Production recovery and economic performance of subsea processing technologies for longer and deeper gas field developments

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ABSTRACT

The exploration of gas fields in more remote and / or deeper water environments will continue to increase over the coming years. The economic viability of these fields needs to be demonstrated or else they will be left stranded. Gas field developments entail numerous multifaceted issues related to the transported fluid such as: pressure drop, liquid hold-up, hydrates, corrosion and sand. The recent subsea technology development, Pseudo Dry Gas System (PDGS), has demonstrated that deep water fields (~2000 m) can be transported long distances (~200 km) to existing processing facilities [Ref. 1].
The objective of this paper is to compare the available subsea processing options, based on recoverable reserves, extent of plateau production and the economic performance.
The paper will examine emerging subsea processing arrangements from subsea dry and wet gas compression to PDGS whilst highlighting the impact of a conventional subsea tieback. The paper examines the work previously performed in the DEPTH study [Ref. 2] in selecting the subsea processing options whilst using the current processing performance as constraints in the modelling. A set of key parameters that impact the amount of recoverable reserves will be assessed; these include: tie-back distance, water depth, water production and reservoir size. The use of a life of field integrated modelling approach using the latest multiphase correlations with the in-built subsea processing equipment is linked with economic models to evaluate the long-distance gas development options and chose the best techno-economic subsea processing technology.
The paper will demonstrate the subsea processing operating envelopes for all the variations examined, water depth, tieback distance, water production and reservoir size and highlight the arrangements which maximise the recoverable reserves, increase the plateau production and provides the best economic performance of all the subsea processing technologies examined.

1 DEFINITIONS AND ABBREVIATIONS

PDG = Pseudo Dry Gas
FLNG = Floating Liquified Natural Gas
LNG = Liquified Natural Gas
DEPTH = Deep Export Production and Treatment Hub
CAPEX = Capital Expenditure
OPEX = Operating Expenditure
CGR = Condensate Gas Ratio
LGR = Liquid Gas Ratio
WGR = Water Gas Ratio
MEG = Mono Ethylene Glycol
GIIP = Gas Initially In Place
TCF = Trillion Cubic Feet
MMSCFD = Million Standard Cubic Feet per Day

NF = Natural Flow
WGC = Wet Gas Compression
FPS = Floating Production System
DGC = Dry Gas Compression
SS = Subsea Separation
SUTA = Subsea Umbilical Terminal Assembly
PSUTA = Power Subsea Umbilical Terminal Assembly
XT = Xmas Trees
CFD = Computational Fluid Dynamics
HP = High Pressure
LP = Low Pressure
ID = Internal Diameter
GVF = Gas Volume Fraction
IRR = Internal Rate of Return
NPV = Net Present Value
MW = Mega Watt
bbl = barrels
D/S = Downstream

2 INTRODUCTION

Pseudo Dry Gas Technology (PDG) aims to dramatically improve the efficiency of gas transportation using the natural gas reservoir pressure by minimising the gravitational pressure losses, by the means of integrated piggable liquid removal units. The liquid removal units are designed to be 'in-line' pipeline structures. The benefits of the technology are to significantly increase the range of subsea tie-backs to existing facilities and increase the recoverable reserves within a gas reservoir.

PDG technology is based on two main proven technology concepts (1) drains along gathering networks developed in the onshore coal seam gas industry (phenomena which is very poorly understood but operationally proven) (2) piggable liquid knock-out drums from onshore flare piping. These two concepts are combined into the subsea environment. Through increased flow assurance understanding and other subsea engineering in key areas, it will be robustly demonstrated that a subsea tie-back more than twice the normal distance is attainable, without the need of compression via topside or subsea.

The current best available design solutions for stranded gas fields are subsea compressors, floating/fixed structures above the water line to process the fluid before pumping it back to shore, or Floating Liquefied Natural Gas (FLNG) vessels. All of which generate a step change in costs.

The DEPTH (Deep Export Production and Treatment Hub) project [Ref. 2] examined the limits to the current subsea gas development approach and highlight technologies needed to solve the technical and economic challenges for future long distance subsea tiebacks to shore. The project focused only on one step out challenge 2500 m water depth, 300 km from shore.

3 OBJECTIVE

This study analyses the life of field studies with various subsea processing arrangements including conventional and emerging technologies using integrated production modelling to characterise the effect on recoverable reserves. The models are tested against a set of key parameters that may drive towards a subsea gas development; these include: tie-back distance, water depth and water production. Where required, the processing constraints, like power, flow and pressure gain are considered in the modelling. The study assesses the influence of each of the key parameters on the performance of the subsea processing arrangements and on the recoverability of the gas to highlight the types of field where subsea processing will have the biggest influence.

The use of the new technology, Pseudo Dry Gas, was also assessed to compare the results with existing subsea development technologies. The commercial impacts (CAPEX and OPEX) on each arrangement have been estimated for all cases.

4 BASIS OF CASE STUDY

4.1 Key Parameters

There are several independent and dependent variables which can impact the results of the study; therefore, it was necessary to select a set of constant input data to readily compare the options to determine the influence of the dependent variables. The dependent variables analysed were:

- Water depth;
- Tie back distance;
- Reservoir size;
- Amount of liquid; and
- Arrival pressure.

The following sections will present the key parameters used within the study.

4.1.1 Fluid Properties

A standard gas condensate composition was selected with a CGR of 2 bbl/MMscf at standard conditions. The CGR varies with pressure and temperature, so the amount of liquid condensed varies as the gas is transported down the pipeline; the variation in CGR is shown in Figure 1

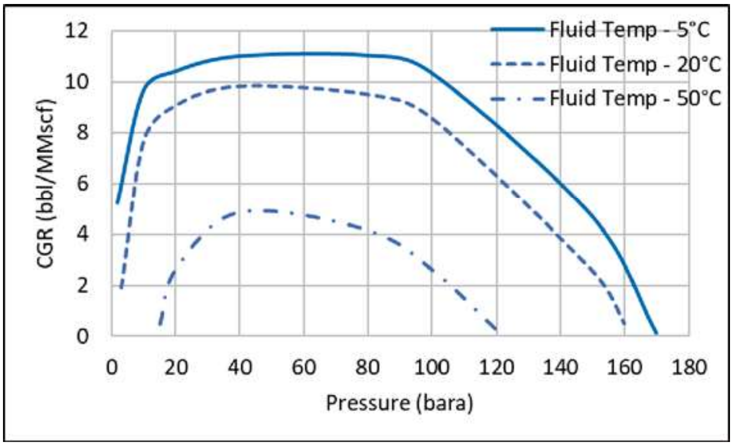

Figure 1: CGR variation with pressure and temperature

The impact of increased liquid was assessed using the addition of more water and MEG (for hydrate inhibition). Two WGRs were analysed; these are:

- Low WGR – 1 bbl/MMscf
- Mid WGR – 10 bbl/MMscf

4.1.2 Reservoir Properties

The reservoir properties were kept constant, except for the 3000 m water depth case and the size of the reservoir in terms of the amount of Gas Initially In Place (GIIP). The total recoverable reserves depend on the abandonment pressure which depends on the process scheme employed. Recovery will be examined for each scheme. The independent reservoir properties which were fixed in the study are presented in Table 1. Three reservoir sizes considered to determine the effect of field size are:

- Small - 1 TCF GIIP;
- Medium - 3 TCF GIIP; and
- Large - 5 TCF GIIP.

The reservoir parameters which change due to water depth are shown in Table 2.

Table 1: Independent reservoir properties

Property	**Value**
Net to gross (%)	95
Porosity (%)	28
Water Saturation[1] (%)	25
Fixed draw down (mmscf/d/psi^2)	2.0e-5
Reservoir Temperature[2] (°C)	96

1. Amount of reservoir rock saturated with connate water (stagnant water)
2. Reservoir temperature kept constant as has minimal impact on recoverable reserves

Table 2: Reservoir parameters

Parameter	**Water Depth (m)**		
	500	**1000**	**3000**
Reservoir Depth (m)	2070	2070	4570
Pressure (bara)	212	212	469

4.1.3 Tieback Details

Three different tie-back lengths were assumed for the pipeline length. Each of these lengths was modelled for three water depth. The tie back and water depths analysed are shown in Table 3.

Table 3: Tieback Lengths and Water Depths

Water Depth (m)	**Tie-back Length (km)**
500	100
	150
	200
1000	100
	150
	200
3000	100
	150
	200

4.1.4 Onshore Facilities

Two LNG trains onshore require a plateau rate of 600 MMSCFD. Therefor the flow for 5 TCF and 3 TCF cases is set for 600 MMSCFD. For 1TCF cases, the flow is set for one LNG train with 300 MMSCFD gas rate. No onshore equipment was modelled. Only 1 km of pipe modelled for onshore section.

Shore arrival pressure of 70 bara and 30 bara used for 5 TCF cases. For 3 TCF and 1 TCF cases, the shore arrival pressure fixed at 30 bara. The arrival pressure of 30 bara represents the use of onshore compression to maintain plateau and extend the production tail.

4.2 Development Options

The development options considered the current available technology considering the areas in the DEPTH project [Ref. 2]. The six development options evaluated in this study are:

1. Subsea tieback to shore – Natural Flow (NF);
2. Subsea tieback to a local Floating Production System (FPS);
3. Subsea tieback to shore with subsea Wet Gas Compressors (WGC);
4. Subsea tieback to shore with subsea Dry Gas Compressors (DGC);
5. Subsea tieback to shore with wellhead Subsea Separation (SS); and
6. Subsea tieback to shore with Pseudo Dry Gas (PDG) technology.

4.2.1 Subsea tieback

A subsea tieback from gas-condensate fields results in transporting multiphase fluids (gas, oil and water) back along either single or dual pipeline(s) to the receiving facilities under Natural Flow (NF) conditions. The selection of the use of a single or dual pipeline and the sizing depends on the tieback distance and water depth, as well as the operational requirements of liquid handling onshore during ramp-up and start-up operations. Generally, single pipelines have a maximum tieback distance of 120 km [Ref. 1].

From a life of field steady state perspective, the use of single or dual pipelines only effects the tail production of the field as the single pipeline will have a much higher minimum flowrate and as such would back out the wells earlier. Figure 2 shows the inlet pressure vs. gas flow rate curve for a single and dual pipeline based on a 100 km tieback from 500 m water depth to highlight the hydrostatic head starts to dominate at higher gas flow rates for a single pipeline.

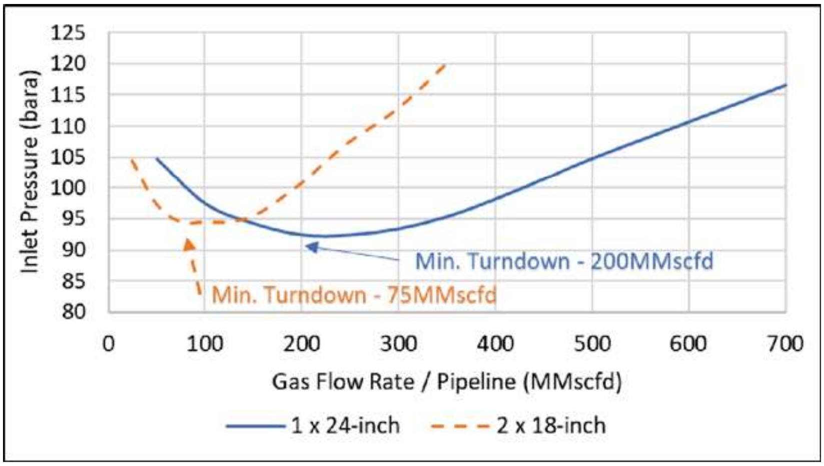

Figure 2: Inlet Pressure Vs. Gas Flow Rate for Single and Dual Pipelines

4.3 Floating Production System

The use of a Floating Production System (FPS) located over the gas-condensate field results in transporting multiphase fluids (gas, oil and water) along short distance flowlines and potentially deepwater risers. The fluids are processed on topsides (i.e. separation, dew pointing, dehydration and compression) and the gas exported down a single-phase pipeline to shore and the oil offloaded to tankers.

4.4 Subsea Compression

The use of subsea compression can either be with:

- Wet Gas Compressors (WGC); or
- Dry Gas Compressors (DGC).

The WGCs are boosting equipment which can handle changes in multiphase flow, but generally operate in GVF of 80 to 100%. The WGC system includes an upstream cooler, a subsea wet gas compressor and subsea power system, as shown in Figure 3.

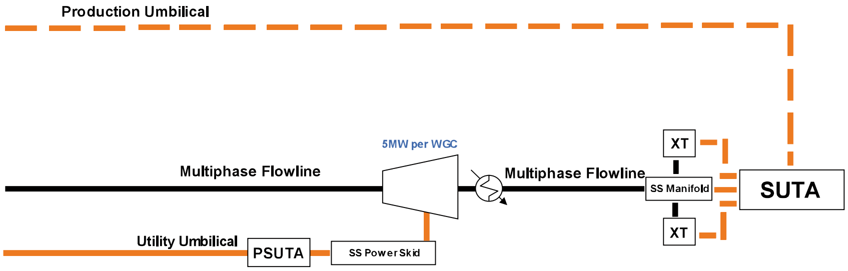

Figure 3: WGC System Schematic

The current available technology as installed on Gullfaks [Ref. 3] has been used in determining the production increases on top of the standard subsea tieback option. The

WGC has been qualified to be installed in water depths of 3000 m and for this study has no limit on tieback distance. The amount of power required for these units is substantial and therefore the qualification of subsea power components is needed. For the purposes of the study, a set of constraints as per the Gullfaks has been used; these are:

- Maximum pressure gain of 32 bar;
- Maximum power of 5 MW for 4,800 m^3/hr of suction flow per unit;
- Maximum suction volume of 4,800 m^3/hr per unit;
- Adiabatic efficiency of 50%; and
- Maximum of 2 units operating in parallel.

The DGC requires an upstream cooler prior to the subsea separator (knock out vessel) to remove the liquid prior to compressing the gas followed by an aftercooler, the liquid is pumped, and the fluids recombined. A dedicated subsea power system is required to handle the large power demands, as shown in Figure 4.

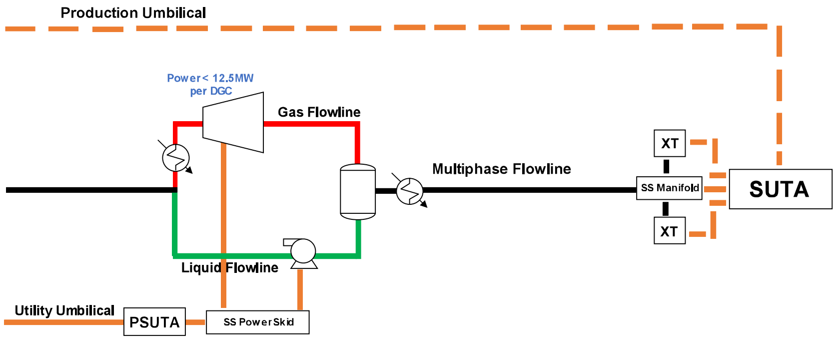

Figure 4: DGC System Schematic

The currently qualified DGC system as per Asgard [Ref. 4] and Ormen Lange [Ref. 5] has been used to determine the potential production increase on top of the standard subsea tieback option;

- Maximum Pressure gain of 60 bar
- Maximum Power of 11.5 MW for 20,000 m^3/hr of suction flow per unit;
- Maximum suction volume of 20,000 m^3/hr per unit;
- Adiabatic efficiency of 70%;
- Maximum of 2 units operating in parallel; and
- Maximum installation depth of 1300 m.

4.5 Subsea Separation

The use of a subsea separator only utilises the upstream cooler and subsea separator as per the DGC system shown in Figure 4. This large knock out vessel is located at the inlet to the subsea tieback and removes all liquids at this point. The liquids are pumped and delivered down a separate pipeline. The size and weight of the subsea separator restricts the maximum installation depth as per the DGC of 1300 m.

4.6 Pseudo Dry Gas

The typical system architecture of a PDG network is composed of a gas and a liquid network linked at each PDG unit (Figure 5). The liquid network also requires pumps which are located at the PDG skid (Mini Pumps) and on the main transport line (Booster Pump) for boosting to the necessary pressure to reach the liquid disposal location or processing facilities, generally onshore. Power, telecommunications cables, hydrate inhibitor such as MEG and other service lines are deployed by means of an umbilical.

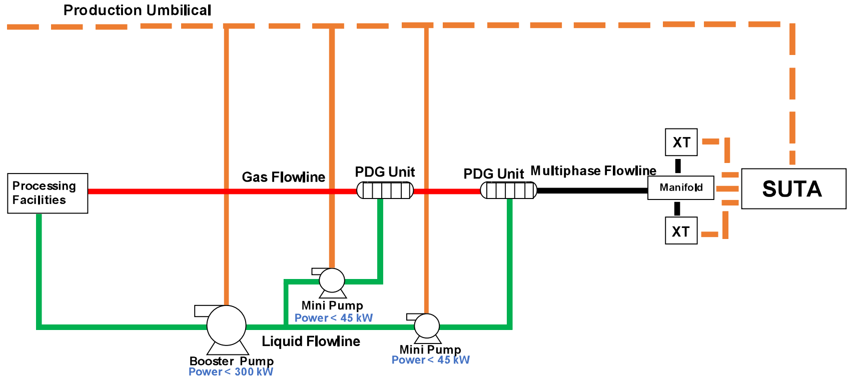

Figure 5: PDG System Schematic

By removing liquid along the pipeline and removing the gravitational pressure losses allows the use of large pipelines to negate the frictional pressure drop and therefore allowing the pipeline to operate like a "Pseudo" dry gas pipeline. The PDG units are liquid removal devices which based on CFD modelling gives separation efficiencies between 90-99% depending on gas and liquid flow rates (i.e. velocities), unit orientation, liquid type and operating pressures and temperatures, in all simulations an efficiency of 90% has been used. The efficiency assists in determining the number and location of PDG units needed along the route.

The limitations on the system now is the allowable pipeline size that can be installed in deep waters. A 36-inch pipeline is the largest pipeline to be installed in 1000 m and lower, whilst a 26-inch is the largest in 3000 m water depth.

5 PRODUCTION FORECASTS

5.1 Case Matrix

The subsea arrangements are explained in Section 4.2. Each arrangement was modelled for different water depth, tie back length, gas initially in place, liquid content and arrival pressure to compare the recovery ratio from the reserves as well as economical aspects considering both CAPEX and OPEX.

Table 4 shows the case matrix of life of field models run for the 5 TCF gas field size.

Table 4: Case Matrix for 5TCF cases

Case[1]	500 m WD [3]			1000 m WD			3000 m WD		
	100 km	150 km	200 km	100 km	150 km	200 km	100 km	150 km	200 km
NF	✓	✓	✓	✓	✓	✓	✓	✓	✓
SS[2]	✓	✓	✓	✓	✓	✓	No	No	No
WGC	✓	✓	✓	✓	✓	✓	✓	✓	✓
DGC[2]	✓	✓	✓	✓	✓	✓	No	No	No
FPS	✓			✓			✓		
PDG	✓	✓	✓	✓	✓	✓	✓	✓	✓

Note 1: All cases with a tick mark have been performed for both HP of 70 bara and LP of 30 bara arrival pressures.

Note 2: The technology for subsea separation (SS) and subsea dry gas compressor (DGC) currently cannot be installed at a water depth of 3000 m.

Note 3: Water depths of 1000 m and 3000 m were analysed for 3 TCF and 1TCF

5.2 Pipeline and Riser Sizing

Prior to conducting the life of field modelling, a series of steady state pipe sizing runs were undertaken to choose the appropriate sizes for the water depths and gas field size. The selection criterion is to balance the two opposing constraints:

- Maintain plateau - minimise frictional pressure drop; and
- Enhance the tail production and increase operability – minimise hydrostatic pressure drop.

Therefore, by achieving at least a 50% turndown without the hydrostatic head dominating and seeing large liquid hold-ups was used to select the pipeline size. The base and PDG pipeline sizes are presented in Table 5 and Table 6 respectively.

Table 5: Base Pipeline Sizes

Water Depth (m)	ID (inch)	
	5 TCF and 3 TCF cases	1 TCF cases
500	24	18
1000	24	18
3000	18	12

Table 6: PDG Pipeline Sizes

Water Depth (m)	ID (inch)
500	34
1000	34
3000	24

The FPS riser size used throughout the analysis is an 18-inch ID steel catenary riser. The use of multiple risers and riser types were not examined in this study.

5.3 Simulation Software

Yokogawa (KBC) life of field flow assurance software Maximus™ 6.16 was used to execute the flow assurance studies, utilising the multiphase flow correlation OLGA-S™ v7.3.1 by Schlumberger Software Integrated Solutions (SIS) to ensure a consistent basis for comparison using the appropriate multiphase physics to represent the frictional and gravitational pressure drops and liquid hold-up predictions.

The life of field simulations ran for 20 years with the subsea processing equipment applied from Year 1. However, when undertaking the cost modelling; the year at which the standard subsea tieback (NF) came off plateau was used to determine the subsea processing CAPEX (spread out of the two years prior) and the OPEX commenced.

In some cases, stopping the analysis after 20 years does not capture the ultimate recovery from the field, especially when the production rates at Year 20 have not dropped below the minimum stable flow.

5.4 Production Profile Results

A maximum plateau rate of 600 MMscfd is selected to compare the various development options for the 5 TCF gas field. Considerable amount of data is captured during the analysis process, with the primary output being the production profile. Starting with analysing the production profile shown in Figure 6 for the shortest tieback (100 km) and shallowest water depth (500 m) where all the options can compete and in fact several pipelines already operate in this space. The key highlights from this chart is subsea separation only makes a negligible impact on a standard subsea tieback, this is due to liquid is only removed at the inlet to the pipeline even with cooling the fluids to 40°C before separating; a large amount of condensate condenses due to changes in operating pressure down the pipeline as well as the temperature dropping to ambient conditions. The addition of more subsea processing or local topsides processing will increase plateau time for 3 to 4 years.

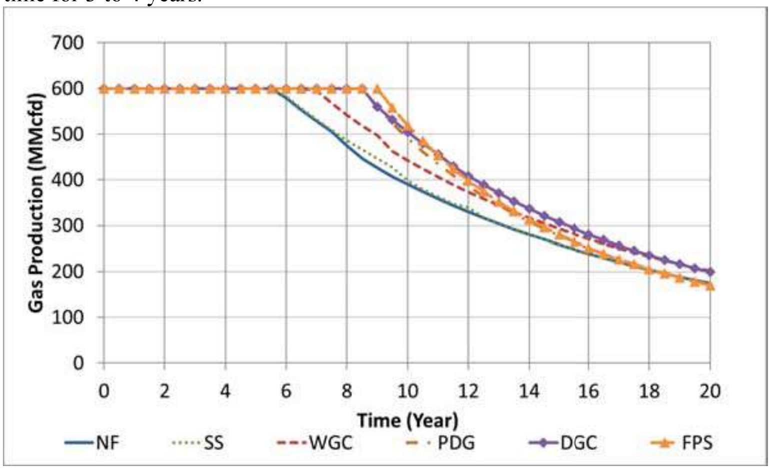

Figure 6: Production Profile – 100 km Tieback, 500 m Water Depth

Moving to the other extreme of the farthest tieback (200 km) and deepest water depth (3000 m) eliminates DGC and SS, there are clear differentiators between the remaining development options. Figure 7 presents the production profiles for NF, FPS, WGC and PDG options. The NF and WGC options suffer due to the long distance and deep water. The production profiles show a kink in the production rate at around 400 MMscfd for both NF and WGC, on further investigation the reduction in production is due a change in the hydraulic flow regime. Above 400 MMscfd the pipeline remains in stratified flow regime, however at 400 MMscfd and below the vertically slightly inclined (5°) sections predict hydrodynamic slugging, which also increases the overall liquid hold-up in the pipeline. This results in an increased back pressure on the wells and a reduction in production.

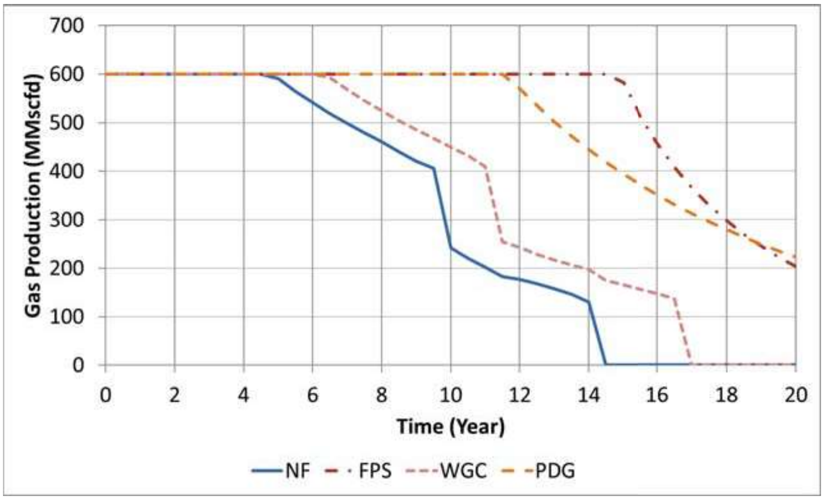

Figure 7: Production Profile – 200 km Tieback 3000 m Water Depth

The FPS and PDG technology do not suffer from this due to the short tieback length for the former and the continual removal of liquid for the later. The ultimate recovery for the FPS and PDG has not been captured in this case due to the simulations being stopped at 20 years, however it is expected that the ultimate recovery between these two options will be similar as the PDG system can operate down to much lower flow rates than the NF option.

The impact on production due to backpressure is highlighted in Figure 8 which shows the downstream choke pressure with reducing gas flow rate for the four development options for a 30 bara arrival pressure, the lowest D/S pressure is for the FPS case due to the shorter tieback distance. The highest backpressure is the NF option followed by the WGC, again at 400 MMscfd and lower the backpressure remains unchanged due to the change in flow regime from stratified to slug flow, the PDG pressure reduces steadily with reducing gas flow rate remaining in the stratified flow regime resulting in increased recovery.

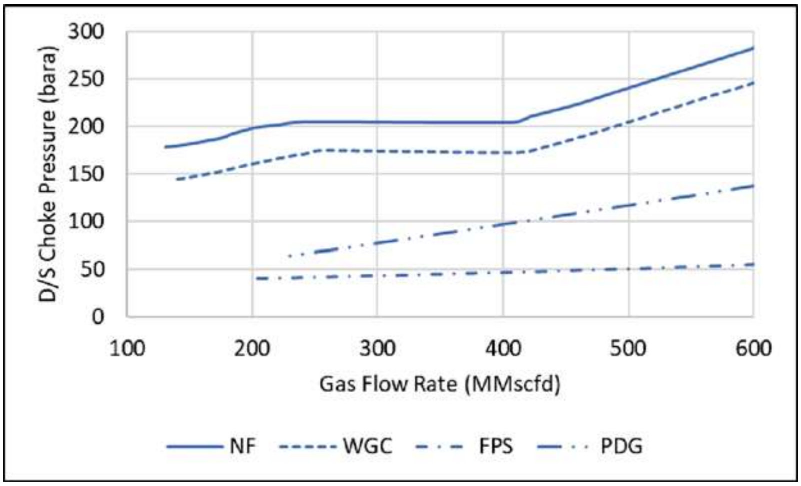

Figure 8: D/S Choke Pressure - 200 km Tieback 3000 m Water Depth

Keeping with the same tieback distance (200 km) but reducing the water depth up to 1000 m to allow the impact of DGC and SS to be evaluated is shown in Figure 9. It is noted that the reduction in water depth results in the tieback options remaining within the stratified flow regime due to the reduction in hydrostatic head. The other key highlights show that SS increases the plateau by 3 years over the NF option with WGC giving an additional year. The biggest impact on NF is from the DGC, PDG and FPS with increasing the plateau by 4.5, 6 and 6.5 years respectively. All development options can operate over the 20 years production period.

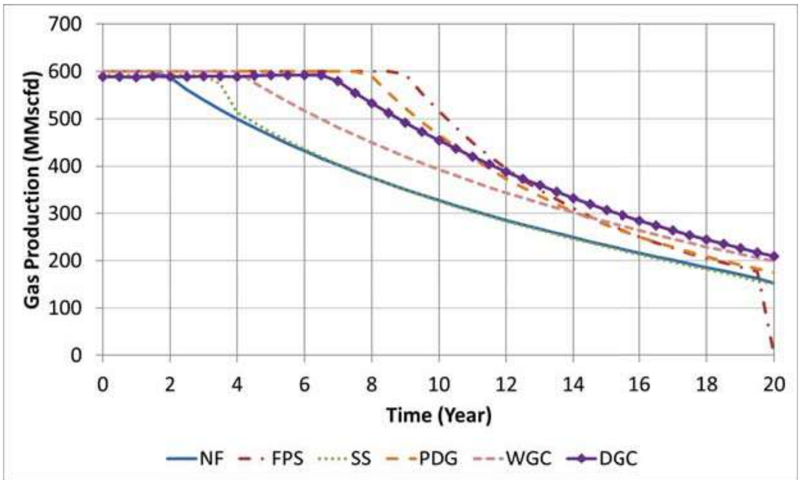

Figure 9: Production Profile – 200 km Tieback 1000 m Water Depth

Data analysis was conducted to evaluate trends with respect to the dependent variables. Figure 10 fixes the tieback length at 200 km for the Low LGR and onshore compression to examine the impact of water depth on the recoverable reserves. Firstly comparing 500 m and 1000 m water depth which utilises the same reservoir properties of depth and pressure, shows that there is a minimal reduction in recoverable reserves for DGC, FPS, PDG and WGC, but the reserves are reduced considerably for the NF and SS options. The increase in water depth to 3000 m sees an increase in recoverable reserves for the FPS and PDG options; this is due to the increased reservoir pressure for this case and that these options benefit from this increased back pressure to deliver the production rates. This is not experienced for the NF and WGC due to the change in flow regime from stratified to slug flow below 400 MMscfd as highlighted in Figure 7 and Figure 8 resulting a reduction in recoverable reserves not to mention the considerable difference in time on plateau due to the increased back-pressures needed for a 200 km 3000 m pipeline.

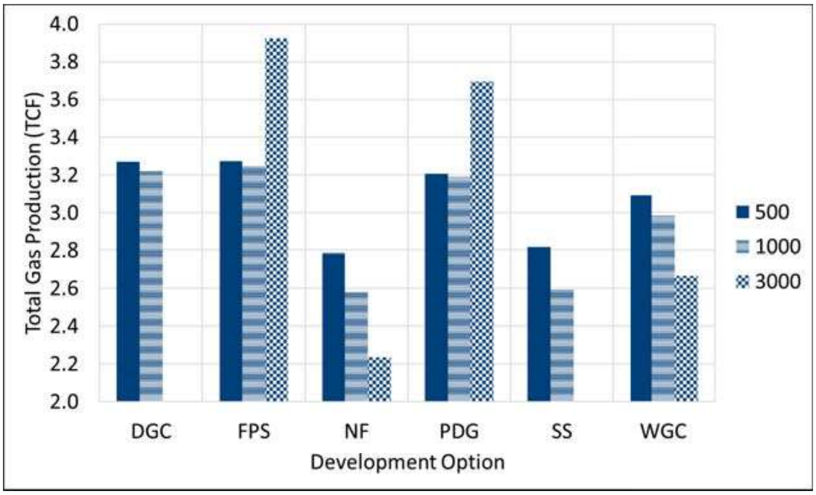

Figure 10: 5 TCF Gas Field – 200 km Tieback, Low LGR with Onshore Compression for Variations in Water Depth – 20 Years Production

Figure 11 keeps the water depth constant at 1000 m and 3000 m with Low LGR and onshore compression to examine the impact of tieback distance on the recoverable reserves. Unsurprisingly, the FPS option is unaffected by tieback distance and results in the same recovery, with the PDG option showing a small reduction in recovery with increasing tieback distance. The NF and WGC options show a considerable impact of tieback distance, which supports the reason that subsea gas tiebacks have been limited. The SS option for the 1000 m water follows the same trend as the NF and WGC, whilst the DGC only shows a small reduction in recover like PDG.

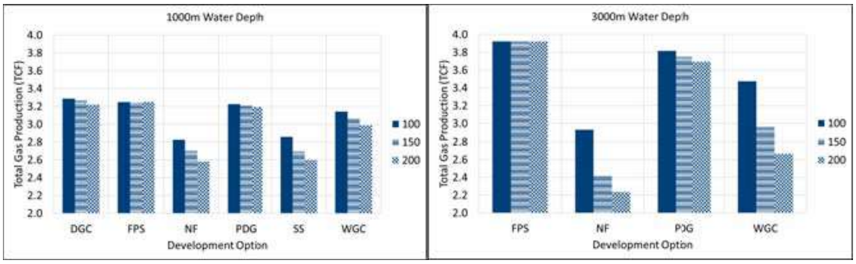

Figure 11: 5 TCF Gas Field – 1000 m and 3000 m Water Depth, Low LGR with Onshore Compression for Variations in Tieback Distance – 20 Years Production

The impact of increasing liquid on the development options are shown in Figure 12. The increase in liquid has a significant and detrimental effect on the production recovery for the NF option. The SS option still has a drop in the recovery as the liquid does not all condense at the inlet of the pipeline. The compression options, DGC and WGC will compensate for the increase in back pressure from the increased liquid production (i.e. higher liquid hold-up, higher gravitational pressure drop), the DGC can deliver a higher differential pressure compared to the WGC; therefore, higher recovery. The increase in liquid also effects the recovery of the FPS option, due to the increase hydrostatic head up the risers. The only option which is unaffected by the increase in liquid is the PDG technology due to removing the liquid along the pipeline thereby negating the effect of increasing hydrostatic head.

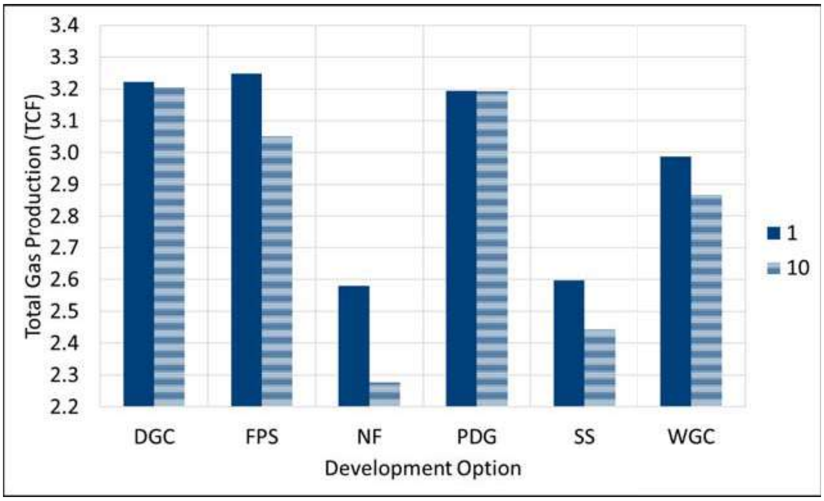

Figure 12: 5 TCF Gas Field – 200 km Tieback, 1000 m Water Depth with Onshore Compression for Variations in WGR – 20 Years Production

The impact of onshore compression on the gas recovery is highlighted in Figure 13, which shows a considerable improvement on the gas produced for all options, with the smallest improvement seen on DGC and PDG. The 5 TCF field in 1000 m water depth and 200 km tieback has been used to demonstrate the conclusions. It is unsurprising that the benefit is reduced for DGC as this has already seen a big increase by supplying pressure at the start of the pipeline where the velocities and the frictional pressure drop are lower. It is also supports the status quo where most offshore developments with long distance tiebacks (NF option in this paper) use onshore compression to prolong the plateau and recover the most from the reservoir, from the results of the NF gas production.

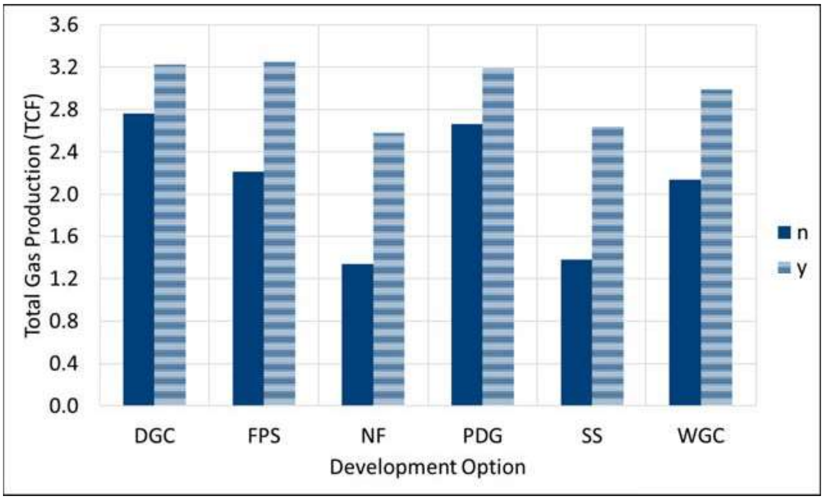

Figure 13: 5 TCF Gas Field – 200 km Tieback, 1000 m Water Depth and Low LGR with / without onshore Compression

6 ECONOMIC PERFORMANCE AND TRENDS

CAPEX estimates have been evaluated for each development option considering tieback distance, water depth and size of the gas field. CAPEX is composed of the following cost blocks:

- Drilling – no difference between options;
- Pre-Engineering Survey – no difference between options;
- Subsea Production System – Xmas trees, manifolds, subsea controls modules
- Pipelines & Risers – dependent on pipe size and costed in \$/m
- Floating Facility – \$1.5 billion to \$2 billion dependent on plateau rate
- Onshore Facility - ~\$1 billion
- Installation – dependent on lay vessel (S-Lay (\$0.5 million/day) or J-Lay (\$1 million/day)) and lay rate (from 1.5 km/day to 5 km/day)

A new onshore plant has been considered for all subsea tieback options but not the FPS option as the gas processing is completed topsides. Factors have been applied to the sum of all cost blocks to derive the total CAPEX. Factors for project management and engineering, owners' costs and insurance and certification have been applied on the raw costs which make up a base total cost. This base cost then has a contingency factor applied to make up the total CAPEX.

OPEX costs have been factored from CAPEX estimates. The following factors have been used:

- 3% of Drilling CAPEX per annum;
- 1% of Subsea Production System and Pipelines CAPEX per annum;
- 2% of Onshore Facilities CAPEX per annum;
- 3% of Offshore Facilities CAPEX per annum (FPSO only).

Economic parameters presented in Table 7 are used to determine the total economic performance and evaluate the Internal Rate of Return (IRR) and the Net Present Value (NPV) of each option. Due to the negligible impact of subsea separator only on gas recovery; this is not considered further. The subsea compression options have been selected on recovery performance; DGC is used for the 500 m and 1000 m water depths and the WGC for the 3000 m water depth case.

Table 7: Economic Parameters

Inputs	Units	Value
Discount Factor	%	10%
HC Liquids	+$/bbl	70
Dry gas	+$/MMscf	6000
CO_2/kWhr	kg/KWhr	0.5
$/$CO_2$	-$/tonne	-36
Taxes / Loans	-	Not Included

Figure 14 shows the economic performance for the shallowest water depth (500 m) for variations in tieback, it shows that for the shorter tieback distance the conventional subsea tieback (NF) is the best economic performer based on IRR and second using NPV. Overall the PDG is the best economic development option which increases its economic performance over all the other options as the tieback distance increases, the NPV increases from 20% to 55% over the other options at 200 km step out.

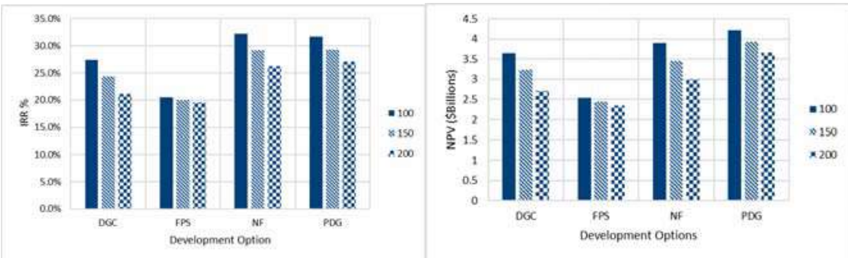

Figure 14: 5 TCF Gas Field –IRR and NPV for 500 m Water Depth, Low LGR with Onshore Compression for Variations Tieback Distance

Gas fields vary considerably in size and this is generally the reason some fields are not developed as they are considered stranded and uneconomic. A comparison on the field size on a 200 km tieback in 1000 m water depth is shown in Figure 15 for 1, 3 and 5 TCF fields. The same plateau rate of 600 MMscfd has been used for the 3 and 5 TCF fields to stress test the economics for the development options using the same infrastructure. The 1 TCF option uses a lower plateau rate of 300 MMscfd. A consistent water depth of 1000 m has been used with variations in tieback distance. Each option shows the performance at 1, 3 and 5 TCF, which unsurprising shows that in most of the cases a 1 TCF field 200 km from shore is uneconomic, only the PDG option results in positive IRR for all tieback distances. The NPV for the 1 TCF option is negative for all development options considered. However, this includes a new onshore plant, tying back to an existing facility would give a much better economic outcome for a 1 TCF field.

The stress test between 3 and 5 TCF of maintaining a IRR above 20% shows that only the longest tieback for NF falls below 20% for the 3 TCF case, even though the NPV for these cases are greatly affected by the increased step out. All the PDG cases remain above the 20% IRR and achieve much higher NPVs over all the other options, an increase of 35% to 100% over the next best option with increasing tieback distances; thus, offering the most robust development option for long distance tiebacks. The DGC development option offers an acceptable IRR and NPV for the 5 TCF case, which supports the current view that the use of DGC systems is being contemplated for gas fields >5 TCF, i.e. Ormen Lange. Similarly, the use of FPS over a gas field requires a much larger gas field than 5 TCF, which supports the rise in the number of FLNG projects being considered.

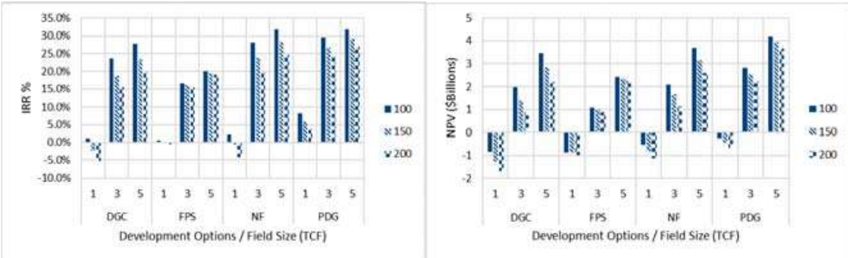

Figure 15: IRR and NPV for 1000 m Water Depth, Low LGR with Onshore Compression for Variations in Field Size and Tieback Distance

7 CONCLUSIONS

The use of integrated production modelling to determine the feasibility and economic viability of long distance deepwater gas fields provides an important part in determining the value early in the development phase. It helps to put in perspective the various development options from conventional tiebacks, FPS through to subsea processing arrangements to make considered and supported conclusions.

The large number of cases analysed in this study gives supporting conclusions to several established behaviours, namely:

- Conventional subsea tiebacks up to ~100 km provide the most cost-effective solution in mid-range water depths – 500 m to 1000 m;
- The use of FPS and subsea compression requires gas fields more than 5 TCF in stranded locations;
- A stranded field is in the range of 1 to 3 TCF depending on tieback distance and the development of these fields should be combined with other fields within the greater basin.

The study also highlights some significant conclusions which should be considered for all future gas field developments; these are:

- Subsea separation alone cannot solve the liquid management problems as the liquid condenses along the pipeline due to changes in pressure and temperature; therefore, this cannot be considered a suitable solution for stranded gas fields (Figure 9 and Figure 13);

- The greater the tieback distance and the deeper the development, the best economic (from 35% to 100% increase in NPV over the next best option) and gas recovery option (Figure 14 and Figure 15) is PDG since removing liquids from the pipeline along the route results in a significant reduction in pressure drop both hydrostatic and frictional without the use of large amounts of power. This somewhat supports the DEPTH conclusions for long distance tiebacks of separating liquid and gas and flowing the pipelines under single phase transportation but using a much simpler process without the need of large power requirements.

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