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Efficient Conceptual Design of an Offshore Gas Gathering Network

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Abstract

Offshore gas gathering networks require large capital investments in wells, subsea equipment, pipelines and compression systems. Generally, the optimum design for such systems can only be found by assessing multiple scenarios. Many scenarios may have significant flow assurance constraints, such as hydrate avoidance and/or minimum operating temperature limitations. This paper highlights the benefits of using a modern thermal hydraulic Integrated Production Model (IPM) to investigate the economics and operability of numerous design options for such systems.

A thermal hydraulic IPM simulator was used to carry out a conceptual study of a large offshore gas field with several satellite tiebacks. Production and drilling profiles were predicted subject to multiple constraints, including drilling access, processing capacity and flow assurance operability limits.

IPM calculations were performed to establish the phasing of drilling, field development and compression necessary to sustain required gas delivery rates. The model computation speed was rapid, permitting the fast turnaround of numerous cases. Moreover, the calculations were performed rigorously, thus allowing the simultaneous simulation of flow assurance issues, such as required glycol flow rates and minimum flowing wellhead temperatures to avoid hydrate formation and blockage. By evaluating the gas delivery requirements in conjunction with the flow assurance constraints, it was possible to select an initial concept that was both economically and technically robust.

The main trade-off in the study were well and compression availability; various maximum available compression power profiles were compared to the drilling schedules to meet a given demand for gas. In summary then, the paper presents the application of a software tool to the quickly evaluate and generate an initial development concept for a large gas gathering system with the principal objective of selecting the most capital efficient and economically optimal scheme.

Introduction

The key aims of conceptual design in the upstream oil and gas industry are to confirm if a project concept is economically feasible and to direct the later design stages towards an optimal design. To do this, numerous options must be analysed in a robust manner to screen-out unworkable solutions and highlight the potential of new technologies. As the locations of new developments enter harsher environments and the fluid properties become more difficult, the possibility of a traditional tieback solution decreases and the need for new technologies increases. Consequently, it is becoming more important to take a multidisciplinary approach to concept design, as disciplines such as drilling, flow assurance, process and corrosion engineering may influence feasibility as much as the traditional subsurface factors. As well as the additional technical issues associated with more novel field developments, there is also a drive to accelerate the design of systems generally. The more robust the initial concept screening the less risk there is for further project development. This further motivates the need for efficient and rigorous design tools as described here.

Consequently, oil and gas companies are continually striving for more efficient and more effective conceptual design, looking at more tieback options, investigating these in more technical detail, and involving more disciplines than ever before. The difficulty with this approach is keeping the numerous disciplines aligned with each other. This is particularly difficult during conceptual design when the rate of change is usually at its greatest. It was with these issues in mind that a new Integrated Production Modelling (IPM) tool, called Maximus, was developed to provide value to project development. This tool is capable of rigorous compositional, thermal hydraulic simulations of entire networks, from reservoirs to topsides facilities. The benefits of such tools are manifold. By solving production networks rigorously, based on full conservation of mass, momentum, energy and chemical species (also referred to as ‘compositional tracking’) such models can simultaneously predict production profiles and solve flow assurance or corrosion problems. Moreover, the production profile can be predicted subject to the various system constraints imposed by multiple engineering disciplines, for example maximum downhole velocities to protect downhole sandscreens or minimum temperatures to avoid hydrate formation. The production 'molecules' from multiple production sources can be tracked within the overall predicted production profile. Thus, such a tool allows a design team to integrate its multidiscipline requirements into a single model which avoid disconnects which lead to costly rework at a later stage.

The system of interest to this study is a large gas gathering network with multiple drill centres. This arrangement is fairly common and occurs in many parts of the world. However, this particular study was unusual in that the fields are located in a region experiencing extreme ambient temperature conditions where the annual window for drilling is comparatively short. Hence, a key objective of the study was to investigate the development plan for offshore facilities within which the drilling schedule can be 'stretched out' while still maintaining to required gas production rates.

The model built for this study is shown in Figure 1. It consists of eight small gas reservoirs (DC-1 to DC-8) individually tied back to an offshore processing and compression facility located on a larger reservoir (referred to as the 'Hub'), which itself is approximately 150km away from an onshore processing facility. Production commences with wells at the Hub but when production rates to the processing facility can no longer be maintained, due to the depletion of the Hub field, the satellite fields are brought on successively. When compression is required, the wells are switched from a HP to a LP manifold in a manner to meet production targets and minimize compression horsepower. The logic controlling this process is described in more detail later in the paper.

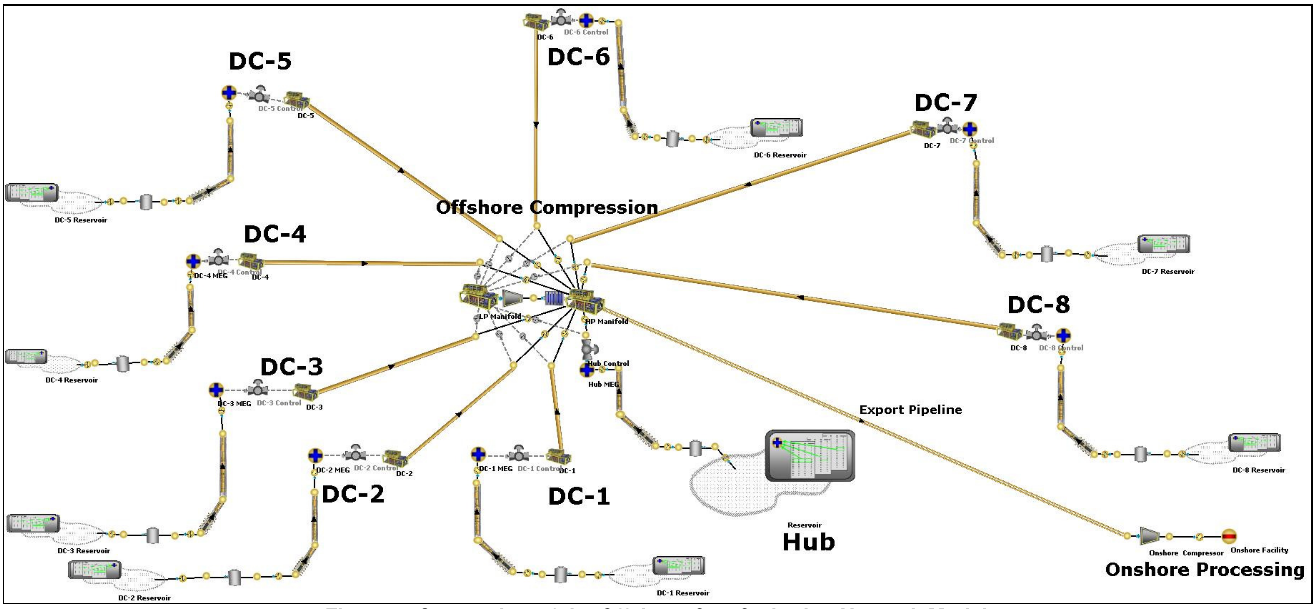


Figure 1: Screenshot of the Offshore Gas Gathering Network Model

Modelling Method

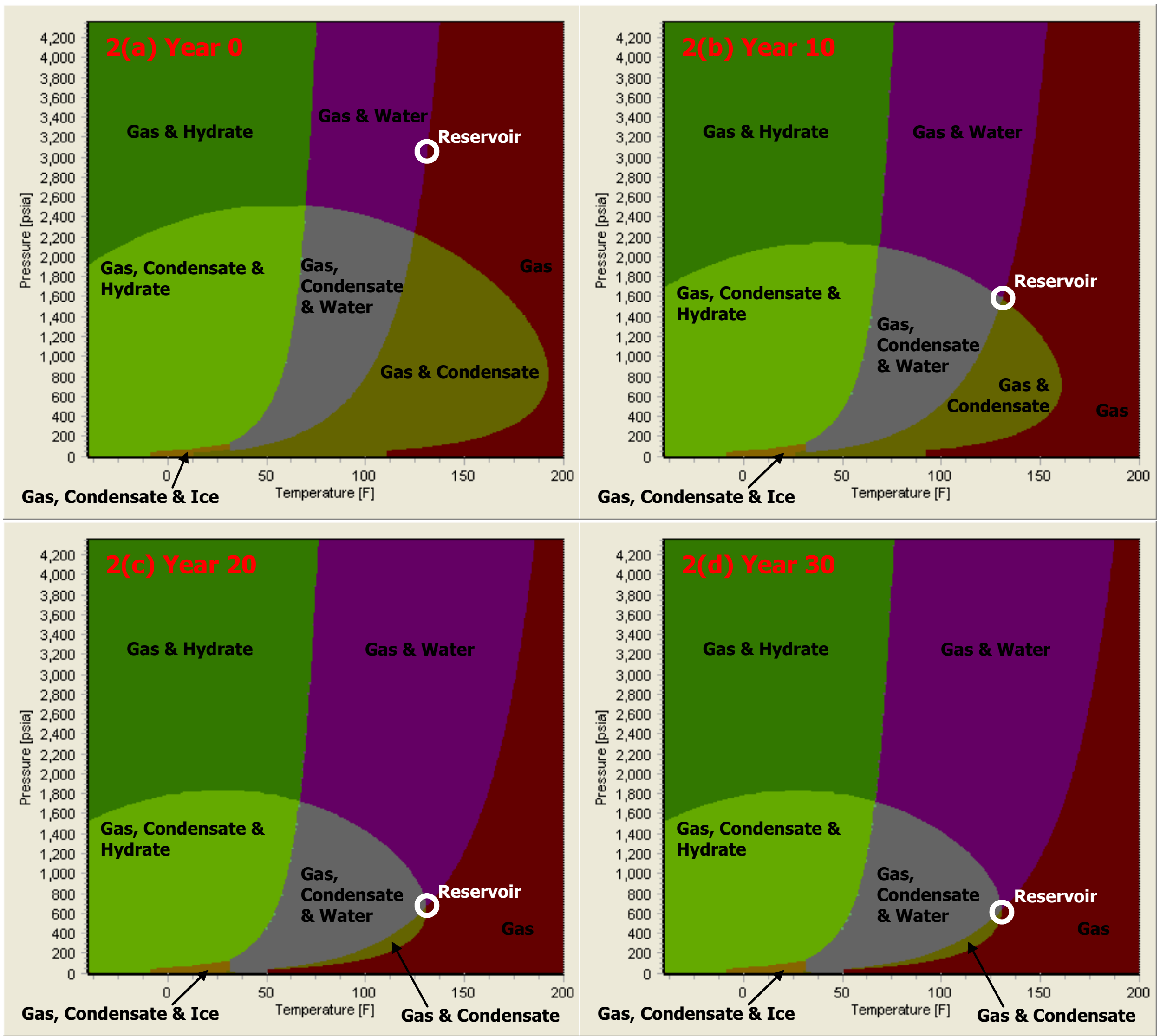
The system was analysed using the Integrated Production Modelling (IPM) technique, i.e. a single simulator capable of predicting the behaviour of the entire production system network, from reservoir to onshore processing facilities. As the simulator used here is a thermal hydraulic IPM, rigorously conserving mass, momentum and energy across the network, temperature is accurately predicted in addition to the prevailing pressures and flowrates. This, combined with its compositional tracking technique, allows the accurate prediction of thermophysical properties, via an interface to the PVT package Multiflash (Infochem, 2008) and the simultaneous calculation of flow assurance issues, such as hydrate formation. Therefore, the production profile is predicted by balancing the pressures and flows in the network, subject to the hydraulic potentials of its components plus any user imposed rules, such as setting the maximum flow rate through a choke or carrying out a set operating procedure if a particular event occurs, etc.

To perform simulations in an efficient and robust manner, the simulator uses the Equation Oriented numerical technique, a method first proposed by Sargent and Westerberg (1964) as a general solver of complex network problems in chemical engineering. How this numerical method was implemented in Maximus is described in more detail in Watson *et al* (2007).

The IPM simulator has two different reservoir descriptions: a material balance method based on one-dimensional tank model and a lookup table containing reservoir depletion characteristics defined by the subsurface discipline. In this study, the reservoirs were modelled using the lookup table approach with simple pressure versus cumulative produced gas decline curves. At each timestep, the composition of the gas produced was saturated with water at constant reservoir temperature, but declining reservoir pressure. It is a simple matter to quickly reassess the concept definition as the reservoir definition improves by updating the lookup table in Maximus.

As the reservoir pressure declines, the mole fraction of water in the gas phase increases, which in turn increases the aqueous phase flow rates in the flowlines over time. Similarly, the hydrocarbon composition of the fluids also changes over time; the completions are assumed to be in a reservoir's gas zone, hence once a reservoir enters the retrograde region and condensate starts to drop out, this remains in the reservoir giving a leaner produced gas composition over time. Figure 2 illustrates how the Hub fluid composition changes by showing a series of pressure-temperature phase diagrams for the fluids over time. Different regions of the diagram are coloured according to which phases are present within them. As time progresses and the fluid composition changes – specifically the gas contains a higher level of saturation water but becomes leaner in condensate components – the phase diagram changes. In particular, the water dewpoint line shifts to the right-hand side and the gas dewpoint curve shifts to the left-hand side as shown in Figures 2(a) to (d).

It should be noted that in Figures 2(a)-(d), the critical points are not shown because they are, in fact, located on the boundary between dense phase and two phase hydrocarbon at lower temperatures than can be seen on these diagrams. For this reason, hydrocarbon fluid in the supercritical region is referred to as "gas" because, while it is strictly dense phase, it is more gas-like than liquid-like.



Figures 2(a) to (d): Phase Diagrams of Hub Produced Fluids at Various Times in the Reservoir Depletion.

The IPM simulator used can currently allow up to ten different phases to coexist in the network simulation, including three hydrate phases (types I, II and H), wax and ice. Hence, the precipitation of solids can be predicted and, provided the user has entered appropriate events, flow assurance procedures can be automatically carried out during a simulation. Hydrates and ice were the main flow assurance concerns in this system and so continuous glycol injection at the wellheads was implemented in order to prevent either solid from forming and causing blockages. As glycol is more dense and has a viscosity that is more than thirty times that of water, if the hydraulics in the pipeline network are to be modelled correctly in the IPM, it is important that glycol injection and water-glycol liquid characteristics are included. Also, the inclusion of glycol in the model enabled early and accurate assessement of glycol injection and regeneration requirements. To achieve this, glycol injection points were added at each drill centre. This was done using mass rate specified sources with a composition of 90 wt% glycol in water. Instead of being set to a fixed mass flow rate, they were set to a user defined equation, which was a correlation of required glycol rate as a function of liquid water flow rate, temperature and pressure at the design point in question. This correlation was tuned to Multiflash hydrate curves at various glycol concentrations to ensure just enough glycol was added at all timesteps.

A mechanistic multiphase model (Ansari *et al*, 1994) was selected to simulate the hydraulic behaviour of the gas wells. The wells spend most of their lives between the annular and churn (froth) flow regimes. To best manage wellhead pressure which is a critical issue for gas well delivery, the flowlines were permanently in stratified flow. It was important to select an appropriate mechanistic multiphase model, since the operability of wet gas flowlines is governed by their pressured drop and holdup characteristics. A sensitivity study of several published stratified flow models was carried out to understand the range of pressure drop and holdup characteristics predicted by various 'steady state' models. The models considered are listed as follows:

- Taitel and Dukler (1976).
- Taitel and Dukler (1976) with the Andritsos and Hanratty (1987) interfacial friction factor model.
- Taitel and Dukler (1976) with the Bendiksen *et al* (1991) interfacial friction factor model.
- Taitel and Dukler (1976) with the Danielsen and Ericksen (1997) interfacial friction factor model.
- Taitel and Dukler (1976) with the Fan *et al* (2007) interfacial friction factor model.
- Fan *et al* (2007).

The Taitel and Dukler model (1976) is one of the first mechanistic stratified flow models to have been used in the oil and gas industry. It is based on the assumption that the gas/liquid interface is planar, and it uses a Blasius (1913) style correlation for the gas/liquid interfacial friction where the interface is assumed to be smooth. By underestimating the roughness of the gas/liquid interface the momentum flux from the gas to the liquid phase is underpredicted, which gives lower liquid velocities, hence higher liquid hold-ups than occur in practice. Despite its limitations, the Taitel and Dukler model is still widely used and many researchers have attempted to improve its closure relationships to give a concomitant improvement in the liquid holdup and pressure drop predictions.

Andritsos and Hanratty (1987) proposed a critical gas superficial velocity, below which the gas/liquid interface was smooth, as per the Taitel and Dukler (1976) model, however above this critical superficial velocity large amplitude waves occurred on the interface. They proposed a correlation for this critical gas superficial velocity based on the gas density and another correlation to modify the Blasius (1913) style friction factor correlation when the system is above this critical superficial velocity.

Bendiksen *et al* (1991) proposed another model for interfacial friction factor, based on a mechanistic model for calculating the wave height. The friction factor calculated by this method was capped between a minimum Blasius style smooth interface value and a maximum value based on a variant of the Wallis (1970) model. This implementation was used in an earlier version of the stratified flow model in OLGA.

Danielsen and Erickson (1997) proposed a variant on the model by Bendiksen *et al* (1991) which compared better to stratified flow holdup data.

The more recent model by Fan *et al* (2007) applies a variant of the Andritsos and Hanratty (1987) model for interfacial friction but, in addition, removes the assumption of a planar interface. Based on experimental evidence, Fan *et al* (2007) propose a model where the interface has a "crescent moon" shape, rather than a simple segment shape (see Figure 3). In this comparison, we have used two forms of the model by Fan *et al*, one with a planar interface (Taitel & Dukler) and one with the crescent shaped interface.

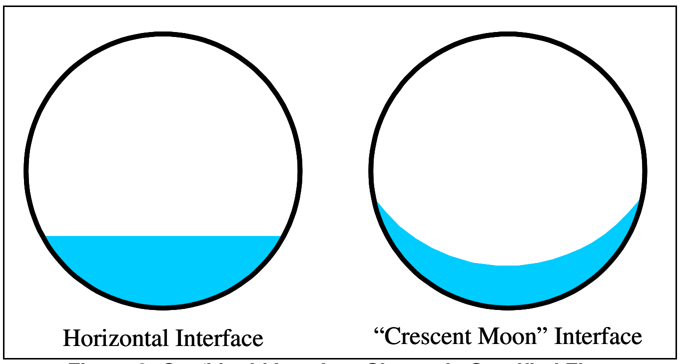


Figure 3: Gas/Liquid Interface Shapes in Stratified Flow

Figures 4 and 5 compares the results for the various stratified flow models as inlet pressure and total liquid content for a range of gas rates for typical early life conditions (CGR 2.4 stb/mmscf, plus condensed water dosed with glycol), assuming twin 36-inch by 150 km export lines. The importance of an accurate pressure drop prediction at full rate is obvious; it will affect the compression and drilling schedule requirements to maintain the system at the rate required by the onshore processing facility (1800 mmscfd). However, at this rate the pressure drop in the system is relatively small (~290 psi) and the various correlations agree reasonably well (+/-30 psia), with Fan et al (2007) being the most conservative. For this system, even if 1800MMscfd passed through the compression system, a 30 psia error in export pipeline inlet pressure would only give an error in offshore power requirement of around 1 MW, which is considered acceptable, given the accuracy at which we need the offshore compression system power requirement at this stage. Accurate holdup predictions are also important; liquid holdup during normal operation is needed to calculate the residence time of glycol, from which the glycol storage volume requirements can be estimated.

More important still is the holdup calculation at low flow rates; or rather the minimum turndown rate the pipeline can operate at without accumulating excessive liquid volumes. Slug catchers can be sized to deal with the problem of liquid surges and the required surge volume can be estimated by analysis of the steady state holdup versus flow rate curve (Cunliffe, 1978) or by transient simulation. However, it is preferable to operate the system above this critical rate, as much as possible, to prevent liquid accumulation and limit the size of onshore slug catchers. Hence, it is desirable to be able to accurately predict the liquid holdup curve as a function of flow rate, and the position where the liquid holdup begins to increase markedly with reducing flow rates.

In this assessement the critical flow rate below which excessive liquid volumes will start to accumulate is between 450 and 600 mmscfd, depending on which model one uses, but excluding the original Taitel and Dukler model which is thought to be overly conservative. If the twin export flowlines are operated at rates below this critical rate for several weeks, the liquid volumes generated could cause significant operational difficulties. These difficulties could arise when the flow rate is increased again and the large liquid volumes are swept out and arrive as a large liquid surge at the onshore processing facility.

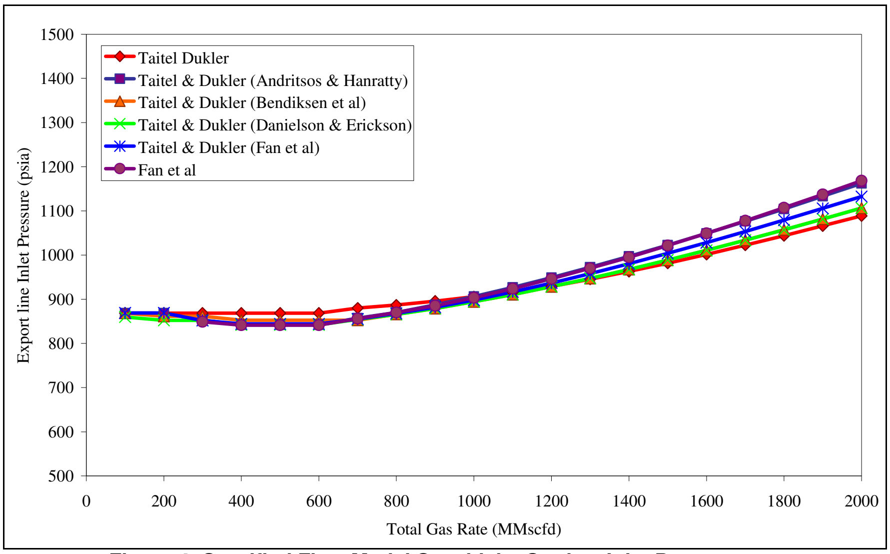


Figure 4: Stratified Flow Model Sensitivity Study – Inlet Pressure

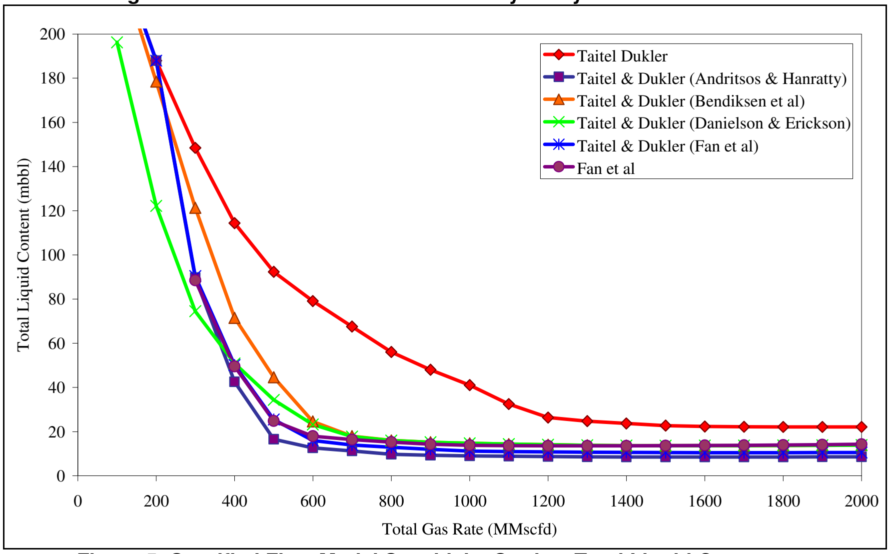


Figure 5: Stratified Flow Model Sensitivity Study – Total Liquid Content

However, in addition to the uncertainties associated with the modelling methods, for example the magnitude of interfacial friction between the gas and the liquid, there are other significant uncertainties that affect the predictions and therefore hydraulic related risks. One such uncertainty is the effect of flowline topography which is notoriously poorly defined at the time of concept selection. For this study, only coarse elevational profiles were available; as can be seen in Figure 6. The pipeline geometry used for the sensitivity studies reported in Figure 5, was a simple series of straight pipe sections between the elevation data. This represents an approximation to the actual geometry the pipeline would have after installation. By comparison, the actual geometry will be considerably more complicated and will follow a smooth curved path through the elevation points.

To investigate the effect of elevation definition and, in particular, small length scales not available till pipeline surveys are taken, a series of different geometries were generated for different undulation assumptions. Sinusoidal waves of various amplitudes and wavelengths were superimposed on the straight pipe geometry from Figure 6. An example of which is given in Figure 7.

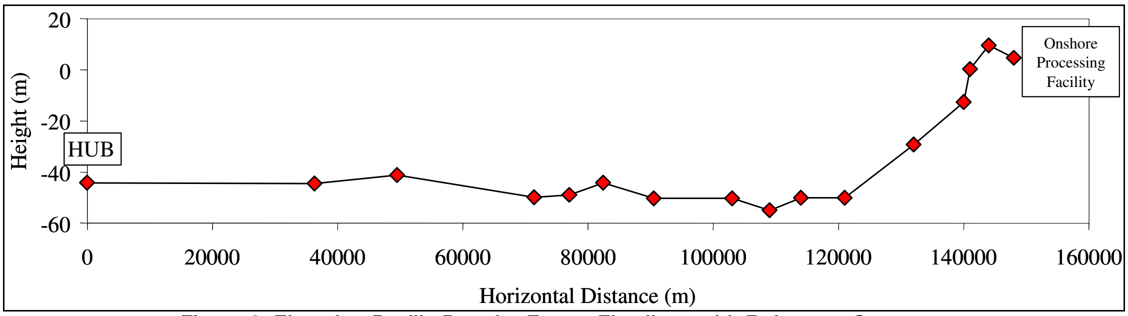


Figure 6: Elevation Profile Data for Export Flowlines with Reference Geometry

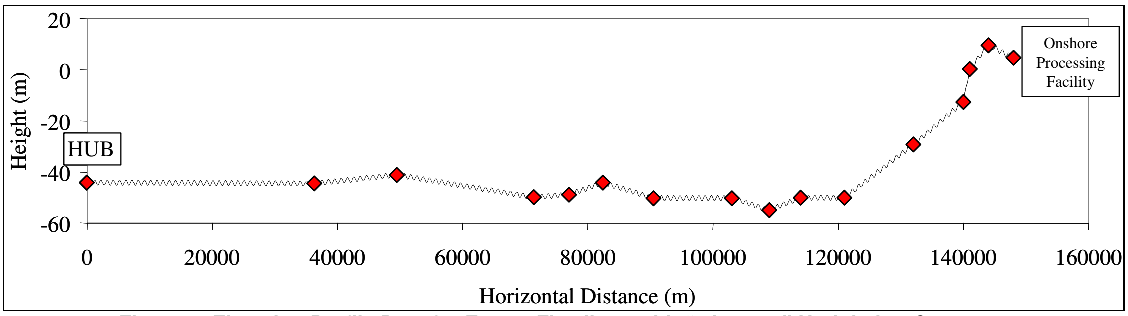


Figure 7: Elevation Profile Data for Export Flowlines with “1 in 1000” Undulation Geometry

The following combinations of amplitudes and wavelengths were investigated:

- “1 in 1000”; i.e. 1m amplitude, 1000m wavelength (as shown in Figure 7).
- “0.5 in 1000”; i.e. 0.5m amplitude, 1000m wavelength
- “0.1 in 1000”; i.e. 0.1m amplitude, 1000m wavelength
- “0.1 in 100”; i.e. 0.1m amplitude, 100m wavelength
- “0.05 in 100”; i.e. 0.05m amplitude, 100m wavelength
- “0.025 in 100”; i.e. 0.025m amplitude, 100m wavelength
- “0.01 in 100”; i.e. 0.01m amplitude, 100m wavelength
- “0.01 in 10”; i.e. 0.01m amplitude, 10m wavelength

Even the largest amplitude undulation (1 in 1000) barely shows in Figure 7 and it should be noted that the scale of the x-axis is nearly three orders of magnitude exaggerated compared to the y-axis; otherwise the whole pipeline would appear as a horizontal line.

Figure 8 shows the total liquid content result from this sensitivity using the Fan *et al* model. As can be seen, even these small amplitude sinusoidal undulations are sufficient to change the location of the minimum turndown flow rate by approximately 200 MMscfd. It is interesting to note from Figure 8 that undulations that change the pipeline gradient by the same amount give similar total holdup results. For example; “0.01 in 10”, “0.1 in 100” and “1 in 10000” span three orders of magnitude of added undulation amplitude, from 1cm to 1m. However they have the same effect on the total hold-up curve. The elevation gradient, as differentiated from absolute evelvation, is known to be a key parameter for gas-liquid slip and liquid holdup distribution.

Though it could be imagined that the geometry of the pipeline will one day be better defined, it is unlikely to ever be known to within “0.1 in 100”, especially during conceptual design, when the pipeline engineers are still optimising the route and no survey data are available.

It is important during concept developments to identify limit state requirements for the system based on the range of definition available. In this case, the production system should not operate either pipeline at less than 700 mmscfd based on the range of predictable definition. Without defining the sensitivity range, a 500 mmscfd might have been determined as an acceptable operating limit. The range of operating limits can have significant design and availability risks for the offshore production and onshore process concept selection.

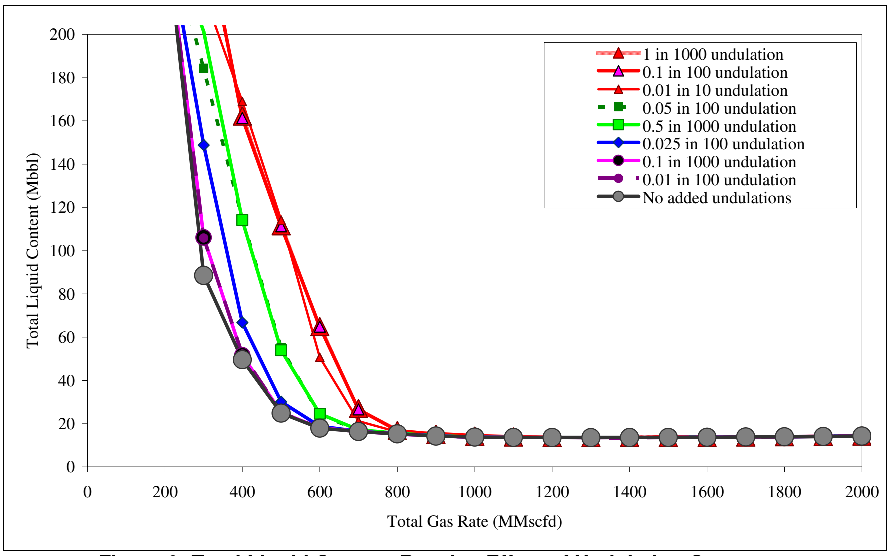


Figure 8: Total Liquid Content Results, Effect of Undulation Geometry

While complex process system networks, with chokes, compressors, separators, heaters and coolers etc can be modelled in the IPM simulator (Watson *et al*, 2007), in keeping with the preliminary nature of this study, the offshore compression system was modelled using a simplified scheme. Figure 9 shows a magnified view of the layout from Figure 1, centred on the offshore compression system. The process system includes a single compressor with its cooler, and two manifolds (LP and HP) together with a network of manifold "pipework". The routing of gas from the various fields to either the LP or HP manifolds is controlled with user-defined logic. The primary objective of this study was to establish the magnitude and timing of the offshore compression systems with optimisation of producing center, production availability.

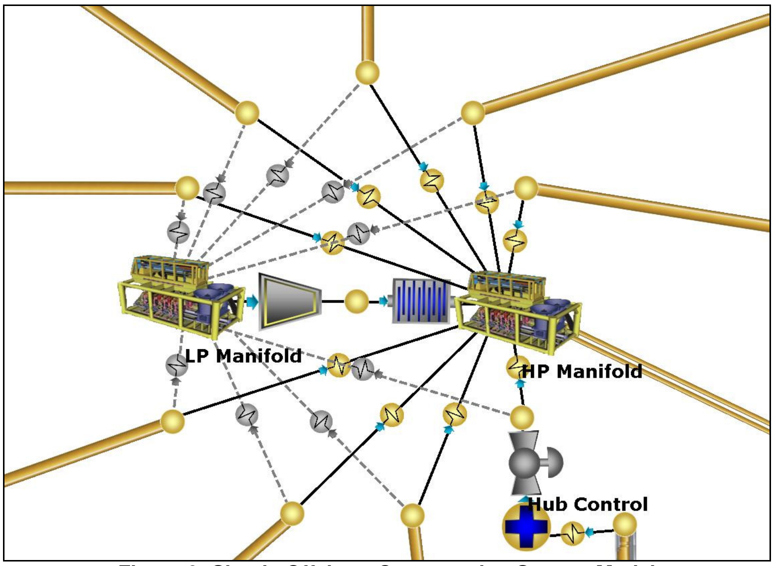


Figure 9: Simple Offshore Compression System Model

The onshore processing facility has a fixed arrival pressure of 800 psia for an initial assessment. The potential benefits of additional onshore compression (as opposed to offshore) were also investigated by the addition of an onshore compressor. The capacity and timing of offshore and onshore compression and integrated impact for offshore, production capacity/availability was also analysed, but will not be discussed in this paper.

Well/Production Availability

Access to site to drill wells had seasonal limitations. Phased production and drilling were important criteria for concept selection. The logical scheme developed for the model is described as follows:

1. Gas was produced from the Hub reservoir at 900 MMscfd as soon as 6 wells had been pre-drilled. This was based on the assumption that the maximum well rate is 150 MMscfd (to avoid formation damage and/or erosion concerns) and that the onshore process facility could operate at half of the maximum capacity (1800 MMscfd) by using only one of its two trains.
2. An additional six wells would be available at the offshore Hub facility one year from startup. The onshore process facility would be ramped up to its full 1800 MMscfd capacity.
3. In these early years, gas from Hub flows directly to the export pipelines; i.e. no offshore compression is required. As discussed above, glycol is injected at the Hub to avoid hydrate and/or ice conditions in the export flowline.
4. How many wells can produce from the central Hub to provide onshore process requirements and the decline rate is a central question in concept selection. Eventually adding new wells at the Hub suffers from the 'law of diminishing returns'; wells are needed at a faster and faster rate as the reservoir is depleted until it is no longer sensible to drill further wells at the Hub. One of the results of this study was to determine the maximum well count at the Hub before offshore compression and/or additional tiebacks are more economic. The maximum Hub well count depends on the systems hydraulic impedance and is, therefore, also a function of the choice of export flowline size.
5. Once the point of diminishing returns for well count has been determined for the Hub, just before the system drops off plateau, the Hub wells are directed to the LP manifold and compression is used to maintain the 1800 MMscfd rate. Specific pressure steps, e.g. a factor of two, were used to determine LP-HP requirements and well productivity against those wellhead pressure steps.
6. The Offshore compression system power requirements were evaluated against time for and number of subsea tieback production centers. DC-1 was the first satellite to come on stream with 4 wells giving a maximum total rate of 600 MMscfd. The timings of the drilling sequence for the subsea centers and compression requirements were key evaluation criteria for the integrated production modelling. Initially, the production from all new satellite fields is directed to the HP manifold (i.e. no offshore compression). As with the Hub, glycol is injected at DC-1 to keep its flowline to the Hub outside of the hydrate and ice regions. In addition, the Hub glycol supply rate was adjusted to take into account these new glycol requirements.
7. When the system's production rate declines below the onshore process requirements, the DC-1 wells are first directed to the LP manifold, where the pressure is again balanced to optimise compressor power.
8. If the compressor power requirement is exceeded and the system is about to drop off plateau, the next satellite field DC-2 starts production to the HP manifold (also with 4 wells and 600 MMscfd maximum total rate). Glycol is also injected at DC-2 to keep its flowline out of the hydrate and ice regions, and the glycol rate at the Hub (for the Export flowline) is adjusted accordingly.
9. Steps 5 to 8 are then repeated to bring on DC-3 to DC-8 and switch them from HP to LP manifold accordingly. The tradeoffs between offshore compression power and timing, HP-LP manifold pressure definition, well availability, and subsea center availability were core concept definition requirements possible with integrated production modelling.

In practice, the optimum production profile from this system would depend on the ownership of the various fields, the relative value of the production streams, and commercial agreements for producton allocation and processing. These commercial issues can be built into the IPM at a later stage of design to track independent fluid molecules, however for this stage the production system potential (i.e. offshore compression capacity and onshore processing rate) was allocated between the active fields by dividing the reservoirs into two classes:

- HP wells; i.e. all the wells directed to the HP manifold. They were allocated their maximum potential rate, subject to the maximum per well rate of 150 MMscfd and the maximum onshore processing rate of 1800 MMscfd.
- LP wells; i.e. all the wells requiring offshore compression. The total amount of gas required from the compression system was calculated as the difference between the processing capacity (1800 MMscfd) and the amount produced from the HP manifold wells. The rate allocated to the offshore compressor was then divided between LP wells on a pro-rata basis, based on their hydraulic optimum potential to produce gas.

From a physical standpoint, this allocation scheme is most efficient because it will preferentially produce from HP wells and thus minimise overall power requirements.

The IPM model is now ready to perform sensitivity studies on key design variables such as pipeline diameter, offshore compression capacity, timing of well availability, and onshore processing capacity.

Results

As discussed in in the previous section, once 12 wells have been drilled on Hub, further wells can be drilled in order to delay the requirement for offshore compression. The first stage to the study was to investigate this "law of diminishing returns" by adding a new well on Hub everytime it was about to drop from the target rate when producing to the HP manifold up to a maximum of 50 wells. Figure 10 plots the minimum Hub well count required to maintain demand rate (900 MMscfd in the first year, 1800 MMscfd thereafter) and, for reference, the pressure drop across the Hub well chokes into the HP manifold. The results clearly show the declining value of increasing well count at the central Hub due to the ever declining reservoir pressure. For example, in year 4, less than one new well is needed per year, between years 6.5 and 8, more than three new wells are needed per year and between years 8 and 10, eight new wells are needed per year. This curve was compared to the Hub drilling constraints for the time required to add additional wells at the hub. A maximum Hub well count of 20 (year 6.5 in Figure 10) was chosen for the offshore compression assessment studies.

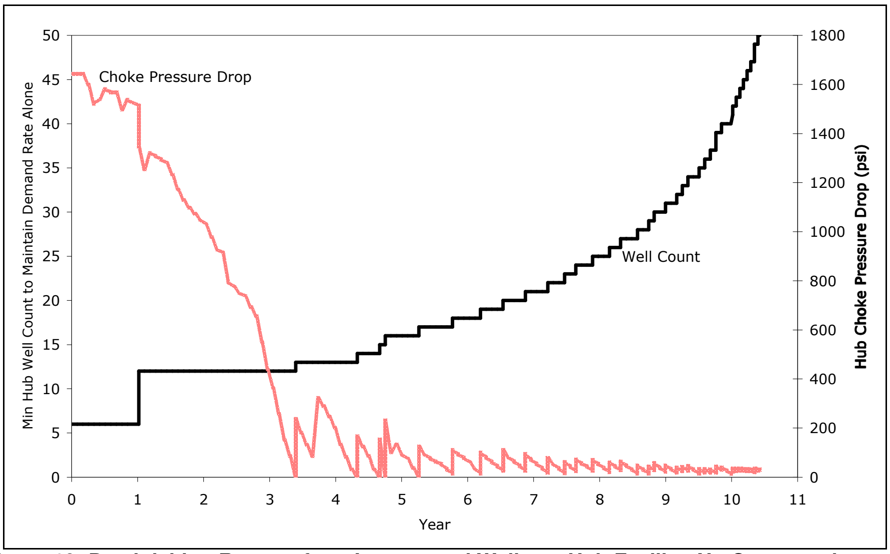


Figure 10: Deminishing Returns from Incremental Wells on Hub Facility, No Compression

An offshore compression power sensitivity study was carried out ranging from 0 to 60MW in 15MW increments. Figure 11 plots the total well count for each of these scenarios (including four wells per subsea production center when greater than 20 Hub wells are required). Figures 12(a) to (e) show the production profiles from these simulations.

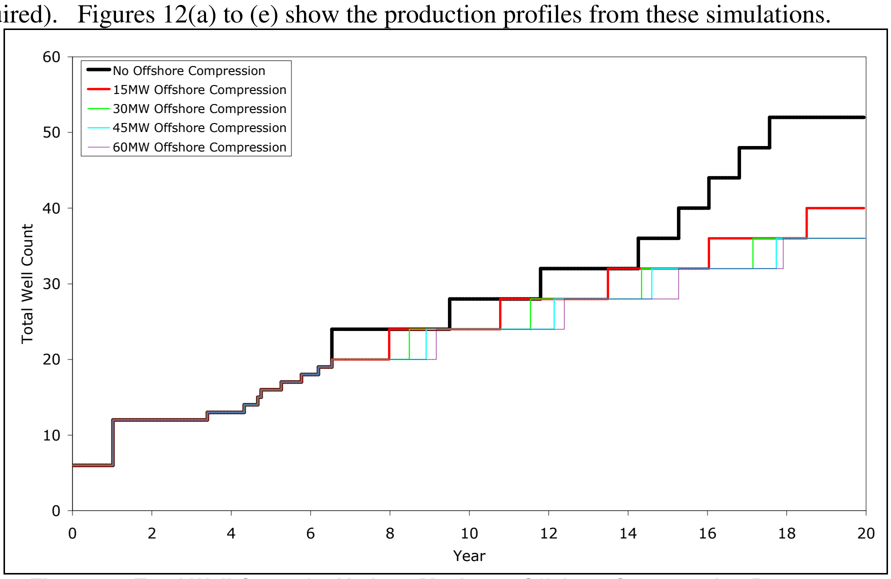
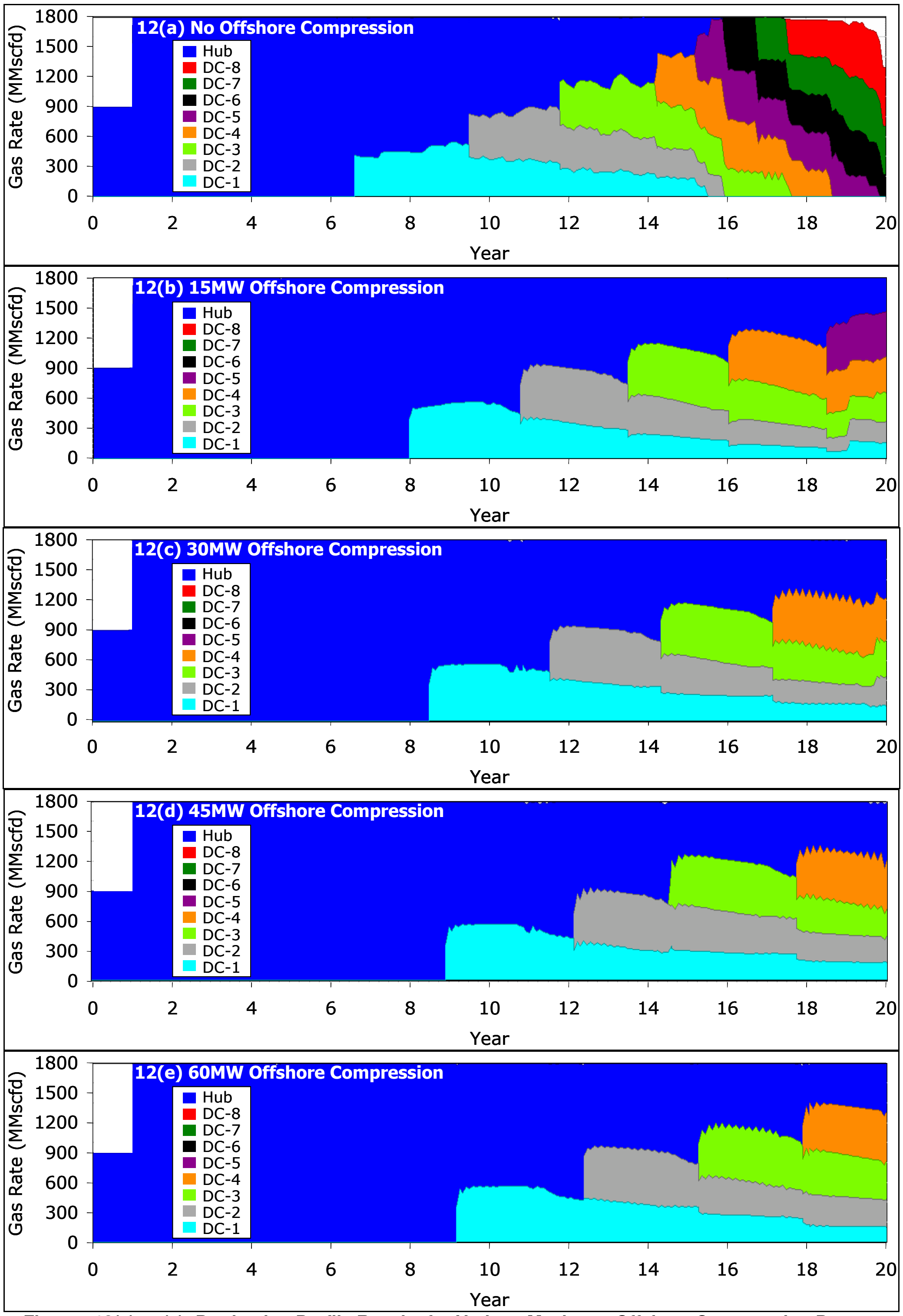


Figure 11: Total Well Count for Various Maximum Offshore Compression Powers

The timing and value of the offshore compression, pressure boosting capacity, i.e. MW, is clearly shown in Figure 12. The greater the offshore compression capacity, the longer the delay is between new satellite fields starting up. The first 15 MW delays the offshore compression need by 1.5 years. An additional 15 MW adds another six months to the delay. The value of this capacity addition might be questionable. An additional 15 MW (i.e. 45 MW total capacity) only adds four months to the delay. However, the first 15 MW reduces the need for three subsea drill centers DC-6, DC-7, and DC-8 to meet the production profile. These three subsea centers represent an additional 12 subsea wells. A 30 MW total capacity, delays the requirement for DC-5, which represents 4 subsea wells. Adding more compression capacity beyond 30 MW to meet the production life requirements does not eliminate the need for additiona subsea wells. There is a clear addition to asset value for 30 MW of offshore compression, but limited value for greater than 30 MW.



Figures 12(a) to (e): Production Profile Results for Various Maximum Offshore Compression Powers

Determining the optimal offshore gas compression capacity requires economic analysis of the system to compare the relative costs of various drilling rates, the offshore compression capacity and the relative values of the gases from each satellite at the various condensate/gas ratios (CGRs) generated during production. However, it is clear from Figure 12 that there is a quickly diminishing return on increasing the compression power beyond 30 MW. This is because the deliverabilities of the tubing and tieback flowlines are non-linear with offshore LP manifold pressure. The root cause is because as the pressure is reduced, the gas velocity increases, and the the frictional pressure drop increases non-linearly with gas velocity.

As the network model is fully compositional, not only are the fluid physical properties calculated accurately, output can also be generated for other disciplines such as corrosion and process engineers. Figure 13 illustrates how the composition changes for the 30 MW case, by plotting CGR and LGR (including glycol). As discussed earlier, once the Hub reservoir drops to the dewpoint curve, the Hub gas becomes leaner over time due to retrograde condensation. Consequently, by the time new fields, which are assumed to have the same initial composition as the Hub, temporarily increase the CGR of the produced fluids in the export line until they too reach their retrograde region. This simulation can now be used as the basis for calculations for other disciplines, such as repeating the holdup sensitivity calculation in Figure 8 for a range of alternative LGRs to get a better picture of the operability of the system through time.

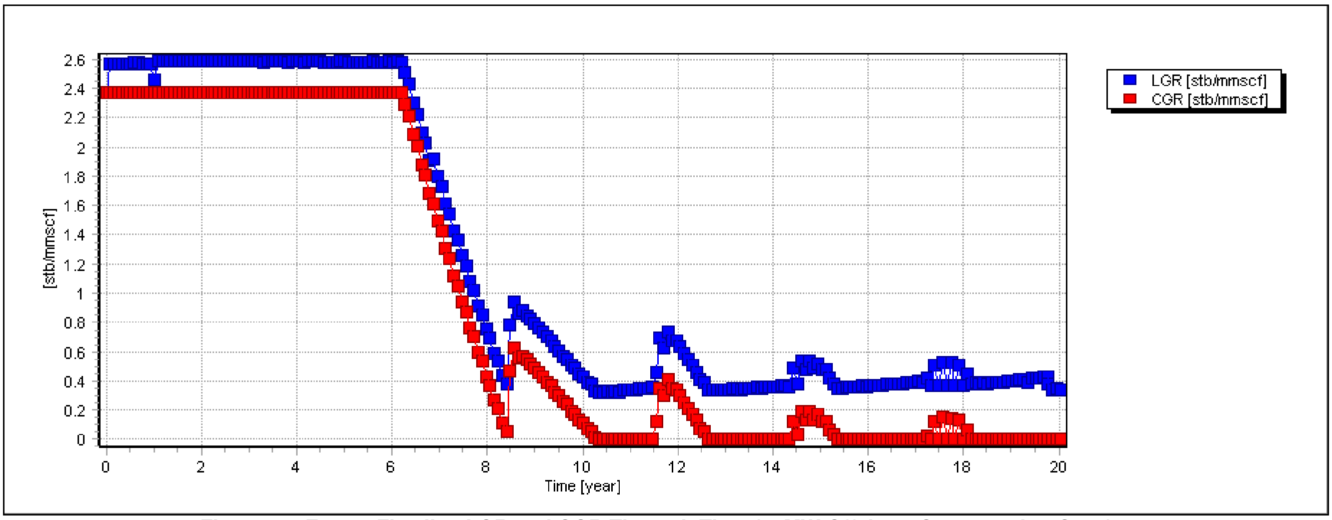


Figure 13: Export Flowline LGR and CGR Through Time (30MW Offshore Compression Case)

Figure 14 plots the glycol injection flow rates calculated as part of the IPM simulation. These data, combined with the manifold pressures, can then be used to design the glycol injection system for hydrate/ice avoidance. As the IPM tool used can model several coexistent thermodynamic phases flowing in the network (not just gas, hydrocarbon liquid and aqueous phase), the effectiveness of the hydrate/ice avoidance strategy can be checked by plotting the hydrate and ice flow rates at all points in the system. This is convenient, as a single plot can show if any section has precipitated hydrates, wax, salts, etc at any time in field life.

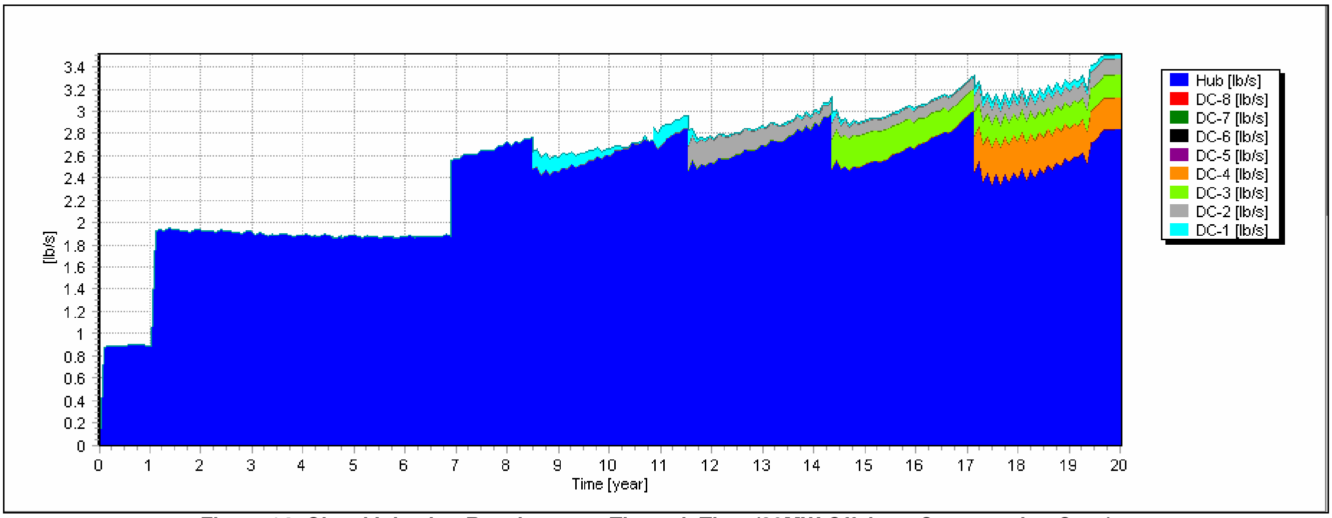


Figure 14: Glycol Injection Requirements Through Time (30MW Offshore Compression Case)

Alternatively, a more traditional way is to plot the pressure/temperature loci of the pipelines on the phase diagram. Figure 15 shows such a plot for the fluid composition, temperatures and pressures in the export flowline for year 15 in the 30 MW compression example. As can be seen, the export line (inlet temperature 55°F, pressure 1100psia) just avoids the hydrate region as it enters the onshore processing facility.

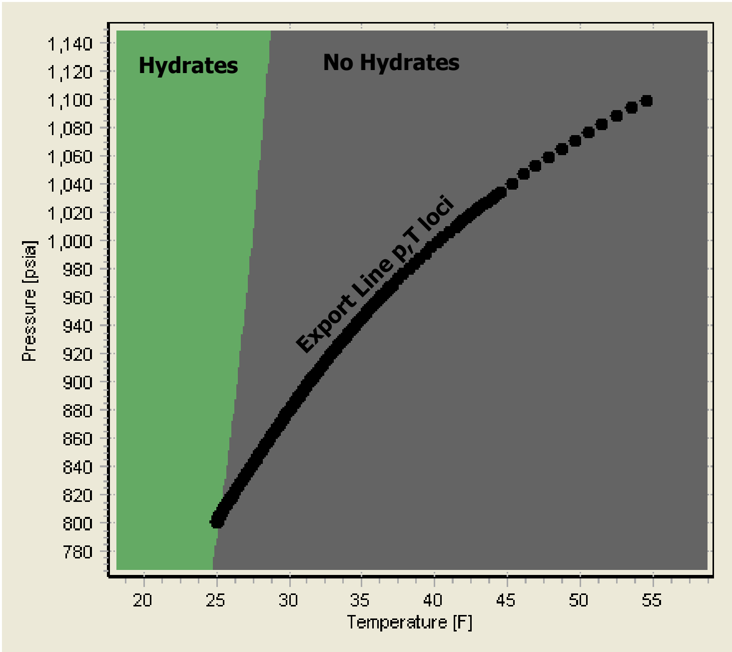


Figure 15: Export Line Phase Diagram Illustrating Hydrate Avoidance (Year 15, 30 MW Offshore Compression Case)

Conclusions

Integrated Production Models (IPMs) can improve the efficiency of conceptual design by enabling fast investigation of hundreds of different development strategies and the effects of the key design variables, such as drilling schedule, tubing/pipeline sizes, production capacity, artificial lift etc on the revenue stream. Even with significant uncertainties in the base data, such studies can improve later design definition towards a robust and economic solution and highlight what technical definition range must be worked further for incremental value.

However, the technical issues associated with new developments are often complex, either due to the nature of the fluids, the location of the field or due to the novel technologies required to make them economic. Many of these complex issues cannot be investigated using conventional IPM tools, as their simplistic approximations regarding the compositional, thermal and thermodynamic behaviour of the fluids limit their ability to screen issues such as flow assurance or corrosion. In more recent years, efficient numerical methods such as the Equation Oriented approach allow Integrated Production Modelling to be carried out quickly with the same level of rigour as traditional flow assurance or process system investigations. Consequently, the issues of concern to other disciplines can be accounted for during the production profile generation, reducing the number of design iterations and reducing the number of unnecessary design assumptions.

Nomenclature

CGR	Condensate Gas Ratio at Stock Tank Conditions
IPM	Integrated Production Model
LGR	Liquid Gas Ratio at Stock Tank Conditions
MMscfd	Million Standard Cubic Feet per day
MW	Mega Watts
wt%	Weight Percent

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