LIQUEFIED CO2 INJECTION MODEL

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Keywords Flow simulations, Liquefied CO2 injection, Injection well

Text (500-1000 words - maximum 2 pages, font 12)

CO_2 injection for geological storage is done today in a number of suitable geological sites around the world. In CCS (Carbon Capture and Storage) pipeline transport and shipped transport of liquefied CO_2 are considered the most applicable transport methods.

The technology for CO_2 injection on the two existing CO_2 injection sites on the Norwegian shelf, namely at Snøhvit, [1], and Sleipner, [2] have been developed for pipeline transport and injection at supercritical conditions. Fluid temperatures are equal to or above the sea water temperatures (typically 4 °C) at the wellhead. For injection of liquefied CO_2, much lower temperatures must be expected and new flow assurance and design challenges due to this must be handled.

In this study a dynamic simulation model of an injection pipeline/well for injection of shipped liquefied CO_2 was set up using the multiphase flow simulator OLGA. The model was used for case studies on the Snøhvit and Sleipner injection wells. Similar simulation work have been reported earlier, mostly modelling CO_2 transport by pipeline ([3], [4], [5], [6] and [7]).

The main objectives of the study was to identify and propose solutions to potential flow assurance and operational problems to be expected during injection of cold liquefied CO_2 and optimization of the offloading process (using the simulator HYSYS). The work was carried out in cooperation with an engineering company developing technology for liquefied CO_2 transport and injection.

The study quantified effects related to flow capacity (pump/compressor requirements and line sizing of the riser, pipeline and well), freezing/hydrate formation, phase change (vaporization), heat transfer from the ambient sea water to the pipeline, from the surrounding formation to the well tubing and in the heat exchangers in the pressurizing/offloading process on the ship.

In the case studies, the liquid CO_2 is transported at conditions near the triple point at 7-8 bara and -53°C. These storage conditions had been selected since they are considered optimal for transportation of large volumes of CO_2. The CO_2 is pressurized up to supercritical state at 90-120 bara using single phase pumps. The capacity of injection is one of the critical factors with respect to the feasibility/economical soundness of liquefied CO_2 transport business concept. However, on the other hand, injecting at high flow rates cause low temperatures when the CO_2 enters the well due to short retention times in the pipeline and thus low heat transfer from the warmer surroundings.

In general, the following main design criteria were identified for a liquefied CO_2 injection system to be feasible:

- Pump capacity (i.e. flow rate and discharge pressure) and well/flowline size should be sufficient to inject the required rate (a short offloading time is affecting economics).
- The flowing temperature downhole in the well where CO_2 might come in contact with formation water should be kept above the hydrate formation temperature.
- Ice formation temperature at the wellhead (lower than -1°C) should preferably be avoided to avoid unwanted freezing/rupturing of the well completion and near formation

The most important findings and conclusions from the case studies on Snøhvit and Sleipner are summarized below.

Injection capacity:

- The reservoir pressure increases with well depth, and this is a determining parameter with respect to injection capacity and pump sizing.
- With an available injection pump discharge pressure of about 120 bara, the injection capacities were predicted to about 275 kg/s on Snøhvit and 400 kg/s on Sleipner when assuming 7" ID tubing size in the well and 700 m flowline length.

The low temperature of the injected CO_2 may cause serious problems during injection:

- Hydrate formation when cold CO_2 meets formation water in the perforations and near well zone
- Freezing of near well formation will cause stresses due to expansion (while tubing and casing steel will contract at low temperature) and possibly fracturing and damage of well casing and associated packers and near formation. Formation freezing may cause potential blockage and fracture leakage of CO_2 to unwanted locations.
- The transient conditions during startup and shutdown will cause imposed stresses on the formation and well materials due to large changes in temperature.
- The flowing bottomhole temperature was calculated to about -38° and -46°C on Snøhvit and Sleipner respectively during injection at a topside temperature of -53°C, and pump design flow rate 400 kg/s with 700 m buried pipeline. This is far below the hydrate formation temperature of about 10-12°C.
- If the pipeline is unburied, and if icing on the pipe outer wall can be handled, a long pipeline can act as a heat exchanger, increasing the retention time of the CO_2 in the pipeline and heating towards the sea water temperature before it enters the well. This can be used to avoid or decrease the risk hydrate formation in the well and may be a cheaper/more practical solution than installing a heater topside for this purpose.
- Icing of the riser may cause problems due to increased weight and loss of flexibility and consequently damage during offloading.

Storage conditions at the ship vs. energy requirements:

- The proposed storage conditions at the ship at 7-8 bara and -53°C are optimized for transportation of large volumes of CO_2 (low density). They are however not optimum for injection into the reservoir, due to the low temperatures, and the energy requirements for cooling prior to ship transport and necessary heating and pressurization before injection are substantial.
- An alternative storage condition at -20°C and 20 bara with less heating power, reduced number of compression stages and increased reliability of operation was suggested and simulated.

The study also pin-pointed other issues and discussed uncertainties in the models used and suggestions for further work in this area, not mentioned here.

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