either previous trip depths or to the last casing shoe, instead of conventional wiper trips has become a common practice. This has proven to help clean the hole of cuttings beds and smooth out ledges for smoother subsequent trips back to bottom or running of casing or liner.

Upgrades to solids control equipment to lower overall mud costs and minimize drilling waste are another area of attention. Injection of drilling waste is a standard practice on the Slope, with all operations employing closed loop systems. Injection is accomplished either through annular injection in existing wells on a pad or in designated Class 2 disposal wells. Various methods of crushing solids to a size acceptable for injection have been tried including conventional ball mills, hammer mills, and ultra-sonic units. The most common method is a conventional ball mill.

Proper sizing of rig pumps for good hole cleaning is also critical for success. As measured depths and hole angles have increased, the old rules-of-thumb on pump sizing have proven inadequate. One drilling contractor has designed and constructed a pump module that can be deployed for those hole sections or wells requiring extra pumping capacity, then “unplugged” for hole sections or wells not requiring the additional capacity.

### **Through-Tubing Sidetracks**

Coiled Tubing Drilling (CTD) is a leading low cost

reservoir access technology and has enjoyed great success in the giant Prudhoe Bay Field. Since 1994 a continuous two+ rig CTD program has drilled 500 sidetracks and added over 230 MMBO in reserves. The pace continues at over 50 sidetracks per year with penetrations now in virtually every field on the North Slope.

CTD's key advantage for maturing fields in Alaska has been the ability to provide a step change 30% reduction in sidetrack cost. This technology has increased the hopper of opportunities allowing access to previously uneconomic pockets of undrained oil. Savings are achieved by sidetracking below existing tubing to reduce de/recompletion cost, short radius drilling capability to get to targets sooner, ability to drill efficiently with surface pressure (well suited for UBD) or in lost circulation environments, and flexibility with completion designs to maximize production and allow future sidetrack opportunities. To get there, continuous innovation and commitment has been required. For example, Alaska is on its 7<sup>th</sup> iteration of rig design to maximize efficiency, and state-of-the-art small bottomhole assemblies have been modified and improved to the point of satisfactory reliability.

However, CTD has its limitations and is not a panacea for areas where rotary drilling has had troubles. The primary factors for a successful CTD program are: 1) a high cost rotary rig environment, 2) relatively stable formation, 3) use of proven tools, and 4) management commitment. When properly applied, CTD can provide substantial cost savings and increase reserves recovery.

CTD sidetracks typically consist of a short build section followed by 1500 to 2500 ft of horizontal lateral. The current North Slope record CTD horizontal length is 3115 ft in a Milne Point well. A world record TD of 17515' was reached at Niakuk in 2004. There are a wide range of proven through-tubing CTD completions techniques (Figures 6-8) ranging from fully cemented and perforated liners to multilateral slotted liners<sup>1</sup>.

An innovative technique of creating lower cost multilaterals but retaining the ability to 100% line each leg has been achieved by an aluminum kickoff billet with 1-in. ID integral to the top of a slotted liner (Figure 8). In this scenario an initial sidetrack window is milled from the parent wellbore and horizontal lateral drilled to TD. A slotted liner of prescribed length with aluminum kickoff billet on top is run in the hole to TD. The aluminum kickoff billet is placed outside the original window in openhole at the desired depth to create the second lateral. A bent motor drilling BHA with rounded PDC bit sidetracks off the aluminum billet and drills the new lateral to TD. This process can be repeated from numerous aluminum top liners. The final lateral is lined from TD all the way back into the parent wellbore.

Advantages include:

- A low cost open hole sidetrack technique
- Positive guidance of the liner into the second lateral leg.
- All multilateral legs are completely lined with the exception of a ½-in. gap between the aluminum kickoff billet and adjacent slotted liner.

To date, three separate Kuparuk field wells have successfully received multi-laterals with this technique. Excellent production rates from the wells suggests that the laterals are open and performing at or above expectations

### Smaller, Lighter Exploration Rig

One of the areas that several explorers are investigating is the impact of rig size and rig design on remote exploration well costs. One such company is Pioneer Natural Resources, a Dallas-based Independent who recently entered Alaska with the drilling of 3 wells in the Beaufort Sea in the winter '02/'03 drilling season.

Subsequent to a discovery at one of these wells, Pioneer began to build a well-rounded exploration portfolio via several State and Federal (BLM) lease sales, and farm-in arrangements. While its exploration staff was assembling this portfolio of prospects, the drilling department began researching the cost drivers of remote exploration wells. The engineers and wellsite supervisors soon realized that a significant share of the costs of an exploration program fell into the category of "drilling logistics", including the cost to move the rig to and from the exploration site and the cost to support such an operation. Pioneer also realized that the rig size and design, choice of move methods, and definition of "necessary" requirements had a huge impact on well costs.

Beginning in late 2003 and through all of 2004, Pioneer searched for companies, designs, and approaches that could help reduce the cost of drilling straight, relatively shallow (<11,000') wells on the North Slope of Alaska. Within a few months into this fact-finding stage, it was apparent that the cost difference between the use of fit-for-purpose equipment and the cost of using existing rigs and methods was the difference between a viable, long-term exploration program, and one that was sensitive to individual prospects and be marked by starts and stops. Given that the North Slope was considered an under-explored basin that would require many wells to evaluate, Pioneer committed the financial and human resources to work the technical, commercial, and contractual issues necessary to support a rig commitment.

A team was assembled that included a Canadian rig contractor, an Alaskan rig contractor, Alaska-based service companies, and Pioneer engineers and wellsite supervisors. The team was charged with recommending a complete solution to the problem, including:

- Rig design and capital cost estimates.
- Manpower and skillset requirements for the specific operations.
- Definition of "must have" versus "nice to have" equipment and personnel.
- Detailed rig move costs based on number of loads, sizes, move vehicles required, etc.
- A contractual arrangement that resulted in a win-win for operator and contractor.

As of December 2004, the team had assembled a cost estimate and was developing a business case for the rig. Several of the more important design considerations and conclusions of the study are described below:

- A simple rig design, which breaks down into less than 30 truckable loads, can be used to drill 95% of the exploration wells on the North Slope.
- The "optimal" rig design is one that sacrifices drilling efficiency for rig move and overall cost efficiency.
- Perfection is cost prohibitive. A sustainable exploration program requires a commitment to less equipment and personnel than a perfect well seeking perfect information requires.

Pioneer is certainly not the only operator who has investigated the benefits of a purpose-built rig in Alaska. ConocoPhillips is currently studying better suited rigs and less expensive ways to mobilize exploration rigs on the North Slope. BP commissioned a study of a light automated drilling system in the late 90's. The most notable effort was one that Marathon commenced about five years ago which led to the construction of a purpose-built rig for the Kenai Peninsula.

As reported in a recent publication<sup>2</sup> and shown in Figure 9, Glacier Drilling No. 1 is a truck-mounted rig owned by a Marathon subsidiary and operated for Marathon by Inlet Drilling, a local drilling contractor. Marathon recognized that the basin needed a better suited rig, and took the initiative to design, fund, and build a rig specific for their fields on the Kenai Peninsula. The rig has proven to be a success as it has consistently outperformed the other rigs in the area. Marathon was also able to show that there is in fact a relationship between well costs and well activity as they have drilled many more wells than conventional rigs and cost structure would support.

## Simpler On-pad Drilling and Production Hardware

In addition to the challenges of reducing exploration costs, several Independents have been looking at simpler on-pad drilling and production facilities as a way to reduce development costs. The idea is to utilize 30 years of North Slope operating experience, but allow the drilling and facility professionals to start with a clean sheet of paper. Several companies including Pioneer, Armstrong Oil and Gas, and Kerr McGee are studying rig layout designs, drillsite production facilities, and the inter-relationships between on-pad production hardware and drilling hardware to deliver equivalent drilling and production functionality at a lower capital cost.

It can be argued that traditional North Slope production facility designs and field rigs are artifacts of high rate, high margin fields like Prudhoe Bay and Kuparuk, or, artifacts of less integrated design teams that were common 20 years ago. As the photograph in Figure 10 shows, traditional North Slope field rigs are designed to facilitate quick well-to-well moves given the physical constraints of the production hardware such as above ground flowlines. If a cantilevered rig were not required, or well rates were such that slower rig moves were acceptable, a less expensive rig could be used to drill the wells.

An example of one of these efforts is a series of studies commissioned by Pioneer to understand the tradeoffs between various rig designs and different wellhead, flowline, and manifold configurations of the on-pad production facilities. One study looked at the hardware layout of an offshore island over a range of different wellhead arrangements including the traditional single row of wells, and a “wellbay” concept with multiple rows of wells. One of the deliverables of this study, as shown in Figure 11, was a 3D CAD model with a conventional two-sided land rig and a sub/mast that skidded in two dimensions over an offshore wellbay.

## Mobile Platforms for Remote Onshore Operations

Anadarko Petroleum has recently demonstrated the use of a reusable Module Platform to minimize the impact of a remote drilling operation on the North Slope<sup>3</sup>. The modular platform was installed on the Hot Ice No. 1 location south of the Kuparuk field beginning in January 2003 and was removed in March 2004.

Anadarko, as other explorers on the North Slope, was faced with the challenge of finding, delineating, and developing a field in a remote area of the North Slope, in a manner that limited the impact and honored the seasonal restriction on tundra travel, but also proved to be commercially viable. The solution was a set of legs and platform sections that could be transported,

assembled, and disassembled without the need for ice roads.

As Figure 12 shows, the platform is constructed in modular sections that are fitted together much like Legos<sup>TM</sup>. The components consist of legs, lower sections shaped like long, shallow buckets, and deck sections that fit over the buckets. The components are sized to be moved by conventional semi-trailer trucks and constructed out of aluminum to facilitate handling and assembly.

The prototype installed on the North Slope was sized to support a small mining-type rig and rig camp. The main working platform was assembled with 16 modules to cover an area of 100' X 100'. The rig camp platform was built with 5 extended sections to cover an area of 62.5' X 60'. The design proved to be viable as it was constructed in harsh arctic conditions. The leg and load tests proved to be beneficial for future applications. It is believed that the Mobile Platform and well conductors can be installed in subsequent applications in a total of 12–15 days, including expected weather events.

The Hot Ice No. 1 well operation established that the Onshore Mobile Platform can be installed without having to build expensive ice roads. The platform proved to be suitable for conventional oil and gas drilling operations, although new rig designs should consider the benefits of shedding weight and minimizing the rig footprint. The platform is also suitable for use as a production platform or as a pipeline pump station platform where gravel use is problematic and/or access roads are not allowed.

## Work Processes

In addition to technology initiatives and cost effective equipment and designs, several companies have been looking at the internal processes used to address the ongoing challenges of drilling on the North Slope. ConocoPhillips in particular has been studying the planning processes, staffing levels, and knowledge sharing techniques to deliver the next generation of cost reduction. Independents are investigating the framework for risk-management decisions as well as the benefits of integrated services.

### Planning Process

As well complexity increased, ConocoPhillips recognized that the planning process needed to adapt. Several years ago it was realized that the old planning paradigms could not handle the increased amount of data, information, and knowledge that needed to be passed between the client organizations (geologists, reservoir engineers) and the drilling department. This resulted in constantly changing well designs, continuous

iteration of well objectives, and a lack of ownership by the client. These inefficiencies in the planning process led to poor rig efficiency and higher well costs.

These inefficiencies prompted a shift to a defined, gated planning process modeled after the Front-End-Loading (FEL) process used by facility engineers. From the outset, a multi-disciplinary team was created to push the well through the various phases and gates of FEL, as shown in Figure 13. Each phase was marked by an approval gate where approval by Management was required to continue to the next phase. The process resulted in several deliverables, including the FEL3 document which then served as the design basis for the well.

This process has delivered greater accuracy in the basic well information, helped to lock down the basis of design, and minimize the number of iterations of well design and objectives. The results are borne out by the drilling statistics – problem time is way down, “train wrecks” are very rare, cost per foot is down, and client organizations are engaged in the process.

#### Staffing Levels

As the well designs became more challenging, there was recognition that the staffing metrics for simple wells were no longer applicable. ConocoPhillips' Drilling Management recognized that staffing levels had to be increased, both in the office and on the rig. As a result, dedicated technical experts, such as torque/drag modelers and drilling fluids specialists, were added to the drilling department. Where one drilling engineer might have watched one rig in the past, it is now common for two drilling engineers to be assigned to one rig for the more complex projects. One engineer will deliver a final well plan to the rig, then be on point to support the rig while it is executing his well plan. While that well is being drilled, the second engineer will be finalizing his well plan to be executed upon completion of the current well. This “leap frogging” of engineers has resulted in better, more detailed well plans and consistent support of the rigs.

A dedicated “Planning Drilling Engineer” was also added to work with the Business Units on long range plans and large development projects. This person is thinking about projects 6 months to 3 years in the future and making sure the goals of the business unit can be delivered by the drilling professionals.

At the rig, the staffing has increased from one Drilling Supervisor to one day and one night Supervisor. A field-based drilling engineer is also assigned to directly support the rig. The role of this engineer is to serve as liaison between the Drilling Supervisors and the town-

based Drilling Engineers on all technical issues. He updates the torque/drag and hydraulics models using real-time values collected by the Driller, then projects forward to make recommendations to the Drilling Supervisor and Drilling Engineer. This role has proven critical to the success of the longer reach horizontal sections. In addition to these staffing adjustments, a dedicated Engineering group has been created to address department-wide issues. These issues may be technical in nature (i.e. close approach and survey management protocols) or process oriented (i.e. development of cost estimating models or management of planning processes).

#### Knowledge Sharing

Another key to successful planning and execution of complex wells has been the creation and maintenance of knowledge sharing networks. Both internal and external networks are used to apply leading edge technology and benefit from lessons learned.

A good example of an external network is the one between BP and ConocoPhillips. The two companies are operating similar fields in close proximity, and as a result, drill wells of similar designs. Sharing lessons learned between the companies has become an expectation for all drilling professionals. Several types of exchanges are common, from formal peer assists, to informal quarterly technical exchanges, to one-on-one discussions of specific drilling incidents.

Internal technical networks are also used to capture and disseminate the lessons learned of past operations. These networks include technical conferences, web-based databases where lessons learned are logged and cataloged, and world-wide technical groups where an engineer can send out an email to a wide group of technical experts.

#### Risk Management Framework

One of the areas that several Independents are investigating is the framework or context of risk management decisions. This relates to the theory that high rate, high margin fields lead to one set of optimal drilling and facility designs, while low rate, low margin fields lead to a different set of optimal designs.

As an example, production facilities that process very high oil rates can justify the expenditure of additional capital on custom-built, redundant, and/or top-of-the-line equipment to achieve near 100% up-time. On the other hand, low margin fields rarely can support the additional cost to marginally improve the uptime, from say 97% to 98%.

The same theory can be applied to the spread day rate of a land-based drilling operation. For high rate or high tech operations where the spread dayrate may run \$100,000 - \$120,000, the additional cost of “insurance” to prevent rig downtime can be justified. On the other hand, the justification for redundant equipment or multiple specialists may rarely be justified if the dayrate is closer to typical land-rig spread rates of \$30,000 - \$50,000 per day.

It is believed that a better understanding of the cumulative impact of all the decisions that drive spread dayrate, and the affect that well rates and margins have on the trade-off analysis, may lead to rig costs and well costs that are more typical of lower 48 and Canadian operations.

### Multi-Disciplined Services, Remote Support

Two areas that several companies are looking at is the concept of remote support and multi-disciplined support personnel (or multi-disciplined service company). These investigations are driven by the very high cost to place a person on a North Slope drilling rig. It has been estimated that the cost to transport, train, feed, house, pay, and support a person on the North Slope is close to \$250,000 per year. A single position, working 12 hour tours and a bi-weekly rotation, costs about \$1MM per year.

Given this high cost of on-site personnel, operators and service companies alike are looking at ways to reduce the numbers of individuals required to support a drilling or production operation. Companies are starting to distinguish between knowledge workers and workers required to move equipment (manual workers). Ways to reduce on-site headcount include the following:

- Cross-training of workers to allow one individual to cover more than one specific area of expertise.
- Use of networks and communications (video, web-based) to provide technical support from afar.
- Remote operations centers with high-tech, high-speed communications designed to replicate the office of a wellsite support technician (e.g. directional driller).

### **Conclusions**

The North Slope has plenty of challenges to offer the drilling professional. New technologies in multi-lateral completions and coiled tubing sidetracks are constantly

being developed. Drill rig sizing, technology, and mobilization methods command the attention of the explorers. Work processes continue to adapt to more complex well designs and lower margin fields as companies realize the legacy systems of Pruhdoe Bay are no longer applicable.

Whether the circumstances are related to downhole technology, surface technology, or people and processes, solutions continue to adapt to the next set of challenges.

### **Acknowledgments**

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### **Nomenclature**

<i>BHA</i>	=	<i>bottomhole assembly</i>
<i>cp</i>	=	<i>centipoise</i>
<i>BLM</i>	=	<i>Bureau of Land Management</i>
<i>CAD</i>	=	<i>Computer Aided Drafting</i>
<i>CTD</i>	=	<i>Coiled Tubing Drilling</i>
<i>ECD</i>	=	<i>equivalent circulation density</i>
<i>ERD</i>	=	<i>Extended Reach Drilling</i>
<i>EMW</i>	=	<i>equivalent mud weight</i>
<i>FEL</i>	=	<i>Front-End-Loading</i>
<i>HSE</i>	=	<i>Health, Safety, Environmental</i>
<i>PWD</i>	=	<i>Pressure while Drilling</i>
<i>TAML</i>	=	<i>Technical Advancement of Multilaterals</i>
<i>TD</i>	=	<i>total depth</i>
<i>TVD</i>	=	<i>true vertical depth</i>

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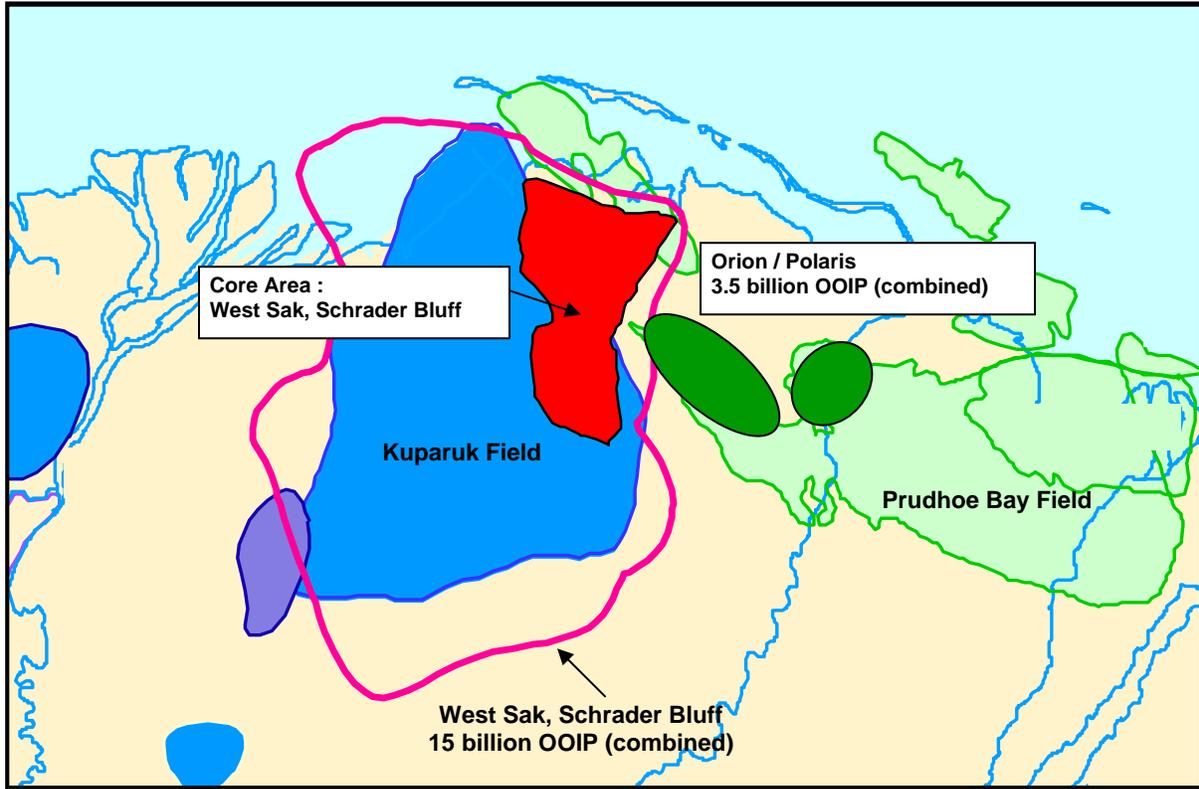


Fig. 1- Viscous Resources on North Slope

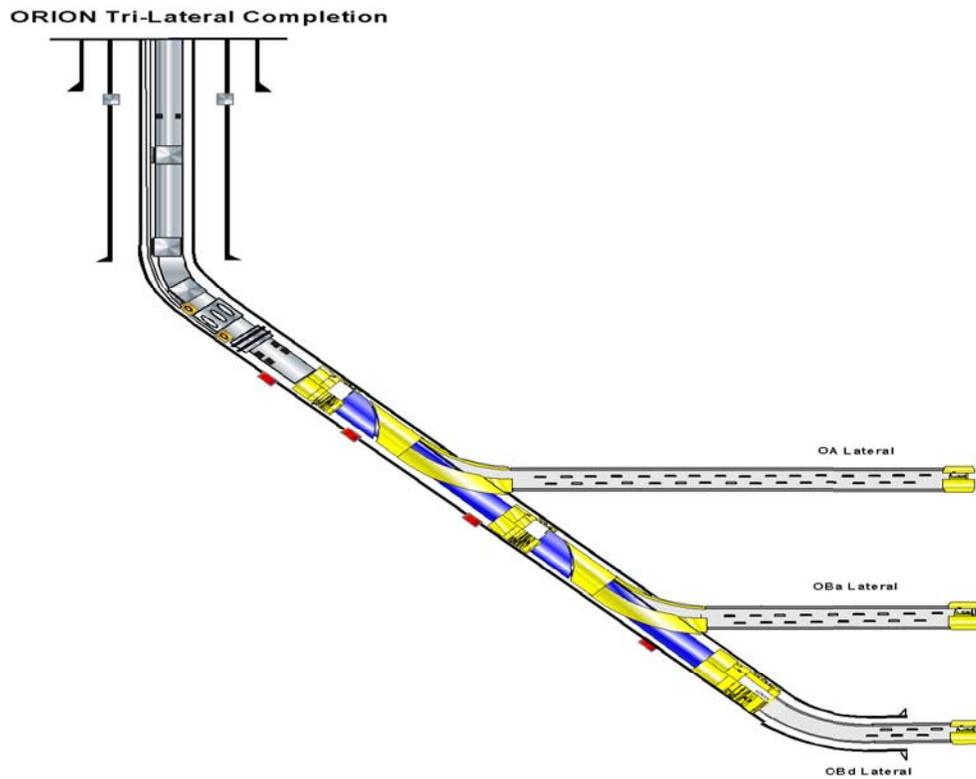


Fig. 2- Tri-Lateral Completion at Orion

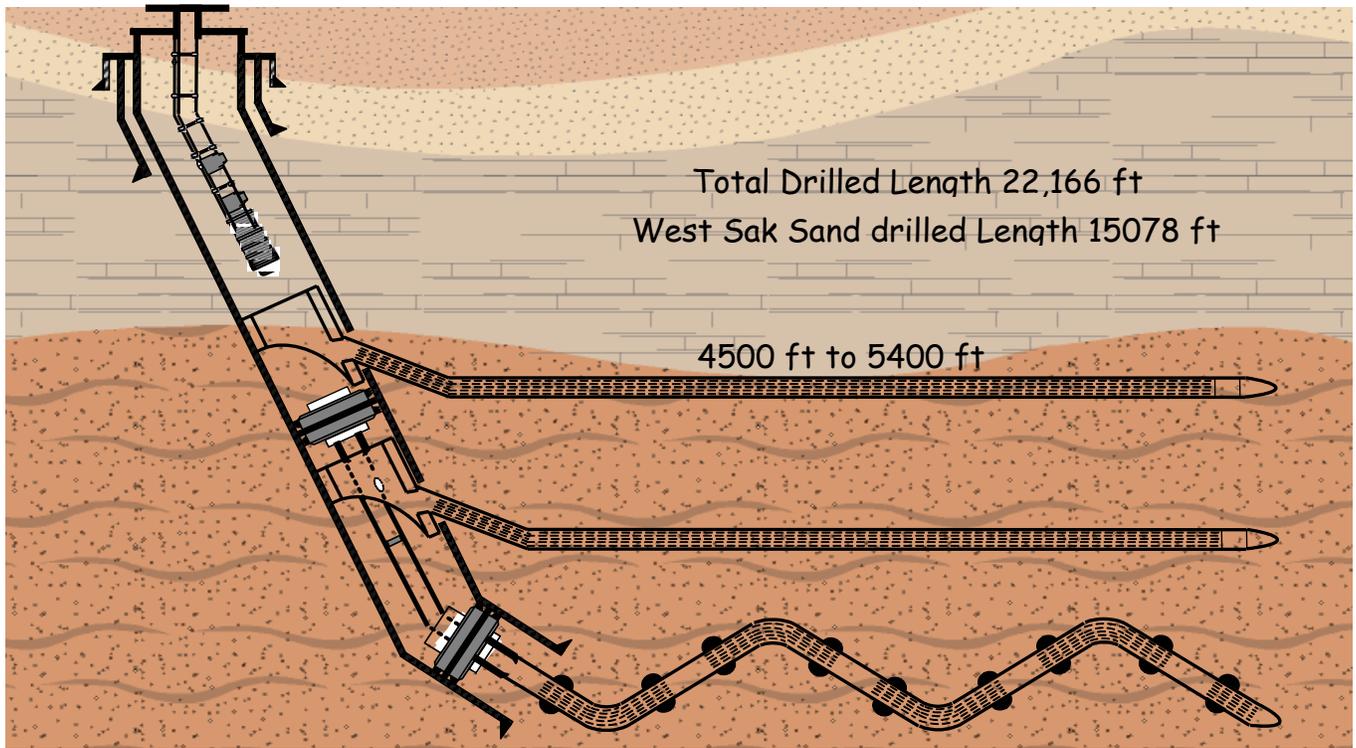


Fig. 3 – Tri-Lateral with Undulating Lateral at West Sak

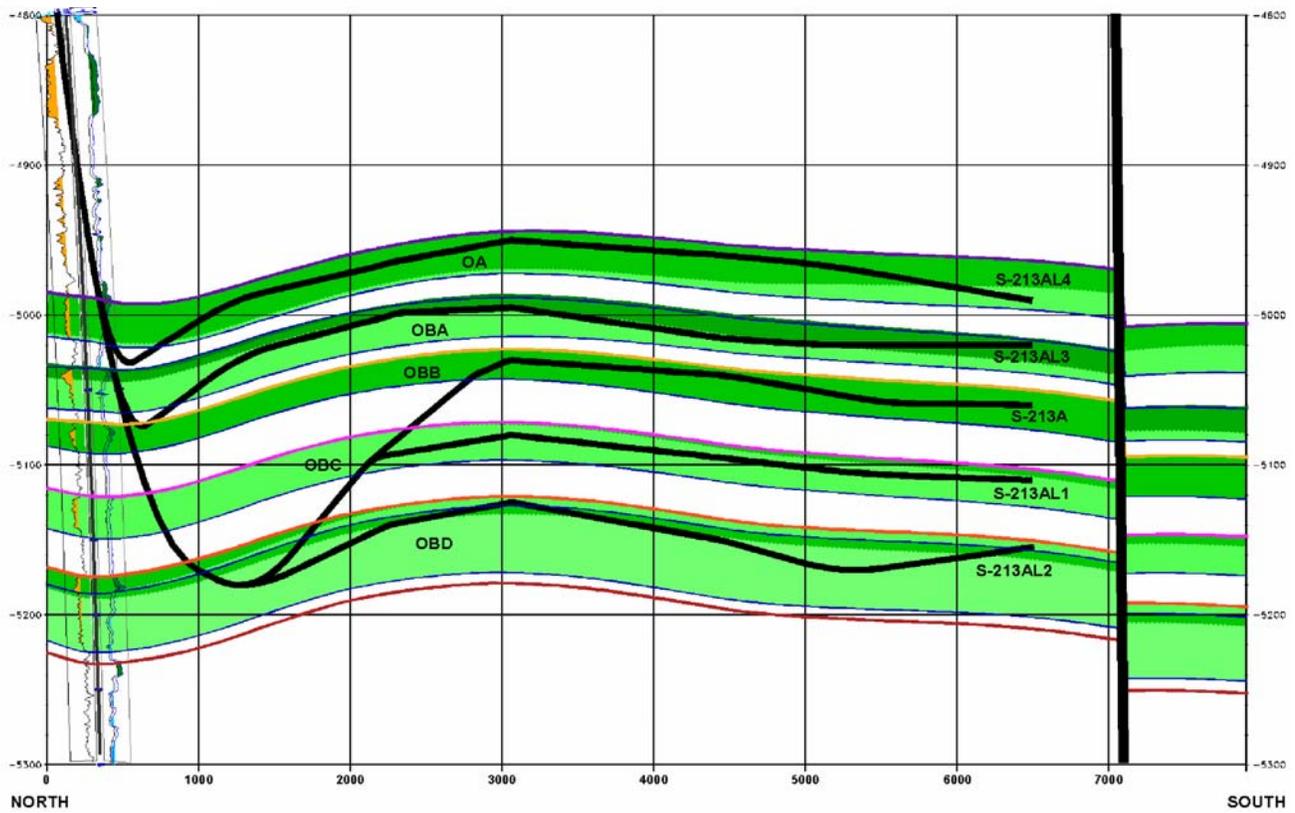


Fig. 4 – Future Well Design for Viscous Oil – Penta-Lateral Well

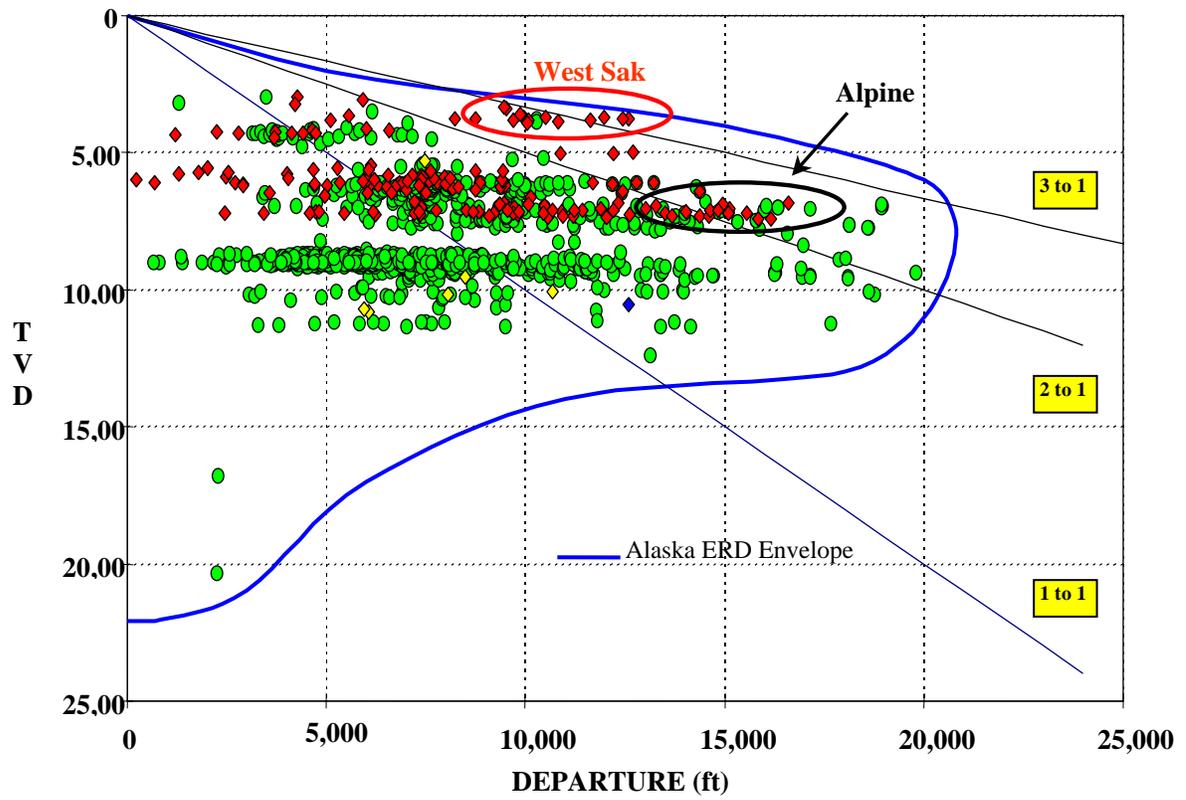
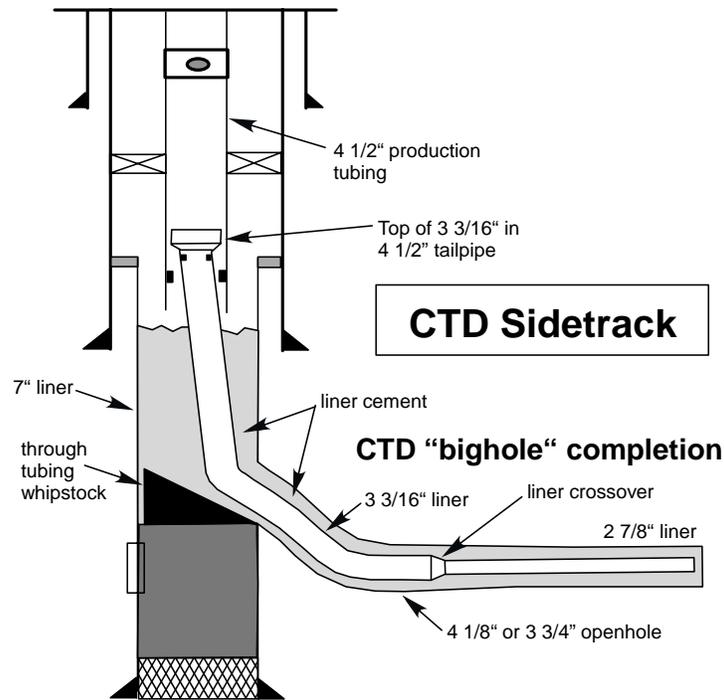
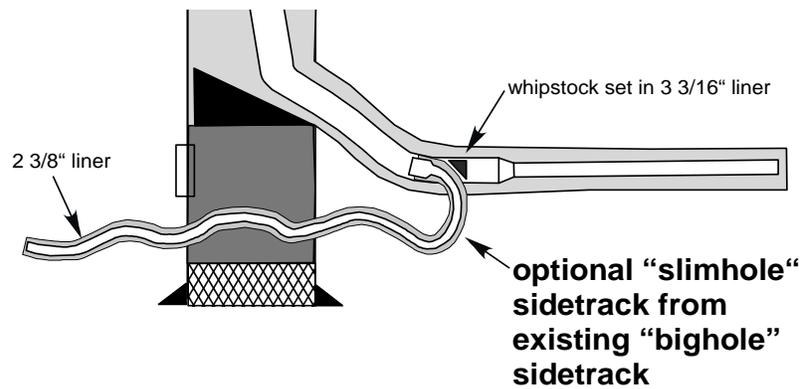


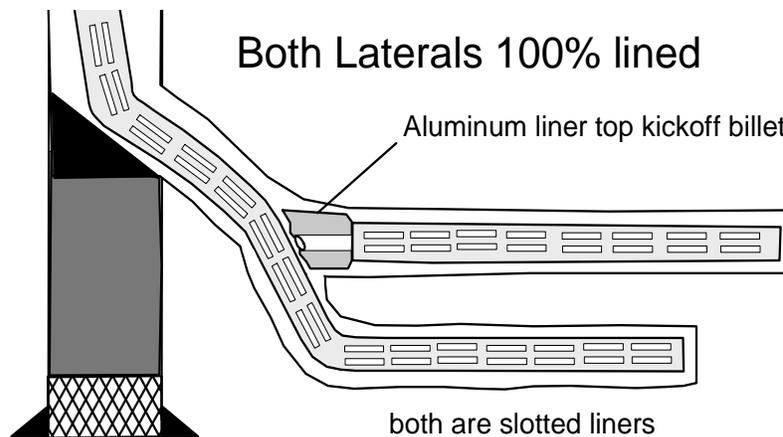
Figure 5 – Alaska ERD Wells



**Fig. 6 – CTD "Bighole" Sidetrack Completion**



**Fig. 7 – CTD "Slimhole" Sidetrack Option**



**Fig. 8 – Aluminum Liner Top Kickoff Billet.**



COURTESY OF MARATHON

**Figure 9 – Marathon’s Glacier Rig No. 1** (Photo courtesy of Marathon Oil Co.)



**Figure 10 – North Slope Cantilevered Field Rig** (Photo Courtesy of ConocoPhillips)

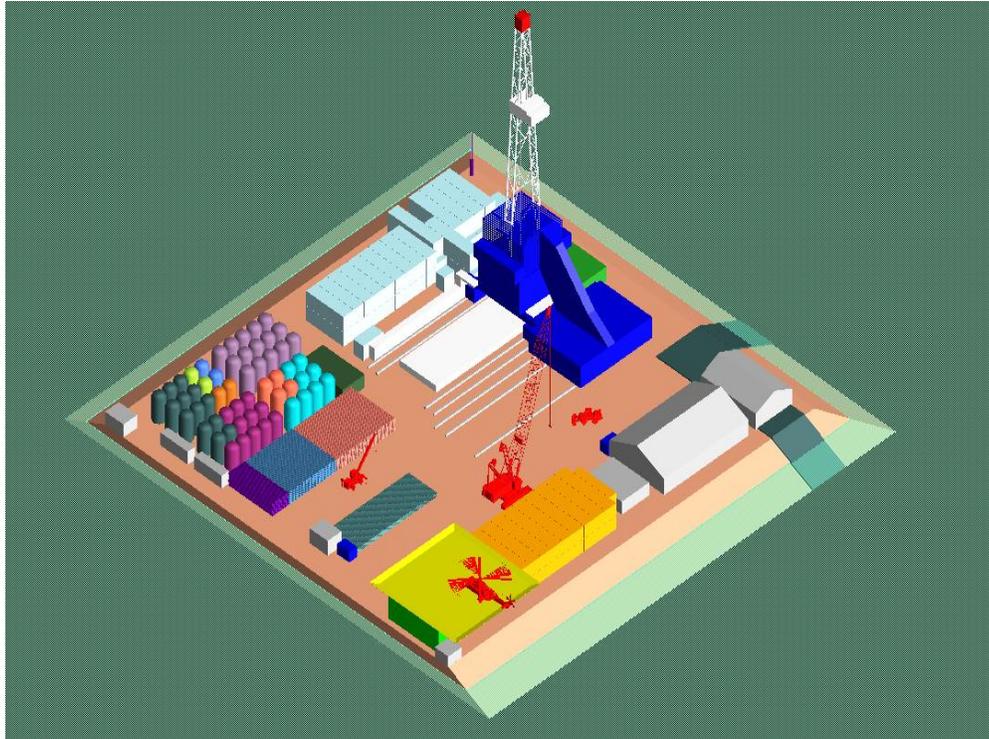
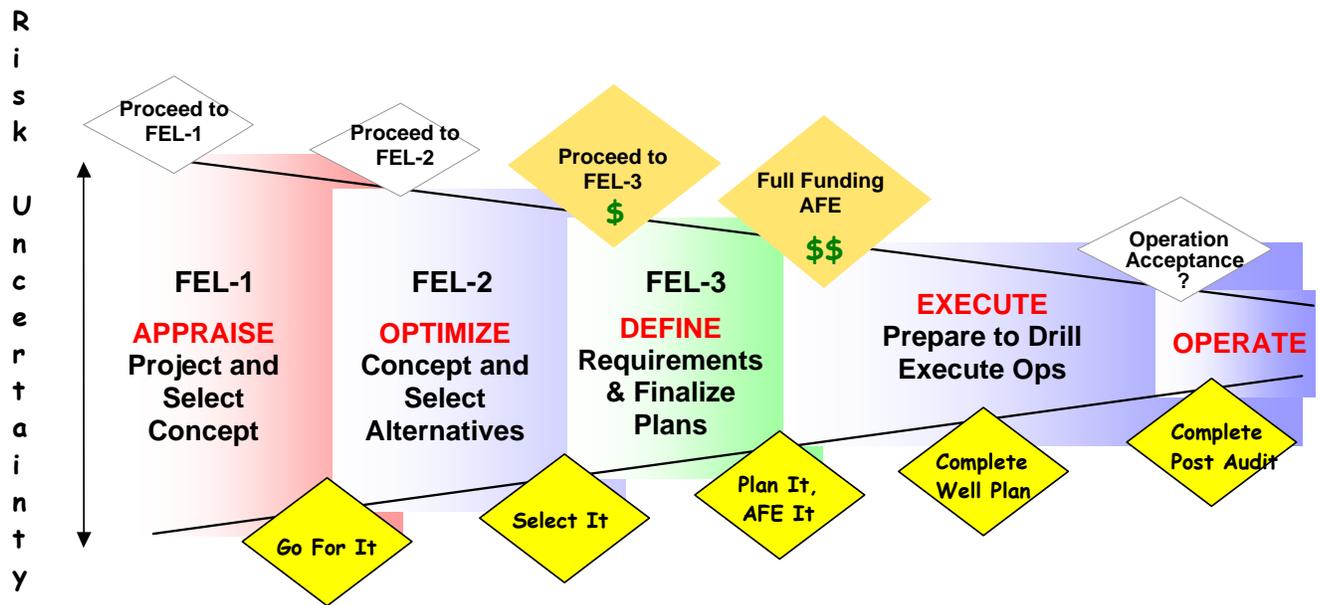


Figure 11 – 3D CAD Model of Offshore Island layout and Skid-Mounted Rig



Figure 12 – Arctic Platform on North Slope (photo courtesy of Anadarko Petroleum)



	FEL-1	FEL-2	FEL-3	Prepare to Execute	Execute
<b>Value Adding Process</b>	Lessons Learned	Zero-based planning Risk, What-if planning	Probabilistic Cost Estimating	Drill Well on Paper Technical Limits	Post Audit (add value to future wells)
<b>Value Assurance Processes</b>	-Define Team Make-up -Establish Clear Goals	-Multi-discipline Peer Assist	-Team, Peer and Supervisor Review		-Superb Communication
<b>Approvers</b>	Asset Supervisor	-Asset Supervisor -Decision Board	-Decision Board -Management	Drilling Team Lead	Drilling Team Lead & Team

Figure 13 – Front-End-Loading (FEL) Applied to Well Planning