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# From Reservoir Through Process, From Today to Tomorrow—The Integrated Asset Model

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## Abstract

Simulation technology from reservoir through process facility has advanced so much, that field development strategies can be developed within a new systematic workflow, using existing applications from many E&P departments. Detailed production data from many sources can be used within simulation models to give a good representation of future field wide behavior. In this paper a fictional case study of a reservoir that has been producing for some 12 years will be examined. The wells are all producing into a sub-sea manifold and then tied back via a 60km flow line and riser system. The reservoir is in severe decline with field production well below the original design capacity of the production system and surface facilities. Hence, further development options are being investigated for this asset. A new, nearby, reservoir has been discovered. A reservoir simulation model has been constructed for the new discovery. This second reservoir is a gas condensate system, much smaller than the existing reservoir and located 90 kms to the east. The current development plan shows six wells drilled and brought into production over an 18 month period. Reservoir 2 is a marginal development, the viability of producing this reservoir will depend on quantification of the reservoir uncertainty and finding a cost effective development strategy with existing processing facilities. The Business Development Team has suggested a number of possible options for developing this new reservoir; Option 1 involves tying in the new reservoir to the existing sub-sea infrastructure. Option 2 is to install a complete new flow line from the sub-sea template of the new reservoir and run this directly to the existing platform. But how do these options effect reservoir management and surface facilities performance? Evaluation is achieved by constructing an integrated asset model of the entire field, allowing the reservoir through facilities interaction to be evaluated in detail.

## Introduction

Everybody wants one, but nobody has one. The Integrated Asset Model (IAM) has been the pursuit of many Oil & Gas companies in the last decade. Finally, the industry shows signs of achieving the prize of the IAM under the banner of the "Digital Oil Field". From reservoir to facility and from today to the end of field life, the IAM promises multi-discipline answers. This paper is intended to serve as a road map for the development and adoption of the IAM into the culture of Oil & Gas Operating Companies. Years from now, new graduates to the industry will have IAM training as part of their Oil & Gas company inductions and they will use the technology to solve many pains from production optimization, operations surveillance & asset planning to uncertainty analysis and fiscal determinations. However, existing work flows and applications will have to change. The questions are by how much, by when, at what cost, and with what benefit? Multiple vendors must collaborate to create cross-discipline compatibility and Oil & Gas companies will need to pilot, evaluate and recommend changes to the resulting IAM technology, which will evolve through a number of rounds of deployment. Collaboration that has never been seen before in the Oil & Gas industry will need to be established if suggested improvements such as $30mn per year per asset for optimization and over $90mn per year in improved Net Present Value (NPV) from planning solutions can be routinely exploited within the average asset. What is needed is a road map for the adoption and development of these IAMs, along with a statement and agreement of the principles that govern the IAM.

## Posing the Problem

Imagine a gas plant that can automatically tune itself to stability. Imagine the same gas plant predicting a problem twelve hours in the future. Imagine a pipeline control system asking the Operations team for a pigging run. Imagine a reservoir telling the Gas Contracts team that it can't make those nominations. Imagine the facility telling the Business Development team that the proposed tie-back in year three will cause compression problems at the current reservoir decline rates. Now, finally, imagine all these solutions executed from a common suite of software applications, those favored by each discipline and connected up from a number of remote locations. The evolution of integrated asset teams has been underway for some years. The quiet revolution of the associated asset applications has just begun. The key question is; can an integrated asset model be formed that utilizes the trusted domain applications, of the Oil and Gas Company today, and can that model be used by all disciplines in a sustainable, maintainable way with a low total cost of ownership?

The chosen domain applications from reservoir through process facilities must be able to play a part in the IAM such that there is maximum discipline involvement ensuring the IAM becomes a sustainable, and field wide approach. The IAM must be able to solve a large number of Oil and Gas production issues and even determine a few that the asset does not even know about yet!

## Model Based Asset Management

Reservoir, production and facility simulation has developed far in the last thirty years. Oil and gas simulation, in these disciplines, has become robust, accurate, easy to use, and boasts over twenty thousand users worldwide, mainly in reservoir, petroleum, production or facility engineering roles. A number of Oil and Gas companies that hold a modeling culture close to their corporate values have extended the use of simulation into Operations and Business Development disciplines. It is here that the true value for the 'Digital Oil Field of the Future', the 'Smart Field' or the 'iField' lies. A fundamental assumption in the Digital Oil Field is the ability to set up and extend the use of one discipline's knowledge as a system of boundary conditions into another discipline across the entire asset. These boundary conditions are automatically known and passed across the discipline borders, in essence breaking those borders down through automated technology. An example would be the knowledge of compression capacity constraints in the process facilities communicated to the production and reservoir communities in an automated way such that the constraint is updated when different operating and field development strategies are formulated.

The Oil and Gas field of today is a complicated system which requires a high degree of discipline interaction and dynamic iteration that make it impossible for the human mind to control and optimize both technical and business parameters. The good news is that Oil and Gas companies have been successful in re-organizing operating fields into 'Asset Teams' that attempt to breakdown cross discipline silo human behavior. The bad news is that while technology has developed at a rapid pace with new, faster, enhanced algorithms for solving all kinds of discipline solutions, technology has not taken account of the new workflows required and the cross-discipline interaction that is demanded from today's asset. Modeling & simulation technology has advanced so much that the most complicated reservoir mechanics can be modeled with ease, deviated wells are simply analyzed, transient flow line response is known ahead of time and the operation of compressors can be pushed to the surge or stonewall limits with some confidence. All this confidence comes from the accuracy and reliability of discipline simulation tools that are routinely used. However, when it comes to full field analysis the industry tends to discard all the knowledge and money invested in these discipline models in favor of spreadsheet models with faulty assumptions and extremely suspect calculations, with almost no update and match to reality. And there is more bad news; at least as many asset operating and development decisions are based on these spreadsheets as are decisions derived from the discipline simulation models. The authors of this paper advocate the development of 'Model Based Asset Management' techniques and the relegation of spreadsheet models to reporting and the development of supplemental methods; a place where spreadsheets truly belong.

Typical questions that Asset Teams need to ask for the development and implementation of model based asset management are shown in Table A-1. The Oil & Gas industry can only achieve the answers to these kinds of questions through integrated discipline workflows and the development of model based asset management techniques.

## Oil & Gas Industry Background

The Oil & Gas Information Technology sector alone is estimated to spend more than $2 billion annually on hardware, software and services, a figure that does not take into account networks and communication infrastructure. The Oil & Gas industry is unusual in its high degree of dependence on information technology in order to meet its business goals and in the enormous quantities of data that it generates and processes. Alongside these IT challenges, the industry is addressing the changes required due to new and evolving work practices that the popularity of inter-disciplinary asset teams has brought about. The oil industry currently spends about 3% of its total revenues on information technology. Despite this level of spend, a number of published surveys show that the industry gets poor value for money. The effects of technology, though, cannot be denied. Figure A-2 is a graph from The Norwegian Petroleum Directorate that shows the recent trend for the Norwegian Continental Shelf to increase Oil & Gas production without increasing significant total capital expenditure. Much of this capital avoidance is directly attributable to the use of information technology, computer simulation and increasingly intelligent operations technology for enhanced and extended recovery.

However, it is not all good news, as the Norwegian Expenditure might imply. There is a problem in providing IT systems to support evolving work practices. Due to the length of time applications take to develop, there is a lag between a change in working practices and the provision of IT systems to support the practices. For a long time, Oil and Gas companies have been unable to reap the benefit of new technology to cut costs. Bought-in applications, as well as those developed in-house, use disparate data formats, different database systems, a variety of application interfaces and are unable to intercommunicate without the production of expensive, bespoke application interfaces.

Suffice to say, the E&P industry will strive to spend more money on information technology to achieve capital deferment and support evolving work practices. E&P is predicted to increase it's overall software spend by roughly $220mn a year for the next three years as emerging uses for modeling technology are found in the Operations and Business disciplines, outside of the traditional use in Engineering. As the Norwegian sector example shows, new and more efficient technology has become the key to growth among Oil and Gas companies and can often explain the lack of growth in their required capital budgets, from the simple equation of software technology costs less than steel. In 2002, oil companies cut capital budgets to focus on improving their balance sheets at a time when low prices and high drilling costs did not justify heavy spending. Now, even with Oil and Gas prices high, with an eye to improving return on capital employed, Oil & Gas companies are not spending much more. Capital expenditure levels have not returned to the levels of pre-2000. Information technology is part of the reason that they don't have to. A recent study by Cambridge Energy Research Associates (CERA)[1] found that so-called 'digital technologies' have the ability to increase world oil reserves by 125 billion barrels in the next five to 10 years; citing that not only do they improve recovery efforts but they also reduce costs:

"Demand will grow by 900,000 barrels-of-oil equivalent a day over the next few years," said CERA President Joseph Stanislaw during a recent conference. "Companies are looking at new ways to restructure themselves. New technology means companies don't need to drill as many wells to find oil."

Figure A-2 shows the type of innovations that have happened in technical, managerial and information technology in the last decade. Major petroleum engineering advances in well & tubing techniques along with ship based production, multi phase flow, integrated production system models and deeper, smaller & more contaminated reservoirs, are at the forefront of the technical revolution. Removal of significant cost layers with mergers and risk sharing through alliances, together with multidiscipline parallel engineering teams have become standard management practice. The information technology revolution will mean that a manager or engineer can see real time process information, real time performance and real time profits. All of this information will be harnessed in an asset wide system under the Digital Oil Field approach.

## The 'Digital' Oil & Gas Field

The Oil and Gas industry continues to experience the effects of a powerful convergence between the need for increased operating efficiency, higher oil and gas recovery requirements, improved productivity, and all at lower costs. An important new result of this convergence has been an emerging vision of the 'Digital' Oil & Gas Field, the accelerating pursuit of innovative, but practical, approaches to improving and potentially transforming reservoir production and management against the background of volatile oil prices and economies. The Digital Oil & Gas Field will enable next generation reservoir performance, offer decision makers a comprehensive framework for pragmatic yet forward-thinking, and provide business insight that can be used in strategic and operational planning.

To build a solution that will enable Oil & Gas companies to see reserves more clearly, plan optimal drilling and production strategies, and manage operations more efficiently, it will be necessary to incorporate a number of core technologies. The five key technologies are commonly accepted as:

- Remote sensing
- Data management & integration
- Visualization
- Production automation
- Integrated Modeling for asset management

Tools based on these five technologies are either already in use in the oil and gas industry, or are widely applied in other industries. We are not waiting on new technology. By applying these capabilities, it is estimated that companies will be able to increase the amount of oil and gas recovered from a given field by 2 to 7 percent, reduce lifting costs by 10 to 25 percent and increase production rates by 2 to 4 percent, all figures reported by CERA[1].

The revolution in digital technologies could well transform the dynamics of world oil supply at a time when the industry faces major choices on investment. Achieving the vision of the 'Digital Oil & Gas Field' will require more than new technologies alone. It will require the alignment of strategy structure, culture, systems, business processes and, perhaps most important, the behaviors of people. Visionary companies who truly want to capture the 'digital value' will need to create a climate for change, and then maintain strong leadership through the change and employ the skills and techniques from leading software and service organizations.

At the heart of the digital revolution in the Oil & Gas industry is a shift from historic, calendar-based, serial processes to real-time, parallel processes for managing oil and gas assets. Real-time data streams, combined with breakthrough software applications and ever-faster computers, are allowing the creation of dynamic, fast-feedback hydrocarbon reservoir and production models. These dynamic models, running in conjunction with remote sensors, intelligent wells and automated controls, will allow operators to visualize like never before what is happening in the subsurface and surface facilities; analyze the interactions between processes, understand the consequences of actions, and then to take actions to optimize the oil and gas asset performance.

Scalable 3D visualization technology combined with massive data management capabilities and high-speed networks are already drastically reducing reservoir development cycle times, up to 75 percent in some cases, for prospect generation, field development planning, well design, drilling and field redevelopment.

Examples of the digital technologies expected to be most significant in the oil and gas industry include:

- Time-lapse seismic technology that enables Oil & Gas companies to identify areas of bypassed oil, map flow pathways and barriers and monitor sweep efficiency. It is expected to improve incremental recovery by up to 3% to 7%, and accelerate the rate of recovery. Other significant remote sensing tools include gravity surveying, electro-magnetic monitoring, permanent surface geophone grids, and permanent fiber optic downhole geophones.

- 4D visualization with large format rendering of complex data sets enhances the field development planners' ability to optimize well placement and well paths, to identify areas of bypassed oil and to minimize group time-to-depth errors. It accelerates the rate of recovery and reduces costs.

- Intelligent drilling and completions bring 'real-time' subsurface data, acquired during drilling operations, to the surface to maximize reservoir penetration by steering the well path and to avoid drilling problems. Downhole sensors (e.g., temperature, pressure, multi-phase flow) and flow control valves installed during completion help to optimize well productivity. They enable operators to identify zones of early water breakthrough and injection inefficiencies, and to control flow in these zones by adjusting choke levels. When applied in conjunction with other technologies, such as remote sensing, recovery may be boosted by up to 7 percent.

- Enhanced process automation allows monitoring and remote control technologies, which are already mature and widely used in the downstream refining and chemicals industry, to enable automated data gathering, reduced personnel in dangerous field operations, and automatic alarming. Prediction and optimization technologies enhance failure prediction for reduced downtime and performance optimization capabilities for increased production. Closed loop, autonomous operation systems allow production platforms to operate as a single entity monitored and controlled from onshore remote operation centers.

## The Case for Integrated Asset Models

The integration of data, that is the collection and management of the information about the reservoir, downhole conditions, flowline, facility and business will enable Oil & Gas organizations to get the right information to the right person at the right time. This produces an integrated situation analysis and operating strategy, identifying and using best practices to achieve the most effective and efficient decision making process. This will only happen if the data collected can be processed and shared collaboratively between disciplines with automation to replace manual data transfer and boundary condition inference, along with models, knowledge and applications stored and retrieved in a consistent manner.

Integrated Asset Models of the reservoir, production, process and economic domains will move from the exclusive use of the Engineering expert to being used by Managers, Operations staff, Contracts, and Finance for the analysis and prediction of near real time asset performance. For this, the complete integrated asset from sand face to transmission will be modeled dynamically in real time slow and fast loop modes.

Fast loop production optimization techniques, traditionally used in downstream processing will be deployed in the oil and gas business for the offline and online closed loop optimization of reservoir, wells, artificial lift, production networks and process facilities. These optimization applications will be deployed on top of the existing domain accepted reservoir, production and process simulation applications with a global controller to orchestrate the solution of the model, dependent upon the solution required by the user.

A number of attempts have been made to use the elements of integrated asset models in optimization, for instance production and process simulation for lift gas allocation. These applications have shown gains of over 12% in equivalent production per year, over existing gas lift applications.

In the slow loop Production planning area, techniques traditionally used in downstream processing will be deployed in the Oil and Gas business alongside traditional Excel spreadsheets for a resulting, new generation model based approach to planning. This innovative approach will allow gas dispatch teams or production planners to perform fast profit meter and planning analytics for the entire asset under many scenarios. Figure A-3 shows the potential benefits of using Integrated Asset Models for production planning applications as estimated by CERA[1].

In the near future modeling and simulation will enable a new way of doing business. Modeling and simulation are migrating away from the exclusivity of experts to a ubiquitous collaboration tool for non-technologists such as Managers and Operators, who make every day production, operational and business level decisions.

For this to happen there must be a role based console that is application independent and capable of integrating multiple discipline simulations with real time and near real time data, along with production data, field data capture, field economics, uncertainty management and field development strategies. This is the Integrated Asset Model and the case for its existence is more valid than ever.

## General Requirements of Integrated Asset Models

Oil & Gas simulation, control, optimization, and planning disciplines, have a rather fragmented application landscape with a number of associated technologies. The Integrated Asset Model will unify these applications into an asset wide solution. It will take a partnership between a number of key vendors in the Oil & Gas business to achieve the IAM. No single vendor can deliver the required breadth across the entire asset. Common platform architectures and agreed upon data standards will need to be developed to ensure cross-discipline convergence.

The Integrated Asset Model is a concept from the software vendor community in the form of a workflow solution that can enable Oil and Gas assets to be modeled from a suite of selected software adaptors including reservoir, well, network and facilities. and can bring data from all these disperse and third party tools into one common environment. One can then apply engineering and business applications to identify asset-wide improvement opportunities. An IT architecture, based on new software standards such as Microsoft.NET is proposed to handle the distributed computing and web services requirements to match the different tools within the Integrated Asset Model, with the required data sources and server nodes to execute the required solutions. CIM-I/O drivers are required to allow the models to map to on-line plant tags from DCS, PLCs and SCADA systems, etc plus SQL driver sets are needed to map Field Data Capture Systems and contract databases.

A full suite of mathematical optimization solvers (LSSQP, MINLP, LP, Neural Networks, etc), proven in the downstream refinery and chemicals industries, are then expected to deliver the advanced production optimization and planning capability to solve complex optimization problems involving both continuous and discrete planning and forecasting events. The Microsoft .NET technology in the asset model allows published data to be subscribed to by other applications; an example being embedded EXCEL to create views, reports, and interfaces, etc.

The Integrated Asset Model is an emerging market space for the delivery of a model controller for reservoir, production and process facilities workflow that will underpin the Digital Oil Field of the Future. The user environment will be agnostic to the underlying simulation models: reservoir, proxy model, well, surface network and process facilities coupling. The IAM should be consistent between upstream and downstream and provide a powerful lifecycle platform.

## Achieving the Integrated Asset Model

The first and most important statement made by the authors is that the IAM is an evolution from existing workflows and applications. The IAM is not one new application that does everything. The IAM is a collaborative environment that can connect existing domain applications across regions and time to form a complete picture of the asset. The initial deployment of the IAM will see local domain models e.g. reservoir, production and process facilities embedded with local control and a relatively simple overall controller that monitors applications for logic and boundary condition violation and orchestrates solution at the boundary. Once proven, the overall controller logic will evolve into global optimization and then further into a system that designs uncertainty from the reservoir into the asset wide model.

At the heart of the Integrated Asset Model is a well management controller that supports well controls in a multiple of worlds across the reservoir simulation locally and the IAM globally. The use of well management controls has a number of similarities in the reservoir and production worlds and also some differences. Well management control is often the boundary condition between the two worlds of reservoir and production engineering, with both worlds using a different representation of the well management and control. However, it remains that, a number of variables, definitions and features will be common to both worlds. For instance the well name and attributes such as depth, deviation, flow rates, and gas lift rates will be common to both worlds. A number of the techniques for optimization and control in each of the paradigms will also be desirable in the other discipline. Although reservoir and production engineering work flows are currently separate and will remain so for some time, the well management controller in the IAM must be designed and built with an expectation that the reservoir and production work flows will become aligned in the realization of the Digital Oil Field of the Future.

Global optimization of the reservoir, production and process simulation models within field wide optimization, planning or surveillance work flows will only be possible with a common well management controller between the reservoir, production and process worlds that can be integrated into a common solution architecture along with the economic controllers. The race is on in the market place to provide reservoir to export workflows in ‘real time’ or ‘near real time’ and ‘Net Present Value’. The easiest solution is to create new applications that do the whole value chain for a particular problem e.g. gas lift optimization or NPV planning, but this approach is not sustainable and is the approach used with MS Excel today. The IAM needs to mature into an infrastructure and global controller over existing domain applications and then evolve with those applications to support global optimization.

The successful sustainable solution provider will be the one that delivers a well management controller that can co-exist in reservoir and production worlds and also integrate both of them within a global optimization framework with the process facilities and business constraints. It is therefore desired that a well management controller is designed and built that can support and provide well management logic and solution for the following applications:

- Reservoir Engineering
- Production Engineering
- Process Engineering
- Contracts Management
- Asset Management

The over-arching vision is one where the well management control is removed from the host simulators, where it exists in multiple formats and functionalities today, to a common component used by any local simulation model or part of the Integrated Asset Model (IAM). The well management controller will provide a 'model control' user interface and engine that can be instanced by reservoir, production & process engineering applications within the IAM. The requirement of this scalability is that while the model control user access is common, the level of functionality that is exposed is dependent on what the user is trying to do. For example, the reservoir simulation engineer looking at a sweep management strategy will need more reservoir simulator specific control capability exposed than an asset manager looking globally at life of project NPV. Similarly, a production engineer using production and process simulation, to de-bottleneck a production system, will have more well functionality and less reservoir specific details exposed. A process engineer may only want to see the deliverability potential and the expected field development options for the wells over time so a sensitivity study of the process facilities that can be conducted automatically from the development options investigated and chosen by the reservoir engineer.

This 'model control' user interface and underlying logic controls form the basis of the IAM. The IAM controller needs to be inter-operable with the individual 'model descriptor' user interfaces and will initially connect the well controller and process controller together. For the reservoir simulation, from within reservoir simulator, the engineer would be able to open a model control interface to set up production strategies for the simulation model, where the reservoir simulator has been used to describe the wells, completions etc. The production & process engineers and asset managers will open the ‘model control’ interface within the Integrated Asset Model environment and be able to specify production targets, oil, water and gas rates and any other defined production variable for use within the IAM model for NPV analysis of the field using the underlying reservoir or proxy model, production network model, process simulation and economic model. The same ‘model control’ interface and engine are used in both cases, local to the reservoir and within the global control, but the information and options supplied in each instance of the well management controller will be unique to the application and defined by the user requirements for well management control by each application. The same is true of the process controller that connects the process options to the IAM.

The ‘model control’ user interface for the well management controller component should be built in a modern and extendable language (e.g. Microsoft.NET) such that it is compatible with future developments of industry leading architectures.

## Use Case - Integrated Field Development

Hart’s E&P[2] reports the emphasis for Integrated Field Development is on the longer-term scenarios. Current field operations data such as choke settings, pressure and temperature measurements at the wellhead and in the surface network, flow rates at custody transfer points, and equipment operating set points, are still needed for initializing the forecast from existing operations and the PVT analysis results from fluid samples, and the results from the latest well tests, are needed to keep the reservoir models and well models up to date in the IAM. The schedule of wells to be drilled, the pressure maintenance strategy, the investment schedule for new pipelines and equipment facilities, are a few of the important components of the forecasting scenario. Additionally, economic parameters such as costing data for estimating drilling costs, laying new pipelines, and investing in new equipment facilities, along with pricing forecasts for oil and gas for revenue estimation, are needed for the evaluation of alternative development strategies. The first step in the modeling process for the integrated field development workflow will be to generate a realistic field model that is representative of current operating conditions. Model adjustment steps such as the tuning of well models with validated well test data, and the adjustment of pipe segment parameters through a global optimization approach that minimizes the overall error of the surface measurements, are also necessary. This initial model will be the basis for subsequent time-dependent simulations representing the production forecast.

Of particular importance to the field development workflow is the maintenance of the reservoir models. In addition to the updates to the lookup tables, this will involve the frequent adjustment of the material balance model parameters to match the predictions of the corresponding rigorous reservoir simulations. Updates to the lookup tables as well as adjustments to the tank model proxy parameters from the more rigorous reservoir simulator runs will be performed on a relatively frequent basis to ensure that changing field conditions and updated PVT behavior are adequately reflected in the IAM.

Key activities in the integrated field development workflow are:

- Production Capacity Planning, involving the execution of the current field development strategy to predict the planned production capacity of the field into the future.

- Field Development Planning, involving the creation of a field development strategy by performing a series of what-if simulations, evaluating alternative approaches through a trial and error approach, with a focus on economics.

- Field Optimization, which is an extension of the Field Development Planning approach to leverage the availability of the built-in optimization tools in the IAM to assist in the evaluation of solution alternatives and improve the decision making process. The objective function in this context will either be the predicted recovery over the forecasted scenario, or in the case of an economic evaluation, will involve a relevant performance indicator tied to the predicted revenue stream less the cost of drilling new wells, developing additional infrastructure, as well as operating expenses over time (such as compressor fuel consumption, cost of makeup gas, etc.).

Armed as most of us are with perfect 20/20 hindsight, how many times have we looked at a situation and thought, “If only we had done things differently…?” Unfortunately this is often the case in oil and gas production. Every day, designers face huge challenges to walk the fine line between over designing their production units, incurring higher CAPEX and OPEX, and under designing them, thus limiting their potential to optimize profitability.

Once the project is on-stream, there is still an opportunity to optimize the asset performance to make the most of the design base that the asset is committed to, or of the remediation of the design early enough in the field life to improve the project performance. The ideal asset management system would predict reservoir problems before they impact the wellbore, maintain production equipment within its operating window, and importantly, assess short term productivity opportunities with reference to strategic depletion plans.

In most cases the problem is information—inaccurate information, information containing gaps or discontinuities, irrelevant, untimely information or information that is not information at all, just data. Critically valuable information on managing the asset is compromised as it is considered in isolation from other dependent processes.

Asset management development specialists comprise a wide spectrum of disciplines. Most companies employ teams of experienced professionals to design and operate each node of the asset, from the reservoir to the wells to the gathering system and finally to the processing facility. For several years, the workflow processes of these specialists have been facilitated by powerful computer models and simulators. These models allow systematic evaluation of alternatives, development and testing of simulated scenarios and validation against economic models. But still, asset planning, development and management have been sub-optimal, as more often than not the specialists are isolated by their domain expertise.

End-to-end integration is key. A system that is capable of communicating with each member of the design and management team in that specialist’s own “language,” and one that can propagate the effect of decisions implemented anywhere in the model to the rest of the model, is fundamental to integrated field design optimization. Even the most sophisticated reservoir models, well models, gathering network models, process facilities models, and economics models are not going to achieve desired results unless they can communicate seamlessly with one another, at the right time.

With integration, domain specialists can perform concurrent tasks while identifying and resolving conflicts that add costs or impair productivity. Similarly, they can exploit synergies that add efficiency, boost output or extend economic life. The resulting IAM, supporting digital oil field workflows, is one step closer these days as vendors collaborate to reduce barriers between these silos. The development of field controllers to support well management work flows and global optimization across the entire asset has been underway for a while and reached the market in 2005. These solutions will have to develop in order to propagate uncertainty management from the reservoir all the way through to the facilities.

To visualize how integrated asset management can simplify a complex development scenario, consider an example where the IAM workflow has been applied to the data of the North Sea’s “Indigo” Field, a prolific black oil reservoir about 12,000-ft (3,659 m) deep. The field was producing 30°API black oil from 17 sub-sea wells and 2 injectors. Water depth is 245 ft (75 m). Over Indigo’s 15-yr history, a comprehensive, 300K-cell, reservoir model had been constructed using a reservoir simulator. On the seabed, wells, flowline and manifolds were modeled using a production simulator to characterize the complex sub-sea production network that culminated in a 31-mi (50 km) multiphase pipeline to the processing platform.

The asset management team is now called to action when a second reservoir, Indigo 2, is discovered about 7.5 mi (12 km) to the south. A compositional field of condensate with associated gas, Indigo 2 development plans calls for 7 producing wells and 2 injectors. Economics are marginal and development is expected to take 12 months. Production has to be routed to the same processing platform used by Indigo 1. The question the team needs to answer is put to the team as, "What's the best way to co-produce the fields?"

Two development options are postulated. Option 1 involves gathering flow from Indigo 2 at a sub-sea manifold and tying it to the Indigo 1 flowline at its manifold (Figure A-4a,b). Option 2 calls for a completely separate flowline and riser system for Indigo 2, with a dedicated first stage separator at the platform (Figure A-5a,b). A rigorous study will be conducted with the IAM to determine, firstly, the cost/benefit implications of each alternative, but equally important, the predicted effect of reservoir and surface interaction when both fields are put on stream. Processing and transportation facilities have constraints, such as hardware limitations and export specifications that must be included. In some cases, operators wishing to make an all-encompassing design will actually model the constraints to see if a better solution can be obtained by changing the parameters. In the Indigo case, however, it is determined that production models would be limited by facilities constraints, and thus all designs have to take the constraints into account. Other technical considerations included reservoir coupling, or synchronization of the two reservoir models with the gathering network, and combining the two reservoir models with a common surface network. Among the simulations that must be performed during the decision-making process are comprehensive comparisons of reservoir coupling, manifold design, and impact on production facilities. Each node of the processing train is modeled, allowing comparisons of such items as platform heating and cooling requirements, compression requirements and water treatment and handling requirements. Each of these will differ depending upon the option chosen. Moreover, the results must be entered into an economic field life model to determine the long-term effects on cash flow.

The IAM field controller would integrate well management control of the reservoir and well strings with the production network and process control. In the case of Indigo, sub-sea tieback networks have to be upgraded for each option. Option 1, tie the production together at the sub-sea manifold and transport it to the platform using a single pipeline requires a CAPEX expenditure of $35 million. Option 2, which involves a second pipeline, costs $120 million. Just looking at the cost of the upgrades, one would have an easy choice, but what is the effect on reservoir production? Here the reservoir coupling model in the IAM will show that tying Indigo 2 to Indigo 1 at the manifold would cause a major difference in production volumes due to increased back pressure difference. Option 1 production would be 44,000 bo/d, whereas Option 2 promises 120,000 bo/d. This is largely due to an increase of sub-sea manifold pressure of up to 120 psi if Option 1 is chosen.

The platform operating costs of each option are compared in the IAM using process simulation results and aggregated over 10 years. The process facility is shown in Figure A-6. The results for cooling duties and throughputs are shown in Figures A7-A11. Table A-2 shows a summary of major conclusions in the two options for field development:

- Cooling Requirements - Option 2 - 16% higher than Option 1
- Heating Requirements- Option 2- - 60 % higher than Option 1
- Compression Requirements- Option 2- 30 % higher than Option 1

The study is then continued and investment options would be compared using process facility costing programs. CAPEX requirements for Option 1 total $80.7 million, compared to $188.5 million for Option 2. Whereas the sub-sea differential is 3.5:1 the differential including the platform facilities is only 2.3:1. Taken together, OPEX net present value (calculated at 10% discount rate) plus CAPEX for Option 2 would be $300 million higher than Option 1 over the field's expected life. At this point, Option 1 looks pretty good.

But a high fidelity IAM system must do more that compare nuts and bolts. It must have the capability to manage uncertainties and run risk sensitivity models. For example, variables such as commodity prices must be considered and factored-in. Using value and risk software inside the IAM, the uncertainties can be analyzed and Tornado plots like Figure A-12 produced. Decision trees, showing P50, P90 and P10 cases can then be output. Most importantly, after tax cash flow can be determined.

And the winner is…This is where Option 2 becomes the clear choice. Notwithstanding the foregoing individual node analyses, Option 2 would be shown to payout in 8 years, the result of its higher sustained production rate. At this time, annual cash flow stabilizes at $110 million (Figure A-13). The decision to choose Option 2 can be made with confidence by all asset team members, secure in the knowledge that they had evaluated the integrated dynamic production model over the projected life of the field to reach their decision.

## Coupling Algorithms for Reservoir to Surface Solutions

The coupling points between the network and reservoir models may either be individual well tubing heads or well-groups and have been proposed by Torrens et al[3]; the latter correspond to manifolds to which several wells may connect sharing the same tubing head conditions. The reservoir simulator determines the pressure drop from the well bottom hole to the tubing head from pre-calculated vertical flow performance (VFP) tables. The choice of coupling points may be extended in the future to include the well bottom hole, although it would increase the computation time if the network simulator has to perform wellbore pressure traverses to the bottom hole.

When the network couples to a single reservoir model, a 'tight' iteratively lagged coupling scheme can be applied. This balances the network with the well/reservoir system at each Newton iteration of the reservoir simulator's time step calculation. As explained earlier, if the time step requires more than a certain number (NUPCOL) of iterations to converge, the network is not re-balanced during the remaining iterations of the time step and the well control targets are left unchanged.

Other options for the frequency of network-reservoir balancing are to balance at the start of each time step (explicit coupling) or at specified time intervals ('loose' coupling).

While these options would require less overall computation time in the network model, the accuracy of the coupled solution would be poorer. At the end of the time step the network is out of balance with the reservoir conditions, depending on how much the reservoir conditions have changed since the last network-reservoir balancing. With a 'tight' iteratively lagged coupling scheme, the end-of-timestep balance error reflects only the changes in reservoir conditions that occur after the NUPCOL'th Newton iteration. But for an explicit scheme it reflects the changes in reservoir conditions that occur over the whole time step (or perhaps several time steps in a 'loose' coupling scheme). To solve the coupled system to a given accuracy in an explicit scheme it may be necessary to restrict the time step size, which would incur additional work for the reservoir simulator. In general, the optimum frequency for network balancing would depend on how the computational cost of a network-reservoir balancing calculation compares with that of a reservoir simulation time step.

When a balanced solution has been obtained for the network-reservoir system, it is applied as a control target for the wells while the simulator performs the next Newton iteration or solves the time step. The control target could be the wells' THP, BHP or flow rate. The choice can be important, particularly in explicit or loose coupling schemes when the reservoir conditions may change significantly between successive balancing calculations. In a reservoir with declining pressure, fixing the BHP will give a pessimistic result for production wells. Indeed, if the subsequent pressure decline before the next balancing calculation is significant compared to the pressure drawdown between the reservoir grid blocks and the well completion, the resulting error in the flow rate will be large. Setting the flow rate as the control target, on the other hand, will not give such a catastrophic error for low-drawdown wells, but it will give a somewhat optimistic result instead. Setting the THP as the control target is the best compromise, if the reservoir simulator can solve the wells fully implicitly under this control mode (usually by interpolating VFP tables). The error is smaller because the well bore response is included in the reservoir solution.

Barroux *et al.*[2] point out that it is still possible to set the THP as the control target in the simulator even if the coupling point is the well bottom hole, provided that the network and reservoir simulators both use the same method for calculating pressure losses in the well bore. However, in a tight coupling scheme the difference between setting the THP or the rate as the control target will not be such a significant issue as it is in an explicit or loose coupling scheme.

## Balancing the Network/Reservoir System

The balancing process managed by the controller involves the exchange of information between the wells or well-groups in the reservoir simulation model and the source/sink nodes in the network model. There are several methods of performing this calculation. Here we describe a suitable method for cases where

- the coupling point is the tubing head, and
- the network simulator can accept source node boundary conditions of either defined flow rates or a defined linear inflow relation.

Figure A-14 illustrates the balancing process for a single production well and a network pipeline. The two curves show the flow rate vs. THP response of the well and the pipeline. The solutions at successive network balancing iterations are represented by Roman numerals (I, II, …). In the procedure described below the superscripts 1, 2, … represent points 1, 2, … on the figure while the subscripts *w* and *p* represent the well and pipeline sides at the boundary node.

I. Given an initial value for the well's THP, $p_w^1$, solve the production system in the reservoir model to obtain the corresponding flow rate, $Q_w^1$. Set the well's corresponding source node in the network to a constant rate $Q_p^2 = Q_w^1$ and solve the network model. The network returns a source node pressure $p_p^2$.

II. Update the well's THP control target to $p_w^3 = p_p^2$ and solve the production system in the reservoir model to obtain the new flow rate $Q_w^3$. We now have two points on the well response curve and we take the gradient between them as a tubing head $PI$: $PI^{II} = \left(Q_w^3 - Q_w^1\right) / \left(p_w^3 - p_w^1\right)$ (the superscript II represents the balancing iteration number). Set the well's corresponding source node in the network to a linear inflow relation with this PI and the corresponding intercept pressure, and solve the network model. The network returns a source node pressure, which lies on the intersection of the pipeline response curve and the source's linear inflow relation.

III. Update the well's THP control target to $p_w^5 = p_p^4$ and solve the production system in the reservoir model to obtain the new flow rate $Q_w^5$. Use the latest two points on the well response curve (3 and 5) to calculate a new tubing head PI and intercept pressure, and solve the network with the new source node conditions. The network returns a source node pressure $p_p^6$.

Step III is repeated, using the latest pair of points on the well response curve, until convergence is achieved. The balancing calculation is deemed to have converged when the changes in all source node pressures and flow rates are within a percentage tolerance. For subsequent balancing calculations we start with the wells' latest THP values and use their most recent tubing head $PI$ for the gradient in the network source node conditions.

The reservoir coupling algorithms have also been used to great effect in Chevron's Deepwater Agbami as referenced in SPE 90976[3]

## Conclusion

Oil and Gas production is a complex industry in terms of assets, operations, planning and capital investment decisions. Nothing is ever constant as reserves deplete and new discoveries are brought on stream. Process equipment is continually required to manage changing production profiles that it was not initially designed for. The financial landscape of an oil and gas company is just as complex and uncertain with the ever changing oil and gas prices, and multiple joint partners to communicate with. The concept of the Integrated Asset Model in Oil and Gas has strong application in linking the Engineering to Business streams, and maintaining communication and decision support with disparate asset bases and joint partners. Only through the adoption of the IAM will the Digital Oil Field of the Future vision be realized.

Are we up to the challenge?

## Acknowledgements

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- **Are the Oil & Gas assets performing to plan and how do we know?**
- **Are we choosing the optimal plans for developing the assets over their lifetime?**
- **Are we achieving the targeted Return on Capital Employed (ROCE) for the assets?**
- **Are we meeting all of the ever-growing HSE guidelines?**
- **Can we forecast reliably, allocate with confidence or optimize with knowledge?**
- **Do we drive enough value from the reservoir simulation and engineering model investments?**
- **How effective is the organization at capital avoidance?**
- **Are we drowning in data or are we knee-deep in knowledge?**

Table A-1. Developing a Model Based Asset Management Culture will enable a Diverse Range of Asset Team Pains to be solved

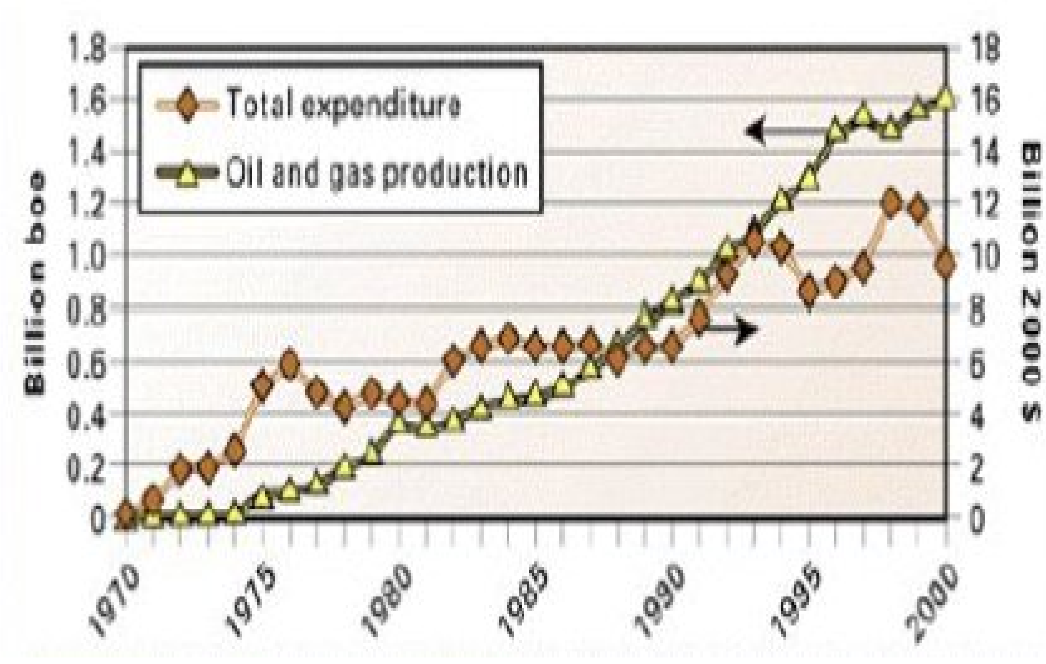



Figure A-1. Norwegian Oil & Gas Expenditure. Source: The Norwegian Petroleum Directorate

| Technical | Managerial | Information Technology |
|---|---|---|
| Horizontal wells | Asset based management | Real time seismic |
| Coiled tubing | De-layering | Complex reservoir simulation |
| Ship based production | De-Manning | Network communications, Internet |
| Multiphase Flowlines | Alliancing | Process data historians |
| Sub sea enhancement | Parallel engineering | Smart well technology |
| Coupled simulation models | Integrated teams | Advanced control systems |
| Deeper, smaller, harder reserves | Mergers | Integrated Asset Models |

Figure A-2. Major changes in Oil & Gas

| Field Type | Base NPV (Billion US$) | NPV Increase of 'Digital Oil Field' Approach (Million US$) |
|---|---|---|
| Green Field Shallow Gas | **1.5** | **100** |
| Brown Field Shallow Gas | **0.803** | **7** |
| Greenfield Deep Water Oil | **3.7** | **505** |
| Brown Field Deep Water Oil | **1.78** | **190** |

Figure A-3. CERA Estimations of the Value of the Value of Digital Oil Field Planning Models

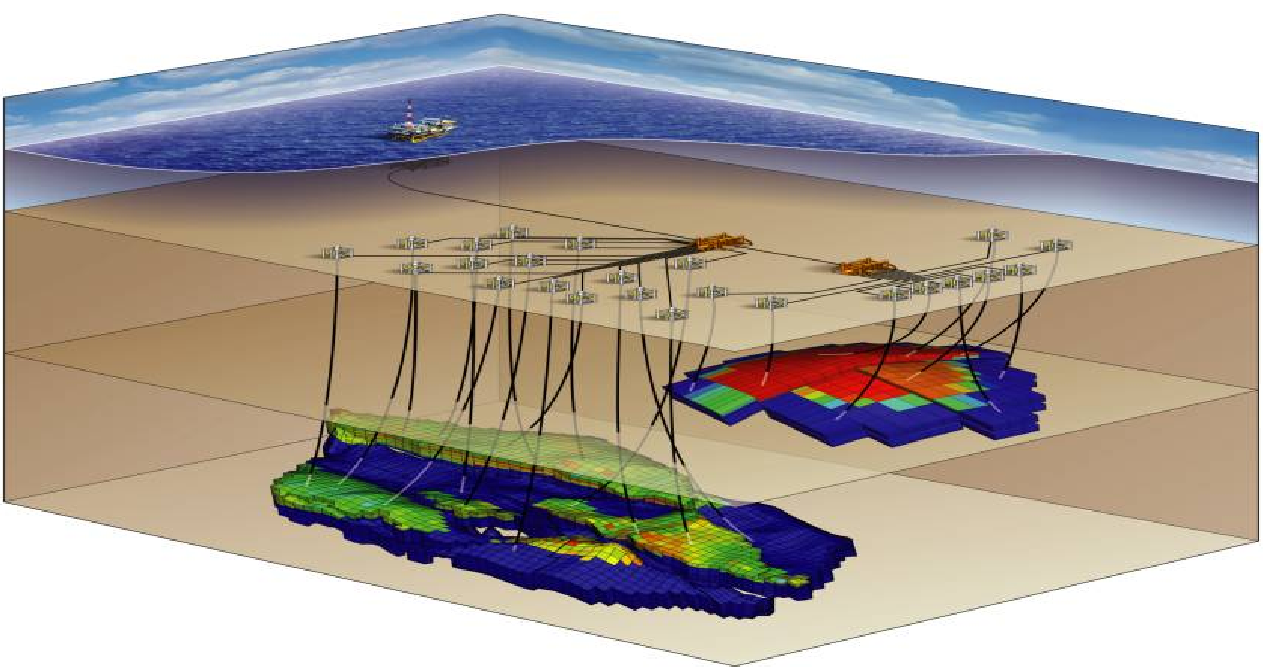


Figure A-4a. Option 1 Layout

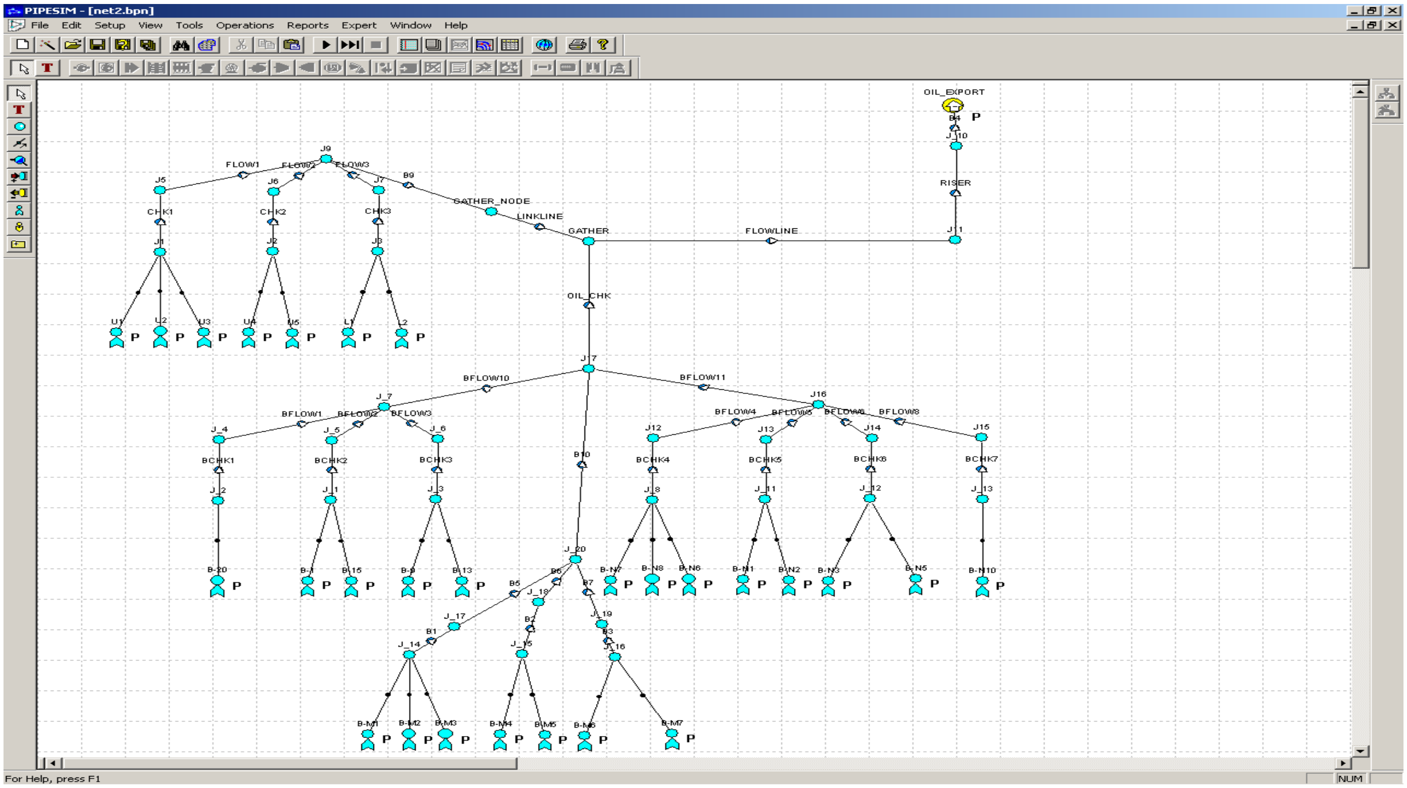



*Figure A-4b. Option 1 Pipeline Model*

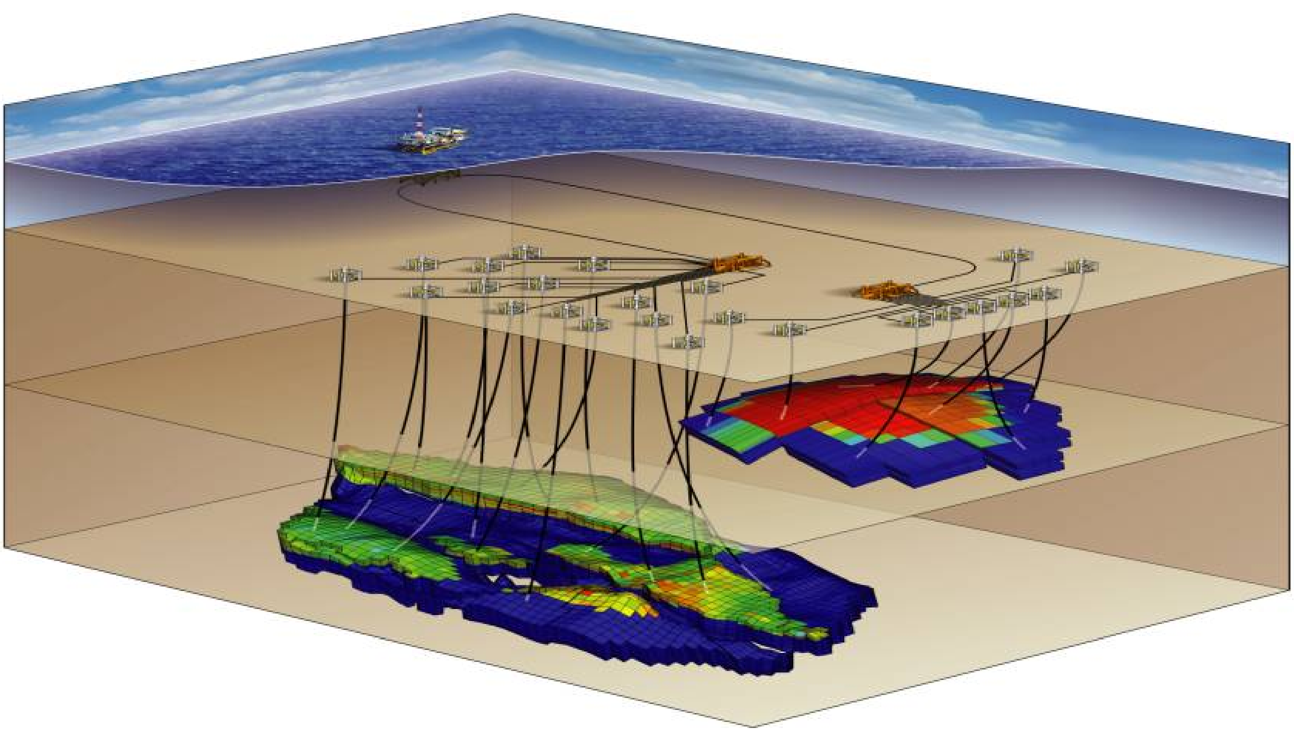


Figure A-5a. Option 2 Layout

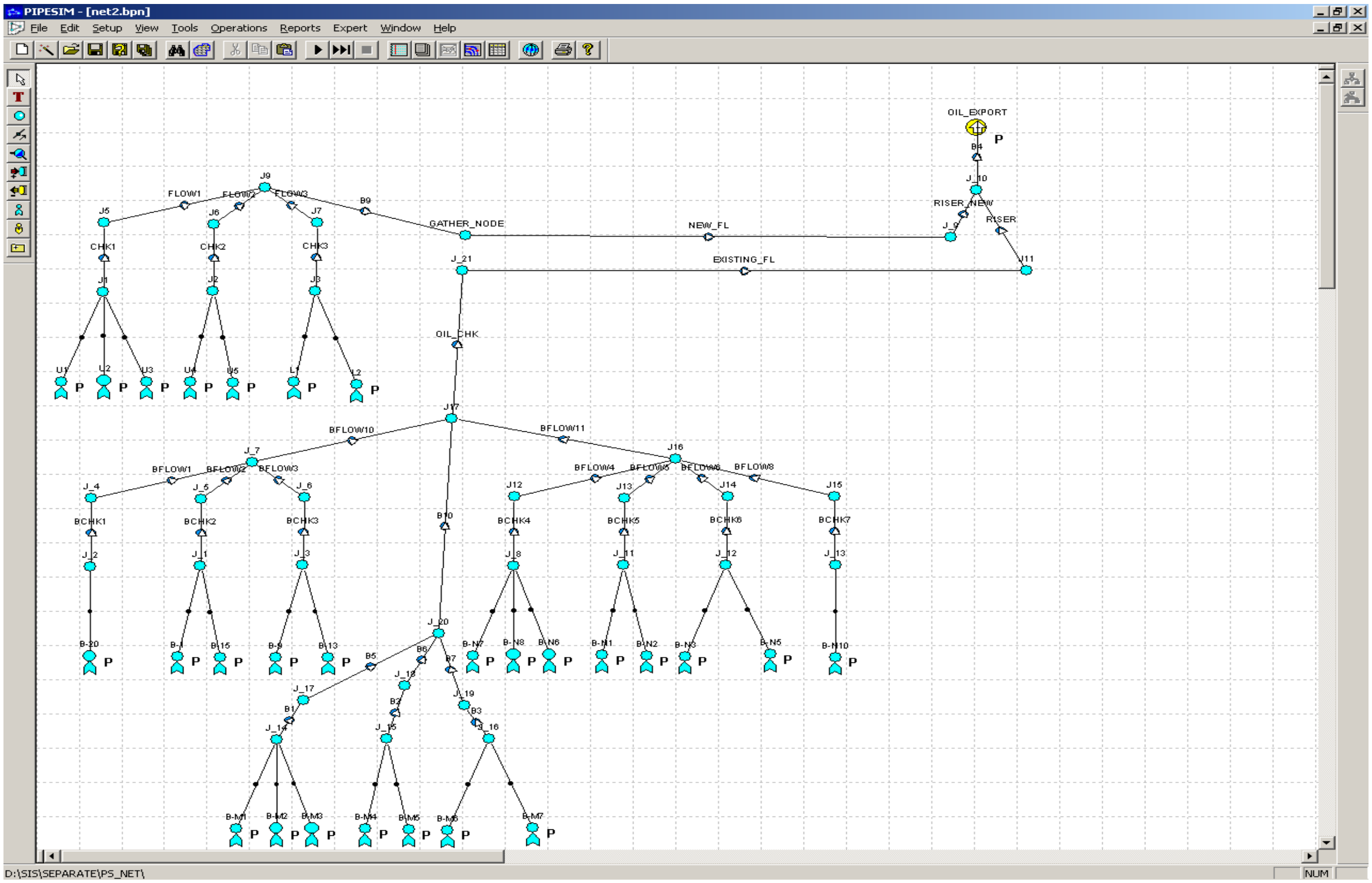



*Figure A-5b. Option 2 Pipeline Model*

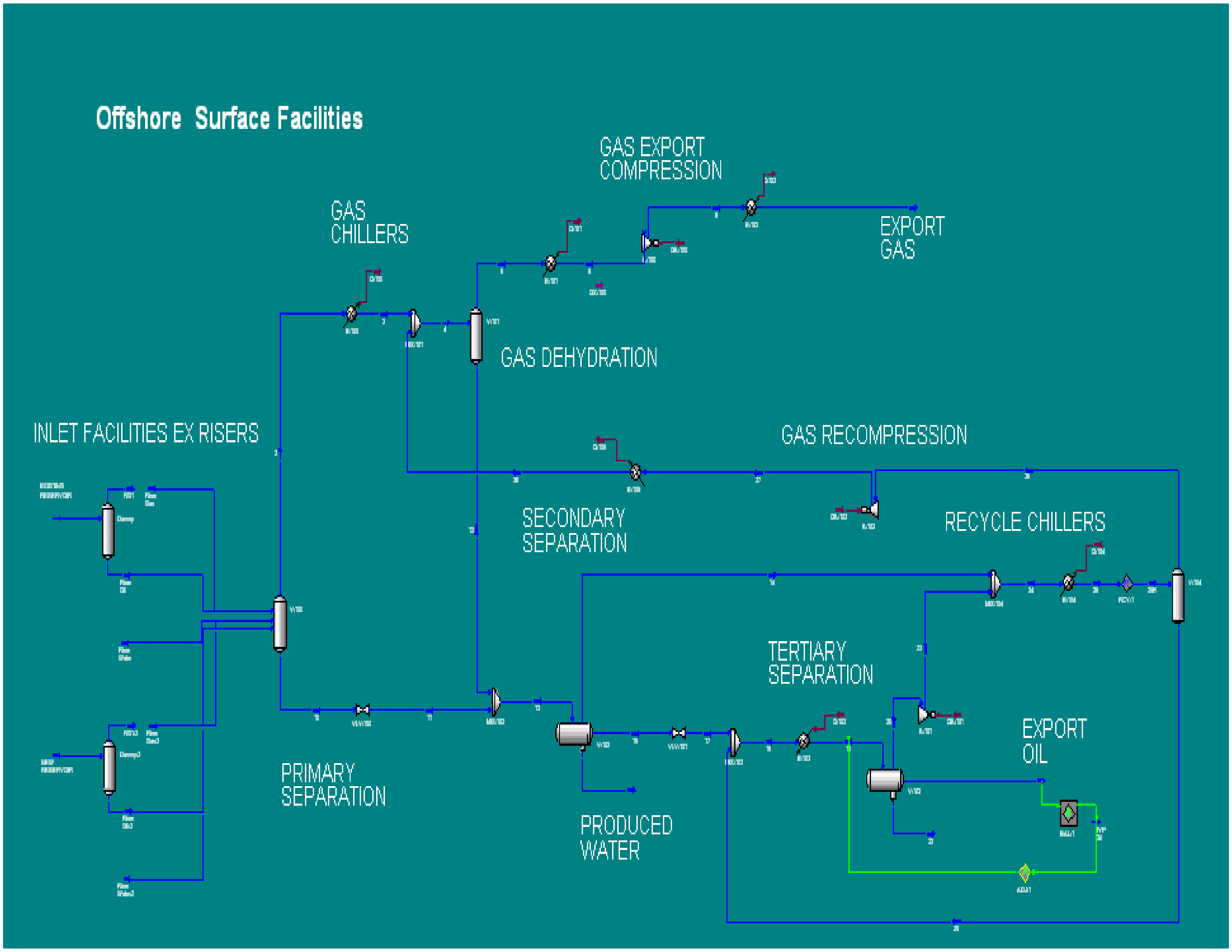



Figure A-6. Process Facilities Model

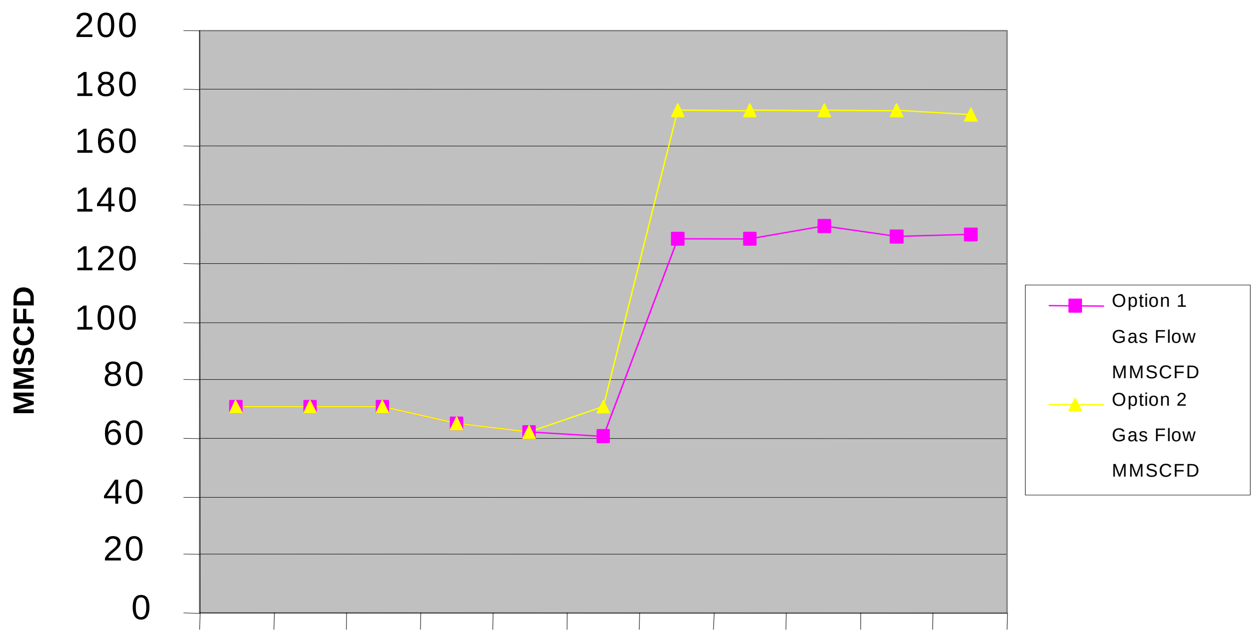



Figure A-7. Predicted Gas Production

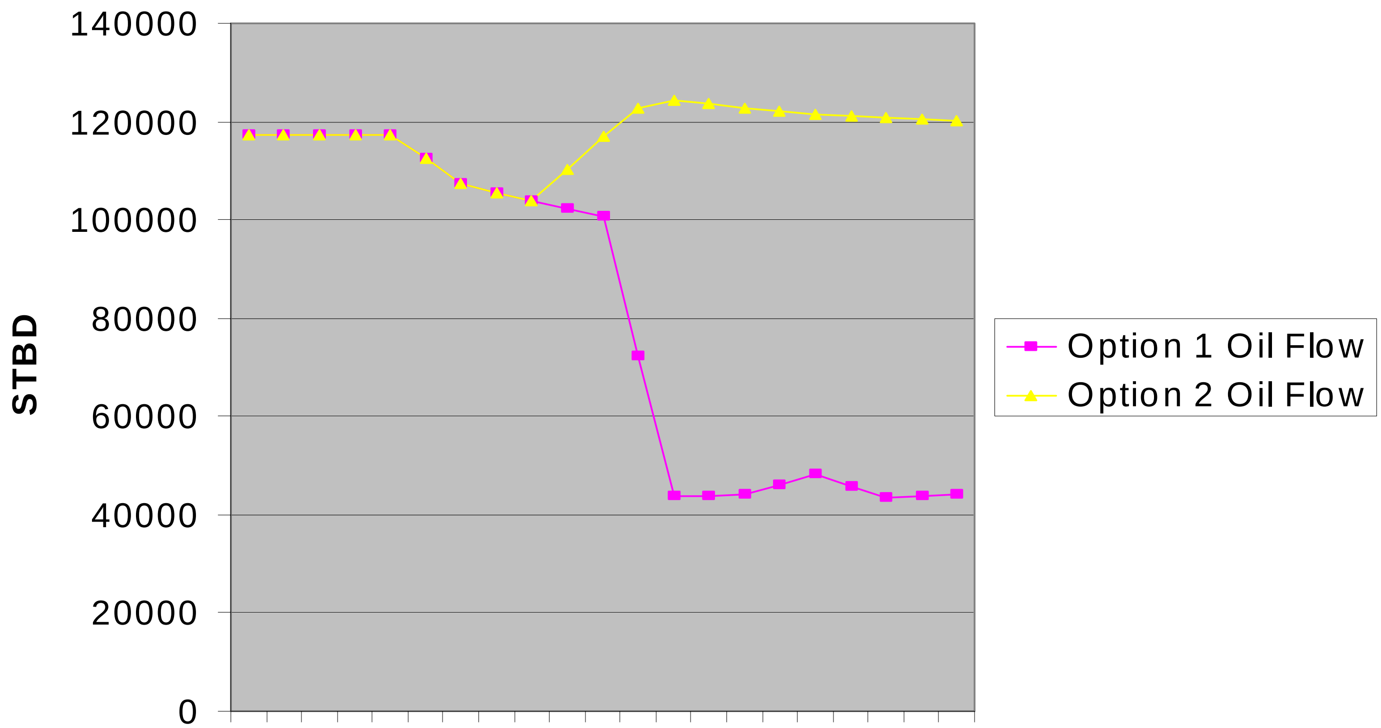



Figure A-8. Predicted Oil Production

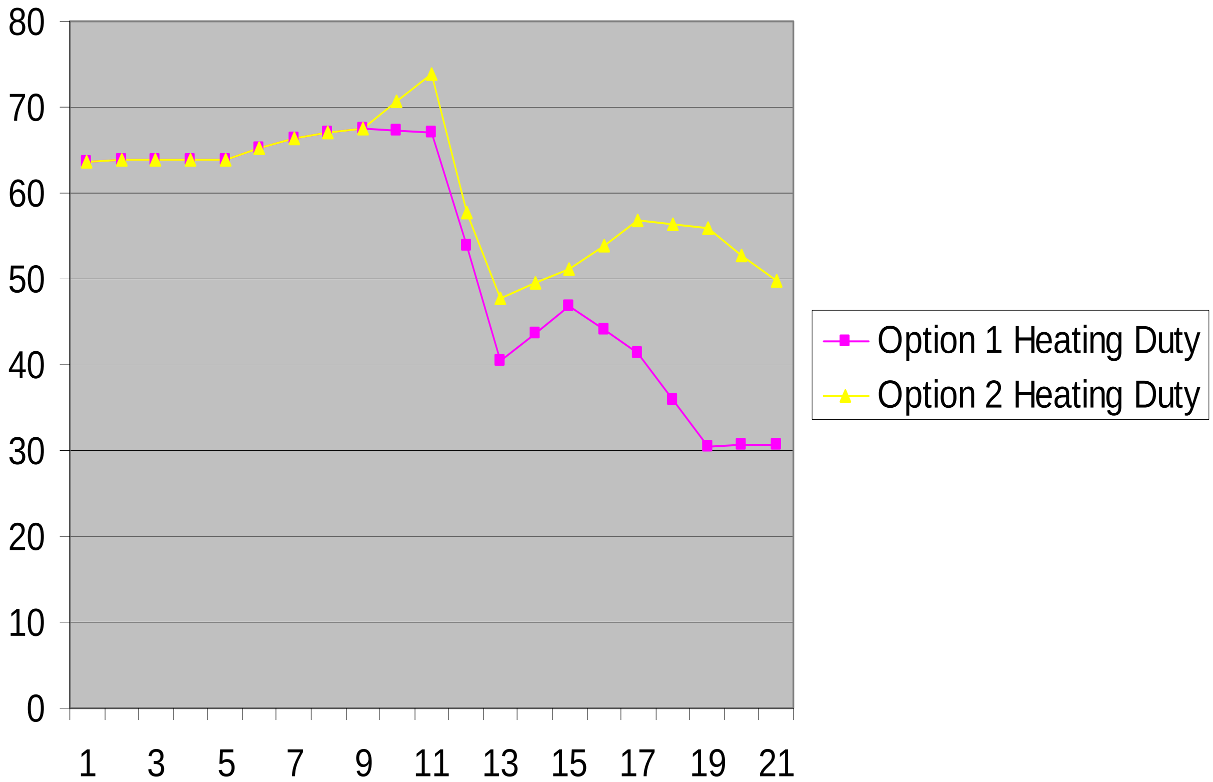



Figure A-9. Platform Heating Requirements

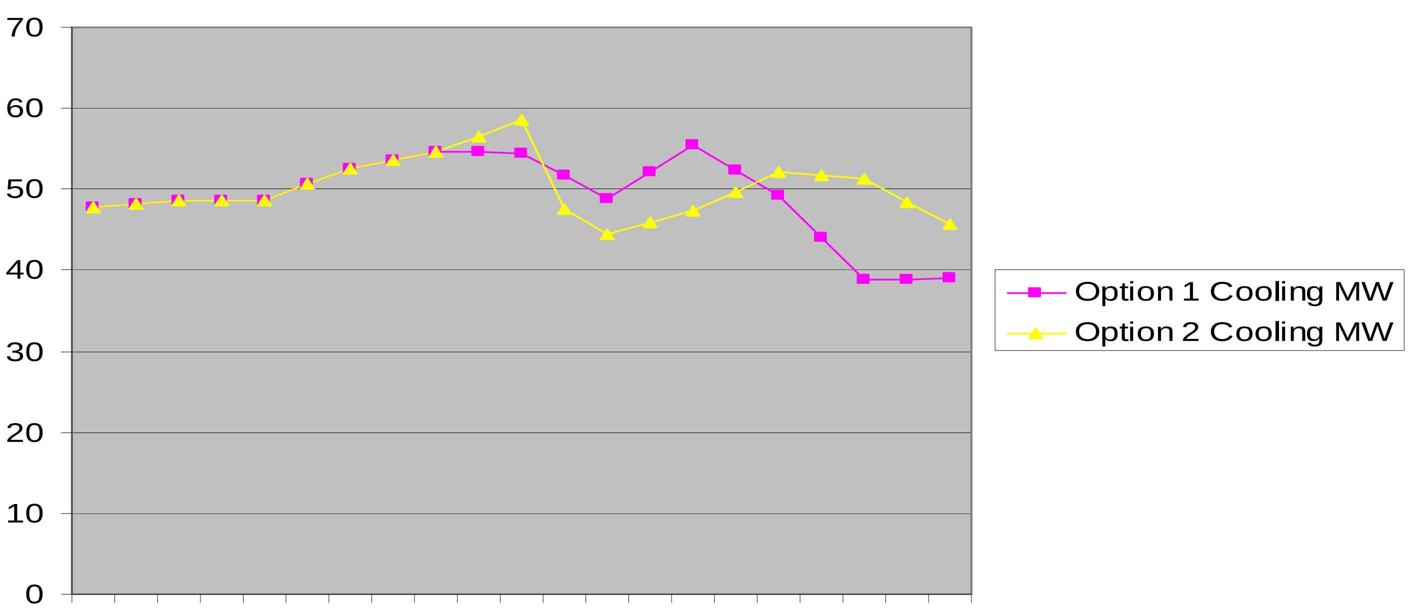



Figure A-10. Platform Cooling Requirements

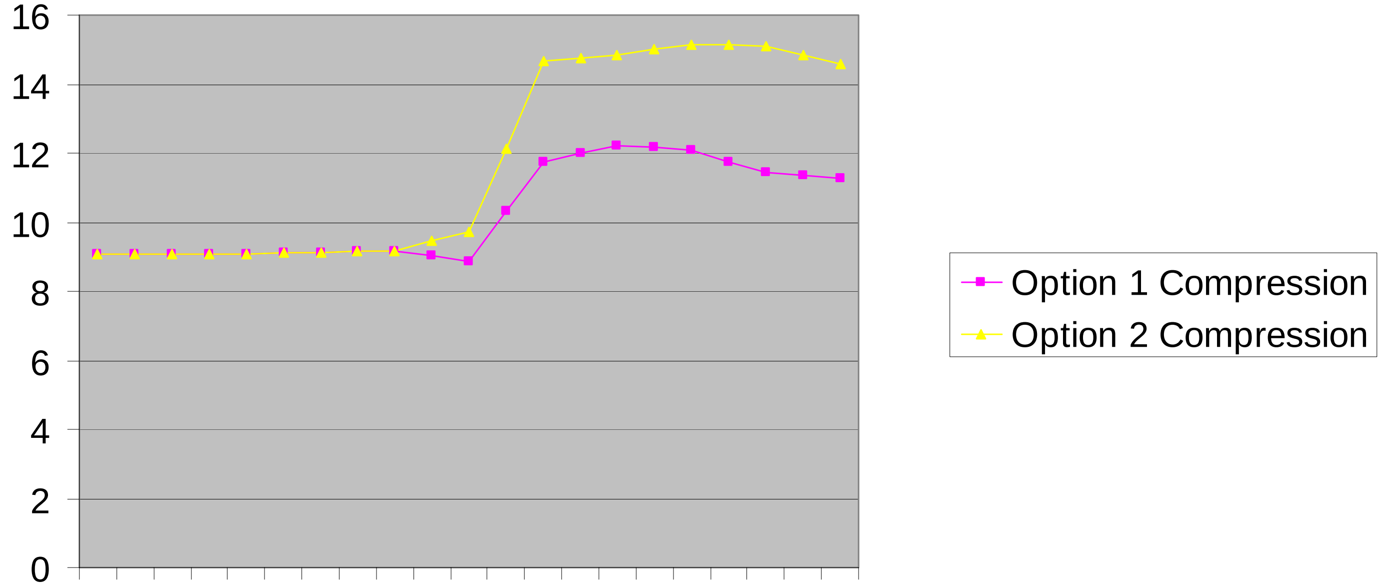



Figure A-11. Platform Compression Requirements

| Parameter | Factors | Results |
|---|---|---|
| Cooling Requirements | Option 2<br>- complicated<br>- worst case 60 MW<br>- best case 45 MW | Option 2 (@ 10 years)<br>- 16% higher than Option1 |
| Heating Requirements | Option 2<br>- sustained higher<br>- worst case 73 MW<br>- best case 50 MW | Option 2 (@ 10 years)<br>- 60 % higher than Option 1 |
| Compression Requirements | Option 2<br>- worst case 15 MW<br>- best case 10 MW | Option 2 (@10 years)<br>- 30 % higher than Option 1 |

Table A-2. Indigo Field Development Conclusions

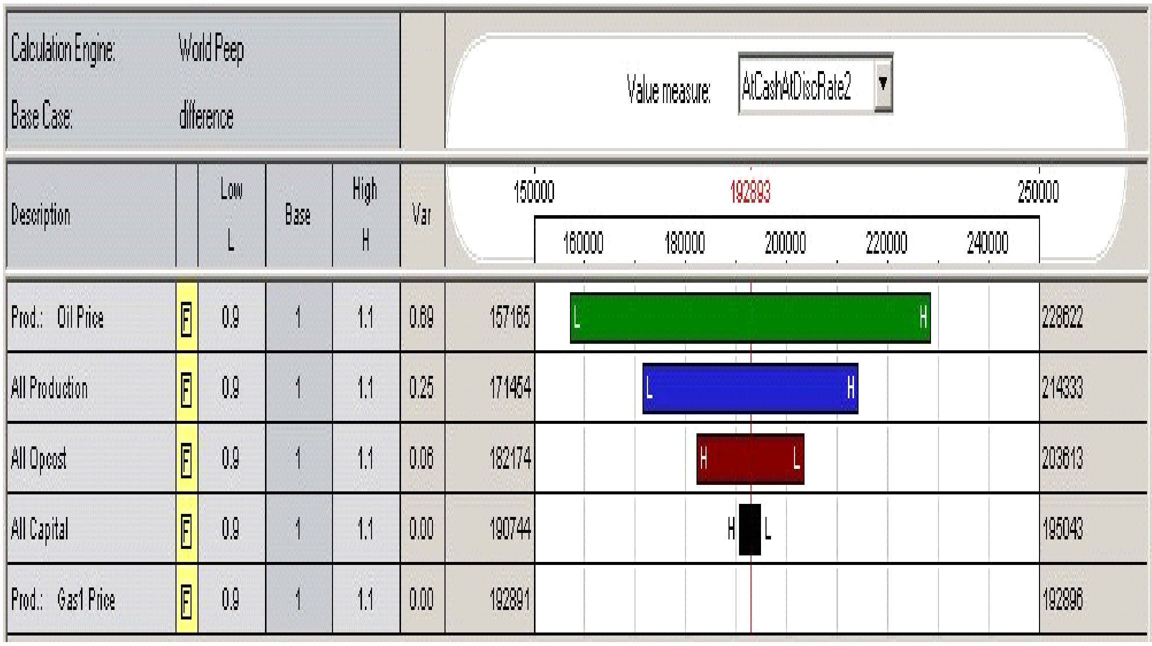
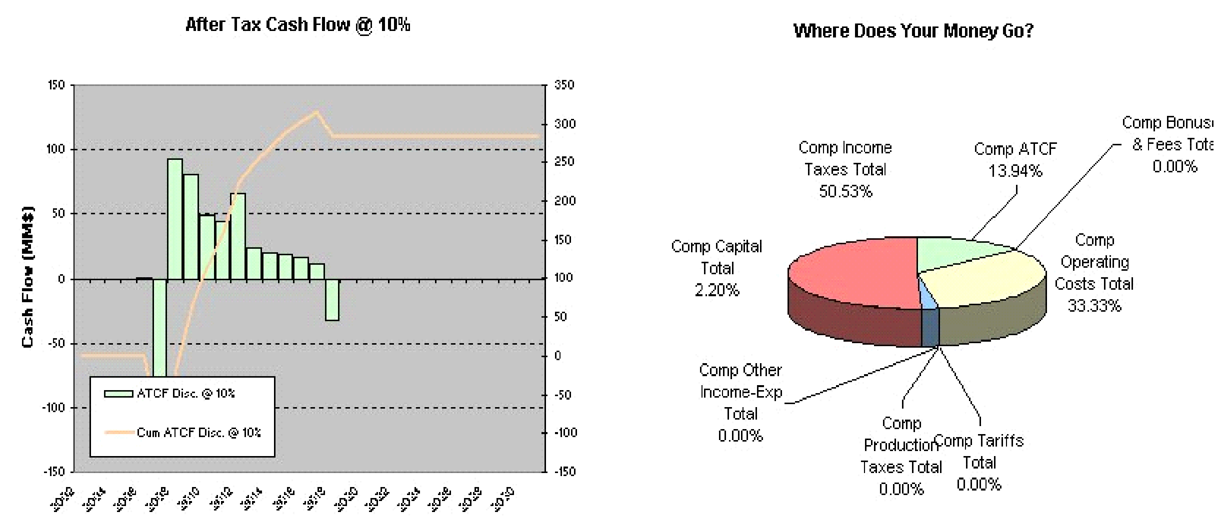



Figure A-12. Tornado Plot for Field Development Options




| Inputs | Project | Company | Company Economics | |
|---|---|---|---|---|
| Gross Production (MMBOE) | 272.05 | - | Net Reserves (MMBOE) | 272.05 |
| Price ($/BOE) | 18.00 | - | Net Revenue Interest (%) | 100.00 |
| Acquistion Capital (MM$) | - | 0.00 | AT NPV @ 10% (MM$) | 192.89 |
| Exploration Capital (MM$) | 0.00 | 0.00 | AT ROR (%) | 83.59 |
| Development Capital (MM$) | 107.80 | 107.80 | AT Payout (yrs) | 0.08 |
| Abandonment Capital (MM$) | 0.00 | 0.00 | F&D ($/Net BOE) | 0.40 |
| Operating Costs (MM$) | 1,632.29 | 1,632.29 | Maximum Exposure (MM$) | -188.50 |
| Bonuses & Fees (MM$) | 0.00 | 0.00 | Govt Take (%) | 73.61 |

Figure A-13. Predicted Comparative Cash Flow – Option 2 : Option 1

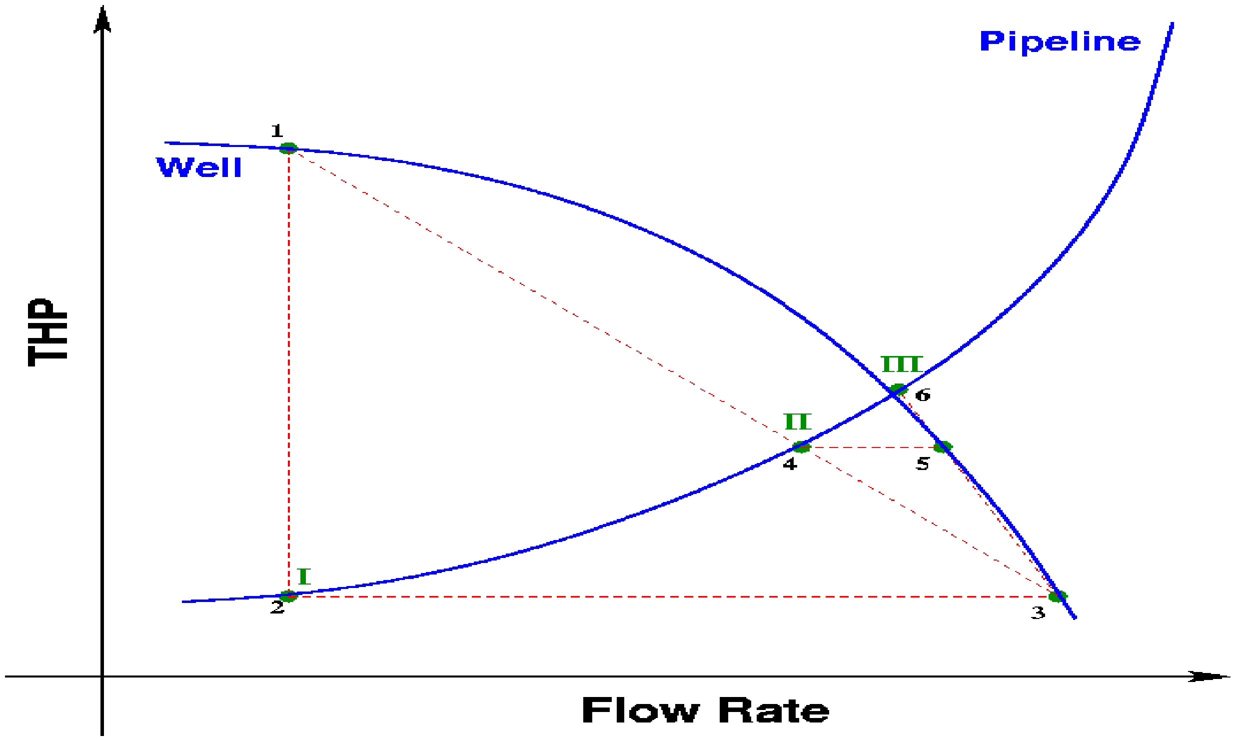



Figure A-14. Reservoir Coupling Scheme