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METHODOLOGY FOR SELECTION OF CONCEPTS OF SUBSEA PROCESSING PLANTS

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Abstract. *The developments of offshore oil and natural gas fields have been moving to deeper waters, harsher environments and more remote areas. The use of conventional solutions to develop such fields, especially sole use of surface processing or downhole artificial lift methods, may not justify the investments. Subsea processing has been increasing the attractiveness or even enabling offshore field developments. Given the increase in its use, the authors proposed a methodology to select concepts of subsea processing plants for oil and natural gas fields, using information available in the literature as well as support from specialists in subsea technology and in asset integrated simulation. Higher drawdown in producer wells is a potential consequence of the use of subsea processing, therefore it may modify the production profile. Consequently, an integrated approach was considered to propose a methodology, taking into consideration the various aspects of field development. In order to overcome the lack of quantitative information regarding concept selection in field developments and impact on production profiles and other parameters, case studies were performed, using information available in public domain, to seek methodology validation. The results suggest that the methodology is valid, although it is not clear if such cases would utilize all phases proposed.*

Keywords*: subsea, processing, offshore, field, development*

1. INTRODUCTION

In field development, processing is the step where produced and injected fluids are treated in order to achieve the required specifications, which depend on the destinations of each of these fluids. The conventional philosophy is to install processing equipment in the surface, such as floating production units, fixed platforms or even onshore locations. Subsea processing comprises the use of processing and artificial lift equipment installed on the seabed, increasing the attractiveness or even enabling the production of offshore fields.

The literature presents the potential benefits of subsea processing. The use of subsea processing technologies is among the most attractive alternatives under consideration by industry to develop offshore fields, processing fluids directly on the seabed, opening many opportunities for higher efficiency in field development, being driven by the necessity to cope with low reservoir energy, eliminate or reduce hydrate formation risks, prevent decline in production decline and increase of water production, and overcome constraints on topsides (Vu et al., 2009). The most important potential benefits of subsea processing are increase in recovery factor, acceleration of production, reduction of capital and operational expenditures, and improvement of health, safety, and environment aspects (Davies et al., 2010). Flow assurance issues may be experienced in long step-out lengths, and the use of subsea processing can contribute to overcome such challenges, enabling the production in complex scenarios (Vichitrananda et al., 2012).

Subsea processing technologies have already been considered in several developments in its diverse phases and implemented in many fields. Significant benefits were already achieved, such as enabling production of heavy oil reservoirs, increase in the recovery factor of many fields, and overcome topsides constraints.

Due to the increase in subsea processing use, a methodology to select concepts of subsea processing plants was proposed. The term “plant” is utilized to emphasize the use of processing equipment in subsea systems, which comprise many other elements, increasing the complexity of subsea installations. The main elements in subsea processing plants are processing and lifting equipment, but electrification equipment also plays an important role due to the trend to increase subsea power consumption when subsea processing is added. Higher drawdown in producer wells is a potential consequence of the use of subsea processing, therefore it may modify the production profile. Consequently, an integrated approach was considered to propose a methodology, taking into consideration various aspects of field development.

2. POTENTIAL BENEFITS OF SUBSEA PROCESSING

The main potential benefit of subsea processing is the possibility to alter the production profile, increasing recovery and/or accelerating production. As per Eq. (1), the inflow performance of a production well depends on the index of productivity and the drawdown available, which is the difference between the reservoir static pressure and the bottom-hole flowing pressure:

$$q = IP \times \Delta P \tag{1}$$

q = inflow performance ($m^3.d^{-1}$)
IP = index of productivity ($m^3.d^{-1}.kgf^{-1}.cm^2$)
ΔP = drawdown ($kgf.cm^{-2}$)

The use of certain subsea processing functionalities leads to the increase in drawdown due to separation of produced water on the seabed and pressure directly given to the fluids by means of pumps or compressors. The higher drawdown potentially achieved ends up modifying the production profile, possibly accelerating the production and/or increasing the recovery factor, if undesired phenomena such as water coning, intolerable sand production and well instability.

In addition to the aforementioned benefits, subsea processing can also contribute to overcome flow assurance challenges such as hydrate formation, slugging regimes, corrosion and erosion.

Enhanced economics is also an important potential benefit of subsea processing. Specifically for brownfield projects, due to lower complexity of modifications required in existing topsides. Specifically for greenfield projects, due to use of unconventional concepts such as subsea to shore and simpler platforms. For both brownfield and greenfield projects, due to optimized use of risers and flowlines, less transport of fluids (such as produced water), and possibility to reach attractive development solutions using less producer wells. In the future, it may also be possible to use a complete subsea processing plant, where fluids meet market, disposal or injection specifications, not needing any surface processing.

As it is less intensive in operational labor than conventional surface processing, HSE benefits are also expected.

3. METHODOLOGY

The methodology is structured in six phases. It starts with the determination of attractive combinations of recovery strategies and respective subsurface targets for production, injections and disposal wells. In the second phase, attractive combinations of wells and respective locations of the wellheads are determined for the attractive combinations identified in the phase 1.

Table 1 describes in details the results of each phase and the specific criterion in phases 3 to 6 to discard combinations that are not attractive. Each criterion is rated from 1 to 4, where 1 is unacceptable, automatically eliminating a combination. A score of 2 is acceptable, but, depending on the criterion, it means that a certain combination is either significantly worse than the other combinations (for example, electricity consumption) or, compared with external references, significantly more complex (for example, installation). A score of 3 is a good rating, similar to the average of the other combinations (again, an example is electricity consumption) or of similar complexity compared to external references. Score of 4 is an excellent rating. It is possible to weight each criterion and reach a total score for each combination, but the author preferred to only discard combinations when unacceptable scores are present as the weights for each criterion may vary a lot depending on the priorities of each oil company.

In the phase 3, production profile is the key criterion where subsea processing can make a difference compared to combinations of production equipment that solely use surface processing and downhole artificial lift methods. In this phase the following studies are executed in parallel: reservoir numerical simulation, lifting, flow assurance, heat and material balance. The proposition of combinations of production equipment to be evaluated in the phase 3 depends on the experience, and will depend on innumerous factors such as the type of reservoir, the quality of the hydrocarbons, well productivity, etc.. After performing the aforementioned studies, a technology maturity assessment is done (API RP 17N, 2009) for the technologies considered and a comparison of all the combinations using the criterion suggested.

In the phase 4, the electrification study is performed only for the combinations not discarded in the phase 3. After performing such study, it shall be performed a technology maturity assessment of the technologies considered and a comparison of all the combinations using the criterion suggested.

In the phase 5, production systems are established for given combinations of production and electrification equipment that managed to pass through phases 3 and 4. In this phase, the first step is to execute the following studies in parallel: finalization of wells conceptual design, integration and modularization of subsea and surface facilities, and marine engineering for selection of types of risers, flowlines and platforms. After executing the aforementioned studies, it shall be performed a technology maturity assessment of the technologies considered and a comparison of all the combinations using the criterion suggested. The second step is the hazard and operability (HAZOP) analysis for the combinations that were not eliminated in the first step. Combinations with unacceptable risks are discarded.

In the phase 6, results of the phase 5 are compared under a set of criteria in order to identify the most promising combinations of production systems, which are loaded into a database. There is a first loop ensuring that phases 3 to 6 are executed for each combination identified in the phase 2. There is also a second loop, ensuring that phases 2 to 6 are executed for each combination identified in the phase 1. After all these steps, the database is fully loaded with all promising combinations of production systems, which are then compared under the same set of criteria in order to identify the best combination.

Table 1: Explanations of each phase of the methodology

Phase	Input parameters	Results	Selection criteria
1	- Reservoir model - Data of other fluids used in recovery strategies	Attractive combinations of recovery strategies and respective subsurface targets	NA
2	- Attractive combinations determined in the phase 1 - Water depth - Metocean - Drilling rigs and production units available	Attractive combinations of wells (numbers and types) and respective locations of wellheads	NA
3	- One attractive combination determined in the phase 2 - Technologies of production equipment available (TRL*>1) and operating ranges - Destinations of fluids and respective market/transport/injection specifications - Existent production capacities and respective distances to the field - Processing sequence - Potential onshore locations and respective distances to the field - Seabed bathymetry - IMR and installation vessels available and respective constraints	Attractive combinations of production equipment. More details on results obtained: - Production profile - Peak of electricity demand - All parameters that significantly influence flow and separation (nominal diameters, geometries, consumption of chemicals, etc..) - Geometry and weight of large equipment (Xmas trees, manifolds, separators, pipelines, etc…) Specific details on each part of the scope: - Producer wells: trajectory between wellhead and subsurface target; sand control; perforation and stimulation; tubing; valves; artificial lift - Injection and disposal wells: trajectory between wellhead and subsurface target; tubing; valves; perforation and stimulation - Xmas trees: types and locations - Manifolds: types, slots and locations - Subsea processing equipment: types and locations - Surface scope, associated with subsea and downhole equipment, possible to be determined - Flowlines and risers: trajectory, roughness, requirements for temperature control - Flow assurance equipment: types and location - Use of HIPPS - Surface processing equipment: types and locations - Platforms: quantity and locations - Onshore locations for processing plants - Export equipment (riser considered in previous category): types, location and route.	- Production profile - Consumption of electricity per boe - Consumption of chemicals per boe - IMR (Inspection, Maintenance and Repair) - Ease to install - Flexibility - Equipment TRL - Criticality to increase TRL
4	- Attractive combinations determined in the phase 3 - Technologies available (TRL*>1) and operating ranges - Electricity available and distance to the field	Attractive combinations of electrification equipment. More details on results obtained - Generation, transmission and distribution equipment (type, location) - Geometry and weight of large equipment (cables, transformers, VSDs, etc..) - Surface scope, associated with subsea and downhole equipment, possible to be determined	- Energy efficiency - CO_2 footprint - IMR - Ease to install - Equipment TRL - Criticality to increase TRL

Table 1: Explanations for each phase of the methodology (cont.)

Phase	Input parameters	Results	Selection criteria
5	- Attractive combinations determined in phases 3 and 4 - Additional soil data - Minimum production availability - Interface technologies (TRL*>1)	Attractive combinations of production systems. More details on results obtained in each combination: - Finalization of conceptual design of wells, with definition of aspects that do not interfere on the flow, such as casing program, cementation, bits, mud, etc... - Subsea systems, including subsea processing plants - Surface plants - Risers and flowlines: types (rigid, flexible, etc…) - Platforms: types (FPSO, SPAR, etc…) - Export systems - Umbilicals: quantity, types and trajectory	- Weight of production systems - Flexibility - Total labor intensity in operational phase - Offshore labor intensity in operational phase - IMR - Production availability - Ease to install - System level TRL - Criticality to increase TRL - Hazards and operability risks
6	- Attractive combinations determined in the phase 5 - Data for economic analysis	Best combination of production systems.	- System level TRL - NPV of CAPEX - NPV

Table *2* shows a proposal of how to rate each criterion identified in the phase 3. Table 3 shows a proposal of how to rate each criterion identified in phases 4, 5, and 6. Some of the criteria of phases 4 and 5 are the same as the phase 3.

4. CASE STUDIES

For methodology validation purpose, information available in public domain was used to perform case studies. The scores given for each criterion were not based on quantitative assessments due to lack of available information, but are based on assumptions made as per the experience of the author. Therefore, such scores shall be used only for academic purposes. Only two case studies are shown in this paper, but more case studies were performed by this author.

4.1 PAZFLOR

In Total's Pazflor field, West Africa, different subsea processing concepts were studied to enable the production of three reservoirs of Miocene age characterized by the presence of heavy and viscous oil and low energy (Bon, 2009). It is a greenfield project where surface processing, in this case a new FPSO, was used to contribute to the achievement of fluids specifications. The recovery strategy is a combination of sea water injection and produced water reinjection as secondary recovery method, comprising 49 wells (Bon, 2009). Making a parallel with the methodology, no evidences were found about variations of the recovery strategy or number of wells to reach the best production alternative, so phases 1 and 2 would have only one attractive combination each.

The production functionalities identified were artificial lift, subsea gas-liquid separation, many surface processing functionalities, surface oil storage, and export pipeline for gas. Three combinations of functionalities were identified, all dependent on surface (Pazflor FPSO) to complete processing. The first combination (C1) was a subsea multiphase pump with a conventional loop. The second combination (C2) was a subsea multiphase pump and riser base gas-lift with production loop. The third combination (C3) was subsea gas-liquid separation with single production lines. Other production equipment combinations, based on the third combination, that could had been considered are use of subsea sea water treatment (C4), use of GLCC instead of conventional gravity separator (C5), and use of centrifugal pump instead of hybrid pump (C6).

In the phase 3, C1 and C2 would be discarded due to unacceptable TRL levels (in this methodology TRL≥4 is necessary). C6 would be discarded because a centrifugal pump does not cope with GVF above 10%, which may happen in the liquid stream downstream the gas/liquid separator. In addition, the production profile of C1 would lag other combinations as the pump could not deliver sufficient head. IMR and installation would be better in C1, C2 and C5 due to use of more compact subsea equipment. C2, C3 and C5 are more flexible to variations in inlet conditions due to the use of conventional gravity separators, which present more volume to absorb variations. In the phase 4, for simplification, there are feasible combinations for C3, C4 and C5. In the phase 5, only one combination of production systems is proposed to each set of combinations identified in phases 3 and 4. C4 would have advantage in total weight, as subsea sea water treatment and injection would save weight in Pazflor FPSO as well as would not require injection risers and long injection flowlines, more than offsetting the own weight of the subsea sea water system. In this case it is assumed that it is raw sea water injection (with no need for fines and sulfate removal, technologies that are very immature subsea) and that a central plant would feed all sea water injection wells. C4 would have less flexibility as, in case modifications are needed to cope with changes in inlet or outlet conditions, it is in general harder to modify a subsea system compared to a surface system. C4 would have advantage in total and offshore labor intensity in operational phase as Pazflor FPSO would be simpler. IMR would be better in C5, as it presents the less complex subsea processing system (few and compact equipment). Production availability of C4 would be worse as it presents the most complex subsea processing plant, harder to maintain compared to surface plants. C5 would be easiest to install given the simplicity of the subsea processing plant. In the phase 6, C4 would win especially due to CAPEX savings. Table 4 shows the ratings given to each combination.

Table 2: Proposal to rate each criterion of the phase 3

Criteria	**Ratings**			
	1	**2**	**3**	**4**
Production profile	Accumulated production considerable lower than average and not concentrated in initial years. Period of production higher than average.	Accumulated production similar to average, but not concentrated in initial years. Period of production higher than average.	Accumulated production and period of production similar to average. Production is concentrated in initial years.	Accumulated production considerable higher than average and concentrated in initial years. Period of production lower than average.
Consumption of electricity/boe	Power available is exceeded during production	Significantly higher than average	Similar to average	Significantly lower than average
Consumption of chemicals/boe	Not applicable			
IMR	Available IMR vessels cannot perform interventions in all equipment required.	Frequency of interventions is significantly higher than average. Interventions are complex, needing drilling rigs or heavy lift vessels.	Frequency of interventions is similar to average. Interventions are not complex, not needing drilling rigs or heavy lift vessels	Frequency of interventions is lower than average. Interventions are not complex, not needing drilling rigs or heavy lift vessels
Ease to install	Installation vessels cannot perform all installation steps. Unacceptable production loss. Required space or weight in topsides not available.	Heavy lift vessels mandatory. Installation time significantly higher than average. Operational routine significantly impacted.	Heavy lift vessels not needed. Installation time similar to average. Operational routine not significantly impacted	Heavy lift vessels not needed. Installation time lower than average. Operational routine not significantly impacted
Flexibility	Operational range do not allow small variations in inlet and outlet conditions. Adaptations to increase operational range are too complex.	Operational range allow small variations in inlet and outlet conditions Adaptations to increase operational range are complex, but not significantly impairing economics.	Operational range allows considerable variations in inlet and outlet conditions. Adaptations to increase operational range are still complex.	Operational range allows considerable variations in inlet and outlet conditions. Adaptations to increase operational range are not complex
Equipment TRL	<4	4 or 5	6	7
Criticality to increase TRL	Concept is not feasible due to cost or schedule to mature technologies	High technical complexity and costs. Long schedule, but concept still feasible	Cost not high and schedule not long, however technical complexity still significant	Cost not high, schedule not long and technical complexity not significant.

Table 3: Proposal to rate each criterion of phases 4, 5 and 6 that are different from the phase 3

<table>
<tr><th rowspan="2"></th><th rowspan="2">Criteria</th><th colspan="4">Ratings</th></tr>
<tr><th>1</th><th>2</th><th>3</th><th>4</th></tr>
<tr><td rowspan="2">Phase 4</td><td>Consumption of electricity per boe</td><td>Power available is exceeded in any moment during production</td><td rowspan="2">Significantly higher than average</td><td rowspan="2">Similar to average</td><td rowspan="2">Significantly lower than average</td></tr>
<tr><td>Consumption of chemicals per boe</td><td>Not applicable</td></tr>
<tr><td rowspan="5">Phase 5</td><td>Total weight of production systems</td><td rowspan="3">Not applicable</td><td rowspan="3">Significantly higher than average</td><td rowspan="3">Similar to average</td><td rowspan="3">Significantly lower than average</td></tr>
<tr><td>Total labor intensity in operational phase</td></tr>
<tr><td>Offshore labor intensity in operational phase</td></tr>
<tr><td>Production availability</td><td>Lower than minimum required</td><td>Significantly lower than average</td><td>Similar to average</td><td>Significantly higher than average</td></tr>
<tr><td>Hazards and Operability risks</td><td>At least one risk with high impact and high likelihood of occurrence that cannot be mitigated or eliminated under the budgetary, schedule or technical constraints</td><td>At least one risk with high impact and high likelihood of occurrence, but can be mitigated or eliminated under the budgetary, schedule or technical constraints</td><td>No risk with high impact and high likelihood of occurrence. In general, risks are of considerable impact and likelihood of occurrence.</td><td>No risk with high impact and high likelihood of occurrence. In general, risks are not of considerable impact and likelihood of occurrence.</td></tr>
<tr><td rowspan="3">Phase 6</td><td>System level TRL</td><td><4</td><td>4 or 5</td><td>6</td><td>7</td></tr>
<tr><td>NPV of CAPEX</td><td>Higher than maximum allowed</td><td>Significantly higher than average</td><td>Similar to average</td><td>Significantly lower than average</td></tr>
<tr><td>NPV</td><td>< 0</td><td>Significantly lower than average</td><td>Similar to average</td><td>Significantly higher than average</td></tr>
</table>

4..2 MARLIM

In Petrobras Marlim field, situated in Brazil, at around 900 meters water depth, a subsea separation and injection station was installed to separate and inject produced water into the producing reservoir (Orlowski et al., 2012). The subsea separator receives a stream from only one well. Making a parallel to the methodology, the phase 1 does not apply, as the recovery strategy for the overall field was not changed. In addition, the phase 2 does not apply, as there are no new wells considered to be constructed.

In the phase 3, one combination of production equipment would be identified according to Orlowski, 2012, depending on existing installations to complete transport, process, export and disposal of fluids. C1 comprises many compact subsea equipment suitable for deep water (such as a desander for removal of sand from the wellstream, the gas harp, pipeseparator, hydrocyclones for produced water cleaning) as well as a pump for water injection. The author suggests more two combinations to compare with C1. C2 uses one subsea horizontal conventional separator, sand management system, and hydrocyclones for produced water cleaning and water injection pump. C3 would be similar to C2, but using two subsea horizontal conventional separators rather than only one. C2 would be eliminated due to the size and weight of the horizontal separator, making it impossible to be retrieved to surface (an assumption here is that IMR vessels available could not cope with the size and/or weight of the horizontal separator). C1 would consume more power due to more pressure drop (more equipment). C3 would be easier to install given the reduced size and weight of each of the horizontal separators (a pipeseparator may have several tens of meters). C3 would have the highest flexibility given the use of two horizontal separators in parallel. C1 would have the lowest TRL as the majority of the equipment had not been commercially used. In the phase 4, for simplification, there are feasible combinations for C1 and C3.

In the phase 5, for combination C1 of the phase 3, there are two combinations (C1 and C2 of the phase 5): the integration performed by Marlim pilot (C1), in only one template, and another integration using more templates (C2).

C4 would have the highest weight given the use of two separators. C2 would be easier to install than C1 given the split in a few templates that would not need heavy lift vessels, which are very expensive and hard to schedule.

In the phase 6, the winner would probably be C2, assuming that less installation costs would more than offset higher capital expenditure due to the use of more templates and piping to share functionalities. Table 5 shows the ratings given to each combination.

Table 4: Comparison of real and other suggested combinations for Pazflor development

Phase	**Criteria**	**C1**	**C2**	**C3**	**C4**	**C5**	**C6**
3	Production profile	2	3	3	3	3	3
	Consumption of electricity per boe	2	2	3	4	3	4
	Consumption of chemicals per boe	3	3	3	3	3	3
	IMR	4	4	2	2	4	2
	Ease to install	4	4	2	2	4	2
	Flexibility	3	4	4	3	4	1
	Equipment TRL	1	1	2	2	2	2
	Criticality to increase TRL	1	1	2	2	2	3
4	**Criteria**	**C1**	**C2**	Attractive combinations for C3, C4 and C5			**C6**
	Energy efficiency	NA					NA
	CO_2 footprint						
	IMR						
	Ease to install						
	Flexibility						
	Equipment TRL						
	Criticality to increase TRL						
5	**Criteria**	**C1**	**C2**	**C3**	**C4**	**C5**	**C6**
	Weight of production systems	NA		2	4	2	NA
	Flexibility			4	3	4	
	Total labor intensity			3	4	3	
	Offshore labor intensity			3	4	3	
	IMR			3	2	4	
	Production availability			4	3	4	
	Ease to install			3	2	4	
	System TRL			2	2	2	
	Criticality to increase TRL			2	2	2	
	Hazards and operability risks			3	3	3	
6	**Criteria**	**C1**	**C2**	**C3**	**C4**	**C5**	**C6**
	TRL	NA		2	2	2	NA
	Net present value of CAPEX			2	4	3	
	NPV			2	4	3	

5. CONCLUSIONS

Subsea processing requires innumerous interfaces with subsurface and subsea systems, reason why the developed methodology involves the definition of all scopes to be installed in a certain field development. The results of the case studies suggest that it is possible to follow a stepped approach, where it is possible to optimize efforts to study all possible combinations of production equipment. On the other hand, it was not possible to identify if subsea processing can lead to attractive production systems that use less producer wells to develop the field.

Currently, any field that utilizes subsea processing will depend on surface to complete processing of the majority of the fluids, either reaching market, transport, disposal or injection specifications. Subsea technologies are still not mature enough to enable a full subsea processing plant, which would eliminate the use of surface processing (platforms, onshore plants), production risers and injection risers, mainly depending on export systems, logistics to refill chemicals and any other fluids, electricity from shore or energy sources to generate electricity.

Table 5: Comparison of real and other suggested combinations for Marlim Pilot

Phase	Criteria	C1		C2	C3
3	Production profile	3		3	3
	Specific consumption of power	2		4	4
	Specific consumption of chemicals	3		3	3
	IMR	3		1	2
	Ease to install	2		2	3
	Flexibility	2		3	4
	Equipment TRL	1		2	2
	Criticality to increase TRL	2		2	2
4	**Criteria**	Attractive combinations for C1		NA	Attractive combinations for C3
	Energy efficiency				
	CO_2 footprint				
	IMR				
	Ease to install				
	Flexibility				
	Equipment TRL				
	Criticality to increase TRL				
5	**Criteria**	**C1**	**C2**		**C3**
	Weight of production systems	4	3	NA	2
	Flexibility	2	2		4
	Total labor intensity	3	3		3
	Offshore labor intensity	3	3		3
	IMR	2	3		3
	Production availability	2	2		4
	Ease to install	2	3		2
	System TRL	1	1		2
	Criticality to increase TRL	2	2		3
	Operational and environmental risks	3	3		3
6	**Criteria**	**C1**	**C2**		**C3**
	TRL	2	2		3
	Net present value of CAPEX	3	4		2
	NPV	3	4		2

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