COUPLED SURFACE/SUBSURFACE SIMULATION OF A DEEPWATER Gulf Of MEXICO FIELD

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Abstract

Modern simulation capabilities were recently applied to a deepwater Gulf of Mexico field to define the scope and timing for the second phase of development. This integrated study relied heavily on new advances to handle complex fluid behavior, derive a history match, resolve future behavior of sub-sea wells, and seamlessly review economic metrics.

Simulations used tightly-coupled surface and subsurface calculations to capture and stabilize the interaction of surface facilities with the reservoir. This robust and rigorous approach improves upon previously reported techniques in which subsurface flow calculations are only loosely coupled to the surface network. Fluid characterization involved a single equation of state with multiple distributed component sets in reservoirs and compositional mixing within the surface network. Super-critical initialization was used to capture an unusually small gas-oil transition. History match parameters included reservoir, facilities, and well properties.

A host of development options involving artificial lift (AL), additional wells, and water injection were evaluated for economic value through an optimization-under-uncertainty approach. This assessment guided a multi-disciplinary project team to detail a short set of developments for highest consideration in a typical situation where the complex interactions among the reservoir, wells, outflow network, and facilities, makes an intuitive solution inaccessible. Although the four geologic models used were considered adequately diverse for the study, further value lies in broadening the geological uncertainty and hence the range of possible outcomes.

While a relatively new application in deep water fields, AL is recognized as a technology to extend producing life for mature fields and enable production from challenging plays such as the Gulf of Mexico lower Tertiary. Few case studies addressing such situations are available. The presented workflow may be repeated on assets with significant outflow performance drivers – assets that would benefit from modeling and resolution of complex surface/subsurface interactions.

Keywords: Modern simulation capabilities, coupled surface, fluid behavior

Introduction

The field of interest known as K2 is located in the Green Canyon protraction area; in the Mississippi fan fold belt (Fig. 1). It was Anadarko’s first deep water sub-salt project, a close second in the industry only to Mad Dog, and was Anadarko’s first large-scale application of sub-sea production facilities. The field is unitized across several lease blocks (Fig. 2). Its eight producing wells are connected to Marco Polo, six miles to the SE. Cumulative production as of January 2011 was 34 MMBO and 25 BCF. The estimated resource is over 2 BBOE in-place, with an oil column that exceeds 5000 ft. The developed reservoir intervals lie in Miocene formations with favorable rock and fluid properties (Table 1). The Marco Polo platform sits in 4,300 feet of water. Its capacity is 120,000 BPD and start of service was July 2004. K2 first oil was May 2005.

For the first five years of production from K2, oil and gas rates show a quick ramp up, peak, and then a period that could be interpreted as an erratic decline (Fig. 3). A sharp drop in early 2008 is due
to a combination of mechanical issues and near-well productivity restrictions. A long interruption in late 2008 is from the effects of Hurricane Ike. Efforts to restore full well productivity continue. Only a small fraction of the resource has been produced and much remains to be learned about the reservoirs from well performance. Significant development decisions remain considering potential for AL, additional wells, water flood and even Enhanced Oil Recovery.

The subject study was conducted as part of a multi-disciplinary effort to evaluate future development alternatives, with a particular emphasis on short-term AL options for the M14 and M20 reservoirs in the K2 field. Most of the work took place in 2009 and early 2010, however elements of the study come from prior contributions. The team followed a traditional workflow but relied heavily on interdisciplinary collaboration and several new engineering advances.

A large modern data set typical of a producing, appraised deep water asset was available for use. The data set included seismic interpretations, well data from some twenty penetrations in the study area, and a comprehensive production and pressure database from all seven producing wells in the M14 and M20 reservoirs over the entire five-year producing period. The team followed an established workflow - static earth model development, dynamic history matching, and forecasting - emphasizing integration among all data types. The earth modeling process involved synthesis of static reservoir and well data including interpreted structural surfaces, fault planes, and flow properties. Sophisticated algorithms helped distribute reservoir properties throughout the 3D volume in a manner consistent with an understanding of depositional processes and flexible enough to accommodate numerous uncertainties.

An advanced numerical simulator allowed us to accomplish several technical challenges: simultaneous simulation of multiple reservoirs in the same model, accurate representation of compositional effects, and integration of sub-sea flow “network” and subsurface solutions. We used optimization software coupled with the simulator to perform the history match through a process involving quick screening of earth model realizations followed by refinement and ranking of possible solutions in the face of many unknowns. The optimization package coupled with both the simulator and a spreadsheet economics model enabled efficient and complete simulation and analysis of all development options.

Results of the study are threefold. First, the history match produced an interpretation of the reservoir drive mechanisms and properties with well-level precision. Second, a host of development options were evaluated and objectively ranked. From the assessment of development options and a context of additional criteria and risk factors, the team has selected and detailed a short set of development plans for highest consideration. Third, the workflow developed and applied here may be repeated for the beneficial use of the asset team as necessary to meet future objectives.

Although the team stands behind these findings as reasonable and consistent with all available information, inherent uncertainties in the data leave possible multiple interpretations and underscore the need for future updates as significant new data or business needs arise.

Coupled Surface/Subsurface Simulation Overview

Simplicity and fit-for-purpose modeling are themes that are given attention in textbook literature and case studies from time to time. As modeling tools become ever more accessible, powerful, downright impressive, practitioners might be enticed away from the fundamental idea, that best solution is the simplest one that solves the problem (Dake 1994). The hierarchy of reservoir engineering prediction methods has been described as a pyramid in which the least complex models, analogs, form the bottom level foundation, followed by different versions of decline curve analysis and reservoir simulation, and finally the most complex, numerical integrated production, or asset, models (IPM or IAM) – sit at the top (Fig. 4, Pande 2005, 2011). The IPM models that are now becoming available carry tremendous appeal for their promise to include the full system,
from reservoir limits to production separator, in one solution. This capability certainly does not make them the most appropriate tool for every problem, but it offered a perfect platform for this study because of the combination of complexities involved – multiple reservoirs, complex fluids, and evaluation of sub-sea outflow network alternatives.

Coats et al. (2003) summarizes the evolution of coupled surface facility-reservoir simulation which spans several decades. In typical reservoir models, flow in the reservoir and flow between the reservoir and wellbores is decoupled. The decoupling can be either at the bottom hole or at the wellheads, from flow through the remainder of the production and injection facilities through specification of pressure and/or rate constraints for each well. If individual well rates and pressures are known from production history, then the decoupled reservoir/well model is sufficient to match historic reservoir behavior by specifying and matching the observed boundary conditions as a function of time. However, when used in predictive mode for reservoirs with gathering and distribution networks, the proper decoupled well boundary conditions are in general variable in time and are dependent on reservoir behavior, equipment performance, production strategy, hydraulics relationships, and pressure, rate, and source composition constraints that may be applied within the surface network. When production is controlled in the surface facilities, it is in general necessary, or at least desirable, to include the facilities in a full field model to predict how the otherwise specified boundary conditions will vary in time.

The simplest example of this decoupling is the decoupling of the reservoir model from facilities at bottom hole well locations, requiring specification of bottom hole pressure and/or rate constraints for each well. If the system is truly constrained by well tubing head pressures and if the composition is varying, then the proper bottom hole pressure constraints are variable in time and are impossible to predict without knowledge of the tubing head pressure constraint, the hydraulics relationship in the well tubing, and the composition of the produced fluids as a function of time. Therefore, the decoupling is dangerous, as bottom hole pressure constraints may be specified which will allow wells to flow, when in fact they cannot flow in the true system (the specified bottom hole pressure cannot be achieved). Most reservoir models can handle this specific case by including the tubing in the well model implicitly, but the same concept applies, for example, to a group of wells flowing against a common manifold pressure constraint.

As this is an obvious limitation of decoupled reservoir simulation, many authors have presented methods for simultaneous solution of the reservoir and facility equations. Most methods are based on modification of a reservoir simulator to iteratively converge separate solutions of the well and facility domains (sometimes referred to as an equilibration loop) prior to a conventional solution of the combined reservoir and well domains. We refer to all these methods as loosely-coupled or closely-bound because at no point are all domains solved simultaneously. The methods differ according to the frequency of equilibration and the definition of final time step convergence. If equilibration is performed only on the first Newton iteration of each time step, then the surface model is coupled at the time step level. If it is performed every Newton iteration, the coupling is at the iteration level. Falling in between, a partial iterative coupling performs the equilibration for some number of iterations. The frequency of equilibration may also be controllable in time, with a conventional decoupled method used in between equilibrated time steps. The coupling method is further classified as explicit, partially implicit, or implicit, with respect to the facility solution, based on the final time step convergence criteria and coupling level. If only convergence of the reservoir equations is required, the method is explicit if coupled at the time step level, partially implicit if coupled at the iteration level. If convergence of the reservoir equations and the well/facility boundary conditions is required, then the coupling is said to be implicit because it yields an effectively implicit facility solution, regardless of the coupling level. The overall level of implicitness of the model depends on the implicitness of the coupling and on the implicitness of the equations within each domain.
A Fully-Implicit Solution Method for Coupled Surface Facilities

The technique described by Coats, et al (2003), and Sharalkar, et al. (2005) used in the simulator of this study gives one approach to the solution of the fully-implicit coupled reservoir simulation/surface facilities problem. At the beginning of each simulator Newton iteration, mobility’s and densities are computed for each reservoir cell either containing a perforation or being treated implicitly in the reservoir. These are the variables, in addition to the reservoir grid cell pressures and compositions, which couple the network equations to the reservoir equations. The network equations are then solved by Newton iteration, holding fixed the current iterate values of the reservoir variables. The form of the decoupled primary system of network equations is as follows:

\[
\begin{bmatrix}
A_{ff} & A_{fp} \\
A_{pf} & A_{pp}
\end{bmatrix}
\begin{bmatrix}
\Delta x_f \\
\Delta x_p
\end{bmatrix} =
\begin{bmatrix}
R_f \\
R_p
\end{bmatrix}
\]  
(1)

where \( f \) and \( p \) denote facility and perforation (facility designates network equations other than the perforation rate equations), \( R \) are the residuals, and \( A \) (the Jacobian) contains the derivatives of the residuals with respect to the variables \( x \).

At the start of each network iteration, the network equations are checked to determine which are active. For connections representing adjustable devices, the limiting constraint for a given iteration is taken as the constraint which is most violated. Additional constraint checking is required to detect and prevent over-constrained systems due to combinations of rate and pressure constraints. When an over-constrained system is detected, constraints are eliminated using estimates of which constraints are limiting. These estimates must become accurate as convergence of the applied constraints is iteratively approached.

At convergence of the network equations, the fully coupled system of network and reservoir equations is assembled, which is represented by

\[
\begin{bmatrix}
A_{ff} & A_{fp} & A_{fr} \\
A_{pf} & A_{pp} & A_{pr} \\
A_{rr} & A_{rr} & \delta x_r
\end{bmatrix}
\begin{bmatrix}
\Delta x_f \\
\Delta x_p \\
\Delta x_r
\end{bmatrix} =
\begin{bmatrix}
R_f \\
R_p \\
R_r
\end{bmatrix}
\]  
(2)

where \( r \) denotes reservoir, and where the terms appearing in Eq. (2) are the values from the network domain solution (the network domain was decoupled from the global system by assuming \( \Delta x_r \) to be zero). The reservoir cell mass and pressure coefficients of the perforation rate equations, \( A_{rp} \), are added to the perforation rate equations. These include coefficients due to the implicit treatment of perforated reservoir cell mobility’s. The reservoir conservation equation residuals \( (R_r) \) and coefficients \( (A_{rr}, A_{rp}) \) are then built. \( A_{rp} \) are the coefficients due to intercell flow and accumulation. \( A_{pp} \) are the coefficients of the perforation rate terms \( (Q_{rp}) \), and for the rows of component conservation equations for a cell, these are identity submatrices for (columns corresponding to) each perforation contained in the cell. Generation terms are currently taken as zero. The values of the perforation rate terms in the residuals are provided by the network domain solution.

At this point, the global system of equations has been built and is ready for elimination of the secondary reservoir equations and variables. For reservoir cells using the IMPES reservoir formulation, the conservation equations (the secondary equations) are used to eliminate the mass coefficients of the cell volume constraint creating the pressure equation, and are also used to eliminate the cell mass coefficients of the perforation rate equations. For fully-implicit reservoir cells, the volume constraint (the secondary equation) is used to eliminate the mass coefficients of the last component (water) in the reservoir conservation equations and, for cells containing perforations, in the perforation rate equations. These linearized and reduced reservoir, modified perforation, and other network equations can also be represented by Eq. (2), with the reduction having modified the dimensions and values of \( R_r, A_{pp}, A_{rp}, A_{fr}, A_{rr} \), and \( A_{pr} \), and the values of \( A_{pp} \). The equations are solved at the end of the simulator Newton iteration with an unstructured solver. The reservoir domain \( (R_r, A_{rr}, x_r) \) may be
divided into subdomains, while the network system is treated as a single domain. Because of the form of the network equations, standard iterative solution techniques cannot be applied to the network domain. In the simulator a direct solution is applied to the network domain using sparse elimination with partial pivoting.

**Advantages of the Coupling Schemes**

Each of the coupling schemes has specific advantages over the other. The loosely-coupled scheme can take full advantage of the rigor of third-party software for surface facility modeling. This includes more comprehensive treatment of artificial lift optimization and automated optimization of surface flow rates to maximize an objective function such as oil production or total revenue. The closely-bound or fully-implicit technique described above provides a capability of rigorous treatment of compositional phenomena. Because the closely-bound method is part of a single software package, input data is likely to be more consistent between the simulation model and the surface network. Finally, the fully-implicit scheme provides the rigor of the closely-bound technique for treatment of the compositional properties and the stability of a fully-implicit method with associated larger timesteps. In addition, tight coupling avoids inherent instabilities and inaccuracies of the loosely coupled and closely bound schemes.

**Model Initialization and PVT (pressure-volume-temperature) Calculations**

The K2 field exhibits a typical variation of fluids among multiple reservoirs. There are many reasons for the variations – different source rocks, diagnosis, or tectonic environments, for example - but inevitably this leads to reservoirs with significantly different PVT characteristics. For the simulator used in this study variable equation of state properties must be used with a common set of components, but often each of the reservoirs will be required to have its own set of component characteristics especially for the heavier components. To overcome this inconsistency, each reservoir is initialized with some common components along with unique heavier components. The components which are not common among the reservoirs and initialized to zero composition in the appropriate reservoirs. The surface network mixes all components from all reservoirs and must therefore utilize a completely separate EOS which is tuned to match the characteristics of the surface operating conditions.

Another requirement of the simulator used in this study was the ability to handle compositional gradients along with near-critical fluids. Deeper drilling and the production of light hydrocarbons at high temperature increase the occurrence of gas condensate and volatile oil systems that exist together at initial conditions. These systems do not have a two-phase region. This is because the original compositions are always at temperatures and pressures that do not cross the equilibrium two-phase envelope. In the top part of the reservoir, the compositions are such that the fluid is classified as a gas condensate. The heavy component composition increases as a function of depth so that the fluid would be classified as a volatile oil at the bottom of the reservoir. At some depth in the reservoir, the fluid would change classification from gas to oil, but there is no classical gas-oil contact (i.e., no two-phase region). Instead, there is a depth at which the local critical temperature is equal to the reservoir temperature. The fluid density increases with depth, but does not show the usual density difference associated with phase change. For this reason phase identification is important since it is subsequently utilized in mobility calculations. The phase classification is generally performed by noting the point where the fluid switches from having a dew point to a bubble point requiring that these calculations be made throughout the reservoir.

**Assisted History Matching and Optimization**

The history matching and optimization software used in the study (the Optimizer) automatically communicates with the simulator, a spreadsheet,
and a database in a user-customized workflow that can be used for history matching, uncertainty, optimization, or optimization under uncertainty. In history match mode the Optimizer seeks to minimize the "misfit" between the model-generated prediction and observed data. The observed data can be any type of simulation output stream at the field, region, network, or well level (Cullick et al, 2006). In uncertainty mode, the Optimizer intelligently samples from the user-defined variable set according to one of a number of sampling techniques such as Experimental Design and Latin Hypercube and runs a series of predictions in order to produce a thorough assessment of cause-and-effect. Details and applications of the optimization method have been discussed in literature (Saputelli et al. 2009; Cullick et al. 2005; Cullick et al, 2007).

The optimization under uncertainty workflow (Cullick et al. 2003; Gonzalez and Griborio 2010) can be represented by a double loop (Fig. 5). Decision variables reside in the outer loop and uncertainties in the inner loop. For each iteration of the outer loop, a combination of decision variables which represents one possible decision path, a user-specified number of inner loop iterations samples the full range of uncertainty. The Optimizer captures performance metrics on each individual uncertainty iteration and each set of inner loop iterations, which can be compared with results from other decision paths. Statistics of the set, such as mean and standard deviation, are also calculated. As a job progresses, the Optimizer seek out combinations of decision parameters that tend to minimize or maximize the objective function, according to user design.

For K2, the assisted history matching routine was used extensively to screen and refine subsurface models, as described below. Pure uncertainty workflows aided by the Optimizer were used to assess the importance of different variables and pre-condition the model for more focused work in both the history matching and prediction phases of this project. Optimization under uncertainty was used during intermediate stages of the prediction study to assess the relevance of geologic uncertainty remaining after the history match on the ranking of development alternatives. Finally, a pure optimization workflow (with no subsurface uncertainty) was used to detail a comparison of numerous development options. The optimizer assisted in this effort by thoroughly automating the process, which involved making 130 iterations of the simulator coupled with a spreadsheet-based economics model, generating meaningful statistics on the results, and archiving results for efficient review and post-processing.

Earth Model
Structure and Grid

The structural interpretations and surfaces were generated in April 2009 following the 2008-9 delineation drilling campaign. The essential structural horizon control was provided by the geophysical 3D seismic interpretation, which included deterministic top-of-reservoir surfaces for both M14 and M20 intervals, in addition to many fault surface interpretations.

The size and style of the grid prepared for reservoir simulation was developed through the collaboration of geologists, geophysicists and reservoir engineers for the purpose of providing a geologically realistic platform for understanding and managing the development of the reservoirs. A single grid was created to serve the dual purpose of property modeling and reservoir simulation. It was scaled fine enough to honor the precision of structural data, capture essential vertical sequence heterogeneity and allow for a reasonable amount of inter-well dynamic pressure and saturation gradient development but coarse enough to allow for practical reservoir simulation run times. Grid cell dimensions are approximately 420 ft in the I-J (bedding) plane and 10 ft in the K (cross-bedding) plane.

For this exercise, we chose a ten-layer proportional model for the M14 interval and a 25-layer proportional model for the M20. Vertical cell thickness varies by zone and area, as controlled by the gross interval isochore for each interval, but averages approximately 10 ft. Once unnecessary cells are removed (e.g. wet fault blocks, and regions far below the OWC), the grid contains approximately 54,000 cells (Fig. 6). This combined M14-M20 reservoir grid allows for a true 3D representation of the subsurface and producing system in which all elements are
ultimately interconnected in the flow lines and producing platform.

**Properties Attribution**

Geological interpretations provided information concerning depositional transport directions used in creating the variogram models. The use of litho types (facies, rock types), in the K2 M14 and M20 models is consistent with depositional models developed from detailed work with conventional cores and well logs (Greene et al. 2008). The five litho types in use belong to the general category of deep water turbidities fan systems: 1) bypass channel (used in M20 only), 2) amalgamated sheet axial, 3) amalgamated sheet medial (used in M14 only), 4) amalgamated sheet marginal, and 5) distal (Fig. 7). The distal litho type includes any facies which is considered to be non-reservoir, including shale, layered-sheets, and other fine grained slope deposits. This prior work provided a log-based facies predictor which was used to create a high-resolution synthetic facies log for each well.

The property modeling process then proceeded with facies and porosity well logs “blocked,” or upscaled, into the grid. The facies property was distributed throughout the model volume by sequential indicator simulation. Stratigraphic sequence control was managed by vertical proportions curves based upon discretized well data input. Global facies proportions were taken from well analyses. Variogram properties evolved through the project, as part of the history matching process, and the values used for final simulation work presented here are shown in Table 2.

Fig. 8 shows a sample lithofacies realization.

Porosity was then distributed by Sequential Gaussian Simulation from facies-specific relationships and depth corrected according to a relationship based on well control. Finally, permeability was calculated as a function of facies and porosity from core-derived relationships.

Multiple property-set realizations (facies, porosity, and permeability) were generated for history matching purposes. We used a RESCUE data transfer format to move the grid files between platforms. Several versions of the earth model were created, passed to the reservoir simulator, and tested in history matching process, in order to develop and improve the earth model. In particular, the Vertical Proportion Curve and Variogram controlling facies proportion and continuity in different directions were adjusted and tuned during the history matching process.

**Simulation Model Preparation**

**Rock Properties**

Routine core measurements from all three K2 cores provided the basis for formation-specific initial water saturation versus permeability relationships. These two relationships were then used in the model to set each grid cell’s initial water saturation. The water saturation referenced in these relationships is the Dean-Stark value; permeability is the Klinkenberg (slip corrected) value at net confining stress.

A substantial amount of relative permeability data for the K2 Miocene and analogous fields has been synthesized and condensed into formation-specific relative permeability type curves for use in the models. In each model discussed here (M14 and M20), all active rock types are assigned the same set of curves.

The simulation model uses representative data from the two K2 rock strength laboratory studies. Data from these reports expressing pore volume and transmissibility reduction along the reservoir pore pressure depletion path was synthesized into formation-specific relationships that are used directly in the simulation model.

**Fluid Properties**

Although the majority of fluids involved are medium gravity black oils, a compositional fluid model was selected for this work for numerous reasons. First, the fluid is understood to have a compositional gradient with depth along the entire column due to normal thermodynamic equilibrium, yielding significant differences in flow properties, such as viscosity, with depth. Second, the M14 reservoir held an initial free gas volume and undersaturated oil in close proximity to each other across a discrete compositional change. Possible explanations for this situation include a physical barrier to compositional equilibrium such as a sub-seismic fault or a rim of asphaltene deposition created by complex charge history. This transition from undersaturated oil to free gas is represented.
expeditiously in the model with compositional anchor points that are very different within a very short distance and invoking supercritical initialization to enforce equilibrium. To honor pressure transient interpretations and long-term production observations, the model must allow these fluids to mix and experience compositional alteration during the historical production period. The third reason a compositional model was selected was to enable the use of common outflow network (wells and flowlines) in which inlet fluids of different compositions mix according to their inflow rates and mixture properties are updated accordingly. Each of these three characteristics is best handled with a fully compositional model.

The fluid model features a Peng-Robinson three-parameter equation of state (EOS) formulation. A consistent set of twelve components, six for the M14 and six for the M20, allows for general consistency but unique compositions for each of five reservoir and producing situations that occur in the field (Fig. 9). The EOS is tuned to a robust set of laboratory data (Lim et al. 2008). Further, in the M14 reservoir, the compositionally graded column observed in the well data is reproduced in the model by the use of anchor points at the different wells, each having a different composition. The EOS was carefully tuned to saturation pressure and viscosity measured at each of these compositions. Viscosity was modeled using the Lohrenz-Bray-Clark correlation, tuned to measured data. Measured water properties for the aquifer have been adjusted to average reservoir pressure and temperature of each formation and used to create a different water types for the M14 and M20 formations in the model.

Outflow Network

The outflow network is the system of connections (pipes) and nodes (intersections) delivering produced and injected fluid between the well completions, at the sand-face, and the Marco Polo production platform (Fig. 10). This system consists of wells, subsea flowlines, risers, separators, and wellheads, manifolds, separators, and gas lift. The simulation model represents this network with a high degree of precision, honoring all line sizes, lengths, elevation changes, and connection points. The outflow system is effectively not part of the reservoir history match process described next, as the wells are matched to the terminal rate and pressures at the bottom-hole node, but outflow is an integral part of the production study.

Reservoir History Match

A database of well-level production and pressure data was synthesized from three sources: 1) static formation tester pressures taken at the time wells were drilled, 2) continuous flowing and shut-in bottom-hole pressures collected for each well, and 3) daily oil, gas, and water rates. The product presented here was updated in April, 2010.

The history match process followed can be explained as two major phases – screening and refinement (Fig. 11). The former involved generation of numerous earth model realizations, with variables describing the proportion and distribution of rock types. These realizations were quickly screened by the reservoir simulator in combination with the optimization program to determine whether they would allow the wells to produce with sufficient bottomhole pressure while replicating the approximate shape of the pressure buildup curves during significant well shut in periods. The 2008 extended shut-in period associated with Hurricane Ike provided invaluable control information in this regard.

The second phase involved work on the individual earth model property set from the point of view of the numerical simulation model. With models that had passed through the earth model screen, a set of engineering variables was designed to provide tuning control with sufficient precision to match well-specific oil, water, and gas rates, and bottom-hole pressures. An overriding idea was to apply variability only where it was deemed necessary or valuable, but the list of match variables remained long. This list included the following variables: aquifer strength, fault transmissibilities, horizontal permeability anisotropy, vertical permeability, well permeability-thickness multipliers, threshold pressure at initial fluid contacts, regional
transmissibility and pore volume multipliers around select wells, and endpoint water relative permeability.

The team settled on an a set of six earth model realizations that were suitable for refinement into acceptable history matches by modification of the “engineering” variables outside of the control of the earth model. Graphical representations of some of the variables and their solution values are shown in Fig. 12. There are subtle differences for individual match variables, but all the solutions have the same general trend (Fig. 13), allowing for a consistent interpretation of fundamental characteristics. Some of the key features of the history match are a strong but delayed water drive for one of the formations, a weaker or more delayed water drive for the other, a leading role for mapped and unmapped faults as pressure seals and baffles, confirmation of the compositional fluid gradients as modeled.

This analysis, along with an optimization under uncertainty exercise, indicated that the different matched realizations spanned a relatively narrow range of geologic uncertainty. If more time were available, additional insight might have been gained by searching for solutions with different geologic themes.

Outflow Network History Match

Consistency checks

In order to ensure proper handling of the network solutions in the simulator, we performed benchmark consistency checks of fluids property and hydraulics calculations. Consistency checks are considered good practice at all stages of a model study due to the sheer amount of information assimilated and the need for many different elements to work seamlessly together. Here, also because the team was using a relatively new technique to integrate inflow and outflow calculations, there was a high level of interest in visibility and validation of the network solution.

The fluid property consistency check involved use of an industry standard fluids package, in which the EOS models for this study were developed, to make a control set of fluid property calculations at selected pressure, temperature, composition conditions, then compare these values against solutions extracted from the numerical simulation model at identical conditions. Our focus fluid property in this exercise was oil viscosity. In doing so, we satisfied ourselves that the simulator properly uses EOS-based fluid calculations in the outflow network, and these calculations match the control data.

After developing a firm understanding of the fluid property solution, we performed a few test runs of the simulator to check the network hydraulics solution against that of an industry standard application. During this process, we focused on only part of the network, and took care to use flowline specifications, rates, a hydraulics correlation, and fluid description that were as close to the same as possible. We performed comparisons of pressure through the sub-sea network with different oil flow rates and gas-lift-assisted oil flow rates with the gas injection point at different places. The result was a good general agreement of pressure values and trends. There were some differences in absolute value of the pressures because of the different boundary conditions of the two models, but these differences do not affect the positive outcome of the comparison.

Network History Match

The historical data record of continuous pressures measured down-hole in the wells, at the wellheads, and at the boarding line entering the Marco Polo platform provides a valuable source of calibration data for the simulation model network. To perform this calibration, we first selected data that would be most straightforward to work with – times in which a well was unaffected by a wellhead choke or by multiple wells flowing into the same flowline. We separated the process into a well calibration and wellhead-to-surface calibration. In the well calibration step, we adjusted the hydraulics correlation to match pressure drop between the bottomhole gauge and the wellhead gauges, upstream of the wellhead choke. In the wellhead-to-surface calibration step, we matched wellhead pressure downstream of the wellhead choke (or upstream of the choke as needed for situations in which the choke is full open) to the boarding line pressure measurements at the
platform, upstream of any platform flow restrictions.

Tuning controls included the gravity and friction pressure terms of the hydraulics correlations and a constant pressure drop “add” term (DPADD) in each connection. For wells and risers, we tuned the Hagedorn and Brown correlation; for seafloor lines we used Dukler II with the Flanigan correction for elevation. Seeking the simplest solution possible, we first tuned the pressures with only the gravity terms. These adjustments are most relevant on the well and riser connections as they are more nearly vertical and much more affected by gravity than the seafloor lines. Second, to bring the individual well solutions in better agreement with the observed data where necessary, we used the DPADD term to force a constant amount of pressure change across the connections. Finally, we simulated and checked the model solutions against a December 2009 gas lift field test. Two relatively small revisions were made to better match this high-fidelity data set in which a single well was flowing. The result was a smaller modification from the defaults.

The net result of all this network tuning was a gravity term that is 8.5% lower than the default in the wells and 30% higher than default in the risers, DPADD of an average of -60 psi in the wells (less than 1% of total pressure drop in the wells) and 10 psi in the horizontal sub-sea flowlines.

For this tuning, we used a simplified form of the network mode in which each well was plumbed to a single flowline and riser. This simplification facilitated adjustments that were centered on well-specific flowing data. In order to transfer these tuning results to the realistic network model in which multiple well streams connect on the seafloor and produce through dual flowlines and risers in different ways over time, average values of the hydraulics tuning parameters are used.

**Forecast Study Framework**

It would have been interesting to take each of the six history matched subsurface realizations through its full paces in the prediction study. However preliminary work, including optimization under uncertainty, indicated that, as a whole, they yield a similar representation of pore volume, drive mechanisms, and fluid migration so although their individual predictions are somewhat different in magnitude, they follow the same trends and lead to the same ranking of development options. So, in order to meet practical deadlines and honor our commission, we selected one realization to detail.

Improved Oil Recovery (IOR) measures come in many forms, but a summary of recent work commissioned by the US government and the non-profit industry group RPSEA (Research Partnership to Secure Energy for America) highlights the most relevant processes for increasing ultimate recovery in the deepwater Gulf of Mexico (DW GoM) as infill wells, fluid injection, AL, and selective completions (Lach and Longmuir 2010). Also, the work recognizes that DW GoM development typically progresses in phases (e.g. primary development, optimized primary, secondary, optimized secondary, and finally tertiary) and that many of the mature fields have only progressed to optimized primary or secondary phases. Because each of these phases can involve significant challenges, risks, and lead-time, it makes sense to maintain a vision of all future development possibilities and look for synergies among phases while maintaining flexibility to respond to different subsurface interpretations.

We have made an attempt to illuminate landscape of possibilities for K2 along these lines. A host of near- and long-term development alternatives involving thirteen alternative well programs and ten production enhancement methods was studied in a systematic fashion using the simulator and optimizer (Fig. 14). These scenario sets combined to create a matrix representing 130 possible development paths. Each scenario was represented by an individual model and run through the same thirty-year forecast. As the iterations were run, results were captured automatically in a data store. Model results were also automatically passed through an economics spreadsheet, linked through the optimizer, that was designed to recognize the models’ characteristics and use the appropriate investment schedules to perform discounted cash flow calculations. Economic metrics such as net present value (NPV)
and return on investment (ROI) were then sent to the data store.

**Well Scenarios**

All well scenarios share common drilling locations and a common drilling schedule. The variables distinguishing these scenarios are 1) number of wells that get drilled, and 2) whether or not two of the wells are commingled M14-M20 producers. Two of the five new development well locations have positions that are suitable for both M14 and M20 reservoir completions.

The drilling order was designed to add the most attractive locations first, but we did not make a rigorous study to rank these locations before setting the schedule for this round of simulations. Nor did we seek to find the absolute most favorable well positions among all possibilities in this model. A follow-up study could be conducted to explore the value of different drilling orders and alternative well locations. However, we would advise a reasonable amount of discretion in using a model to “fine tune” well locations beyond the precision of the reservoir description. If multiple history match realizations were carried through the development optimization exercise, the fine-tuning from one realization might be somewhat different than the that of others. We would, however, expect the ranking of infill locations and preferred drilling order to be consistent among different interpretations.

**Production Enhancement Scenarios**

Five individual production enhancement methods, were combined in the most feasible ways to create ten prediction scenarios comprising the production enhancement scenario set in the forecast matrix (Table 3). Fig. 15 illustrates where each of the AL enhancements, described below, intersects the outflow network. Here we will detail only the near-term AL options, not the longer term options of downhole gas lift, water pressure maintenance, and extended infill drilling.

**Natural flow**

A baseline prediction assumes no AL is used for K2 at any time. This scenario even excludes the contribution of riser gas lift on the north loop, although it is presently installed and tested.

**Riser gas lift**

In all gas lift scenarios, the simulator’s gas lift optimization algorithm controls the lift gas injection rate. The maximum gas lift rate is first set according to facilities design limits. The gas lift optimization routine then adjusts rate every 30 days according to a benefit function that amounts to a cost-benefit analysis comparing the incremental value from oil and gas streams with the increased cost of lift gas and produced water.

The K2N riser gas lift scenario (02_518RGL) activates the existing GC518 gas lift method in January, 2010 and for the duration of the forecast. The lift gas is made available to both risers. The maximum gas lift rate was set to 10 MMSCFD per riser, according to estimated facilities limits. Also, the minimum producing separator pressure (the outlet pressure at the top of the risers in the model, or “topsides”) has been set to 200 psia. This is the base-case assumption in all lift scenarios unless otherwise noted.

The K2N and K2 riser gas lift scenario (03_RGL) activates the GC518 (“K2N”) gas lift method in January, 2010 as in the previous scenario, and adds gas lift to both GC562 (“K2”) system risers in April, 2012.

The next scenario (04_RGL100) is the same as 03_RGL except it lowers the minimum topsides pressure to 100 psia.

**Manifold gas lift**

One scenario (05_518RGL_562MGL) injects lift gas from Marco Polo into the flowlines at the southern K2 system manifold situated in the near the GC562#1 wellhead. A maximum lift gas rate of 7 MMSCFD per flowline is consistent with facilities design constraints. This “manifold” gas lift is made available for service in October, 2011. The K2N system uses riser gas lift beginning in January, 2010.

**Riser pumping**

Three riser pump operations were included in this study. Riser pumps were simulated by effectively moving the terminal node to the riser
base and applying a minimum pressure at the riser base that approximates the estimated capabilities of the pump across a wide range of flowing conditions. Our base-case assumption for this terminal pressure was 500 psia. This assumption was meant to approximate the capabilities of a variety of different pumping options under study by the larger team. As this operating assumption is refined, and software developments allow, a more rigorous set of modeling criteria may be possible. For now, sensitivities are meant to address a range of possibilities.

In the first pump scenario (06_518RGL_562RP), the K2N system uses riser gas lift beginning January, 2010 and the K2 system has a riser pump. The pump is available for service in April, 2012. The K2N and K2 riser pump scenario (07_RP) uses riser pumps on both the K2N and K2 systems (all four risers) beginning in April, 2012. Before this, starting in January, 2010, the K2N system is served by existing riser gas lift. Finally, the pump intake pressure sensitivity case (08_RP300) is exactly the same as 07_RP except it takes the minimum pump pressure down from 500 to 300 psia.

Results

Short- versus Long-term Development

The development options studied here can be thought of as either short- or long-term measures. The short-term bucket includes projects that might be accomplished in the one-to-three year timeframe with an investment level that is significantly smaller than that of the initial field development. These options include development drilling and seafloor AL methods. Longer-term projects are represented by downhole gas lift and water pressure maintenance, which may require longer lead times and higher levels of investment. Short- and long-term projects are not necessarily incompatible; in fact one of the areas this study helped with was helping focus the team on the tremendous benefit for synergies between the two. For example, if seafloor gas lift is installed first, this method can provide some benefit to the wells, and the investment in reconfiguring the Subsea system reduces the investment for seafloor pumping some time later. Ultimately, if some type of pressure maintenance scheme is employed, the earlier investment in AL should help the scheme to be most efficient.

Regarding the next phase of infill drilling program in combination with short-term AL (seafloor) alternatives, a consistent theme of high value associated with one select well stands out. Additional wells add production volumes but not enough to offset the increased investment. However with the longer-term development schemes that process the reservoir more efficiently, we see a steady progression of NPV with increasing well count.

Commingled Completions

If the two wells in the simulated drilling program are given commingled completions, we are allowing them to flow from the M14 and M20 simultaneously for the entire producing life of the wells. We have not simulated any downhole flow control, recompletions, or zone-specific isolation of any type. These types of controls might be reasonable to expect in the operation of such wells and they represent possible upside to the simulation results shown here. In future work, there could be value in investigating an optimized control strategy for these completions.

We have given the commingled completions a 10,000 STBD maximum rate limit, as opposed to 6000 STBD for the single-zone completions. Preliminary simulations of unconstrained rate potential showed this increased limit to be a reasonable approximation of sustained rate potential.

In seafloor lift scenarios, the commingled well case accelerates production but at the expense of long-term reserves, as higher rates also lead to earlier water break-through and a less efficient water drive. However, if we consider the case in which only one new well is drilled in combination with a water pressure maintenance scenario, the commingled well case provides much higher volume and value because it gives an additional take-point in the reservoir and so increases the waterflood process rate and volumetric sweep.

Artificial Lift

In order to focus on the relative performance of the different AL methods, we consider the set of
cases in which there is only one new well drilled, and this well has a commingled M14-M20 completion. We first review the discounted volumes versus discounted investment of each of the alternatives (Fig. 16). Discount rate is 10%. A positive trend shows incremental volume benefit for each level of investment, from existing riser lift, to manifold lift, to full riser lift, to combined riser lift and pump, to pumps on all risers. The two sensitivity cases to minimum terminal pressure, one for riser lift topsides pressure and the other for pump intake pressure, show considerable performance improvements relative to the full range of results represented here.

Next we consider the intrinsic financial metrics metrics NPV and ROI. Fig. 17 illustrates the relative ranking of each of the eight short-term production enhancement schemes all combined with one new development well. These metrics are both calculated as increment relative to a situation in which there are no new development wells and no AL. The incremental NPV shown here includes the value of the new well. ROI is defined here as incremental NPV divided by incremental discounted investment, again relative to the present operations reference case. All AL methods modeled show increased NPV relative to the existing method (02_518RGL). ROI is consistently higher for riser lift than for riser pump.

Two scenarios that could be considered our leading base-case options for riser pump and riser gas lift (03_RGL and 06_518RGL_562RP) rank very closely together on an NPV scale, with riser lift leading on ROI. Both outlet pressure sensitivities for the pump and riser lift cases give significantly more favorable NPV and ROI metrics. Note that the 08_RP300 sensitivity compares with the full riser pump method, 07_RP. K2 manifold lift (05_518RGL_562MGL) ranks lower than the riser base lift as, relative to riser gas lift, it produces increased friction load on the sub-sea lines between the K2 south manifold and the riser base. The full riser pump case, 07_RP, ranks well below the other pump options on NPV, because the investment in a pump for the K2N system is high for the projected benefits provided relative to the already available riser lift. The K2N system serves only the three existing wells for all time, so there is limited opportunity for enhancement there relative to the K2 system.

When will AL be needed? The model projections show that relatively small differences in rate profiles until year 2015, regardless of AL method, considering even the natural flow scenario (Fig. 18). Until that time, there is sufficient energy in the reservoirs to keep the wells operating at higher than “line” pressure.

Conclusions
The analysis supports the drilling of at least one high-impact infill well and equipping all risers for gas lift. Designing flexibility for addition of seafloor pumping and longer-term IOR schemes such as additional infill wells, downhole gas lift, and water pressure maintenance, is considered important. These future development phases will require further study, with wider scope, by the integrated project team to refine feasibility, investment assumptions, and benefits. Additional time and production data will also allow the team to evaluate well performance to gauge the ultimate drive mechanism for the M20, which has a direct bearing on the projected benefit of any options studied here.

Relative to dedicated M14 and M20 wells, commingled wells offer rate acceleration and access to potential long-term volumes for lower investment.

All AL methods studied add value. Riser gas lift and riser pump rank closely. There is significant differential value for “aggressive” operating pressure cases. Refinement of operating assumptions will be helpful in determining a final selection. Also, the additional criteria outside the scope of this study, such as performance uncertainty, design improvements, installation risk, and future flexibility will be considered. For example, one scenario that has gained favor is the installation of K2 riser gas lift followed by a pump at the same location at some later time.

According to our best predictions, significant benefits from an AL system do not begin until year 2015 as wells fall to line pressure. Investment in additional AL for earlier service may not benefit the project.
We recognize that all interpretations expressed by this report carry uncertainties and recommend regular updates of the model suite so that recommendations can be kept current with new information. In particular, new information that should be incorporated into the model includes 1) improved seismic interpretations, 2) new and improved Pressure Transient Analysis interpretations, and 3) continued well performance, and 4) addition of the M15 reservoir.

Acknowledgments
This work was made possible by the K2 Integrated Project Team, a joint effort among all partners – Anadarko, ConocoPhilips, ENI, MCX, Nippon, and EcoPetrol, and by Halliburton. The authors would like to thank and recognize each of these companies for their support. Special thanks also goes to several individuals who made significant contributions: Nathan Bowden (information technology), Todd Butaud (geology), John Davidson (Halliburton), Tim Dean (subsea facilities), Rich Drumheller (geology, earth modeling), David Janise (management), Nikhil Joshi (fluid characterization, network modeling), Jim King (Halliburton), Matt Lamey and his team (facilities), Frank Lim (fluid characterization), Brian O’Neill (Petrophysics), and Arnold Rodriguez (geophysics).

References


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Table 3 - Production enhancement methods and scenarios

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<td>manifold gas lift</td>
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<td>DHGL</td>
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<td>WPM</td>
<td>water pressure maintenance</td>
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<thead>
<tr>
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<tr>
<td>01_NF</td>
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<td>07_RP</td>
<td>K2N and K2 riser pump</td>
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<td>08_RP300</td>
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<td>10_RGL_WPM</td>
<td>K2N and K2 riser gas lift + waterflood from Marco Polo</td>
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Figures

Fig. 1 - K2 locator map
Fig. 2 - K2 unit map

Fig. 3 – K2 Production history
Fig. 4 - Prediction method pyramid

Fig. 5 - Optimization under uncertainty workflow
Fig. 6 – Combined M14-M20 Model Grid showing initial saturations

Sand-rich Fan

Fig. 7 - K2 model lithofacies
Fig. 8 – Lithology realization, M20 formation

Fig. 9 - Fluid types
Fig. 10 - Outflow system components

Fig. 11 - History matching workflow
Fig. 12 - History match variables

Fig. 13 - Sample well-level history match

Fig. 14 - Prediction study framework

Earth Model
one history matched realization

Simulate matrix of development options
10 production enhancement methods
* 13 well programs
= 130 scenarios

Metrics
Rate, recovery, and commercial
Fig. 15 - Network schematic with artificial lift elements

Fig. 16 - Artificial lift ranking - volumes vs. investment
Fig. 17 - Artificial lift ranking - incremental NPV vs. ROI

Fig. 18 - Artificial lift timing