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Review article

Review and reliability modeling of maturing subsea hydrocarbon boosting systems

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ABSTRACT

This paper details the strategic importance of maturing subsea hydrocarbon boosting systems in the effective exploitation of matured fields. Reliability modeling is done for a long step out, all-subsea boosting station operating multi megawatt variable speed pumps at 1000 m water depth. It is found that, with the present technological maturity, one pump requires three redundancies to have an MTBF of 4.25 years. Analysis also reveals that a similar station shall require a booster compressor with Failure-In-Time not exceeding 10000 for attaining the same MTBF. Results serve as a guideline for subsea boosting system designers in planning technology qualification programs.

1. Introduction

The present global energy requirements are met with 34% from oil, 25% from coal, 21% from natural gas, 12% from renewable, and 8% from nuclear energy sources. The world energy consumption is expected to reach 20679 Mtoe in 2040, about 56% over the 2010 levels, with conventional fossil fuels continuing to supply around 80% of the world energy through 2040 (International energy outlook, 2013). Fig. 1 shows the contributing sectors where the demand for Natural Gas (NG) continues to be in the uptrend with the consumption in 2040 expected to reach 5.23 Trillion cubic meters (TCM), a 64% increase from the 2010 consumption level (International energy outlook, 2013) (Fantazzini et al., 2011). The spreading waves of safety concern due to the Fukushima tragedy, challenges in spent nuclear fuel management (Hayashi and Hughes, 2013) (Kim et al., 2013) and stringent carbon dioxide emission norms, further increases the demand for NG (International energy outlook, 2013).

During the period 2012–2018, as a part of global NG trade ensuring global energy security, Trans-Alaska Pipeline System, White stream, South stream, Nord stream and Iran Pars pipelines are planned to additionally transfer 217 Billion Cubic Meter (BCM) of NG per year through subsea pipelines, and the quantity contributes to 7.5% of the present day global NG consumption (Society for underwater technology Journal and UT2, April May 2014a). As the demand for oil and gas is on the upswing, new discoveries are on the decline (Hook, 2014). Based on the survey conducted on 331 giant fields (Hook et al., 2009), it is estimated that the global hydrocarbon production from giant fields are declining at the rate of 5.1% every year (Tang et al., 2010), specifically, the offshore fields are depleting at the rate of 9.7% per year (Hook, 2014). Higher production capabilities built into offshore installations in order to repay expensive investments, result in higher decline rates. In order to catch up with the declining production, investments in the global investments in deep water subsea projects is increasing and the cumulative spending during the period 2014–2018 is expected to reach US $260 billion, a130% increase compared to the preceding five-year period. This present paper details the challenging deep sea hydrocarbon resources and the need for subsea boosting techniques for enabling Enhanced Gas Recovery (EGR). Reliability modeling and the results presented serve as a guideline for subsea boosting system designers could be bused plan technology qualification programs, and to arrive at a tradeoff between the system capital expenditure, operating expenditure, redundancy requirements, and subsea system modularity.

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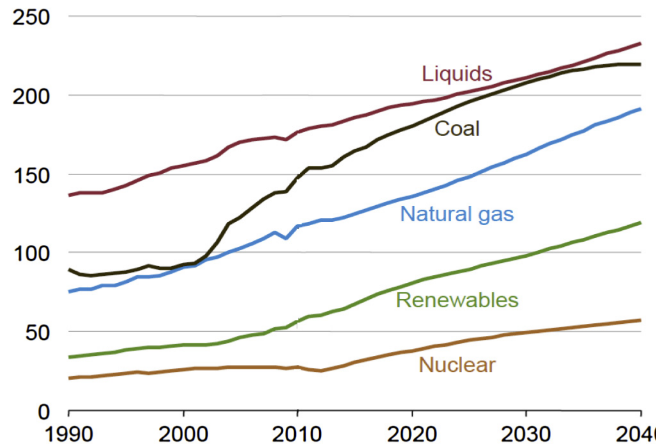

Fig. 1. Global forecast on contribution of primary energy consumption Quadrillion BTU (International energy outlook, 2013).

2. Challenging deep sea resources and need for subsea boosting

Driven by matured technologies such as integration of geological and drilling expertise, azimuthal resistivity for geo-steering with real time optimization of borehole trajectories (Randolph et al., 2011), dynamic position keeping capabilities, reliable work over control systems and the increase in the global deep water work class Remotely Operated Vehicle fleet from 641 units in 2011 to 1102 units in 2013 (Douglas-Westwood, 2013) have enabled safe (Cai et al., 2012) (Skogdalen et al., 2011) (Skogdalen and Vinnem, 2012) (Skogdalen et al., 2012) and efficient deep water drilling and construction capability. The investments on projects located at water depths ranging less than 500 m, 1000–2000 m and greater than 2000m are 28%, 39% and 32% respectively (Offshore hydrocarbons and Panorama, 2012) (Society for underwater technology Journal and UT2, Aug/Sep 2014). Thus the future offshore hydrocarbon industry is moving towards ultra deep waters. By 2035, deep water production is expected to reach about 10 million barrels per day, equivalent to 10% of the global production (International energy outlook, 2013).

More than 75% of the global deep water hydrocarbon resources (Society for underwater technology Journal and UT2, Aug/Sep 2014) is expected from the Libra and Lapa fields in the Santos and Campos basins in Brazil (Albuquerque et al., October 2013), discoveries in West Africa, Stones and Julia fields in the Gulf of Mexico (GoM) (International energy outlook, 2013) and Ormen Lange field (Bjerkreim et al., 2009) in the Norwegian Continental Shelf (NCS). The fields are identified to have massive hydrocarbon resources at depths 8000 m below the sea floor in water depths greater than 2000 m. Subsea tie-back solutions developed in NCS (Lin et al., 2013) (Knowledge Reservoir, 2010) involving integration of marginal fragmented fields with existing platforms facilities reduces the cost and time involved in developing marginal fields. In the NCS, during the period 2012–20, the annual average growth rate forecast is 13% for subsea tie-backs, compared to independent field developments, which is less than 3%.

Based on estimates made by the US Geological Survey, 412 Billion Barrels of Oil equivalent of NG is located in the Arctic (Noble et al., 2013), of which 84% is located offshore. Mineral Management Services (MMS) of USA estimates that a market price of more than US $9.07 per thousand cubic feet of gas (based on 2006 rates) is the economic indicator for production in the Alaskan region (Noble et al., 2013) and it is also estimated that with the present development trend, 55 BCM of NG could be produced cumulatively till 2057 (Hagel et al., 2013). Production of methane gas from deep marine Natural Gas Hydrate (NGH) reservoirs (Moridis et al., 2011) (Rutqvist et al., 2012) (Birchwood et al., 2010) (Lu, 2015) located in Krishna Godavari basin in India (Ramesh et al., 2014) (Sain et al., 2012), Shenhu Area in the South China Sea (Li et al., 2011), Nankai Trough in Japan (Zhou et al., 2014) and in deep waters of GoM require energy delivery to deep marine locations to enable methane gas production based on thermal and depressurization techniques (Rutqvist et al., 2012) (Saeki, 2014). Subsea processing is an emerging technology for hydrocarbon resource recovery from challenging ultra deep water maturing fields, subsea tie-back solutions, remote offshore arctic fields and marine gas hydrate production. The technology provides enhanced hydrocarbon recovery, increased offshore safety, reduced offshore emissions and installation costs, compared to platform based processing systems (Knowledge Reservoir, 2010) (Det Norske Veritas and GL, 2014) (Hannisdal et al., 2012). Subsea boosting is the critical process in subsea processing, which involves subsea pumping and compression.

3. Advantages of subsea boosting

3.1. Improved process efficiency

As the deep water fields mature, the reservoir pressure becomes insufficient to drive the hydrocarbon to the surface, as it has to overcome the significant weight of the overlying liquid column. Thus the production decreases, and below a certain flow, the reservoir becomes uneconomical to be operated and needs to be abandoned. In order to maintain the production plateau or to enhance the hydrocarbon recovery, boosting systems are required to provide pressure support for the reservoir, with the aid of booster pumps or compressors (Knowledge Reservoir, 2010) (Henri et al., 2010). Locating the boosting system on the sea bed gives higher efficiency to the system, especially for well streams with high gas fractions. It also helps efficient utilization of the entire flow lines, and the riser could be operated at higher pressure than by implementing suction based boosting from the platform end of the riser (De Oliveira et al., 2013) (Society for underwater technology Journal and UT2, April May 2014b).

Advanced well testing methods such as the Pressure Transient Analysis are used to evaluate the reservoir pressure, reserves, and production potential (Torres and Vasconcelos, 2013). Rock compaction and moderate aquifer influx often provide moderate to good drive energy for oil recovery. The Enhanced Oil Recovery (EOR) process could be enhanced by injecting water into the reservoir. In the GOM, water injection has good EOR effects. Water injection is difficult to execute in tight, abnormal pressurized palogene reserves. Carrying our water injection using platform based systems requires dedicated flow lines from the platform and increased energy to overcome the pipeline friction. Seabed located water pumps, that can take the sea water inlet and inject it into the reservoir as production support, require comparatively lesser infrastructure and energy, compared to platform based alternatives (Det Norske Veritas and GL, 2014) (Duan et al., 2013).

As fields mature, and due to the implementation of water injection based EOR techniques, the water content in the produced oil increases, which is normally separated in platform based separators and injected back into the reservoir, using platform located water injection pumps (Buk et al., 2013). Localized subsea processing involving water separation and injection helps to increase the utilization of the riser and platform facilities, as well as to reduce the energy similar to injection. Thus, in subsea processing solutions involving water separation and water re-injection,