HyNet CCUS Pre-FEED

Key Knowledge Deliverable

WP5: Flow Assurance Report

EXECUTIVE SUMMARY

The Flow Assurance Report was generated as part of the Preliminary Front End Engineering and Design (pre-FEED) study for the HyNet Industrial CCUS Project. The HyNet CCUS pre-FEED project commenced in April 2019, and was funded under grant by the Department for Business, Energy and Industrial Strategy (BEIS) under the Carbon Capture Utilisation and Storage (CCUS) Innovation Programme.

Delivery of the project was through a consortium formed between Progressive Energy Limited, Essar Oil (UK) Limited, CF Fertilisers UK Limited, Peel L&P Environmental Limited, University of Chester, and Cadent Gas Limited.

The main project objectives are as follows;

- To determine the technical feasibility of a full chain Industrial CCUS scheme comprising anchor loads from Stanlow Refinery and Ince Fertiliser Plant and storage in Liverpool Bay fields.
- To determine the optimised trade-off position between lowest initial cost and future scheme growth
- To determine capital and operating costs for the project to +/- 30% to support HMG development of a policy framework and support mechanism
- To undertake environmental scoping and determine a programme of work for the consent process

This document is one of a series of Key Knowledge Deliverables (KKD’s) to be issued by BEIS for public information, as follows;

- HyNet CCUS Pre-FEED KKD WP1 - Basis of Design
- HyNet CCUS Pre-FEED KKD WP1 - Final Report
- HyNet CCUS Pre-FEED KKD WP2 - Essar Refinery Concept Study Report
- HyNet CCUS Pre-FEED KKD WP2 - Hydrogen Production Plant
- HyNet CCUS Pre-FEED KKD WP3 - Fertiliser Capture Report
- HyNet CCUS Pre-FEED KKD WP4 - Onshore CO2 Pipeline Design Study Report
- HyNet CCUS Pre-FEED KKD WP4 - CO2 Road Rail Transport Study Report
- HyNet CCUS Pre-FEED KKD WP5 - Flow Assurance Report
- HyNet CCUS Pre-FEED KKD WP6 - Offshore Transport and Storage
- HyNet CCUS Pre-FEED KKD WP7 - Consenting and Land Strategy

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HyNet Phase 1: Industrial CCUS

Flow Assurance Report

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1. SUMMARY

1.1 Purpose of this Document

The purpose of this document is to provide an overview of the key operational constraints and required facilities upgrades, over the life of the HyNet project, identified through steady state flow assurance analysis of the full-chain integrated CO_2 transportation and injection network (Stanlow Industrial Site – storage reservoirs).

'System constraints maps' have been generated with the aim of providing a tool to visualise the complex interactions between different components of the transportation network. The maps are intended to serve as a guidance to establish an initial system configuration with minimum expenditure. In addition, it enables the identification of required modifications to debottleneck the network for future expandibility.

1.2 Full-Chain Integrated CO_2 Transportation and Injection Network

Two configurations of the full-chain integrated CO_2 transportation and injection network have been identified:

- **Option 1**: Initial operation in the gas free-flow operating mode (no intermediate compression, no flow control at wellheads) with subsequent transition to the liquid phase offshore only, once the MAOP of 35 barg (Ref. 1) is reached in the system as the reservoirs pressures increase with CO_2 injection.
- **Option 2**:
    - *Option 2A*: Operation in gas phase mode throughout the project life (onshore and offshore systems) with transition to offshore wellhead compression, once the MAOP of 35 barg (Ref. 1) is reached in the system as the reservoirs pressures increase with CO_2 storage.
    - *Option 2B*: Operation in gas phase mode throughout the project life (onshore and offshore systems). First, upgrading the capacity of the offshore system to extend operation in gas free-flow mode (no intermediate compression, no flow control) once the MAOP of 35 barg (Ref. 1) is reached in the existing system. The offshore wellhead compression will be installed once the upgraded system reaches its maximum capacity.

1.3 Impact of Flow Assurance in the Design and Operation HyNet CCUS

The design and operation of the CO_2 transportation and injection is driven by:

- Avoid two-phase flow in the pipelines (both onshore and offshore) during normal operation and upset conditions (i.e. after a long-term shutdown)
- Inherently safe design
- Robust and flexible operation
- Minimise cost (and emissions/energy consumption)
- Start operation with minimum modifications and delay major investments

The Flow Assurance work has identified several conflicting project drivers (trade-offs) and, therefore, an operating strategy has been developed in order to satisfy and accommodate several design constraints. Special consideration has been given to the fact that the existing facilities will be operating beyond their original design life and upgrades will be required over time.

The Flow Assurance analysis has shown that the existing facilities, with minor modifications and with the new onshore pipeline between Stanlow and Connah's Quay, are adequate for the transportation and injection of a flowrate of 1.6 $MtCO_2$/year (corresponding to the captured emissions of the CF Fertiliser plant, 0.4 $MtCO_2$/year, and two Auto-thermal Reforming Units) until a bottom hole pressure of 30 barg is reached. Depending on the ramp-up rate, the time horizon for major modifications (i.e. compression at PoA or at the wellhead and new offshore pipelines) would be 6-10 years after initial operation. This is based on high-level estimates of the pressure build-up in the reservoirs and is, certainly, subject to change once detailed sub-surface modelling is carried out. The proposed modifications and upgrades will enable further expandability so that the transportation network would have a capacity of potentially more than 10 $MtCO_2$/year.

From a Flow Assurance perspective, Option 2b provides the most cost-effective and low risk system. The system operates at low pressure (gas phase) and minor retrofit of the existing facilities is required. Therefore, this Option offers the most flexible road map for rapid commercial deployment. In this Option, the first required investment is to upgrade the offshore pipelines (new sizes and pressure ratings), once their primary maximum capacity has been reached, enabling the system to inject up to 3.5 $MtCO_2$/year. Higher flowrates, up to 5 $MtCO_2$/year, will require further expenditure in the form of wellhead compression (this has the advantage of significant energy savings as it eliminates the need for significant post-compression cooling at PoA and offshore heating). Finally, the system can be further expanded with additional upgrade of the existing onshore pipeline. With this, the transport network will be 'ready-for-liquid' for future operation.

An additional concept has arisen which considers the transportation of CO_2 in multiphase flow in the offshore pipelines. This concept has not been investigated here. In theory, steady-state operation in multiphase (two-phase) flow is possible.

Multiphase flow operation is currently observed in some European developments but only in the injection wells but not in the transportation pipelines (i.e. Sleipner, Ref. 2 or Ketzin, Ref. 3). Indeed, there are potential benefits in allowing multiphase flow in the pipelines. For example, the existing offshore system would have an adequate design pressure and upgrading the offshore pipelines can be further delayed. However, this may incur significant energy expenditure due to the required wellhead heating to manage low temperature excursions into the wellbore.

It is generally agreed that two-phase flow should be avoided due to potential difficulties in operation of process equipment. For example, a pressure booster designed for a compressible fluid can be damaged by using two-phase CO_2 (Ref. 4). The Peterhead CCS project also considered two-phase flow in the pipelines. This concept was discarded as it was deemed complicated from the control perspective due to slugging (Ref. 5)

Furthermore, there a number of issues that are not fully understood or analysed due to the limited experience operating multiphase CO_2 pipelines and modelling uncertainties in commercial multiphase flow simulators. European projects such as ROAD (Ref. 6) or Northern Lights (Ref. 7) have reported that the following key issues need to be addressed:

- Unstable temperature variations (thermal stresses)
- Slugging
- Cavitation and flashing
- Hammer effects

Moreover, it has been identified that the additional challenges in multiphase CO_2 transport requires further investigation:

- Metering and holdup measurement (Ref. 8,9)
- H_2 as key impurity in CO_2 streams (Ref. 10)

Therefore, although it is recommended to study the potential of steady-state multiphase flow transport during FEED, it is important to note that this operating mode may not be suitable for rapid industrial/commercial deployment as pilot scale testing/demonstration would be required to understand these issues and validate multiphase flow and thermodynamic models.

2. METHODOLOGY

2.1 Simulation Models

In this work, the full chain CO_2 transport and injection system, which extends between the gathering manifold located in the Stanlow area and the bottom-holes of the storage reservoirs, has been considered.

2.1.1 Gas Phase

For the operation in the gas operating mode, where both the onshore and offshore systems operate in a single gas phase, there are two system configurations considered:

1. The onshore and offshore systems are modelled together with injection wells being connected to the infield pipelines, as an intermediate compression at Point of Ayr is not required in this configuration. The boundary conditions are specified in the form of the mass source and a pressure sink set at the inlet and outlet of the system respectively.

2. The onshore and offshore systems are modelled together but independently of the injection wells, as this configuration considers offshore compression (not modelled) located on the wellhead platforms. The injection wells are modelled separately, with the mass source specified at the wellheads and the pressure boundary set at the bottom of the wells. The inlet temperature is assumed to be 40 °C (minimum post-compression cooling with seawater) for all cases under investigation. Moreover, operating scenarios which require multiple wells per field are set up using 0.1 m tie-in spool of the same size as the infield pipeline (pipeline size varies per field). In this case, the mass source is specified at the inlet of the tie-in spool to allow for the natural flowrate split between the wells with different geometries.

2.1.2 Transition / Liquid Phase

The simulation models for assessing the system transition from gas to liquid phase injection comprise offshore system only (from Point of Ayr to bottom-holes).

In this scenario, offshore pipelines will operate in a liquid phase, and since the onshore section is to be operated in a gas phase at all times it is not included in this steady state modelling, to avoid repetition of previously conducted analysis for the onshore system. The operating conditions for the onshore system, for the range of flowrates and arrival pressures, have been reported in (Ref. 1).

The offshore system and injection wells have been modelled independently. This is to simplify the OLGA model, as the minimum arrival pressure at the wellhead platforms must be maintained at 97 barg to avoid gas breakout in the offshore pipelines after an extended shutdown (Ref. 1). Therefore, wellhead choking is required. Hence, the models have been set up in such a manner that a mass source is specified at the wellhead (upstream of the choke) and a pressure sink at the bottom of the well, allowing for the upstream pressure to be calculated by OLGA. The flow control is used here to ensure an appropriate upstream pressure.

2.1.3 Injection Wells

Wells have been modelled as a 7” tubing with an overall heat transfer coefficient of 10 W/m²-°C, to account for the heat transfer characteristics of the well completion. All wells have been modelled with the tubing of the same size.

Assumed trajectories for the wells in Hamilton Main, Hamilton North and Lennox platforms, as well as maximum number of available wells for CO_2 injection are given in Appendix D.

2.2 Offshore Pipeline Size Upgrade

An upgrade of the existing offshore pipelines is inevitable, due to unsuitable pressure ratings for a liquid phase flow (HP mode) and insufficient capacity for a flow ramp-up above 2.5 $MtCO_2$/year (Ref. 1).

Therefore, for the purposes of this work, the offshore system has been sized to accommodate up to 5 $MtCO_2$/year in the gas phase. Should there be a need for further expansion (up to 10 $MtCO_2$/year) in the gas phase operating mode larger pipelines diameters than the selected will be required. The selected pipeline sizes are shown in Table 2-1

Table 2-1: Upgraded Offshore Pipelines Sizes

Pipeline	New Size (NB)
	in
PoA to Douglas	36
Douglas to Hamilton Main	26
Douglas to Hamilton North	16
Douglas to Lennox	26

The sizing of the offshore system has been performed with emphasis on maximising its deliverability in the gas phase mode. This, however, restricts operation in the liquid phase mode as the system is likely oversized.

Optimisation of the offshore line sizes has not been performed, and only one set of upgraded line sizes has been considered for both gas and liquid operating modes. It is recommended that the above pipeline sizes are optimised during the FEED once the decision has been made by project as to whether the line sizing should be driven by the gas or liquid operating mode.

2.3 CO_2 Flowrate Allocation and Reservoir Filling

As a baseline scenario it is considered that all three storage reservoirs (Hamilton Main, Hamilton North and Lennox) will be filled in parallel, once reservoir pressure across all fields is brought to the same level (i.e. 13.8 barg). Unless, hydraulics of the system precludes simultaneous injection, predominantly due to insufficient frictional pressure drop along the infield pipelines, sequential filling is considered.

The pressure rise in each reservoir, during parallel injection, is managed to be identical, provided that an overall CO_2 stream distribution to each field is proportional to its storage capacity, given in Table 2-2 (Ref. 11). Hence, the same pressure specification has been applied to all bottom holes for each case investigated (BHPs vary on a case by case basis).

Table 2-2: Capacity of Storage Reservoirs

Field	Storage Capacity	Flowrate Split
	$MtCO_2$	
Hamilton Main	125	55%
Hamilton North	23	10%
Lennox	80	35%

In order to obtain the best possible match in terms of the total CO_2 flowrate split between Hamilton Main, Hamilton North and Lennox fields (proportional to the reservoirs volume) the following methodology has been employed:

- Infield Pipelines:
    - Existing offshore system – pipelines from Douglas to Lennox WHP with sizes 12”, 14” and 16” were used alternately or altogether depending on the total flowrate.
    - Upgraded offshore line sizes – infield pipelines have been sized appropriately to the storage volume ratios (Table 2-2), given that all three fields are in simultaneous operation. However, when parallel injection to two fields is carried out the flowrate split ratio might diverge from the required one, as flow control is not considered. It is noteworthy that, the Lennox infield pipeline is three times longer than the Hamilton Main line; therefore, it requires the same size as Hamilton Main line to deliver 35% of the total CO_2 flowrate to the Lennox WHP.
- Injection Wells: an appropriate intake of the CO_2 mass rate per field has been also controlled by modelling an adequate number of wells for each field, using only existing wells. The number of required wells varies on case by case basis.

2.4 Project Timeline

In the absence of available injection profiles, the life of the project is expressed in the form of increasing bottom-hole/reservoir pressure, where an initial pressure of the depleted Hamilton Main reservoir (4.5 barg, Ref. 12) represents day one of operations with the last day being once the Lennox reservoir reaches its maximum pressure (111 barg, Ref. 12).

3. SYSTEM CONSTRAINTS MAPPING

The aim of this section is to identify the key operational limits and facilities upgrades of the gas and liquid operating modes, considering an integrated CO_2 transport and injection system from the gathering manifold (Stanlow Area) to the storage reservoirs.

The current operating strategy is to maintain single-phase flow in the onshore and offshore pipelines during normal operating conditions. This means that operation of the onshore system remains in the gas phase throughout the project life, whereas the offshore system will initially operate in the gas phase with an alternative of maintaining gas phase flow or transitioning to liquid phase at a later stage.

Two configurations of the full-chain integrated CO_2 transportation and injection network have been identified:

- **Option 1**: Initial operation in the gas free-flow operating mode (no intermediate compression, no flow control at wellheads) with subsequent transition to the liquid phase offshore only, once the MAOP of 35 barg (Ref. 1) is reached in the system as the reservoirs pressures increase with CO_2 injection.

- **Option 2**:
    - *Option 2A*: Operation in gas phase mode throughout the project life (onshore and offshore systems) with transition to offshore wellhead compression, once the MAOP of 35 barg (Ref. 1) is reached in the system as the reservoirs pressures increase with CO_2 storage.
    - *Option 2B*: Operation in gas phase mode throughout the project life (onshore and offshore systems). First, upgrading the capacity of the offshore system to extend operation in gas free-flow mode (no intermediate compression, no flow control) once the MAOP of 35 barg (Ref. 1) is reached in the existing system. The offshore wellhead compression will be installed once the upgraded system reaches its maximum capacity.

3.1 Option 1: Transition to Liquid Offshore (PoA Compression)

This option represents the baseline operating strategy over the life of the storage sites, namely Hamilton Main, Hamilton North and Lennox.

In this scenario the onshore section from Stanlow to Point of Ayr (via Connah's Quay) continuously operates in the gas phase. The captured CO_2 emissions are boosted at Stanlow and transported to the storage reservoirs, in gas phase, with no intermediate compression or flow control (free-flow mode), until the MAOP of 35 barg (subject to normal operational margins, Ref. 1) is reached in the system, as the reservoir pressure progressively increases with storage. At this point, the offshore section will need to switch to a liquid phase mode with the CO_2 being compressed at Point of Ayr to a maximum pressure of 125 barg (Ref. 1). Pressure/flow control located on the wellhead platforms is required to maintain the minimum normal operating pressure of 97 barg upstream of the injection choke (subject to normal operational margins, Ref. 1) during transition phase of the injection wells.

The system operational constraints for the Option 1 presented in Figure 3-1 have been mapped for the range of CO_2 injection rates between 0.4 $MtCO_2$/year and 10 $MtCO_2$/year.

3.1.1 Gas Free-flow Operating Mode

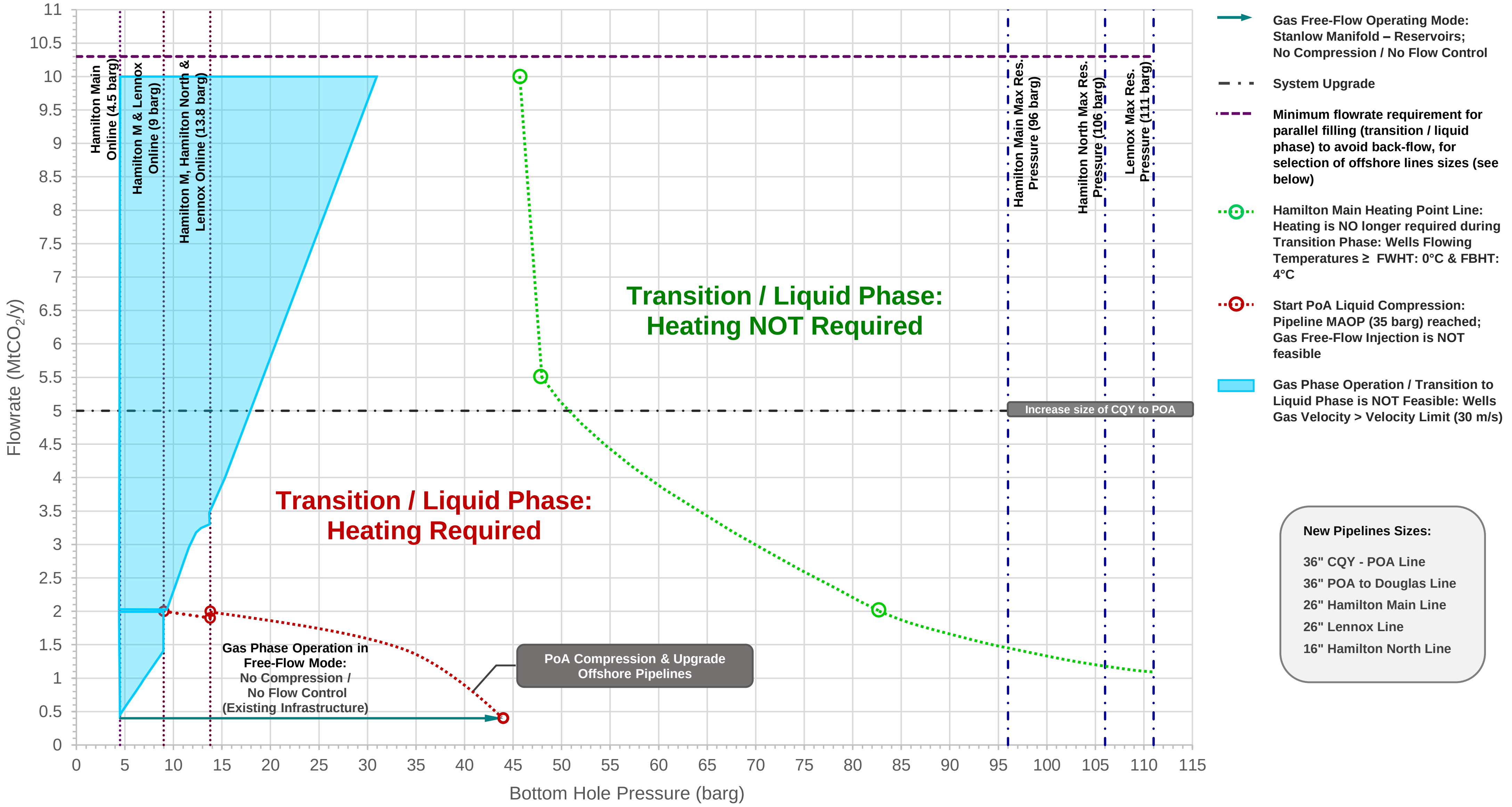
In early project life, the existing onshore and offshore systems with minimal modifications are intended to be used, until the maximum capacity of the system is reached (at MAOP of 35 barg). At which point, a system upgrade is required (Figure 3-1: red-dotted line).

It can be seen from Figure 3-1 that at the start of operations, when low reservoir pressures are expected, the CO_2 transport system is constrained predominantly by the high gas velocities (> 30 m/s) in the injection wells (blue-shaded region), as a result of relatively low gas densities (low hydrostatic pressure, high frictional pressure drop).

Since the CO_2 injection commences with a single reservoir filling, utilising Hamilton Main site with the four available injection wells, the maximum feasible CO_2 rate for an injection from day one (reservoir pressure of 4.5 barg) is 0.4 $MtCO_2$/year. Flow increase during single reservoir (Hamilton Main) filling is possible but at reservoir pressures above 4.5 barg. This is due to increasing hydrostatic head of the well as the gas density increases (gas velocity reduction). However, for flowrates above 1.4 $MtCO_2$/year injection to Hamilton Main only is no longer possible. The gas velocities in the wells exceed limit of 30 m/s (Ref. 1), even at reservoir pressure of 9 barg (Lennox initial reservoir pressure). Nevertheless, once the Lennox field is brought online (reservoir pressure of 9 barg) with additional injection wells, high gas velocities in the wells are no longer an issue for flowrates below 2 $MtCO_2$/year.

It is noted that wells of shorter length experience higher gas velocities than longer wells due to higher total pressure drop gradient (barg/m) resulted from higher flowrate intake. Consequently, in those wells greater fluid temperature drop is expected due to increased Joule-Thomson cooling. However, they remain within the required limits (given in Section D-5) for all the CO_2 injection rates considered.

Figure 3-1: System Constraints Map for Operating Option 1



The trigger point for transition to liquid phase flow is when the system reaches the MAOP of 35 barg (Figure 3-1: red-dotted line). At this point, the system cannot accept any additional increase in pressure of the storage reservoirs (risk of two-phase flow in the pipelines) nor CO_2 injection rates without further modifications to the offshore system.

The time interval for operation in a gas free-flow mode greatly depends on the CO_2 injection rate and the number of storage sites being in operation. This period, expressed here in terms of rising bottom hole pressures, ranges from 44 barg (for CO_2 rate of 0.4 $MtCO_2$/year) to 13.8 barg (for CO_2 rate of 2 $MtCO_2$/year), assuming all three fields are in operation. For the configuration where the CO_2 is transported to Hamilton Main and Lennox fields simultaneously, the range is 13.8 barg (for CO_2 rate of 1.9 $MtCO_2$/year) to 9 barg (for CO_2 rate of 2 MtCO2/year).

CO_2 injection at lower rates can be maintained in gas free-flow operating mode for longer durations, as the frictional pressure drop across the transportation network is significantly low, leading to a more rapid increase in gravitational pressure gain along the tubing with increasing reservoir pressures (increase in CO_2 density).

3.1.2 Transition / Liquid Phase Mode

As discussed in Section 3.1.1, once the CO_2 injection in a gas free-flow mode is no longer feasible with the existing offshore facilities, upgrades of the offshore pipelines as well as installation of compression at Point of Ayr are required. The majority of the infields pipelines, except the 12” Lennox line, are not suitable to transport high-pressure CO_2 liquid above 99 barg (maximum design pressure, Ref. 1, 11). In addition, the capacity of the 12” Lennox infield pipeline in a liquid phase is limited to 2.5 $MtCO_2$/year (Ref. 1). Therefore, upgrades of the infield pipelines (pressure ratings and line sizes) are required. The methodology and reasoning behind the offshore system sizing for the purposes of this flow assurance study are given in Section 2.2. It is acknowledged that the upgraded offshore pipeline sizes used to assess the liquid phase operating scenarios are over-sized, and that smaller line sizes are more appropriate for liquid CO_2 transportation.

The selected sizes (see Table 2-1) constrain parallel reservoir filling to a minimum CO_2 injection rate requirement of 10.3 $MtCO_2$/year (Figure 3-1: purple-dashed line). This is because the offshore system experiences back-flow from the wells at lower flowrates due to a difference in pipelines lengths and diameters in the network (back-flow can be avoided with check-valves although this was not considered in the modelling). In consequence, there is insufficient frictional pressure drop in pipelines of longer length / smaller diameter. For this reason, it is recommended that optimisation of the offshore lines sizes is performed during FEED, once the decision has been made by the project as to whether the line sizing should be driven by gas or liquid operating mode. Since the parallel reservoir filling is not viable at lower flowrates than 10.3 $MtCO_2$/year only single injection to Hamilton Main is considered, which is adequate for evaluation of the heating requirements during transition phase. The number of wells required for an injection of 10 $MtCO_2$/year in liquid phase is three.

In order to maintain the entire offshore system in a single liquid phase, the minimum arrival pressure at the wellhead platforms is 97 barg (subject to normal operating margins, Ref. 1). To achieve this, wellhead choking is required, which leads to a need for continuous heating during initial stages of the transition phase. This is to prevent very low temperatures, resulted from Joule-Thomson cooling across the choke, from entering the tubing.

Figure 3-1 shows that low flowrates, i.e. 2 $MtCO_2$/year, require significantly higher reservoir pressures in order to avoid continuous heating than flowrates ranging between 5.5 $MtCO_2$/year and 10 $MtCO_2$/year. This is because the pressure drop across the choke is greater for the low flowrates, leading to more severe Joule-Thomson cooling. The temperature of the fluid arriving at the bottom of the well at low rates is lower than for higher rates. Although, at higher flowrates there is additional cooling along the tubing resulted from increased frictional losses.

It is observed that shorter wells sustain larger pressure drop across the choke than longer well, resulting in lower fluid temperature downstream of the choke. Since longer wells require higher pressure downstream of the choke due to their length (larger pressure drop), the required pressure drop across the choke to maintain upstream pressure of 97 barg is lower. It follows that, for those wells, continuous heating can be ceased sooner. Although, such advantage has only been observed for CO_2 injection rates below 5.5 $MtCO_2$/year, as for higher rates, frictional pressure drop is the primary contributor to the overall cooling of the CO_2 along the tubing.

As the reservoir pressure progressively increases with the storage, the density of the CO_2 mixture along the wellbore also increases (increase in hydrostatic pressure), leading to lower pressure drops across the choke and lower frictional losses along the tubing. As a result, cooling of the CO_2 decreases, to the point that continuous heating upstream of the choke is no longer needed, as the fluid temperature in the well satisfies the minimum design temperature limit (i.e. 0 °C at wellhead, 4 °C at bottom hole (Ref. 1)).

Additionally, wellhead choking is required for the life of the Hamilton Main field, as the pressure downstream of the choke is always lower than the minimum normal operating upstream pressure (97 barg), even when the storage reservoir reaches its maximum capacity (96 barg). This is due to an increasing hydrostatic pressure (as density increases) exerted by denser CO_2, as reservoir pressure rises, where the gravitational pressure gain outweighs the frictional losses. In this instance, the pressure at the wellhead is lower than reservoir pressure. This well flow behaviour can be expected among all the three storage sites.

The evaluation of the continuous heating duty required at the wellhead platforms for the three CO_2 injection rates analysed and a range of bottom hole pressures is presented in Section 4.

3.2 Option 2: Maintain Gas Phase Operation (Offshore Wellhead Compression)

In this option, the initial operating strategy is to operate in a gas free-flow mode (no intermediate compression, no flow control), utilising the existing infrastructure, until the MAOP of 35 barg (subject to normal operational margins, Ref. 1) is reached as the reservoir pressure increases with CO_2 storage. Once the maximum capacity of the system has been reached there are two options for the system upgrade to be considered, in order to continue injection:

Option 2a

- Maintain operation of the onshore and offshore systems in gas phase mode at MAOP of 35 barg (Ref. 1), recompressing the CO_2 at the wellhead platforms. An upgrade of the existing offshore pipelines sizes is required when the flow ramp-up is no longer feasible due to their limited capacity, which is at 2 $MtCO_2$/year. Similarly, the existing 24” onshore section from Connah’s Quay to Point of Ayr requires increase in size at 5 $MtCO_2$/year (Ref. 1).

Figure 3-2 shows the system constraints map for the Option 2a for a range of CO_2 injection rates between 0.4 $MtCO_2$/year and 4.8 $MtCO_2$/year.

Option 2b

- Upgrade sizes of the offshore pipelines to allow for extended operation in the gas free-flow mode (no intermediate compression, no flow control). Once the system with upgraded offshore capacity reaches the MAOP of 35 barg (Ref. 1), operation of the onshore and offshore systems in the gas phase mode is maintained at this pressure, recompressing the CO_2 at wellhead platforms. An upgrade of the 24” onshore pipeline from Connah’s Quay to Point of Ayr occurs when the onshore system reaches its maximum capacity (5 $MtCO_2$/year, Ref. 1).

Figure 3-3 shows an operational constrains map for the Option 2b for a range of CO_2 injection rates between 0.4 $MtCO_2$/year and 4.8 $MtCO_2$/year.

Figure 3-2: System Constraints Map for Operating Option 2a

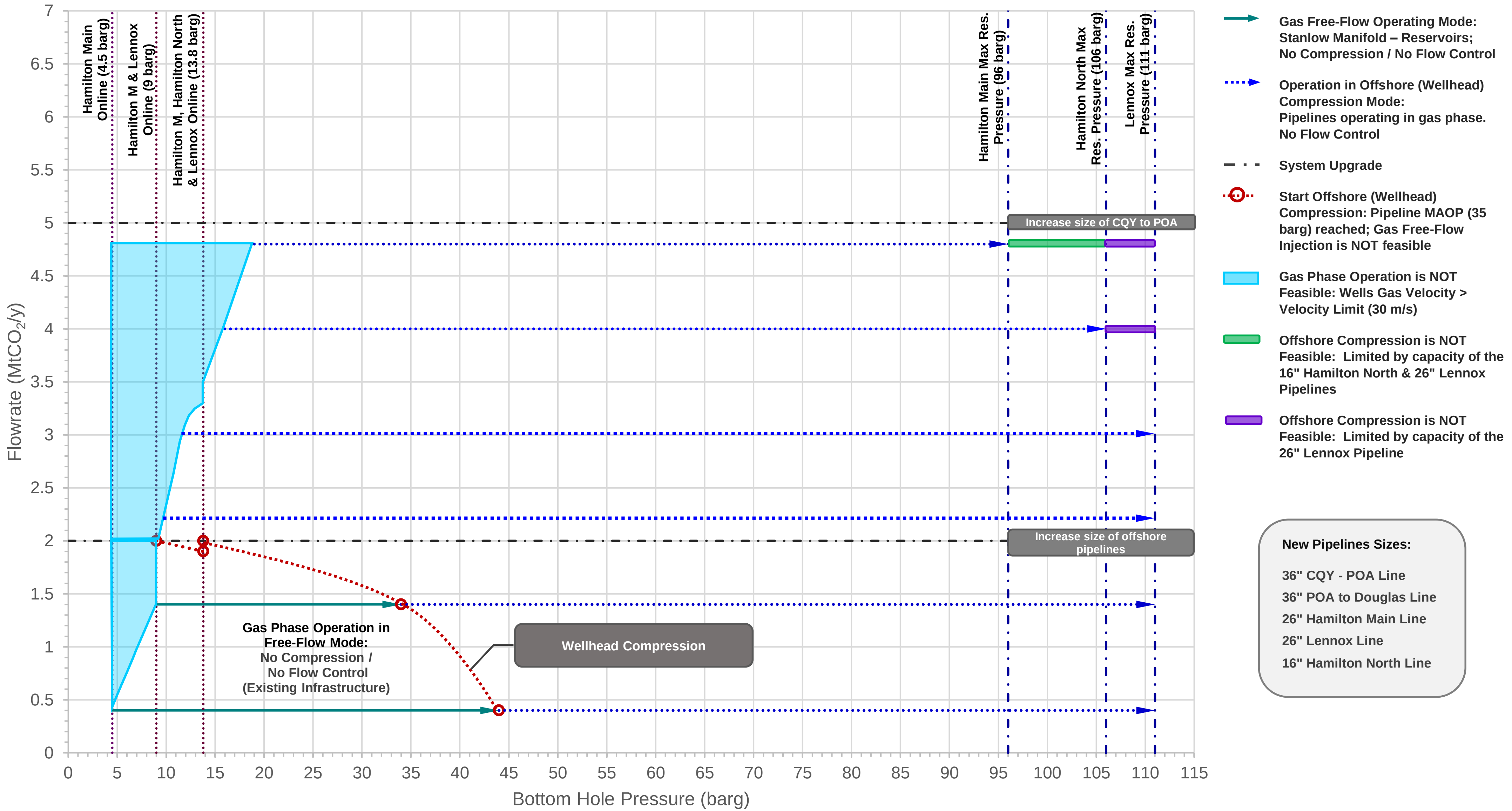
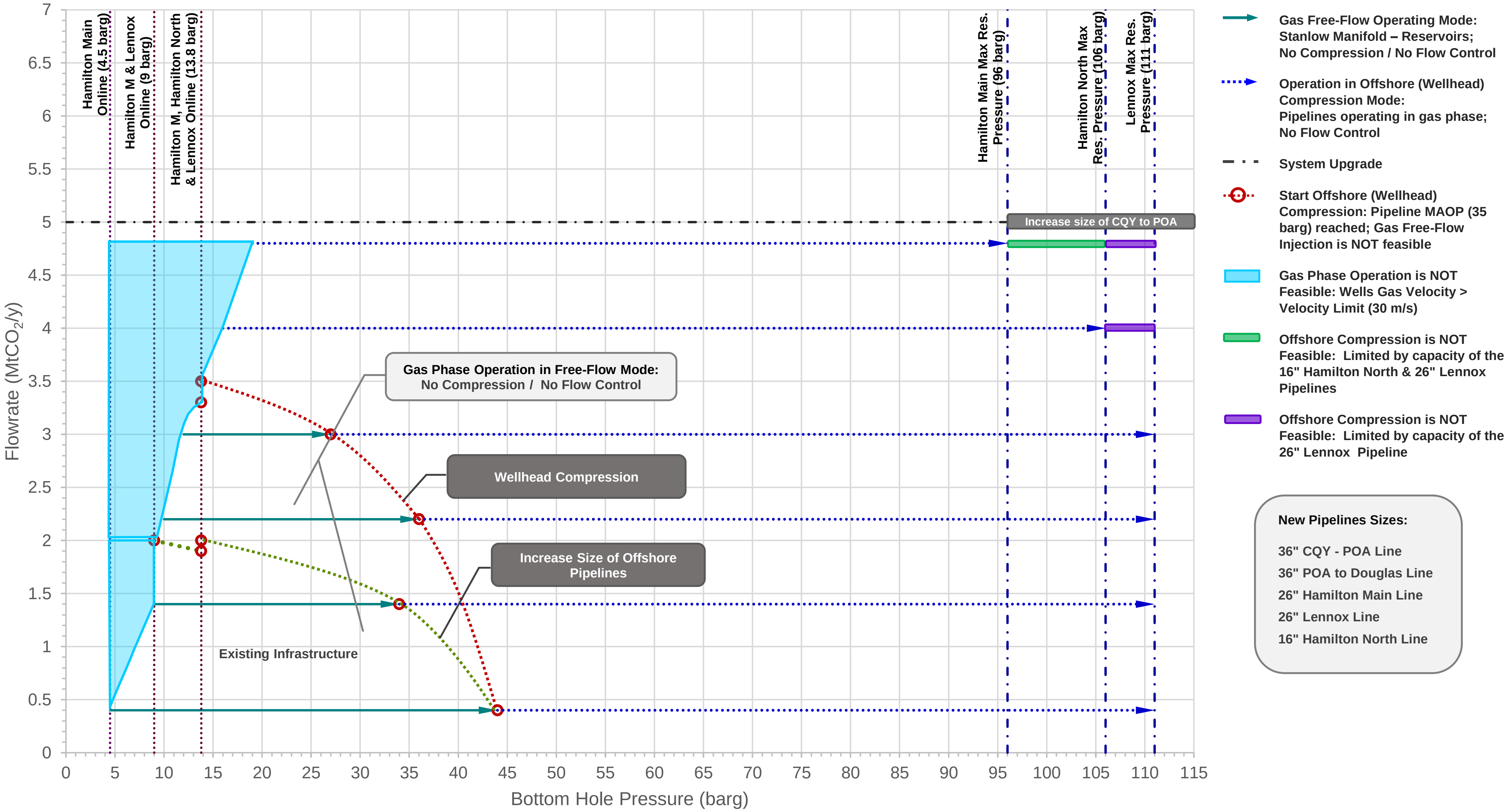


Figure 3-3: System Constraints Map for Operating Option 2b



3.2.1 Gas Free-Flow Operating Mode

Option 2a

Operation in the gas free-flow mode (no intermediate compression, no flow control) for this option is identical to that of the Option 1 which is described in detail in Section 3.1.1.

Here, the trigger point for installation of wellhead compression is when the system reaches the MAOP of 35 barg (Figure 3-2: red-dotted line). At this point, the system cannot accept any additional increase in pressure of the storage reservoirs (risk of two-phase flow in the pipelines) nor CO_2 injection rates without further modifications to the offshore system.

Option 2b

This option is analogue to the Option 2a, except that for this option an early upgrade of the offshore pipelines sizes is considered (Figure 3-3: light green-dotted line). This is in order to delay installation of the offshore (wellhead) compression for when the upgraded system reaches its maximum capacity in a gas free-flow mode (Figure 3-3: red-dotted line).

In order to expand the operation in a gas phase flow to higher flowrates, for the purpose of this study, the offshore system has been sized to accommodate 5 $MtCO_2$/year for parallel injection (all fields online). Selected sizes and methodology behind the line sizing are documented in Section 2.2. Should there be a need for further expansion (up to 10 $MtCO_2$/year) in the gas phase operating mode larger pipelines diameters than the selected will be required. It is noted that upgraded size of the offshore system is not suitable for parallel injection at CO_2 injection rates below 2 $MtCO_2$/year as there is back-flow from the wells. Therefore, at these flowrates only injection to a single reservoir is feasible.

Figure 3-3 shows that the blue-shaded region, where the operation in the gas phase is not viable due to the gas velocity breaching the limit of 30 m/s, expands rapidly with increasing CO_2 injection rate above 2.2 $MtCO_2$/year. This is because the number of available wells per field is limited, regardless of the injection rate. The extent of this unfeasible region could be reduced if the gas velocity limit is relaxed or additional wells are drilled.

In addition, it is noteworthy that, in order to allow for an appropriate flowrate distribution between fields such that the flowrate split ratio reflects the storage reservoirs' capacity, an adequate number of wells in operation per storage site is required. Therefore, not necessarily all available wells will be utilised, unless flow control is applied.

The time interval, expressed here in terms of rising bottom hole pressures, for operation in the gas free-flow mode, considering an upgraded offshore system, ranges from 44 barg (for CO_2 rate of 0.4 $MtCO_2$/year, single reservoir filling) to 13.8 barg (for CO_2 rate of 3.5 $MtCO_2$/year), assuming all three fields are in operation at flowrates above 2 $MtCO_2$/year. For the configuration where the CO_2 is transported to Hamilton Main and Lennox fields simultaneously, the range is 13.8 barg (for CO_2 rate of 3.3 $MtCO_2$/year) to 10 barg (for CO_2 rate of 2.2 MtCO2/year).

3.2.2 Offshore (Wellhead) Compression

Installation of compressors at wellhead platforms is required, in order to maintain operation in the gas phase across the system, once the CO_2 transport network with the existing (Option 2a) or upgraded (Option 2b) offshore system operates at the MAOP of 35 barg (Ref. 1). The bottom hole pressure at which the offshore compression is required depends on, as mentioned earlier, the CO_2 injection rate and the capacity of the transportation network.

The compression system discharge temperature of 40 °C has been assumed for all the cases studied. The choke at each wellhead is assumed to be fully open to allow for the compressor discharge pressure requirements to be calculated by OLGA. The required wellhead injection pressures vary with the length of the well and its flowrate. This means that wells of longer length require higher injection pressures compared to shorter wells, due to greater frictional pressure drop. The same applies to short wells operating at high CO_2 flowrates.

It should, however, be pointed out that for the CO_2 injection rates of 4 $MtCO_2$/year and above, the capacity of the Lennox infield pipeline, for the current line size selection, is not sufficient for a single reservoir filling. Once the Hamilton Main and Hamilton North reach their maximum reservoir pressure of 96 barg and 106 barg respectively, injection to Lennox only will not be feasible. Additionally, for the CO_2 injection rates of 4.8 $MtCO_2$/year and above, the CO_2 transport in the gas phase mode becomes infeasible once Hamilton Main reaches its maximum reservoir pressure of 96 barg. The capacity of the Hamilton North and Lennox infield pipelines is not sufficient to accommodate such flowrates without Hamilton Main. If bigger sizes of offshore pipelines have been considered the CO_2 injection at those rates would not be an issue.

Furthermore, the CO_2 injected into the tubing at the temperature of 40 °C is in a superheated state (temperature above the critical point of the CO_2 mixture). Hence, as the reservoir pressure increases with the storage and the gravitational pressure gain begins to overcome frictional losses, due to increasing density of the fluid (increasing hydrostatic pressure), the temperature of the superheated CO_2 increases (rather than decreases to ambient temperature) as it flows through the wellbore. This is because the pressure increasing down the well (top to bottom) compresses the superheated gas, increasing its internal energy, consequently the amount of superheat increases. Therefore, at end of the fields' life when majority of the well is in a supercritical state the flowing bottom hole temperatures reach even 55 °C. On the other hand, at initial stages of the offshore compression frictional pressure drop across the wellbore is a dominant factor due to low gas density, and therefore the superheated gas cools down to certain extent (circa 22 °C for 4.8 $MtCO_2$/year).

In addition, the two-phase flow has not been observed in any of the wells studied. This is credited to post-compression temperature of 40 °C which yields operating temperature along the tubing above dewpoint temperature, maintaining a CO_2 mixture in gaseous state at associated operating pressure.

4. HEATING REQUIREMENTS

A high-level evaluation of the heating requirements for the transition from gas to liquid phase injection has been performed. This is to determine heating duty necessary to overcome Joule-Thomson cooling across the choke and resulted from the frictional pressure drop along the well, so that the temperature of injected CO_2 remains within the design limits (i.e. 0 °C at wellhead and 4 °C at bottom hole (Ref. 1)). The estimation of the required power for continuous heating assumes heaters to be located upstream of the choke and is based on the OLGA reported results obtained for scenarios discussed in Section 3.1.2.

Table 4-1 shows the heating duties required during transition phase. The CO_2 injection rates given below correspond to a single well, therefore the power requirements provided here are for one injection well.

Table 4-1: Illustration of Heating Requirements for the Transition from Gas to Liquid Phase Injection

Hamilton Main – Well HM1 / HM2:	**Total Injection Rate: 2 MtCO2/y**			**Total Injection Rate: 5.5 MtCO2/y**			**Total Injection Rate: 10 MtCO2/y**		
	BHP=29 barg	**BHP=50 barg**	**BHP=85 barg**	**BHP=29 barg**	**BHP=40 barg**	**BHP=48 barg**	**BHP=29 barg**	**BHP=38 barg**	**BHP=46 barg**
No. of Wells at Hamilton Wellhead Platform	1	1	1	2	2	2	3	2	2
Flowrate per well, $MtCO_2$/y	2	2	2	2.75	2.75	2.75	3.3	5	5
Flowrate per well, kg/s	70.4	70.4	70.4	96.8	96.8	96.8	117.3	176	176
Operating Conditions Prior Heating									
Temperature u/s of the choke, °C	9.6	9.6	9.6	15	15	15	16.6	16.6	16.6
Pressure u/s of the choke, barg	97	97	97	97	97	97	97	97	97
Temperature d/s of the choke (no heating), °C	-2	-1.7	0.03	4.7	4.9	5	8.7	15.7	16
Pressure d/s of the choke, barg	43	44	47	51.3	51.8	52.2	58.3	90	91
FBHT (no heating), °C	-11.2	4	12.6	-9.8	-0.7	4.5	-9.1	-0.6	4.5
JT cooling across the choke, °C	11.6	11.3	9.57	10.3	10.1	10	7.9	0.9	0.6
CO_2 temperature drop along the well, °C	9.2	-5.7	-12.57	14.5	5.6	0.5	17.8	16.3	11.5
Pressure drop across the choke, barg	54	53	50	45.7	45.2	44.8	38.7	7	
Power Requirements									
Required temperature d/s of the choke, to meet min well temperature limits (FWHT: 0°C & FBHT: 4°C), °C	16	0	**Heating NOT Required**	20	10	**Heating NOT Required**	22	21	**Heating NOT Required**
Required temperature increase u/s of the choke, °C	63.5	13.5		59.2	28.8		54.4	22	
Power Requirements to Increase Gas Temperature, MW	**10.6**	**0.8**	**-**	**13.3**	**4.2**	**-**	**14.3**	**3.1**	**-**

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12. Email: from Paoli Lodovico (Eni) on 25/10/2019, Subject: RE: HyNet Interface Register: Reservoir issues

APPENDICES CONTENTS

Appendix A ABBREVIATIONS

Abbreviation	Description
BHP	Bottom Hole Pressure
CCS	Carbon Capture and Storage
CCUS	Carbon Capture Utilization and Storage
CO_2	Carbon Dioxide
CQY	Connah's Quay
d/s	Downstream
FEED	Front-end Engineering and Design
FBHT	Flowing Bottom Head Temperature
FWHT	Flowing Well Head Temperature
H_2	Hydrogen
HMG	Her Majesty's Government
HP	High Pressure
JT	Joule-Thomson
LP	Low Pressure
MAOP	Maximum Allowable Operating Pressure
$MtCO_2$	Mega ton of Carbon Dioxide (1E9 kg)
NB	Nominal Bore
PoA	Point of Ayr
ROAD	Rotterdam Opslag en Afvang Demonstratieproject
u/s	Upstream
WHP	Well Head Pressure

Appendix B FIGURES AND TABLES

Figures

Tables

Appendix C KEY OLGA RESULTS

This section presents key results obtained from OLGA simulations conducted to support the conclusions provided within this document. Only results from operating scenarios that determine operational limits are shown here.

Diagrams presented in the following sections depict the full-chain integrated CO_2 transportation and injection network, from Stanlow Industrial Site to all storage reservoirs. When a component of the network is not in operation, this has been greyed out.

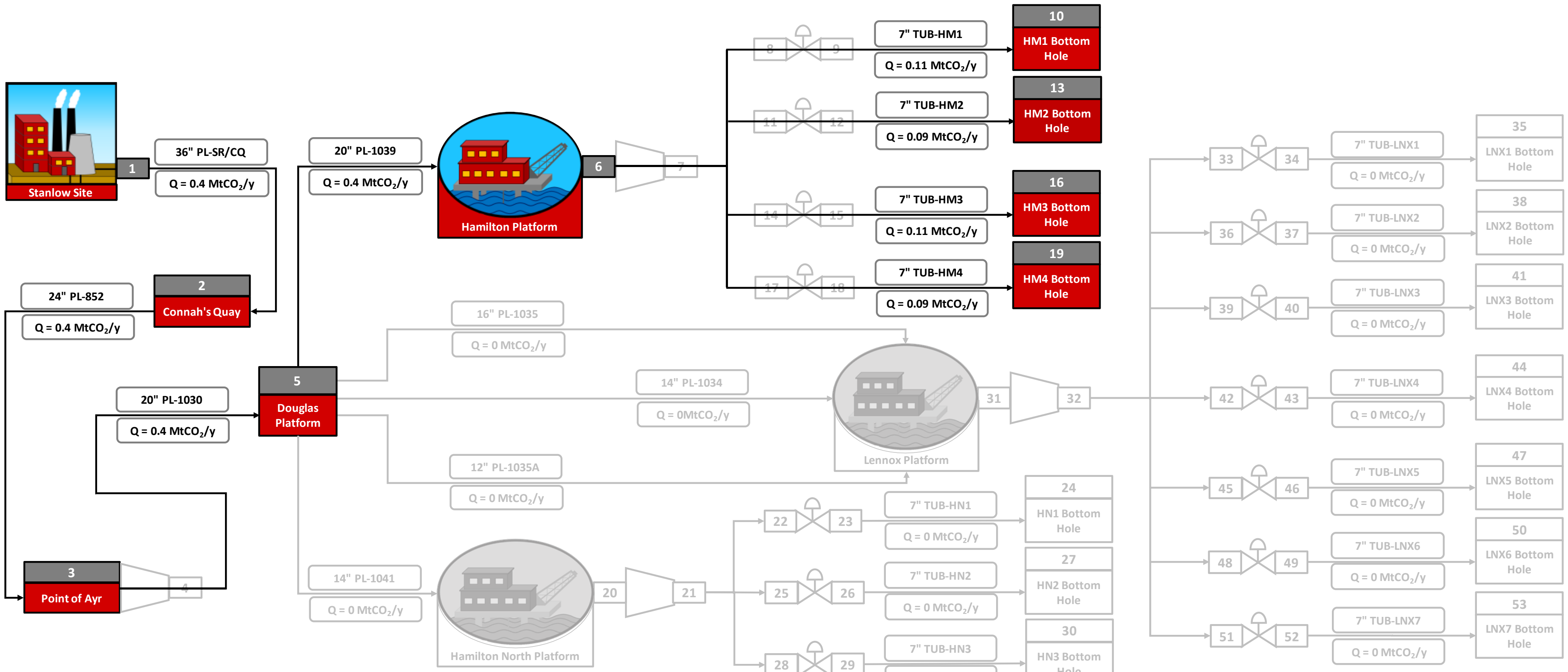
Tables associated with diagrams present key operating conditions prevailing at the inlet / upstream and outlet / downstream of each component of the CO_2 transportation and injection network, covering a range of operating scenarios over the project life.

C-1 Gas Free-flow Operating Mode: Existing Offshore Capacity

C-1.2 CO_2 Injection to Hamilton Main only

Figure C-1- Figure C-3 show initial stages of the CO_2 injection, where only Hamilton Main field is in operation. This period is expressed here in terms of rising bottom-hole pressure and ranges from 4.5 barg to 9 barg with CO_2 injection rates ranging between 0.4 and 1.4 $MtCO_2$/year. Higher injection rates, within this pressure range, are not feasible due to the gas velocity limit (30 m/s) in the wells.

Figure C-1 Injection to Hamilton Main only, Bottom-hole Pressure of 4.5 barg, CO_2 Injection Rate of 0.4 $MtCO_2$/year.

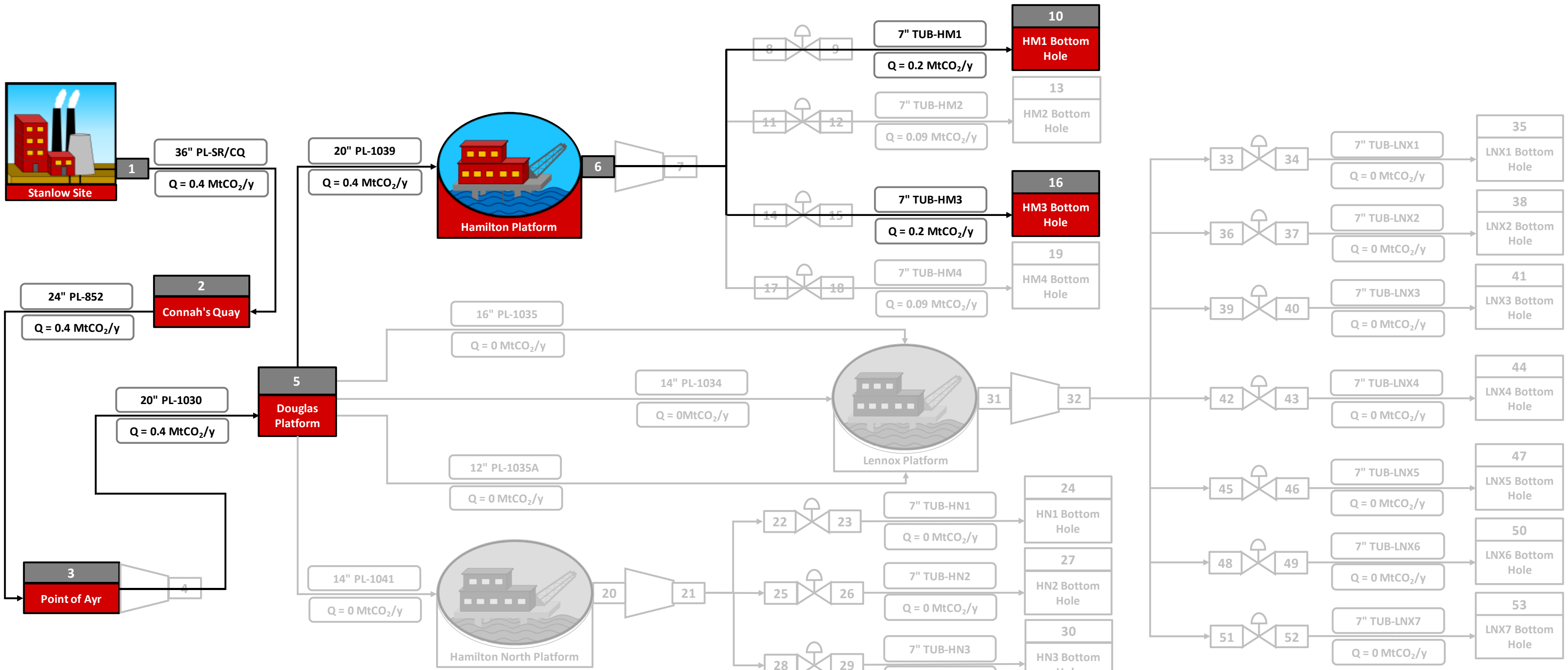


Note 1: Components of the onshore/offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-1.

Table C-1 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-1

CO_2 Flow Properties	1	2	3	5	6	10	13	16	19
Pressure (barg)	9.5	9.4	9.1	7.2	6.4	4.5	4.5	4.5	4.5
Fluid Temperature (°C)	20.0	0.1	1.2	4.8	3.9	25.1	27.3	25.1	27.3
Fluid Density (kg/m^3)	19.6	21.2	20.4	16.2	14.5	9.9	9.8	9.9	9.8
CO_2 velocity (m/s)	1.2	1.1	2.6	5.1	5.5	19.0	16.0	19.0	16.0

Figure C-2 Injection to Hamilton Main only, Bottom-hole Pressure of 9 barg, CO_2 Injection Rate of 0.4 $MtCO_2$/year.

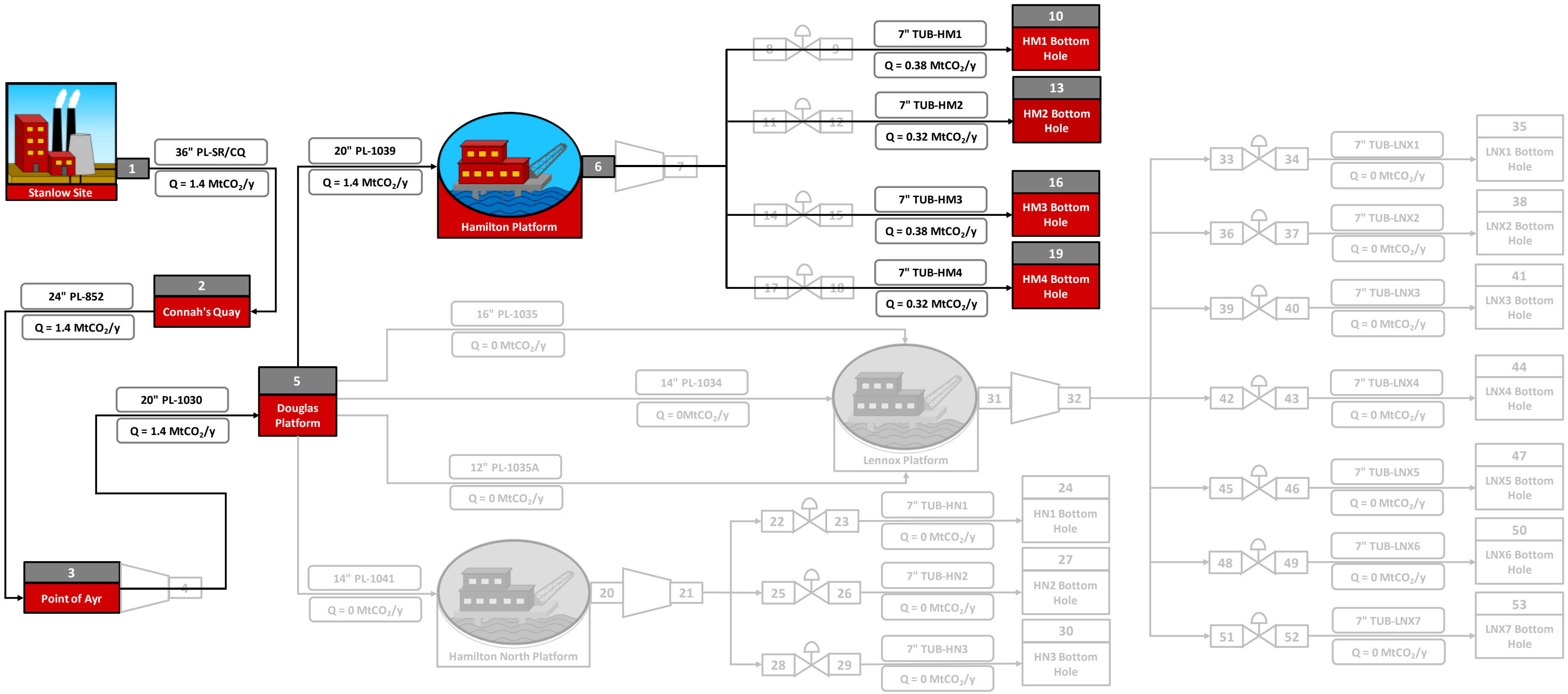


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-2.

Table C-2 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-2.

CO_2 Flow Properties	1	2	3	5	6	10	16
Pressure (barg)	14.1	14.1	13.9	12.8	12.2	9.0	9.0
Fluid Temperature (°C)	20.0	0.1	1.3	4.9	3.9	20.9	20.9
Fluid Density (kg/m³)	29.3	32.0	31.2	28.3	27.1	18.7	18.7
CO_2 velocity (m/s)	0.8	0.7	1.7	2.9	2.9	18.4	18.4

Figure C-3 Injection to Hamilton Main only, Bottom-hole Pressure of 9 barg, CO_2 Injection Rate of 1.4 $MtCO_2$/year.



Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-3.

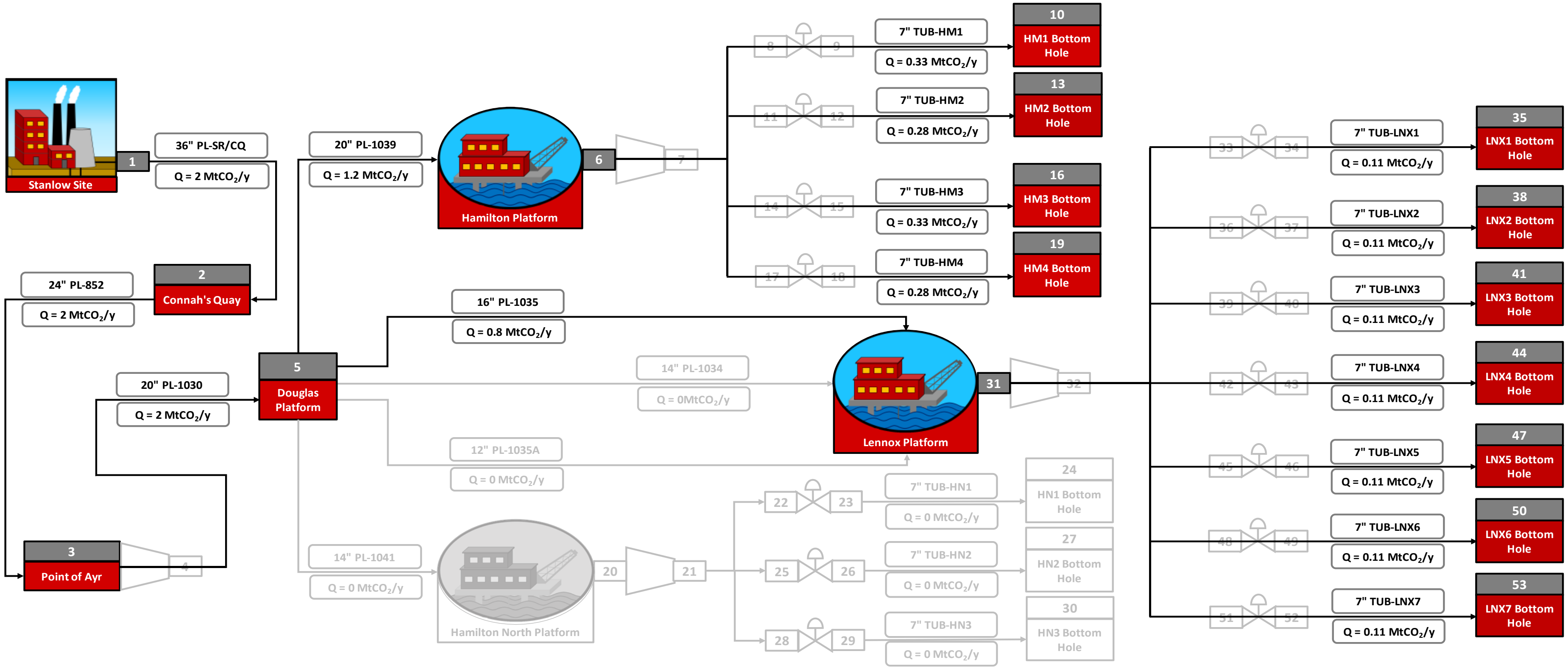
Table C-3 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-3.

CO_2 Flow Properties	1	2	3	5	6	10	13	16	19
Pressure (barg)	30.4	30.3	29.2	22.8	19.7	9.0	9.0	9.0	9.0
Fluid Temperature (°C)	20.0	5.0	2.2	1.7	0.6	8.8	12.6	8.8	12.6
Fluid Density (kg/m³)	68.2	75.3	73.2	54.2	46.0	20.0	20.0	20.0	20.0
CO_2 velocity (m/s)	1.2	1.1	2.4	5.3	6.0	30.2	28.2	30.2	28.2

C-1.3 CO_2 Injection to Hamilton Main and Lennox Reservoirs

Figure C-4 and Figure C-5 illustrate parallel reservoir filling during gas free-flow operating mode, where captured CO_2 emissions are transported (in the gas phase) and injected into Hamilton Main and Lennox fields simultaneously. The time interval for this operation, expressed here in terms of rising bottom-hole pressure, begins once Hamilton Main reservoir pressure reaches 9 barg (at this point Lennox field is brought online) and ends when both Hamilton Main and Lennox reservoirs are at the pressure of 13.8 barg. For this configuration only operation at maximum viable CO_2 injection rates is presented here, i.e. 1.9 $MtCO_2$/year (at BHP=13.8 barg) and 2 $MtCO_2$/year (at BHP=9 barg), as further expansion in the gas phase within this pressure range requires additional upgrades to the offshore system.

Figure C-4 Simultaneous Injection to Hamilton Main and Lennox Sites, Bottom-hole Pressure of 9 barg, CO_2 Injection Rate of 2 $MtCO_2$/year.

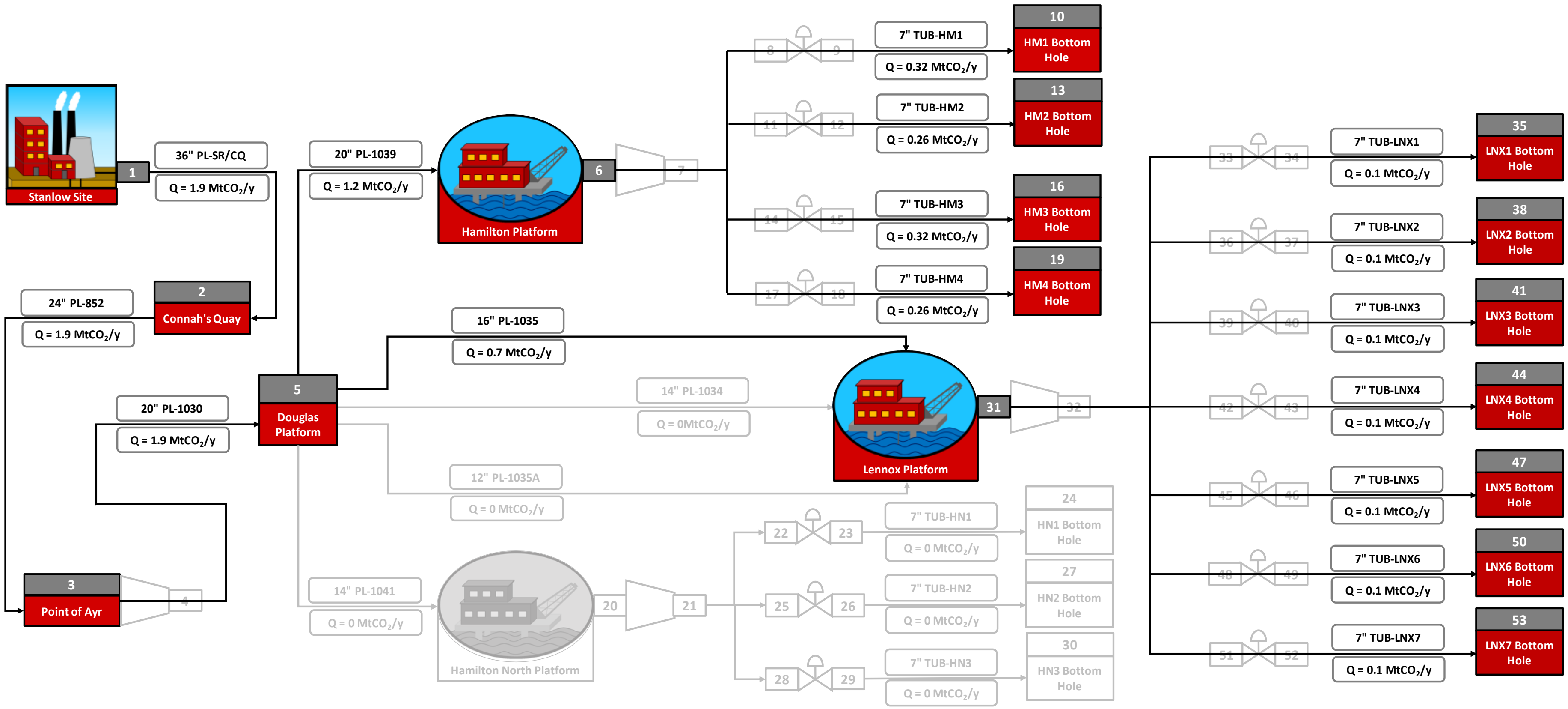


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-4.

Table C-4 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-4.

CO_2 Flow Properties	1	2	3	5	6	10	13	16	19	31	35	38	41	44	47	50	53
Pressure (barg)	34.9	34.4	32.7	20.2	17.6	9.0	9.0	9.0	9.0	9.7	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Fluid Temperature (°C)	20.0	7.9	3.0	-3.9	-0.3	11.9	15.8	11.9	15.8	0.6	26.6	26.6	26.6	26.6	26.6	26.6	26.6
Fluid Density (kg/m^3)	80.9	88.1	85.0	48.6	40.6	19.6	19.2	19.6	19.2	21.9	18.2	18.2	18.2	18.2	18.2	18.2	18.2
CO_2 velocity (m/s)	1.4	1.3	3.1	8.5	5.9	28.8	24.8	28.8	24.8	11.0	10.6	10.6	10.6	10.6	10.6	10.6	10.6

Figure C-5 Simultaneous Injection to Hamilton Main and Lennox Sites, Bottom-hole Pressure of 13.8 barg, CO_2 Injection Rate of 1.9 $MtCO_2$/year.



Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-5.

Table C-5 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-5.

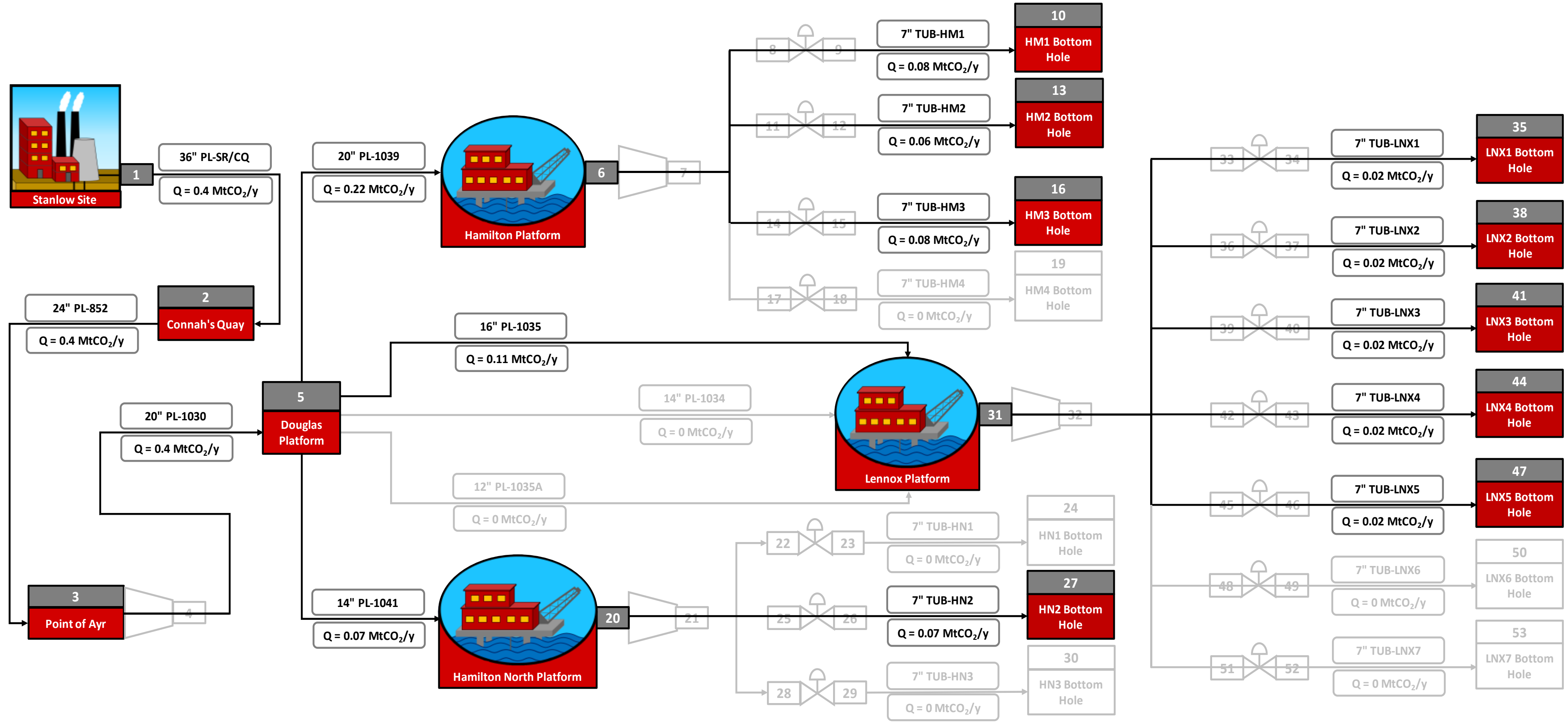
CO_2 Flow Properties	1	2	3	5	6	10	13	16	19	31	35	38	41	44	47	50	53
Pressure (barg)	34.6	34.2	32.3	21.1	21.1	13.9	13.8	13.9	13.8	21.1	13.8	13.8	13.8	13.8	13.8	13.8	13.8
Fluid Temperature (°C)	20.0	7.5	2.9	-2.7	-2.7	15.5	18.8	15.5	18.8	-2.6	27.2	27.2	27.2	27.2	27.2	27.2	27.2
Fluid Density (kg/m^3)	79.3	86.6	83.7	50.9	50.7	29.2	28.7	29.2	28.7	50.7	27.6	27.6	27.6	27.6	27.6	27.6	27.6
CO_2 velocity (m/s)	1.4	1.3	3.0	7.7	4.5	18.5	15.7	18.5	15.7	4.5	6.6	6.6	6.6	6.6	6.6	6.6	6.6

C-1.4 CO_2 Injection to Hamilton Main, Hamilton North and Lennox Reservoirs

Figure C-6 - Figure C-10 illustrate parallel reservoir filling during gas free-flow operating mode with all three fields in operation. The time interval for this operation, expressed here in terms of rising bottom-hole / reservoir pressure, begins once Hamilton Main and Lennox reservoirs pressure is at 13.8 barg (at this point Hamilton North field is brought online) and ends when MAOP of 35 barg is reached in the system. The duration of operation in the gas free-flow mode at this configuration greatly depends on the CO_2 injection rate, meaning that it decreases with the flowrate increase. The maximum viable flowrate for this configuration, however, only for the bottom-hole / reservoir pressure of 13.8 barg (the time Hamilton North is brought online) is 2 MtCO_2/year. This is because the system, in this instance, reaches its maximum allowable operating pressure of 35 barg.

It is noted that at low flowrates (0.4 MtCO_2/year) Lennox field experiences back-flow from the wells, due to insufficient frictional pressure drop in pipelines, which aggravates while reservoir pressure increases. Such behaviour has been observed for bottom-hole / reservoir pressures above 35 barg. At this point CO_2 injection to Lennox reservoir is no longer feasible, hence its operation has been ceased for the purpose of this study.

Figure C-6 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 13.8 barg, CO_2 Injection Rate of 0.4 $MtCO_2$/year.

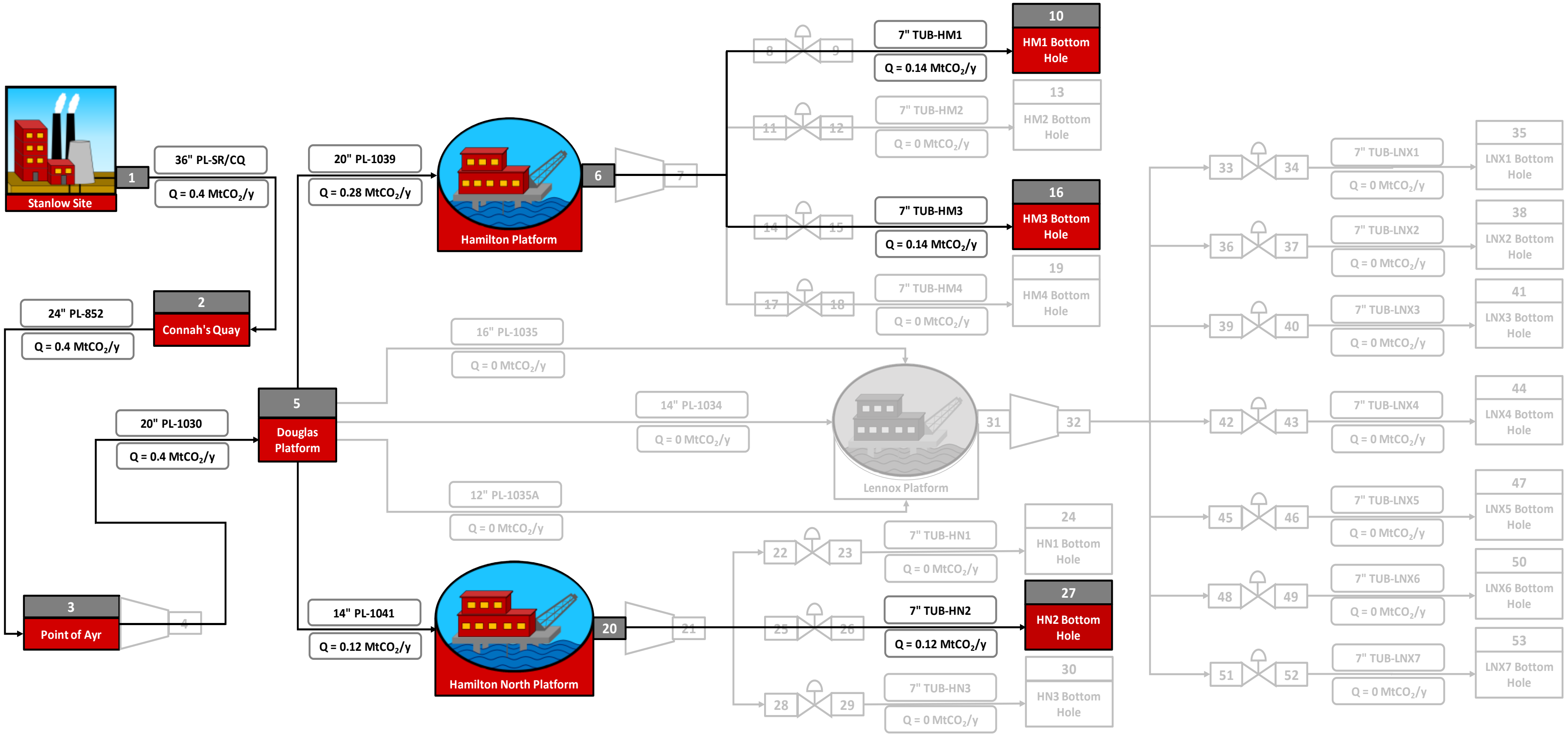


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-6.

Table C-6 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-6.

CO_2 Flow Properties	1	2	3	5	6	10	13	16	20	27	31	35	38	41	44	47
Pressure (barg)	13.3	13.3	13.0	11.9	11.6	13.8	13.8	13.8	11.6	13.8	11.4	13.8	13.8	13.8	13.8	13.8
Fluid Temperature (°C)	20.0	0.1	1.3	4.9	3.9	27.5	29.2	27.5	4.0	28.3	3.9	30.1	30.1	30.1	30.1	30.1
Fluid Density (kg/m^3)	27.5	30.0	29.3	26.1	25.7	27.5	27.3	27.5	25.7	27.4	25.3	27.2	27.2	27.2	27.2	27.2
CO_2 velocity (m/s)	0.8	0.8	1.8	3.2	1.7	5.0	3.4	5.0	1.2	4.5	1.4	1.4	1.4	1.4	1.4	1.4

Figure C-7 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 44 barg, CO_2 Injection Rate of 0.4 $MtCO_2$/year.

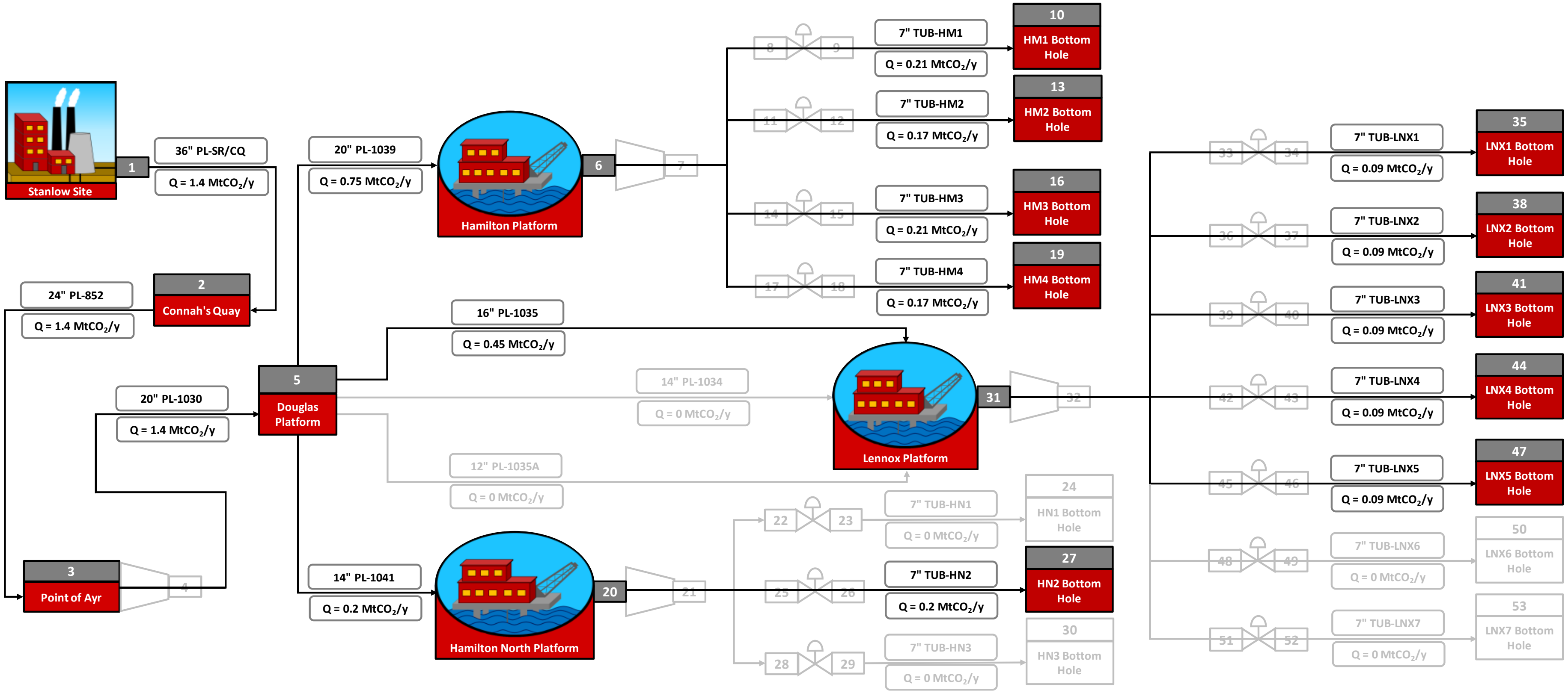


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-7.

Table C-7 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-7.

CO_2 Flow Properties	1	2	3	5	6	10	16	20	27
Pressure (barg)	34.6	34.5	34.4	34.3	33.8	44.0	44.0	33.8	44.0
Fluid Temperature (°C)	20.0	0.4	2.1	5.1	3.8	27.5	27.5	3.8	28.2
Fluid Density (kg/m³)	80.3	94.3	92.2	89.4	88.4	104.0	104.0	88.2	103.4
CO_2 velocity (m/s)	0.3	0.2	0.6	0.9	0.6	2.4	2.4	0.5	1.9

Figure C-8 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 13.8 barg, CO_2 Injection Rate of 1.4 $MtCO_2$/year.

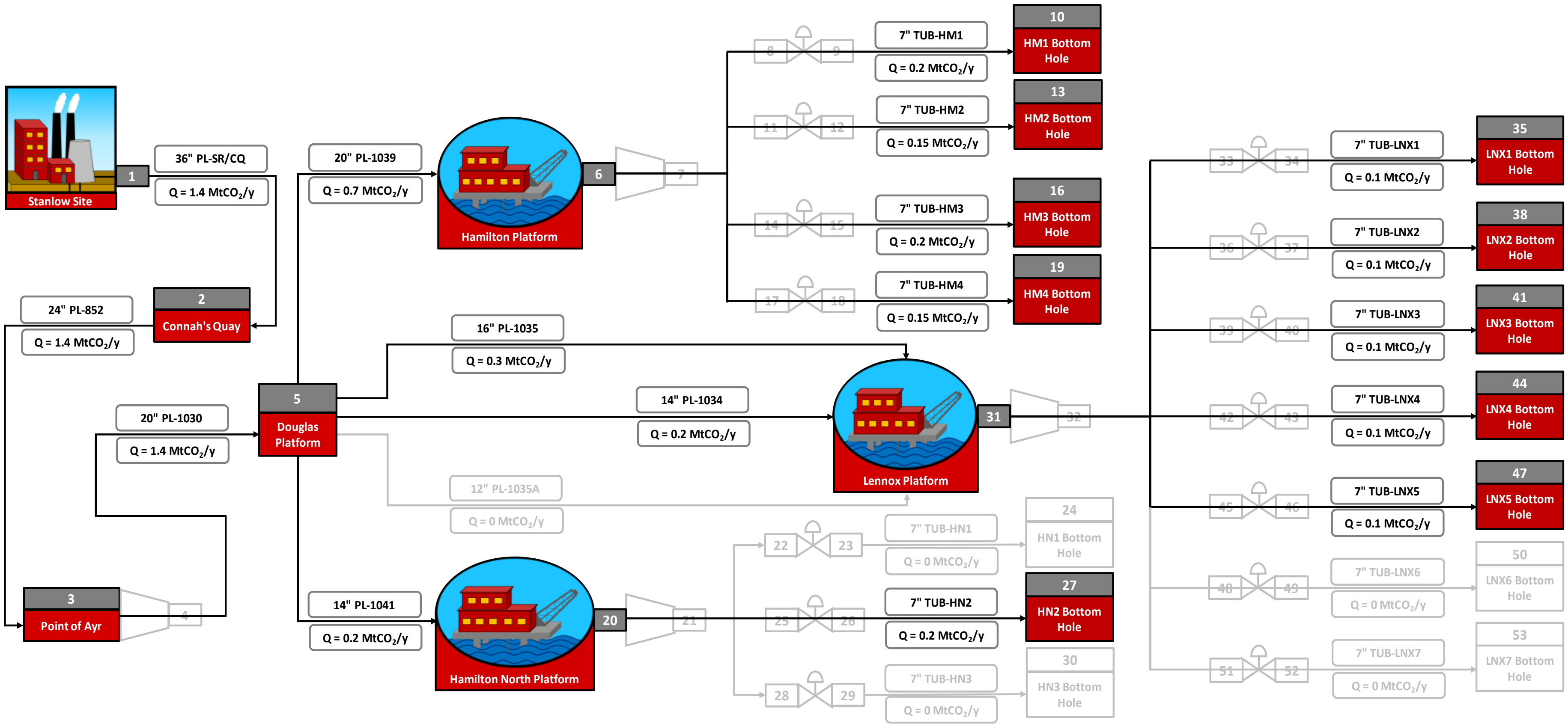


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-8.

Table C-8 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-8.

CO_2 Flow Properties	1	2	3	5	6	10	13	16	19	20	27	31	35	38	41	44	47
Pressure (barg)	26.2	26.1	24.7	16.2	14.9	13.8	13.8	13.8	13.8	15.3	13.8	12.4	13.8	13.8	13.8	13.8	13.8
Fluid Temperature (°C)	20.0	4.5	1.8	0.8	3.0	21.8	24.5	21.8	24.5	4.0	22.6	3.7	28.0	28.0	28.0	28.0	28.0
Fluid Density (kg/m^3)	57.2	62.5	59.7	37.1	33.4	28.3	27.9	28.3	27.9	34.3	28.2	27.6	27.5	27.5	27.5	27.5	27.5
CO_2 velocity (m/s)	1.4	1.3	3.0	7.8	4.4	12.5	10.4	12.5	10.4	2.4	12.2	5.0	5.6	5.6	5.6	5.6	5.6

Figure C-9 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 34 barg, CO_2 Injection Rate of 1.4 $MtCO_2$/year.

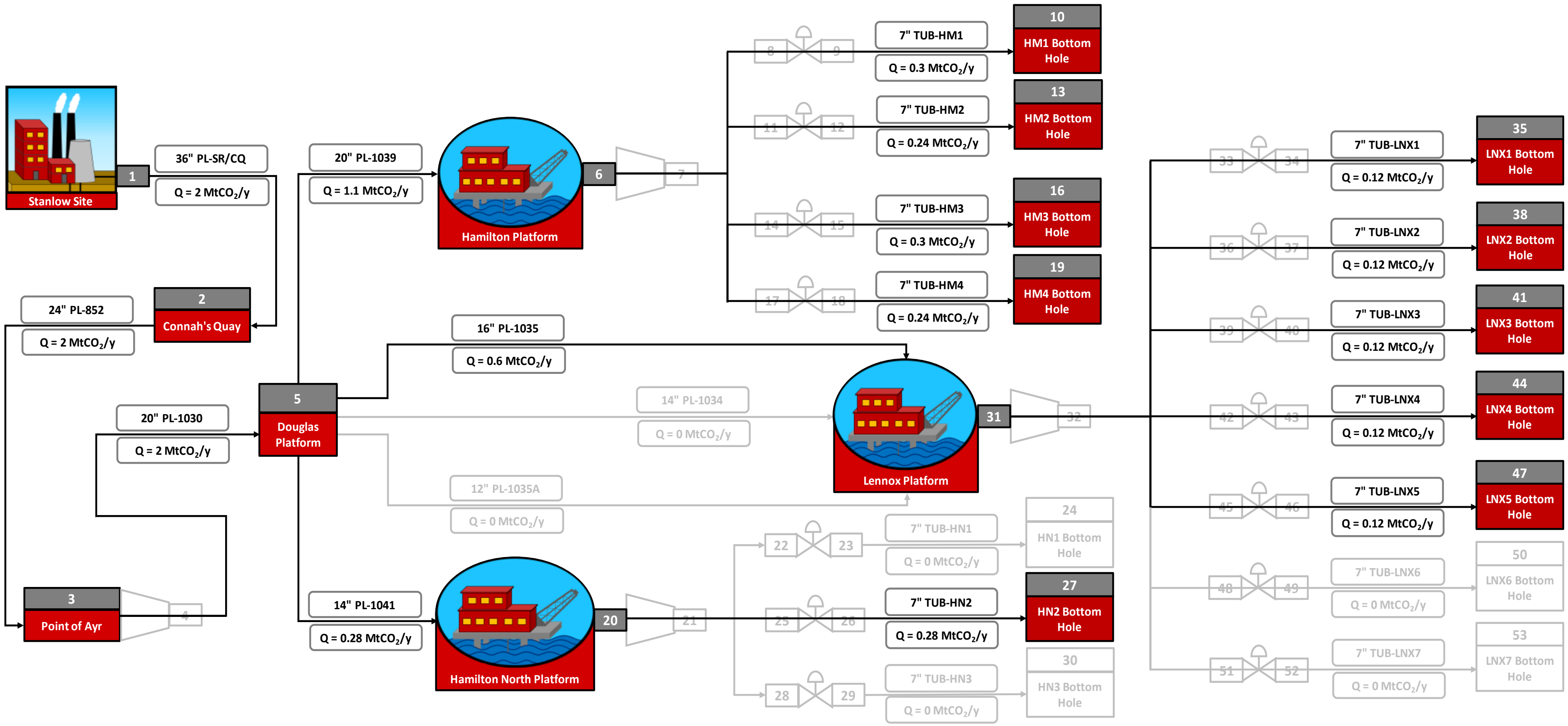


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-9.

Table C-9 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-9.

CO_2 Flow Properties	1	2	3	5	6	10	13	16	19	20	27	31	35	38	41	44	47
Pressure (barg)	34.8	34.7	33.8	28.9	28.0	34.0	34.0	34.0	34.0	28.1	34.0	27.8	34.0	34.0	34.0	34.0	34.0
Fluid Temperature (°C)	20.0	5.5	2.7	2.2	3.2	24.7	26.9	24.7	26.9	3.9	25.3	4.0	28.1	28.1	28.1	28.1	28.1
Fluid Density (kg/m^3)	80.9	90.3	89.2	72.4	68.9	75.7	74.7	75.7	74.7	69.0	75.4	68.1	74.1	74.1	74.1	74.1	74.1
CO_2 velocity (m/s)	1.0	0.9	2.0	4.0	2.1	4.9	3.4	4.9	3.4	1.2	4.6	1.3	2.2	2.2	2.2	2.2	2.2

Figure C-10 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 13.8 barg, CO_2 Injection Rate of 2 $MtCO_2$/year.



Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-10.

Table C-10 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-10.

CO_2 Flow Properties	1	2	3	5	6	10	13	16	19	20	27	31	35	38	41	44	47
Pressure (barg)	34.7	34.5	32.6	20.0	17.9	13.9	13.8	13.9	13.8	18.6	13.9	13.5	13.8	13.8	13.8	13.8	13.8
Fluid Temperature (°C)	20.0	7.9	3.0	-4.0	0.6	16.9	20.1	16.9	20.1	3.8	18.1	2.6	26.1	26.1	26.1	26.1	26.1
Fluid Density (kg/m³)	80.6	87.7	84.5	48.0	41.2	29.0	28.5	29.0	28.5	42.3	28.8	30.1	27.7	27.7	27.7	27.7	27.7
CO_2 velocity (m/s)	1.4	1.3	3.1	8.6	5.1	17.2	14.6	17.2	14.6	2.8	16.9	6.6	8.0	8.0	8.0	8.0	8.0

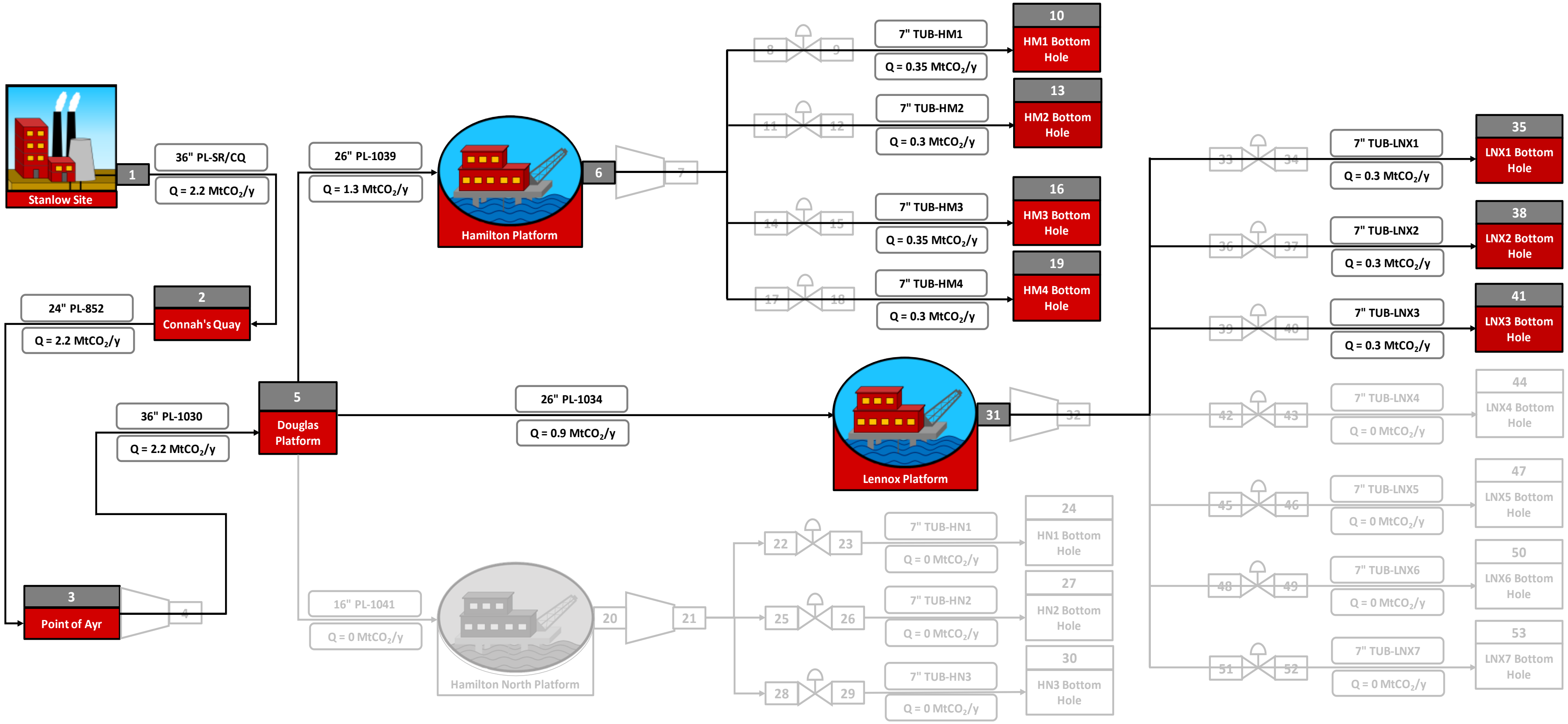
C-2 Gas Free-flow Operating Mode: Upgraded Offshore Capacity

C-2.1 CO_2 Injection to Hamilton Main and Lennox Reservoirs

Figure C-11 - Figure C-13 show an extended operation in the gas free-flow mode. This operating mode considers upgraded capacity of the offshore pipelines to allow for the higher flowrate intake. In this scenario, captured CO_2 emissions are transported and injected into Hamilton Main and Lennox fields simultaneously.

The time interval for this configuration, expressed here in terms of rising bottom-hole / reservoir pressure, begins once Hamilton Main reservoir reaches 9 barg (at which point Lennox field is brought online) and ends when both Hamilton Main and Lennox reservoirs are at the pressure of 13.8 barg. The maximum viable CO_2 injection rate for this pressure range is 3.3 $MtCO_2$/year. Above this flowrate operation in the gas phase with the current number of wells is no longer feasible, due to gas velocity limit of 30 m/s being exceeded in the wells.

Figure C-11 Simultaneous Injection to Hamilton Main and Lennox Sites, Bottom-hole Pressure of 10 barg, CO_2 Injection Rate of 2.2 $MtCO_2$/year.

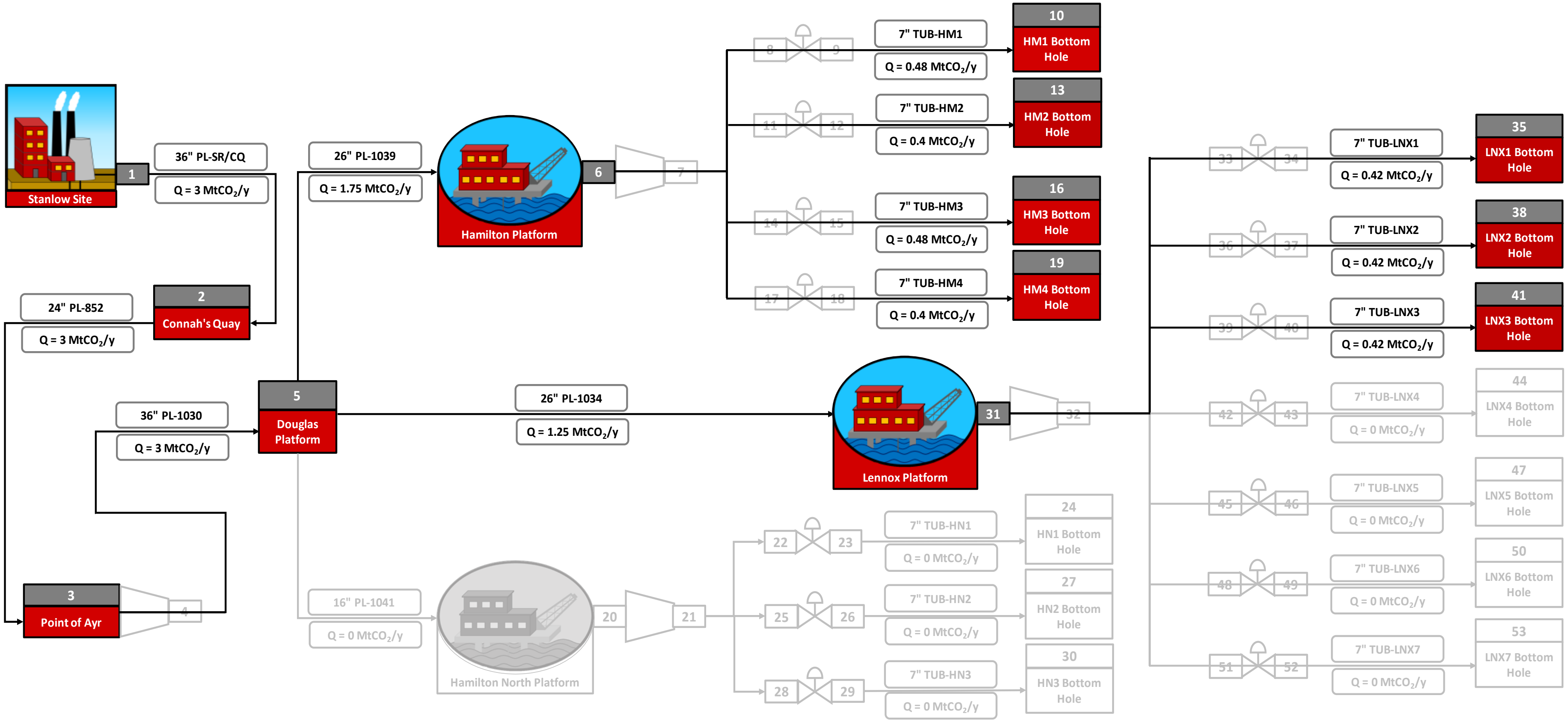


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-11.

Table C-11 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-11.

CO_2 Flow Properties	1	2	3	6	7	10	13	16	19	31	35	38	41
Pressure (barg)	24.3	23.9	20.0	19.5	18.8	10.0	10.0	10.0	10.0	18.6	10.0	10.0	10.0
Fluid Temperature (°C)	20.0	7.2	0.7	4.4	3.6	12.4	15.7	12.4	15.7	4.1	14.6	14.6	14.6
Fluid Density (kg/m³)	52.4	55.2	46.7	44.4	42.8	21.6	21.2	21.6	21.2	42.3	21.3	22.3	23.3
CO_2 velocity (m/s)	2.5	2.3	6.1	2.8	3.3	27.7	23.7	27.7	23.7	2.4	24.4	24.4	24.4

Figure C-12 Simultaneous Injection to Hamilton Main and Lennox Sites, Bottom-hole Pressure of 12 barg, CO_2 Injection Rate of 3 $MtCO_2$/year.

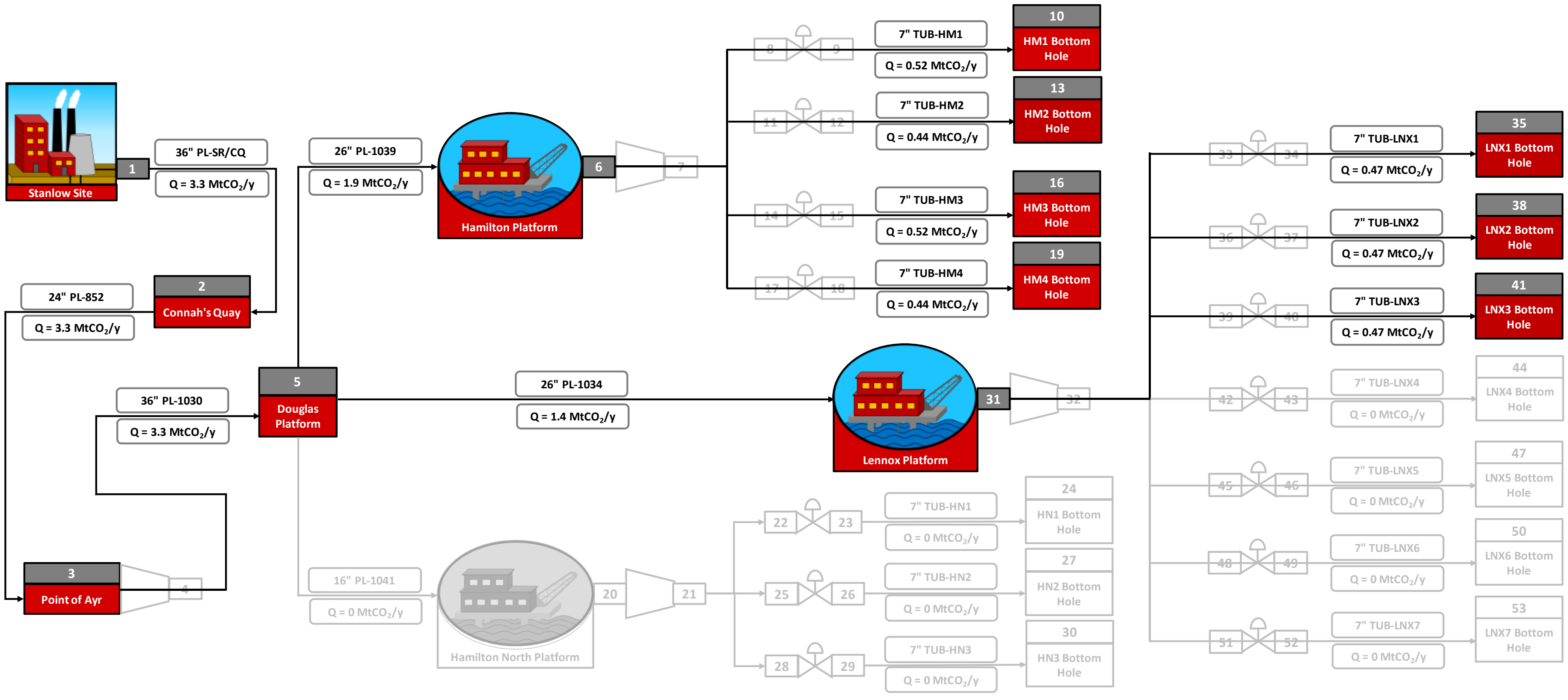


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-12.

Table C-12 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-12.

CO_2 Flow Properties	1	2	3	5	6	10	13	16	19	31	35	38	41
Pressure (barg)	31.9	31.4	26.1	25.5	24.5	12.0	12.0	12.0	12.0	24.3	12.0	12.0	12.0
Fluid Temperature (°C)	19.9	10.0	1.2	3.9	3.1	5.7	8.9	5.7	8.9	3.9	7.9	7.9	7.9
Fluid Density (kg/m^3)	72.5	76.0	64.1	60.9	58.4	26.8	26.2	26.8	26.2	57.5	26.4	26.4	26.4
CO_2 velocity (m/s)	2.4	2.3	6.1	2.8	3.3	30.0	26.1	30.0	26.1	2.4	26.8	26.8	26.8

Figure C-13 Simultaneous Injection to Hamilton Main and Lennox Sites, Bottom-hole Pressure of 13.8 barg, CO_2 Injection Rate of 3.3 $MtCO_2$/year.



Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-13.

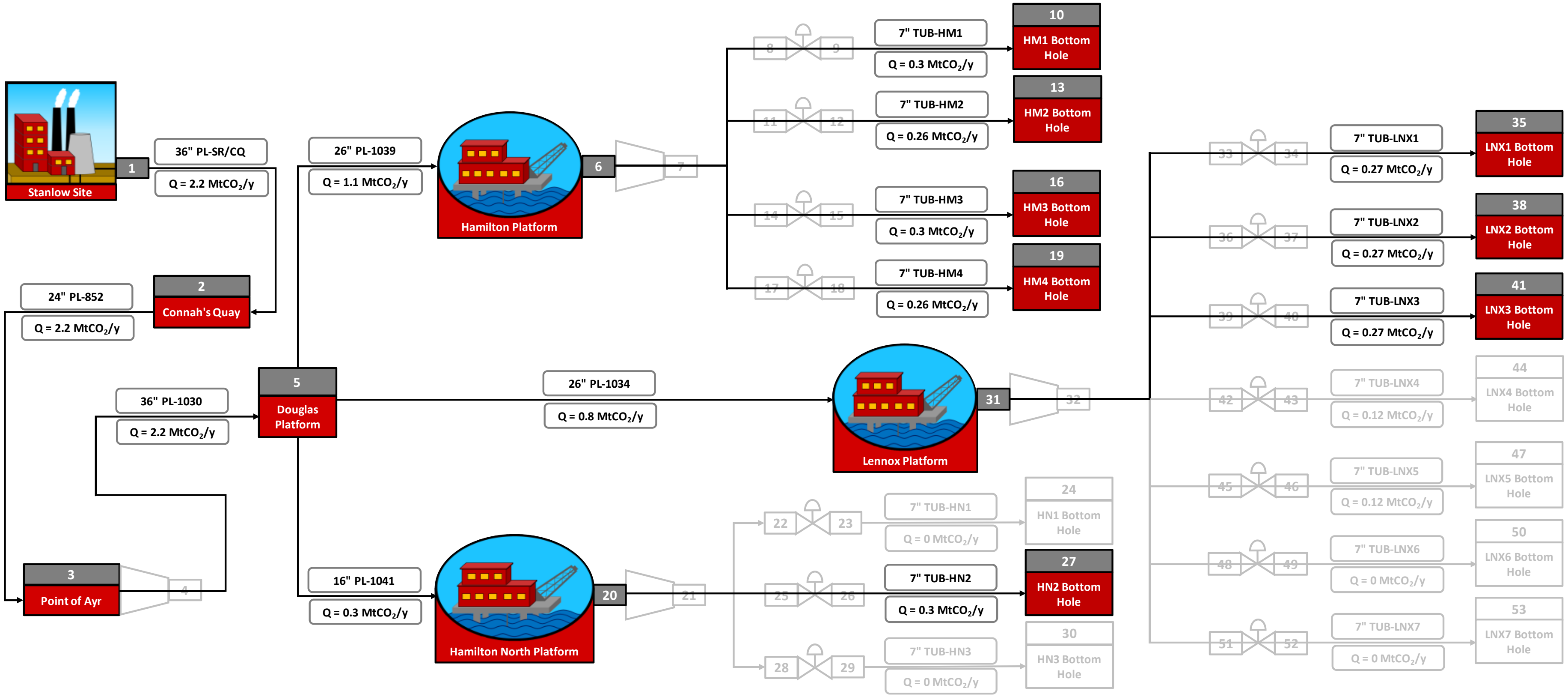
Table C-13 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-13.

CO_2 Flow Properties	1	2	3	5	6	10	13	16	19	31	35	38	41
Pressure (barg)	34.9	34.3	28.6	27.9	26.8	13.8	13.8	13.8	13.8	26.6	13.8	13.8	13.8
Fluid Temperature (°C)	20.0	10.9	1.5	3.8	2.9	4.1	7.1	4.1	7.1	3.7	6.1	6.1	6.1
Fluid Density (kg/m³)	80.9	84.7	71.7	68.2	65.3	31.1	30.5	31.1	30.5	64.3	30.7	30.7	30.7
CO_2 velocity (m/s)	2.4	2.3	6.0	2.7	3.3	28.7	24.7	28.7	24.7	2.4	25.3	25.3	25.3

C-2.2 CO_2 Injection to Hamilton Main, Hamilton North and Lennox Reservoirs

Figure C-14 - Figure C-18 illustrate parallel reservoir filling during extended operation in the gas free-flow mode with all three fields in operation. The time interval for this operation, expressed here in terms of rising bottom-hole / reservoir pressure, begins once Hamilton Main and Lennox reservoirs pressure is at 13.8 barg (at this point Hamilton North field is brought online) and ends when MAOP of 35 barg is reached in the system. The duration of extended operation in the gas free-flow mode at this configuration greatly depends on the CO_2 injection rate, meaning that it decreases with the flowrate increase. The maximum viable CO_2 injection rate for this configuration, however, only for the bottom-hole / reservoir pressure of 13.8 barg (the time Hamilton North is brought online) is 3.5 MtCO_2/year.

Figure C-14 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 13.8 barg, CO_2 Injection Rate of 2.2 $MtCO_2$/year.

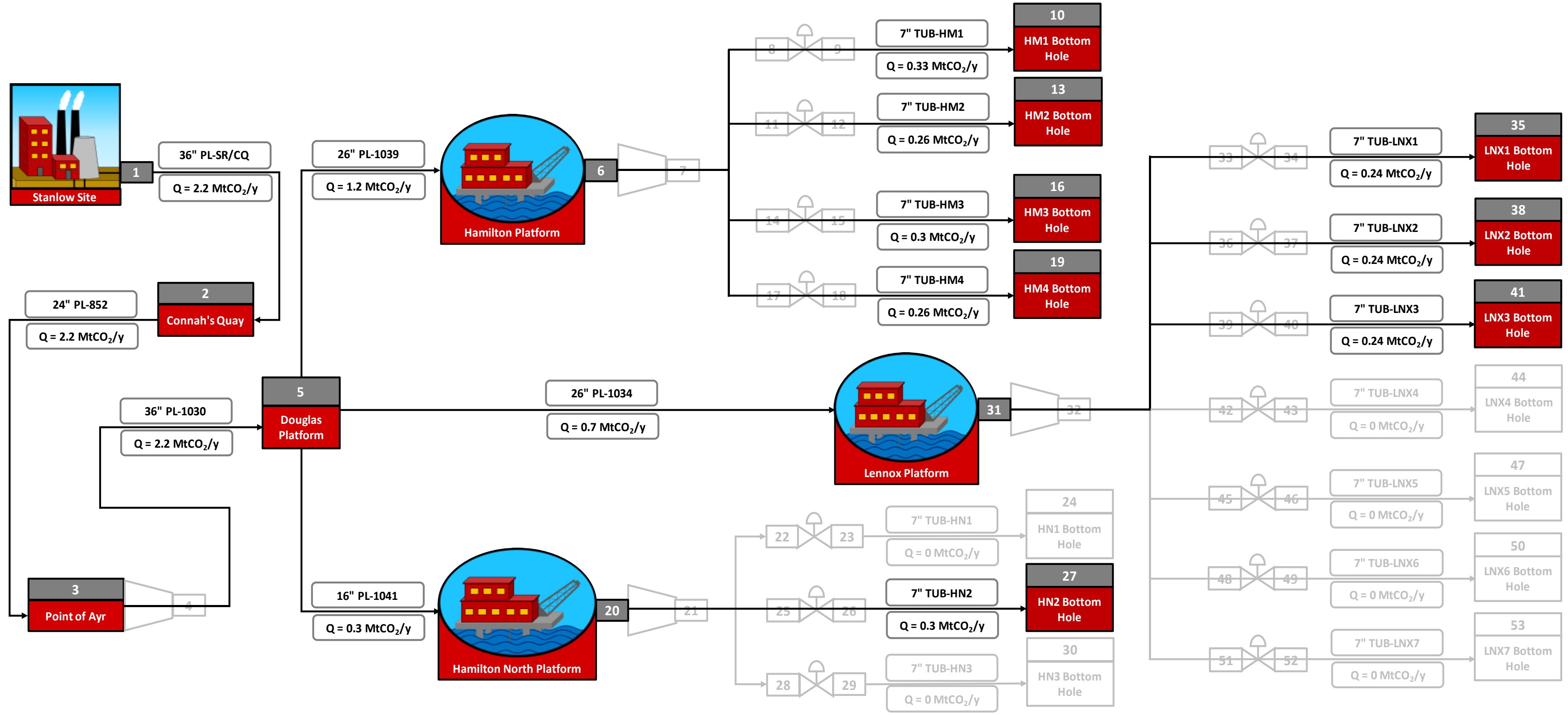


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-14.

Table C-14 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-14.

CO_2 Flow Properties	1	2	3	5	6	10	13	16	19	20	27	31	35	38	41
Pressure (barg)	24.1	23.6	19.7	19.2	18.5	13.8	13.8	13.8	13.8	18.5	13.8	18.4	13.8	13.8	13.8
Fluid Temperature (°C)	20.0	7.2	0.7	4.4	3.7	16.8	19.7	16.8	19.7	3.9	18.2	4.1	18.8	18.8	18.8
Fluid Density (kg/m³)	51.7	54.5	45.9	43.6	42.2	29.0	28.6	29.0	28.6	42.0	28.8	41.8	28.7	28.7	28.7
CO_2 velocity (m/s)	2.5	2.4	6.2	2.9	3.0	18.1	15.4	18.1	15.4	2.1	16.8	2.1	15.7	15.7	15.7

Figure C-15 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 36 barg, CO_2 Injection Rate of 2.2 $MtCO_2$/year.

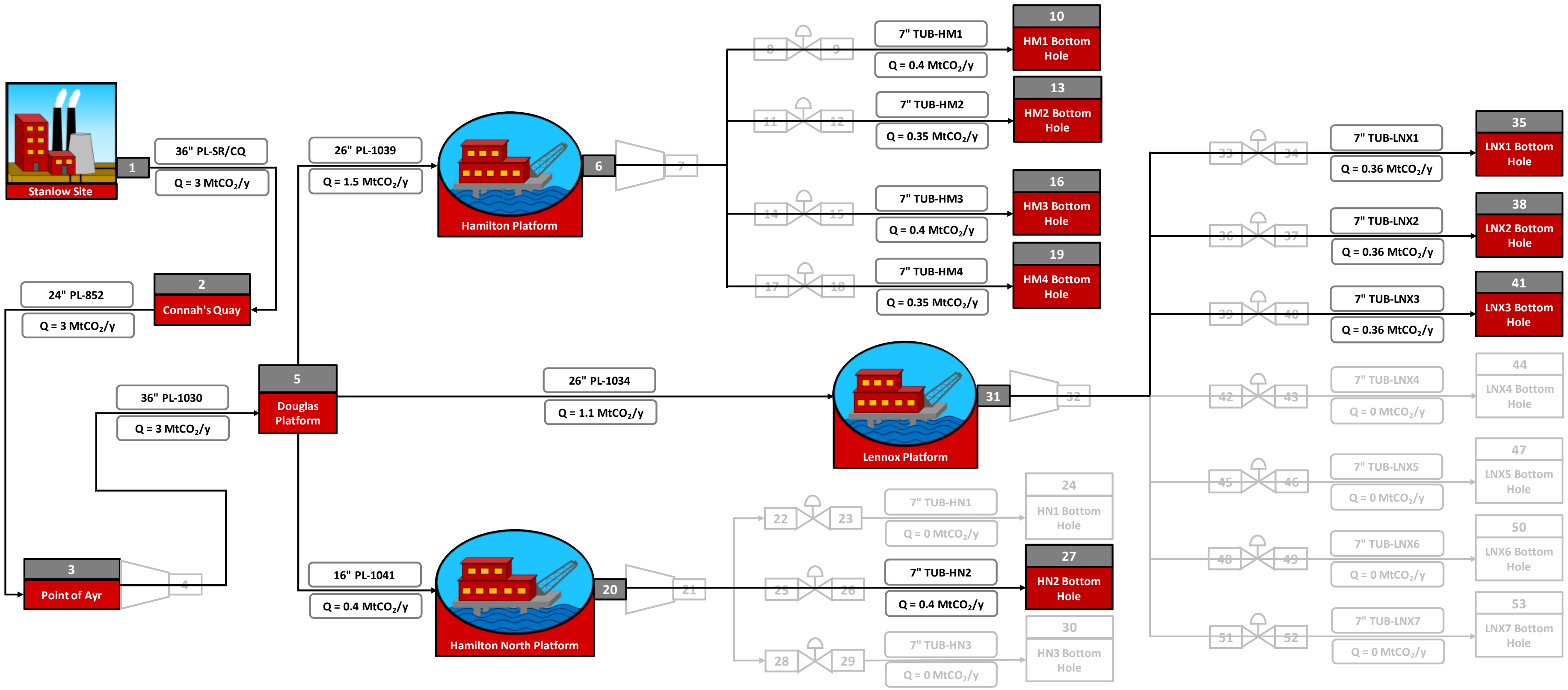


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-15.

Table C-15 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-15.

CO_2 Flow Properties	1	2	3	5	6	10	13	16	19	20	27	31	35	38	41
Pressure (barg)	34.7	34.4	32.0	31.9	31.3	36.0	36.0	36.0	36.0	31.3	36.0	18.4	36.0	36.0	36.0
Fluid Temperature (°C)	20.0	8.5	3.0	4.8	3.8	22.1	23.7	22.1	23.7	3.8	23.0	4.1	23.5	23.5	23.5
Fluid Density (kg/m³)	80.5	87.0	82.7	81.2	79.6	83.0	82.0	83.0	82.0	79.5	82.5	79.4	82.2	82.2	82.2
CO_2 velocity (m/s)	1.6	1.5	3.5	1.5	1.7	6.7	5.4	6.7	5.4	1.2	6.3	1.0	5.0	5.0	5.0

Figure C-16 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 13.8 barg, CO_2 Injection Rate of 3 $MtCO_2$/year.

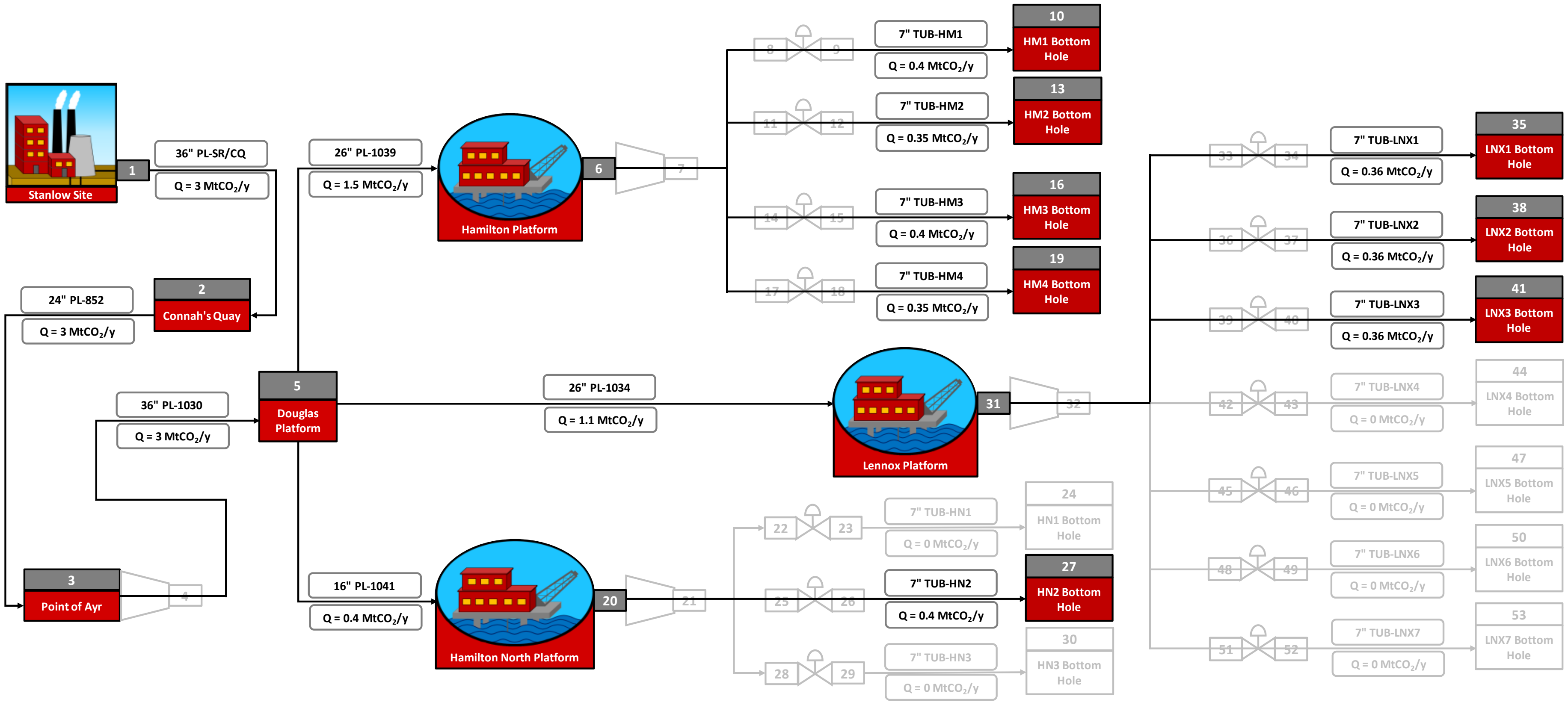


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-16.

Table C-16 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-16.

CO_2 Flow Properties	1	2	3	5	6	10	13	16	19	20	27	31	35	38	41
Pressure (barg)	30.3	29.7	24.0	23.3	22.4	13.8	13.8	13.8	13.8	22.4	13.8	22.3	13.8	13.8	13.8
Fluid Temperature (°C)	20.0	10.0	0.9	4.1	3.5	11.1	14.1	11.1	14.1	3.9	12.8	4.2	13.1	13.1	13.1
Fluid Density (kg/m³)	67.8	70.7	58.0	54.6	52.5	29.9	29.4	29.9	29.4	52.2	29.7	51.8	29.6	29.6	29.6
CO_2 velocity (m/s)	2.6	2.5	6.7	3.1	3.2	23.4	20.0	23.4	20.0	2.2	21.7	2.3	20.5	20.5	20.5

Figure C-17 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 27 barg, CO_2 Injection Rate of 3 $MtCO_2$/year.

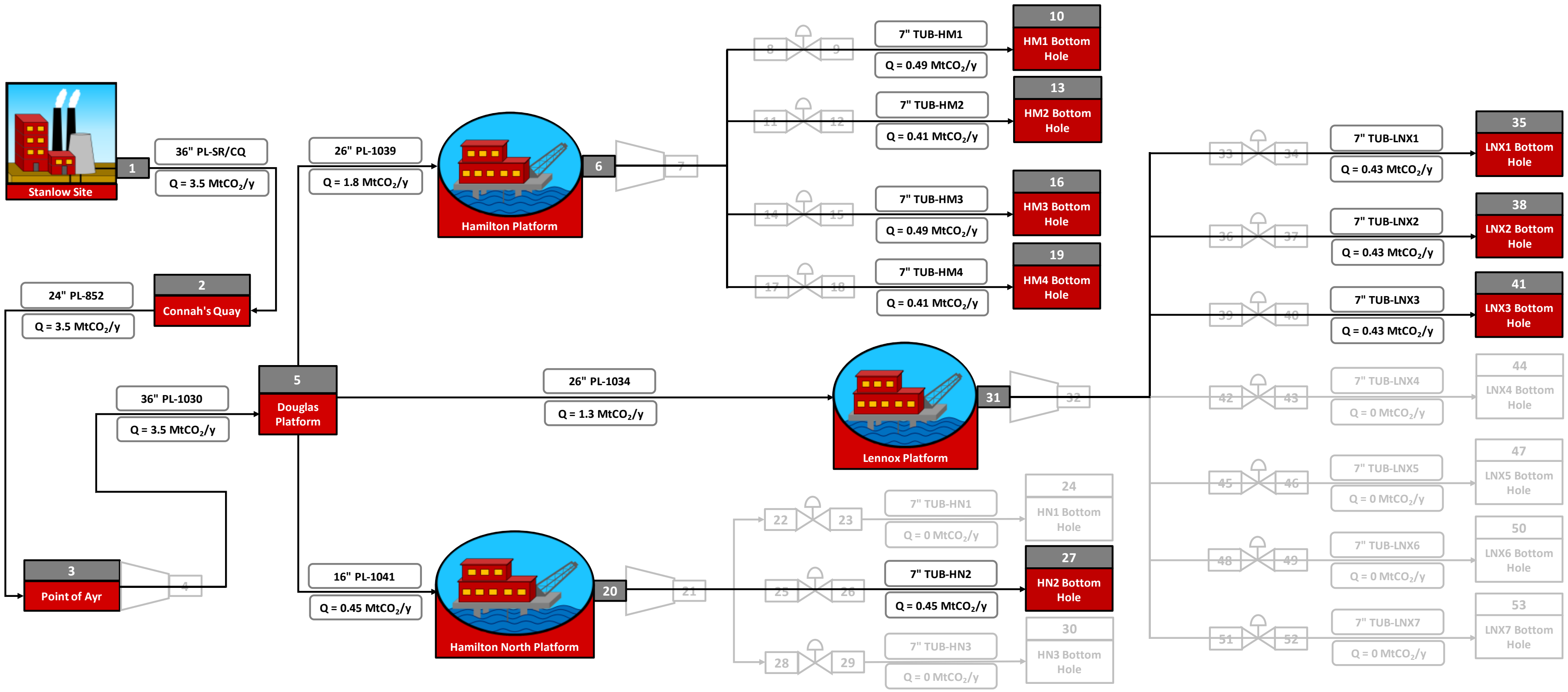


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-17.

Table C-17 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-17.

CO_2 Flow Properties	1	2	3	5	6	10	13	16	19	20	27	31	35	38	41
Pressure (barg)	35.0	34.5	29.9	29.5	28.6	27.0	27.0	27.0	27.0	28.6	27.0	28.5	27.0	27.0	27.0
Fluid Temperature (°C)	20.0	10.4	2.2	4.2	3.3	16.2	18.2	16.2	18.2	3.7	17.4	4.0	17.6	17.6	17.6
Fluid Density (kg/m³)	81.4	85.9	75.9	73.1	70.9	60.5	59.7	60.5	59.7	70.6	60.1	70.3	60.0	60.0	60.0
CO_2 velocity (m/s)	2.2	2.0	5.1	2.3	2.4	12.0	10.0	12.0	10.0	1.7	11.1	1.7	10.1	10.1	10.1

Figure C-18 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 27 barg, CO_2 Injection Rate of 3 $MtCO_2$/year.



Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-18 .

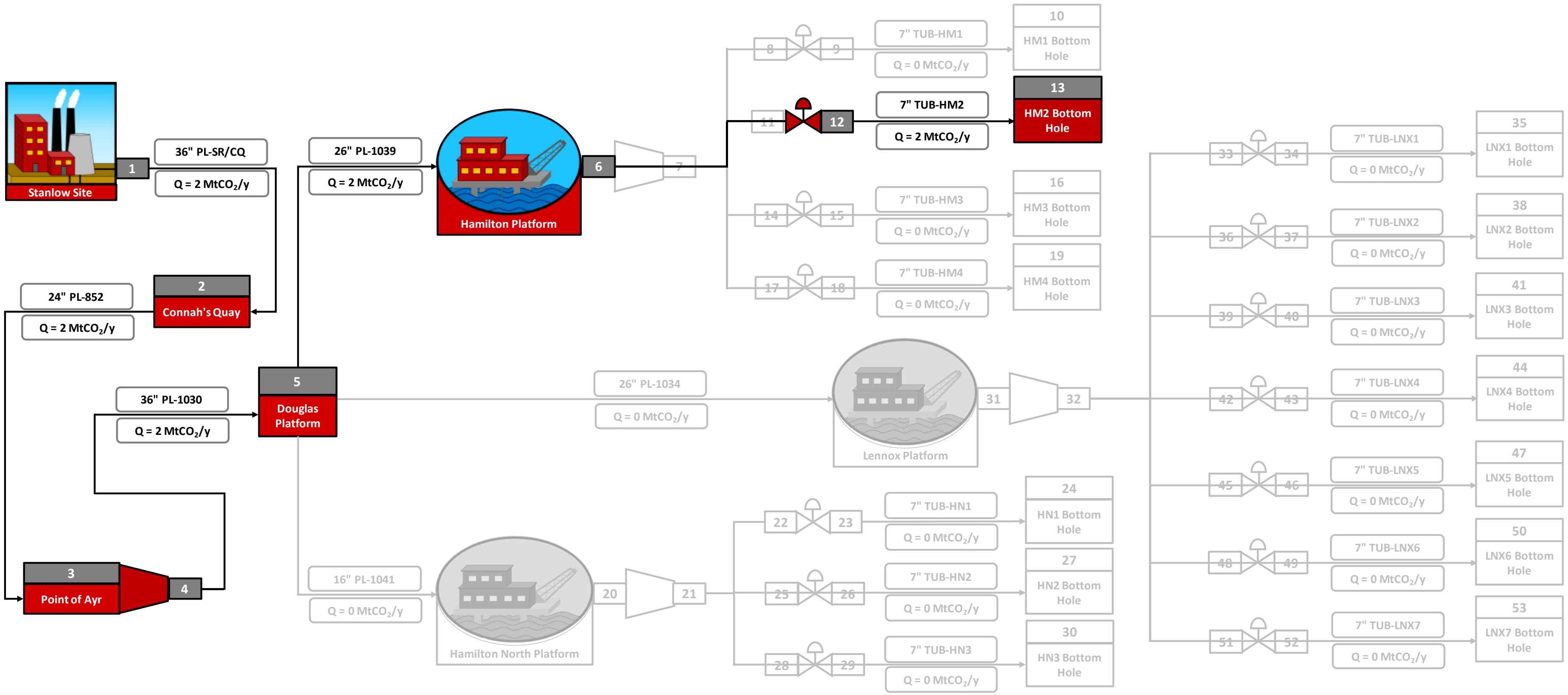
Table C-18 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-18.

CO_2 Flow Properties	1	2	3	5	6	10	13	16	19	20	27	31	35	38	41
Pressure (barg)	34.7	33.9	27.3	26.4	25.4	13.8	13.8	13.8	13.8	25.3	13.8	25.2	13.8	13.8	13.8
Fluid Temperature (°C)	20.0	11.1	0.7	3.3	2.8	6.2	9.3	6.2	9.3	3.6	8.3	3.8	8.4	8.4	8.4
Fluid Density (kg/m^3)	80.1	83.4	68.0	63.9	61.1	30.7	30.1	30.7	30.1	60.6	30.5	60.2	30.3	30.3	30.3
CO_2 velocity (m/s)	2.5	2.4	6.7	3.1	3.2	27.0	23.2	27.0	23.2	2.3	25.1	2.3	23.8	23.8	23.8

C-3 Transition / Liquid Phase Mode

Figure C-19 - Figure C-28 illustrate transition of the offshore system from the gas phase operating mode to a liquid phase flow, while onshore system remains its operation in the gas phase. In this scenario only single reservoir filling is demonstrated, utilising Hamilton Main field. The commencement of this operating phase depends on the CO_2 injection rate and bottom-hole / reservoir pressure, at which the existing system can no longer operate in the gas free-flow operating mode (MAOP of 35 barg) without additional upgrades. Once the system begins to operate in the liquid phase mode it will remain in this mode for the duration of the storage reservoirs life.

Figure C-19 Single Injection to Hamilton Main Field, Bottom-hole Pressure of 29 barg, CO_2 Injection Rate of 2 $MtCO_2$/year.

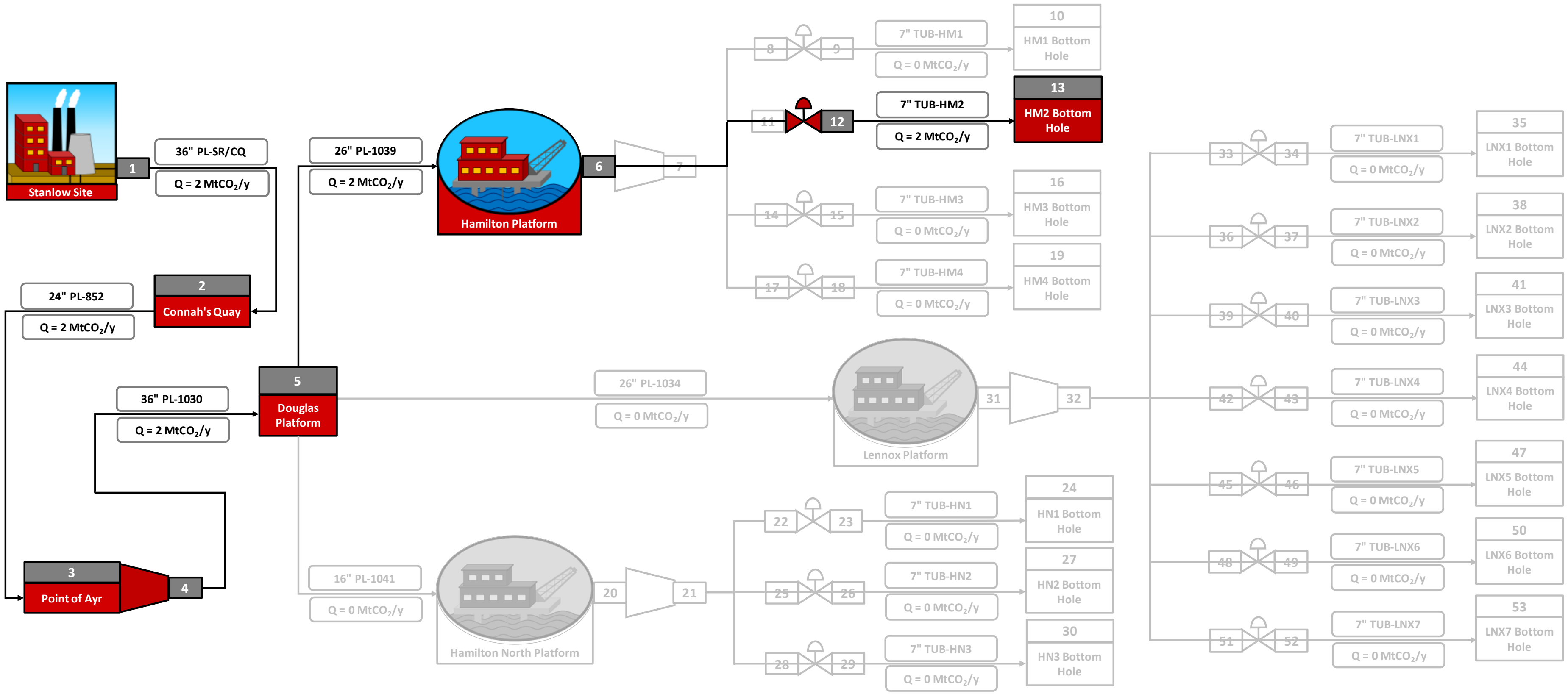


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-19.

Table C-19 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-19.

CO_2 Flow Properties	1	2	3	4	5	6	12	13
Pressure (barg)	35.0	34.8	33.0	99.0	101.7	97.0	43.1	29.0
Fluid Temperature (°C)	20.0	7.9	3.1	20.0	12.0	9.6	-2.1	-11.2
Fluid Density (kg/m³)	81.7	89.0	86.0	744.0	830.0	844.0	443.4	207.7
CO_2 velocity (m/s)	1.1	2.9	3.0	0.2	0.1	0.3	7.9	15.4
Gas rate ($MtCO_2$/y)	2.0	2.0	2.0	0.0	0.0	0.0	0.3	0.5
Liquid rate ($MtCO_2$/y)	0.0	0.0	0.0	2.0	2.0	2.0	1.7	1.5

Figure C-20 Single Injection to Hamilton Main Field, Bottom-hole Pressure of 50 barg, CO_2 Injection Rate of 2 $MtCO_2$/year.

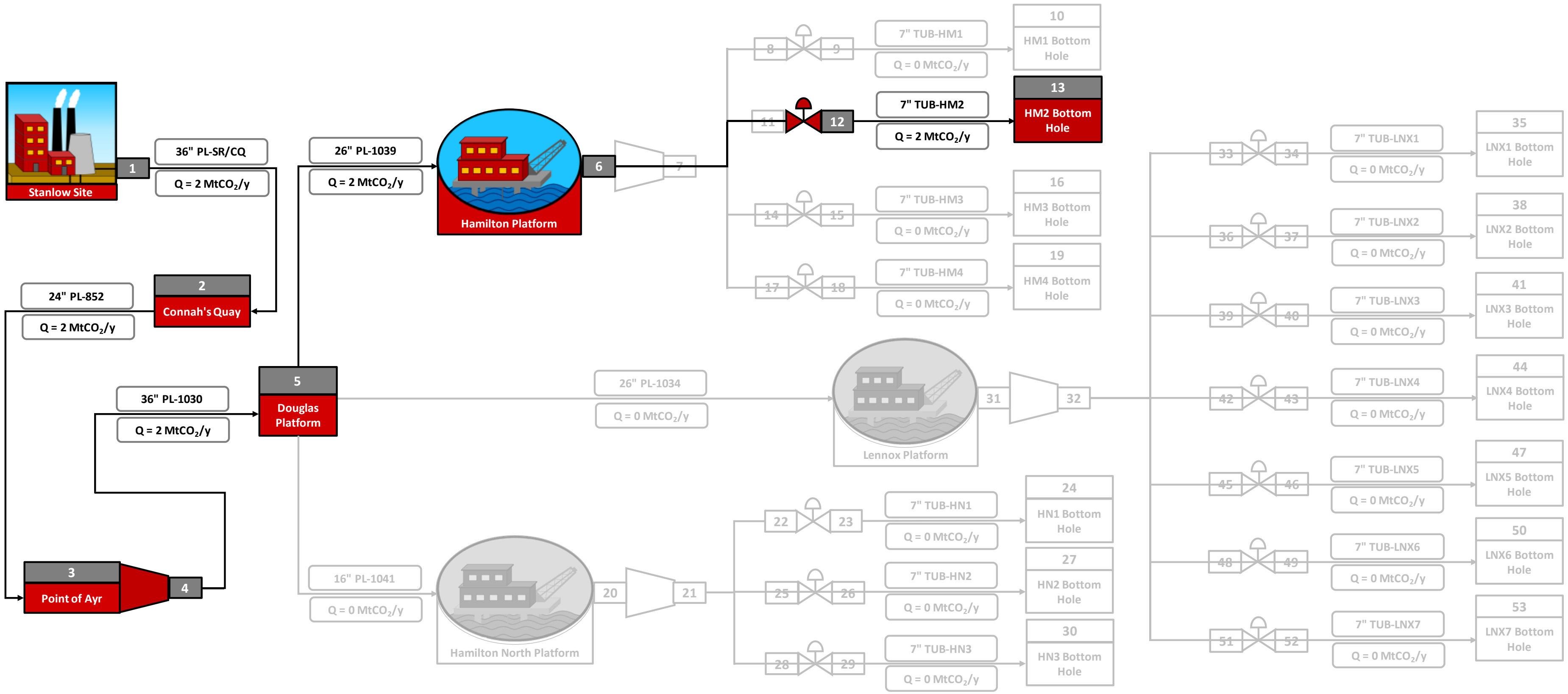


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-20.

Table C-20 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-20.

CO_2 Flow Properties	1	2	3	4	5	6	12	13
Pressure (barg)	35.0	34.8	33.0	99.0	101.7	97.0	43.7	50.0
Fluid Temperature (°C)	20.0	7.9	3.1	20.0	12.0	9.6	-1.8	3.8
Fluid Density (kg/m^3)	81.7	89.0	86.0	744.3	830.1	843.9	453.4	476.6
CO_2 velocity (m/s)	1.1	2.9	3.0	0.2	0.1	0.3	7.8	6.9
Gas rate ($MtCO_2$/y)	2.0	2.0	2.0	0.0	0.0	0.0	0.3	0.3
Liquid rate (MtCO2/y)	0.0	0.0	0.0	2.0	2.0	2.0	1.7	1.7

Figure C-21 Single Injection to Hamilton Main Field, Bottom-hole Pressure of 83 barg, CO_2 Injection Rate of 2 $MtCO_2$/year.

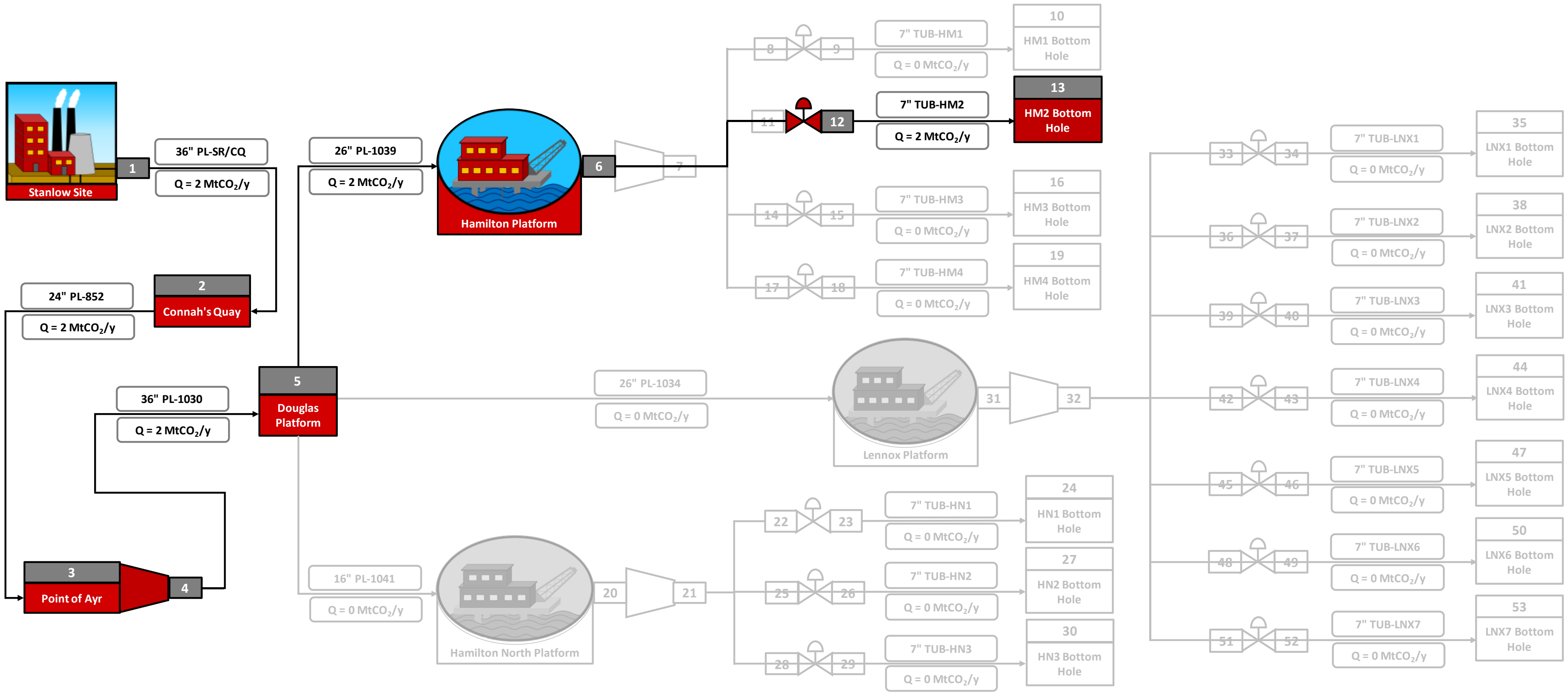


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-21.

Table C-21 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-21.

CO_2 Flow Properties	1	2	3	4	5	6	12	13
Pressure (barg)	35.0	34.8	33.0	99.0	101.7	97.0	46.9	83.0
Fluid Temperature (°C)	20.0	7.9	3.1	20.0	12.0	9.6	-0.1	12.6
Fluid Density (kg/m^3)	81.7	89.0	86.0	744.3	830.1	843.9	500.5	786.2
CO_2 velocity (m/s)	1.1	2.9	3.0	0.2	0.1	0.3	7.0	4.4
Gas rate ($MtCO_2$/y)	2.0	2.0	2.0	0.0	0.0	0.0	0.2	0.0
Liquid rate (MtCO2/y)	0.0	0.0	0.0	2.0	2.0	2.0	1.8	2.0

Figure C-22 Single Injection to Hamilton Main Field, Bottom-hole Pressure of 96 barg, CO_2 Injection Rate of 2 $MtCO_2$/year.

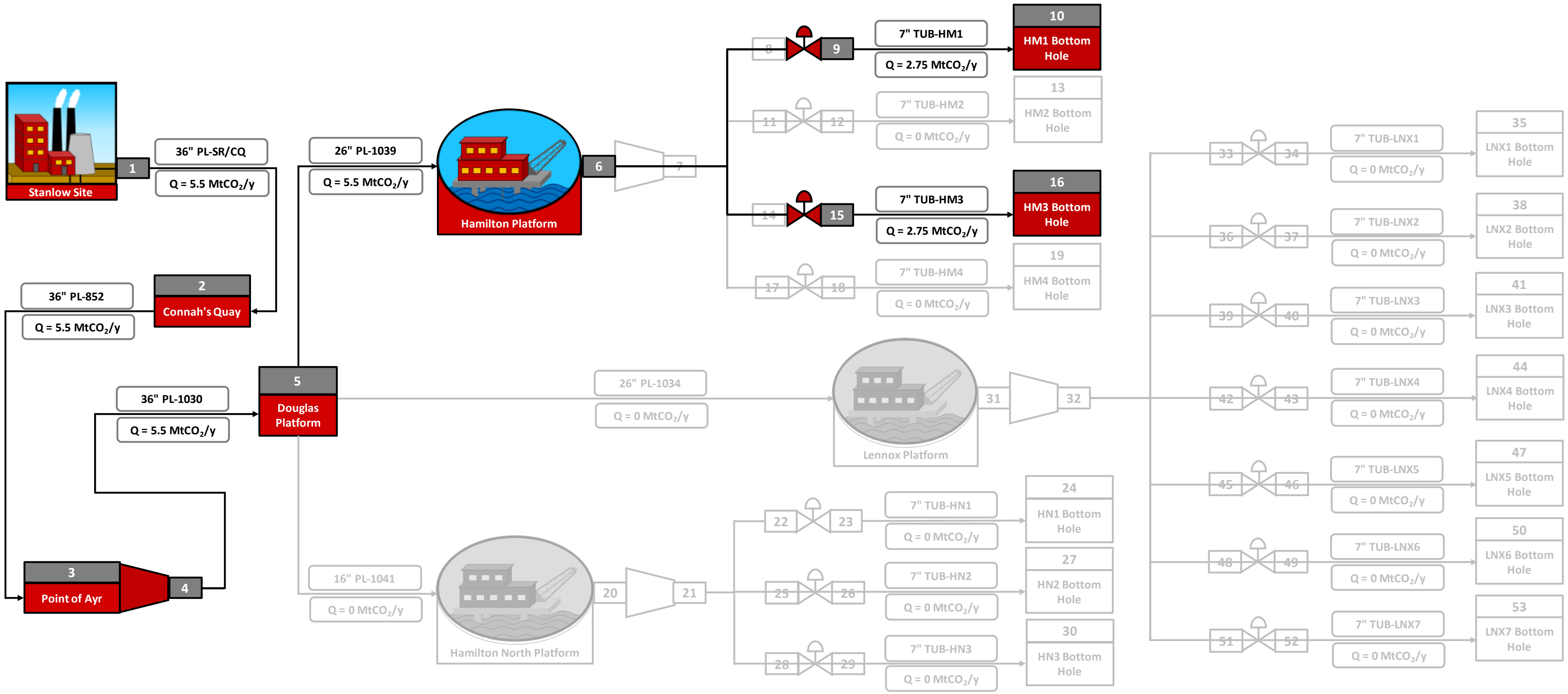


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-22.

Table C-22 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-22.

CO_2 Flow Properties	1	2	3	4	5	6	12	13
Pressure (barg)	35.0	34.8	33.0	99.0	101.7	97.0	48.7	96.0
Fluid Temperature (°C)	20.0	7.9	3.1	20.0	12.0	9.6	0.8	13.9
Fluid Density (kg/m³)	81.7	89.0	86.0	744.3	830.1	844.0	526.4	801.5
CO_2 velocity (m/s)	1.1	2.9	3.0	0.2	0.1	0.3	6.6	4.3
Gas rate ($MtCO_2$/y)	2.0	2.0	2.0	0.0	0.0	0.0	0.2	0.0
Liquid rate (MtCO2/y)	0.0	0.0	0.0	2.0	2.0	2.0	1.8	2.0

Figure C-23 Single Injection to Hamilton Main Field, Bottom-hole Pressure of 29 barg, CO_2 Injection Rate of 5.5 $MtCO_2$/year.

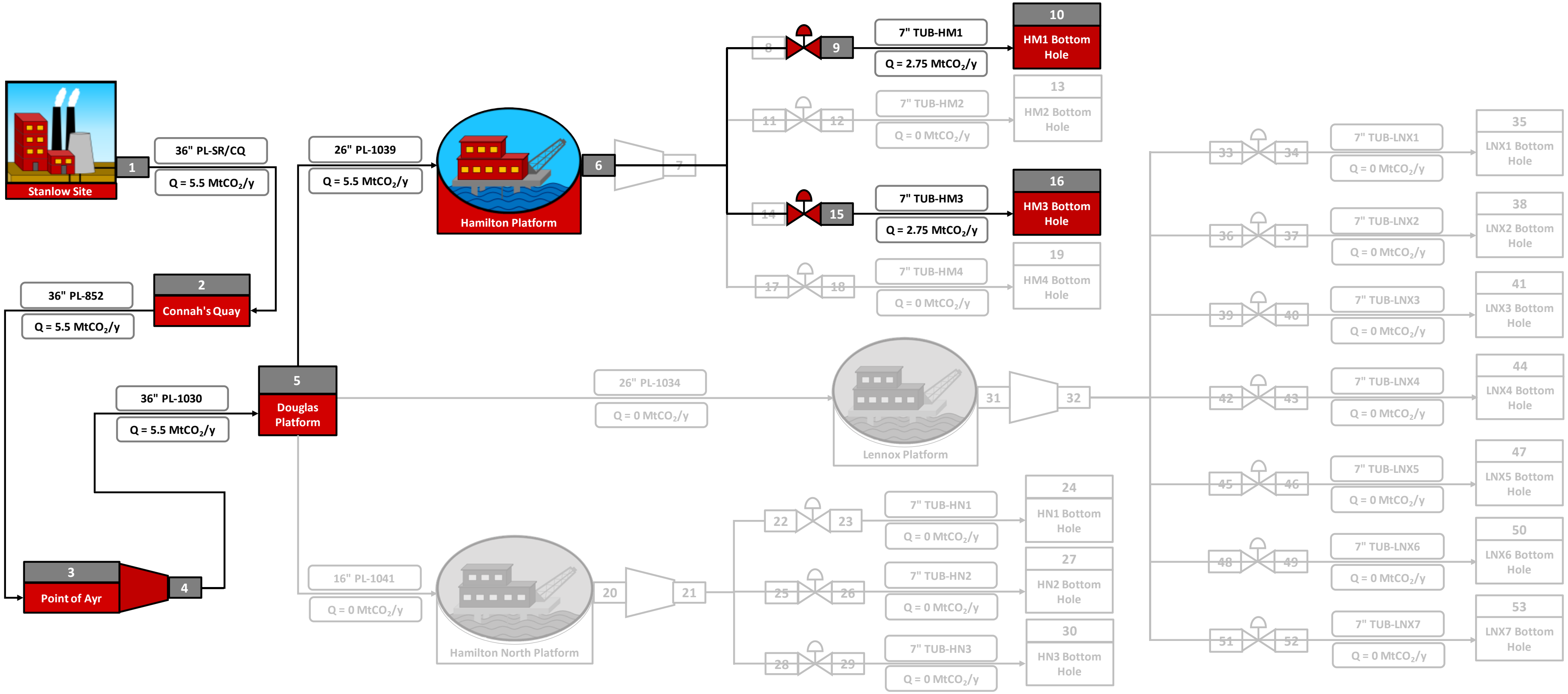


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-23.

Table C-23 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-23.

CO_2 Flow Properties	1	2	3	4	5	6	9	10	15	16
Pressure (barg)	34.7	33.0	31.0	99.5	101.8	97.0	51.8	29.0	51.8	29.0
Fluid Temperature (°C)	20.0	12.5	7.0	20.0	16.7	15.0	4.9	-9.8	4.9	-9.8
Fluid Density (kg/m³)	81.0	79.6	76.5	745.4	785.7	794.0	495.2	161.8	495.2	161.8
CO_2 velocity (m/s)	3.7	4.0	4.2	0.3	0.4	0.8	10.2	22.9	10.2	22.9
Gas rate ($MtCO_2$/y)	5.5	5.5	5.5	0.0	0.0	0.0	0.4	0.9	0.4	0.9
Liquid rate (MtCO2/y)	0.0	0.0	0.0	5.5	5.5	5.5	2.4	1.9	2.4	1.9

Figure C-24 Single Injection to Hamilton Main Field, Bottom-hole Pressure of 48 barg, CO_2 Injection Rate of 5.5 $MtCO_2$/year.

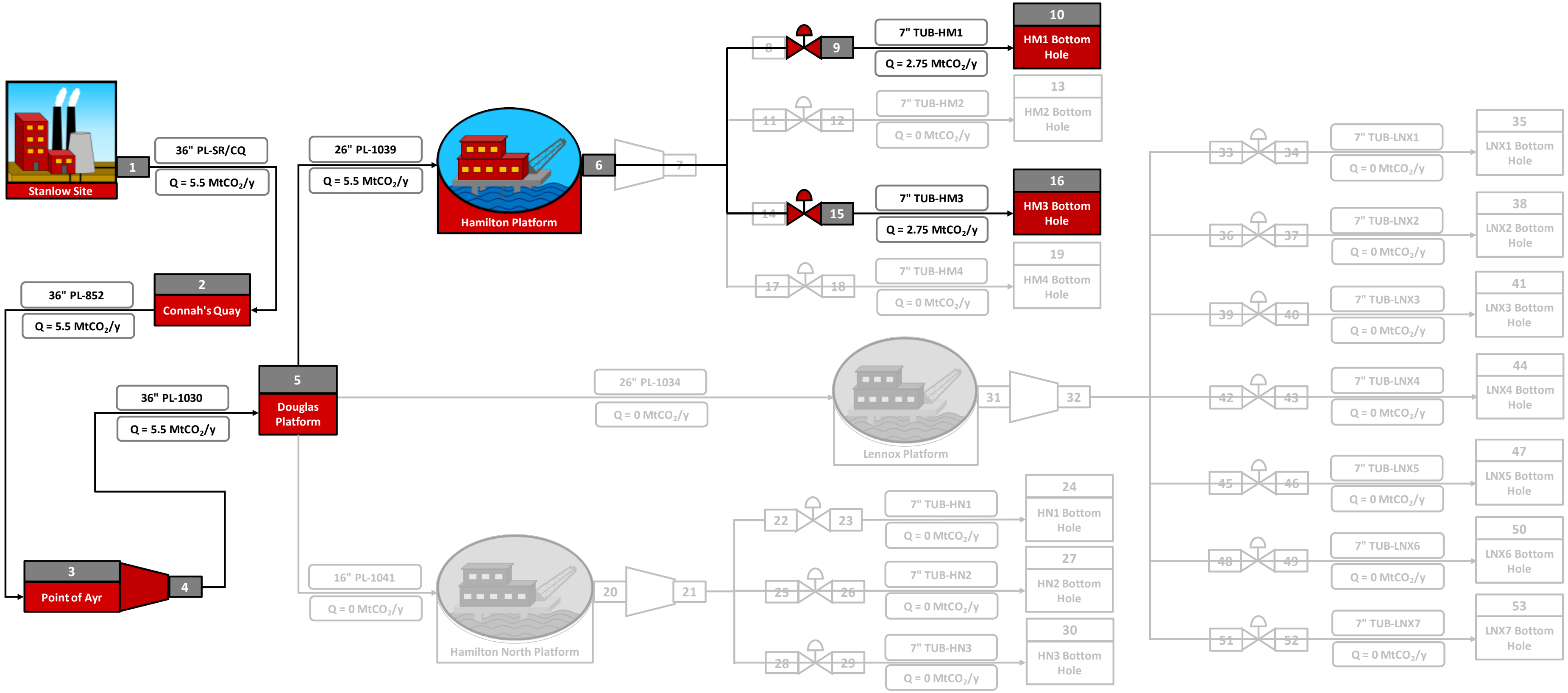


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-24.

Table C-24 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-24.

CO_2 Flow Properties	1	2	3	4	5	6	9	10	15	16
Pressure (barg)	34.7	33.0	31.0	99.5	101.8	97.0	52.2	48.2	52.2	48.2
Fluid Temperature (°C)	20.0	12.5	7.0	20.0	16.7	15.0	5.1	4.5	5.1	4.5
Fluid Density (kg/m^3)	81.0	79.6	76.5	745.4	785.7	794.0	500.6	398	500.6	398
CO_2 velocity (m/s)	3.7	4.0	4.2	0.3	0.4	0.8	10.0	11.8	10.0	11.8
Gas rate ($MtCO_2$/y)	5.5	5.5	5.5	0.0	0.0	0.0	0.4	0.6	0.4	0.6
Liquid rate (MtCO2/y)	0.0	0.0	0.0	5.5	5.5	5.5	2.4	2.1	2.4	2.1

Figure C-25 Single Injection to Hamilton Main Field, Bottom-hole Pressure of 96 barg, CO_2 Injection Rate of 5.5 $MtCO_2$/year.

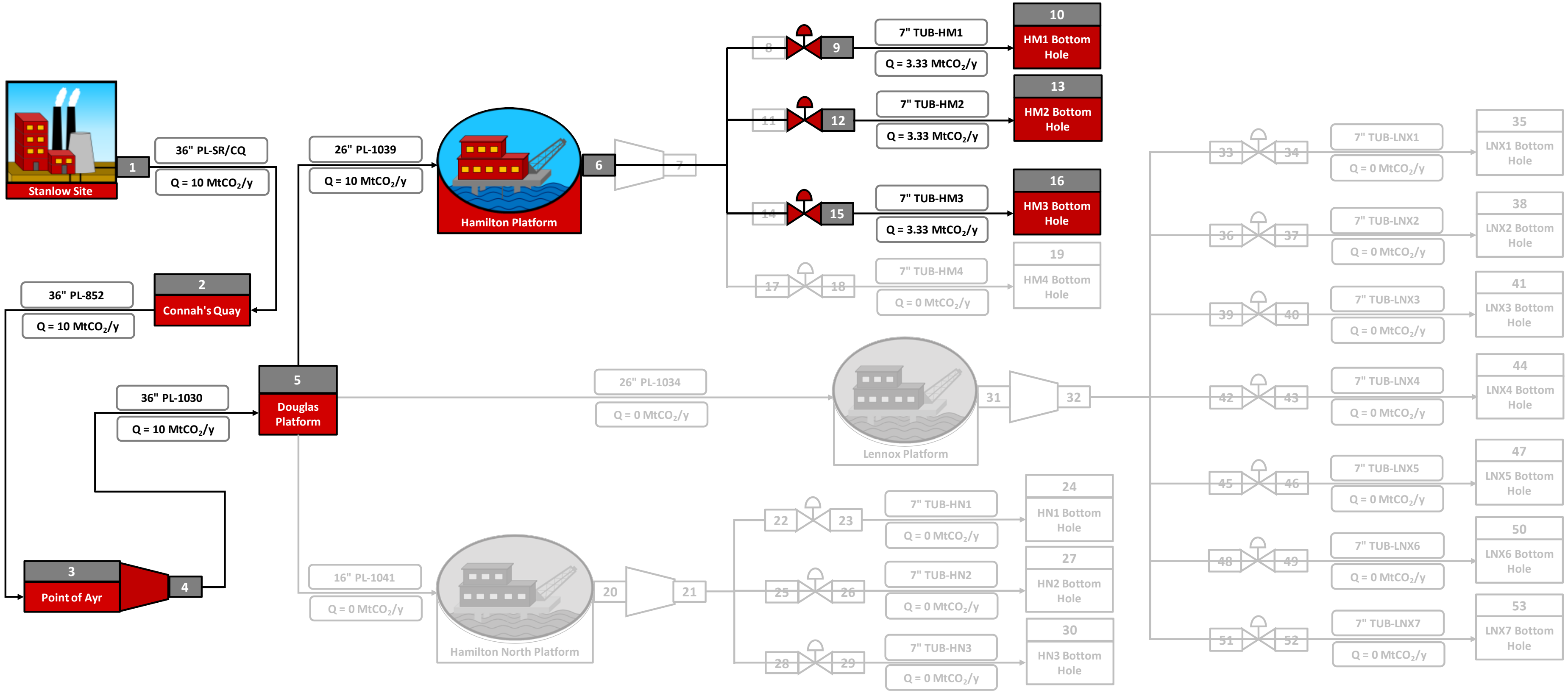


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-25.

Table C-25 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-25.

CO_2 Flow Properties	1	2	3	4	5	6	9	10	15	16
Pressure (barg)	34.7	33.0	31.0	99.5	101.8	97.0	56.9	96.0	56.9	96.0
Fluid Temperature (°C)	20.0	12.5	7.0	20.0	16.7	15.0	7.2	18.3	7.2	18.3
Fluid Density (kg/m³)	81.0	79.6	76.5	745.4	785.7	794.0	565.4	754.5	565.4	754.5
CO_2 velocity (m/s)	3.7	4.0	4.2	0.3	0.4	0.8	8.7	6.2	8.7	6.2
Gas rate ($MtCO_2$/y)	5.5	5.5	5.5	0.0	0.0	0.0	0.3	0.0	0.3	0.0
Liquid rate (MtCO2/y)	0.0	0.0	0.0	5.5	5.5	5.5	2.5	2.8	2.5	2.8

Figure C-26 Single Injection to Hamilton Main Field, Bottom-hole Pressure of 29 barg, CO_2 Injection Rate of 10 $MtCO_2$/year.

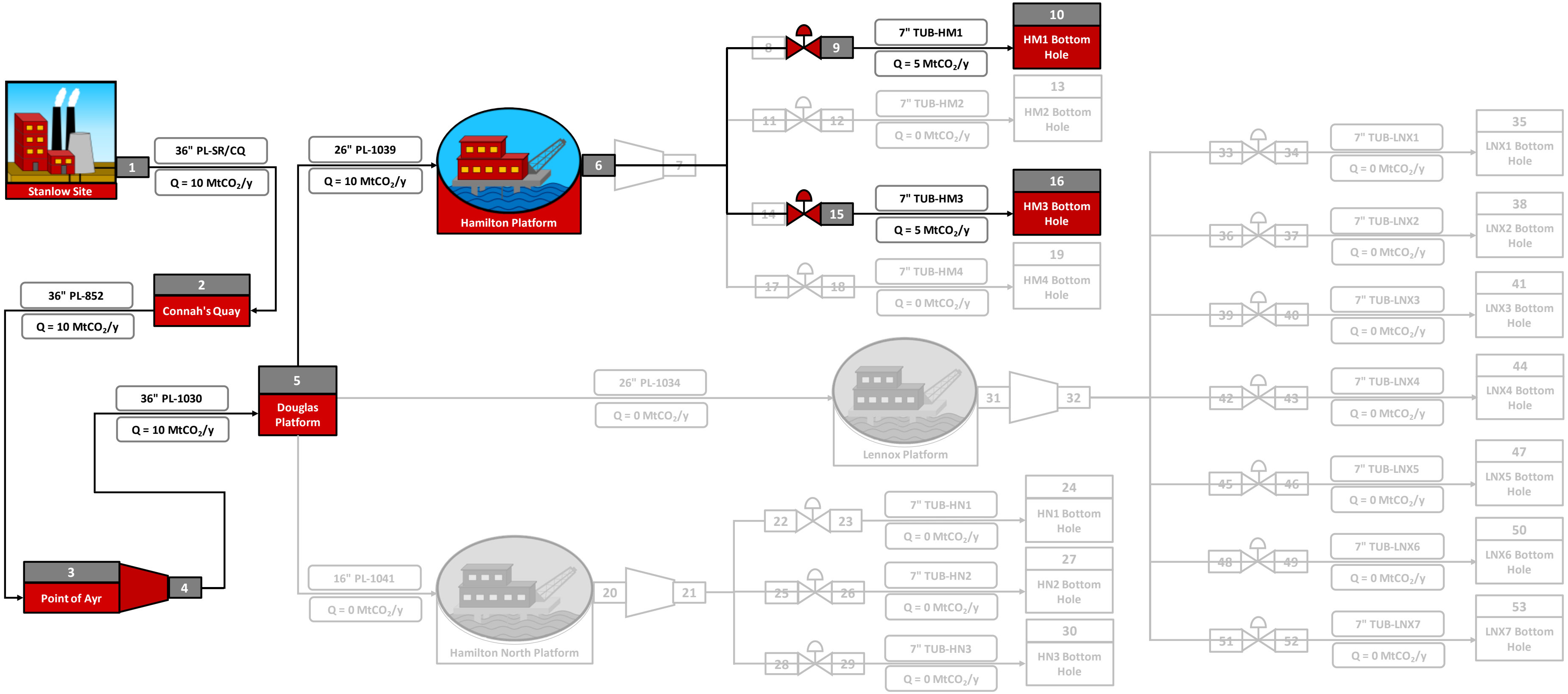


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-26.

Table C-26 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-26.

CO_2 Flow Properties	1	2	3	4	5	6	9	10	12	13	15	16
Pressure (barg)	34.8	30.0	20.0	101.0	103.0	97.0	58.3	29.0	63.3	29.0	58.3	29.0
Fluid Temperature (°C)	20.0	10.0	-2.1	20.0	18.2	16.6	8.7	-9.1	10.6	-9.4	8.7	-9.1
Fluid Density (kg/m³)	81.0	68.4	47.6	749.7	773.0	776.0	557.8	138	525.3	148.2	557.8	138
CO_2 velocity (m/s)	7.2	8.5	12.3	0.8	0.7	1.4	12.5	27.8	10.1	28.0	12.5	27.8
Gas rate ($MtCO_2$/y)	10.0	10.0	10.0	0.0	0.0	0.0	0.3	1.1	0.2	1.1	0.3	1.1
Liquid rate (MtCO2/y)	0.0	0.0	0.0	10.0	10.0	10.0	3.0	2.2	3.1	2.2	3.0	2.2

Figure C-27 Single Injection to Hamilton Main Field, Bottom-hole Pressure of 46 barg, CO_2 Injection Rate of 10 $MtCO_2$/year.

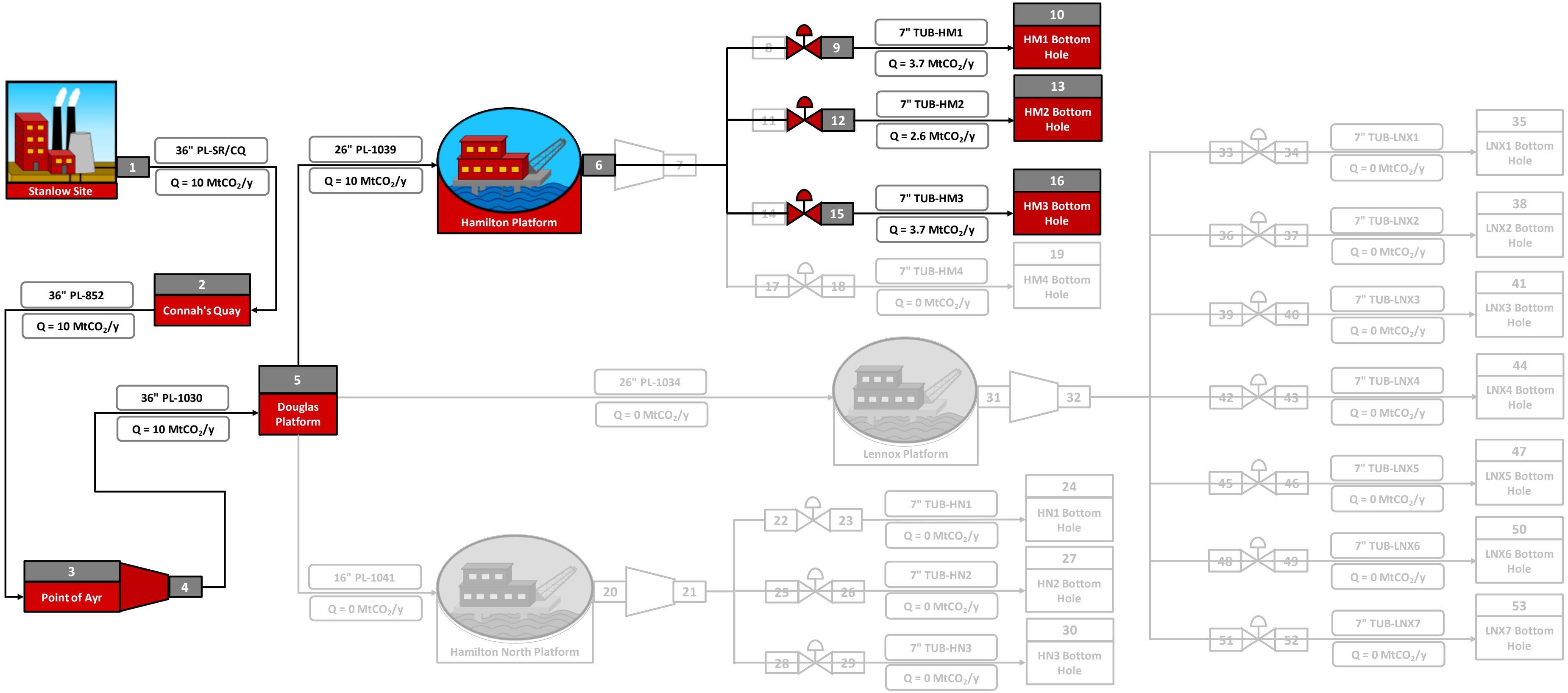


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-27.

Table C-27 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-27.

CO_2 Flow Properties	1	2	3	4	5	6	9	10	15	16
Pressure (barg)	34.8	30.0	20.0	101.0	103.0	97.0	90.8	46.0	90.8	46.0
Fluid Temperature (°C)	20.0	10.0	-2.1	20.0	18.2	16.6	15.8	4.5	15.8	4.5
Fluid Density (kg/m³)	81.0	68.4	47.6	749.7	773.0	776.0	769.9	322.7	769.9	322.7
CO_2 velocity (m/s)	7.2	8.5	12.3	0.8	0.7	1.4	11.1	22.4	11.1	22.4
Gas rate ($MtCO_2$/y)	10.0	10.0	10.0	0.0	0.0	0.0	0.0	1.1	0.0	1.1
Liquid rate ($MtCO_2$/y)	0.0	0.0	0.0	10.0	10.0	10.0	5.0	3.9	5.0	3.9

Figure C-28 Single Injection to Hamilton Main Field, Bottom-hole Pressure of 96 barg, CO_2 Injection Rate of 10 $MtCO_2$/year.



Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-28.

Table C-28 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-28.

CO_2 Flow Properties	1	2	3	4	5	6	9	10	12	13	15	16
Pressure (barg)	34.8	30.0	20.0	101.0	103.0	97.0	74.4	96.0	63.3	96.0	74.4	96.0
Fluid Temperature (°C)	20.0	10.0	-2.1	20.0	18.2	16.6	13.7	19.4	10.6	19.3	13.7	19.4
Fluid Density (kg/m³)	81.0	68.4	47.6	749.7	773.0	776.0	751	742.2	625.3	743.6	751	742.2
CO_2 velocity (m/s)	7.2	8.5	12.3	0.8	0.7	1.4	8.5	8.6	7.1	5.9	8.5	8.6
Gas rate ($MtCO_2$/y)	10.0	10.0	10.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0
Liquid rate (MtCO2/y)	0.0	0.0	0.0	10.0	10.0	10.0	3.7	3.7	2.4	2.6	3.7	3.7

C-4 Offshore (Wellhead) Compression Mode

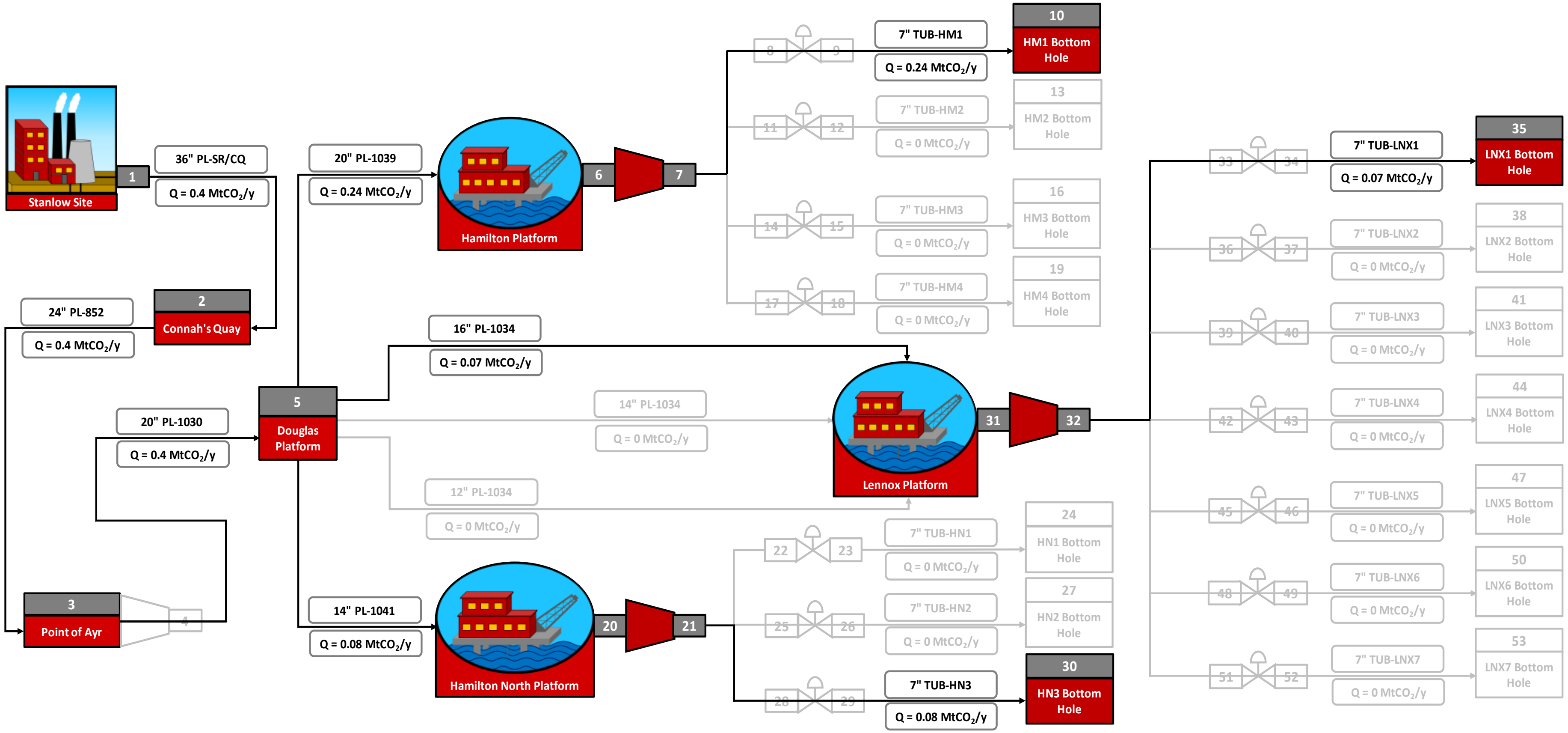
Figure C-29 - Figure C-45 illustrate operation in the offshore compression mode, where the onshore and offshore systems operate in the gas phase at their maximum allowable normal operating pressure of 35 barg, with CO_2 being recompressed at the wellhead platforms. The commencement of this operating phase depends on the CO_2 injection rate and bottom-hole / reservoir pressure at which the existing / upgraded system reaches its maximum allowable operating pressure. Once the operation moves to offshore compression mode it will remain in this mode for the remainder of the project life.

The maximum compression requirements, in terms of the injection pressure, are to be expected at the end of each storage life and are given in tables presented below.

In this operating scenario the CO_2 flowrate split between Hamilton Main, Hamilton North and Lennox fields is spontaneous, which is largely dependent on the hydraulics of the offshore system, as the flow recirculation in compressors is not considered.

Operating conditions presented below are for the system with existing infrastructure, considering the range of CO_2 injection rates from 0.4 – 2 $MtCO_2$/year, and for the system with upgraded capacity offshore for which only the range of flowrates between 2.2 $MtCO_2$/year and 4.8 $MtCO_2$/year is shown here.

Figure C-29 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 44 barg, CO_2 Injection Rate of 0.4 $MtCO_2$/year.

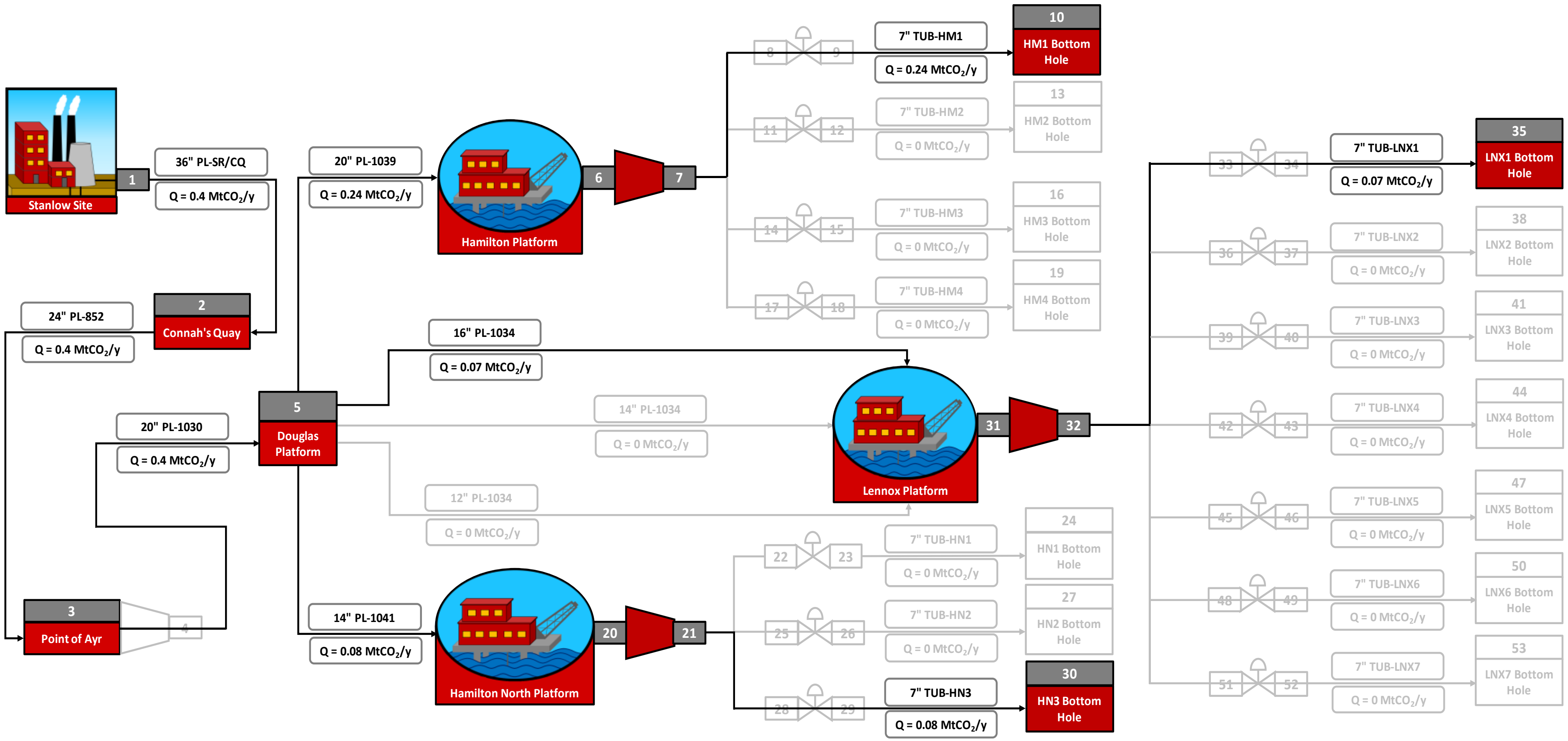


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-29.

Table C-29 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-29.

CO_2 Flow Properties	1	2	3	5	6	7	10	20	21	30	31	32	35
Pressure (barg)	34.8	34.7	34.6	34.5	34.0	35.4	44.0	34.0	33.9	44.0	34.0	36.4	44.0
Fluid Temperature (°C)	20.0	0.8	2.2	5.1	3.8	40.0	32.8	3.8	40.0	30.0	3.7	40.0	30.9
Fluid Density (kg/m³)	80.9	94.6	92.8	90.1	89.2	72.8	99.7	89.2	69.6	101.7	89.3	75.4	101.3
CO_2 velocity (m/s)	0.3	0.2	0.5	0.9	0.5	4.8	3.5	0.4	1.7	1.2	0.2	2.9	2.2

Figure C-30 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 96 barg, CO_2 Injection Rate of 0.4 $MtCO_2$/year.

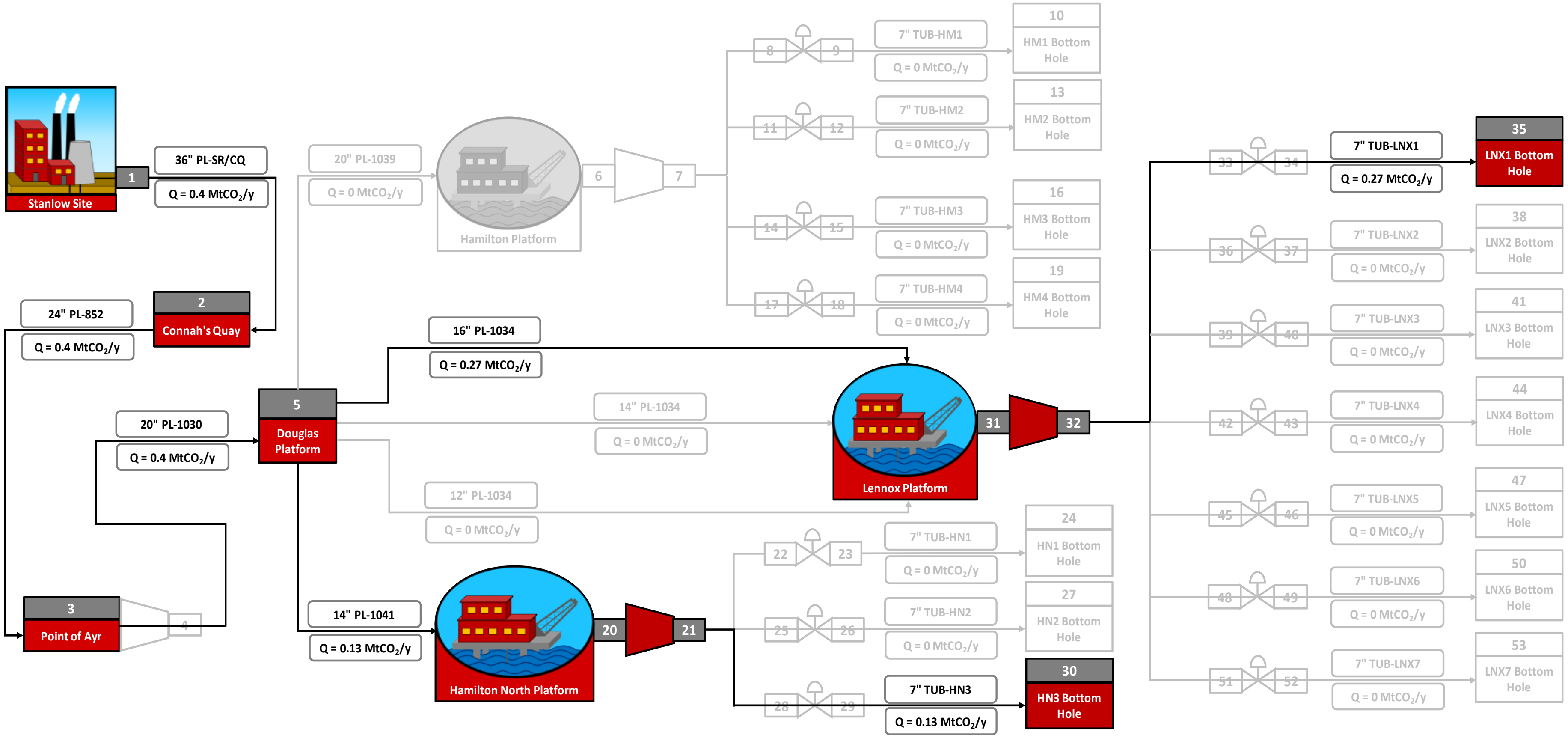


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-30.

Table C-30 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-30.

CO_2 Flow Properties	1	2	3	5	6	7	10	20	21	30	31	32	35
Pressure (barg)	34.8	34.7	34.6	34.5	34.0	67.0	96.0	34.0	63.2	96.0	34.0	71.2	96.0
Fluid Temperature (°C)	20.0	0.8	2.2	5.1	3.8	40.0	46.0	3.8	40.0	41.3	3.7	40.0	42.2
Fluid Density (kg/m³)	80.9	94.6	92.8	90.1	89.2	175.3	314.7	89.2	160.5	361.2	89.3	195.2	352.9
CO_2 velocity (m/s)	0.3	0.2	0.5	0.9	0.5	2.0	1.1	0.4	0.8	0.3	0.2	1.1	0.6

Figure C-31 Simultaneous Injection to Hamilton North and Lennox Sites, Bottom-hole Pressure of 106 barg, CO_2 Injection Rate of 0.4 $MtCO_2$/year.

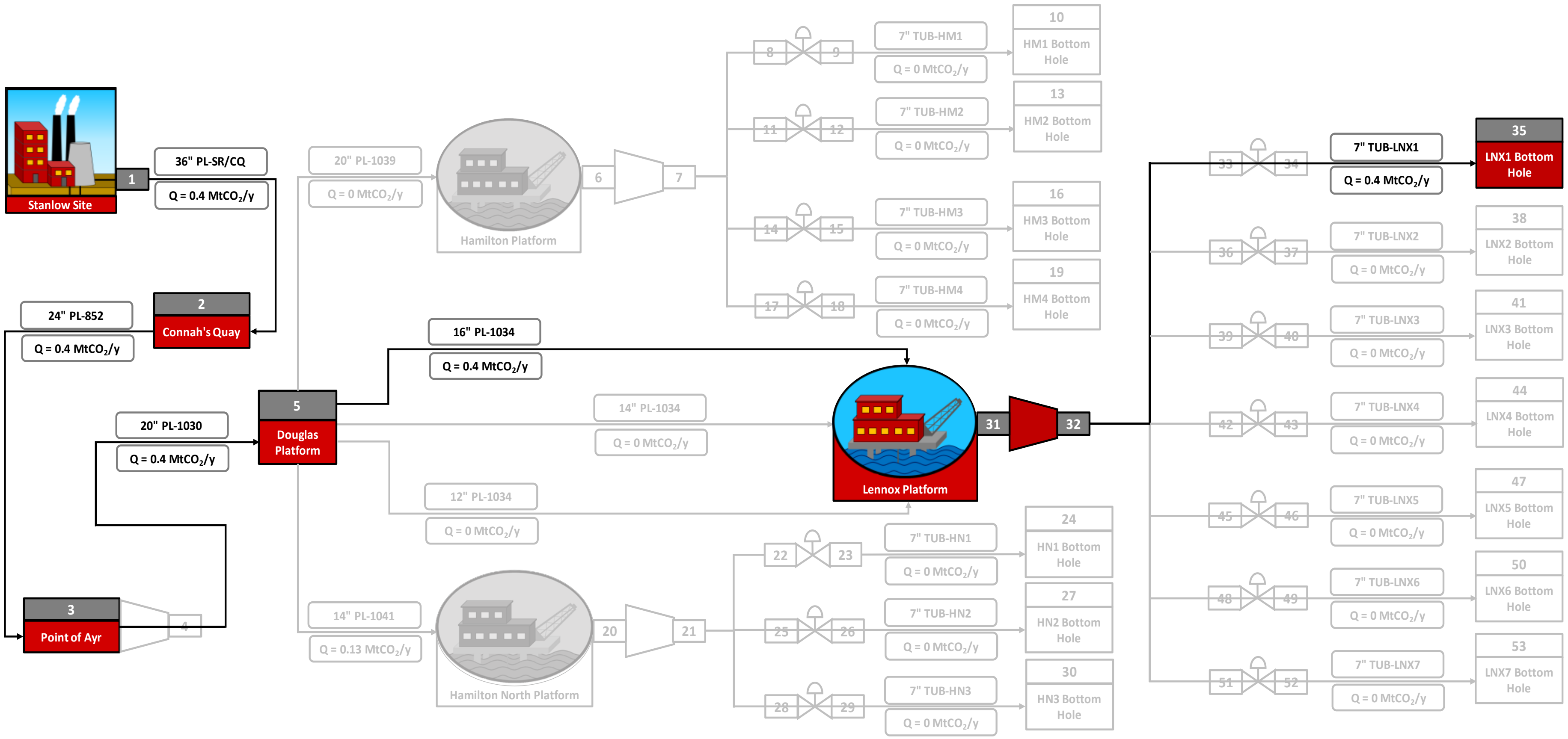


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-31.

Table C-31 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-31.

CO_2 Flow Properties	1	2	3	5	20	21	30	31	32	35
Pressure (barg)	34.9	34.9	34.8	34.7	34.0	70.2	106.0	34.0	79.0	106.0
Fluid Temperature (°C)	20.0	1.1	2.3	5.1	3.8	40.0	46.8	4.0	40.0	48.6
Fluid Density (kg/m^3)	81.4	95.1	93.4	90.8	89.1	190.3	381.5	89.0	238.1	365.2
CO_2 velocity (m/s)	0.3	0.2	0.5	0.9	0.9	1.2	0.6	0.7	1.9	1.3

Figure C-32 Injection to Lennox Reservoir only, Bottom-hole Pressure of 111 barg, CO_2 Injection Rate of 0.4 $MtCO_2$/year.

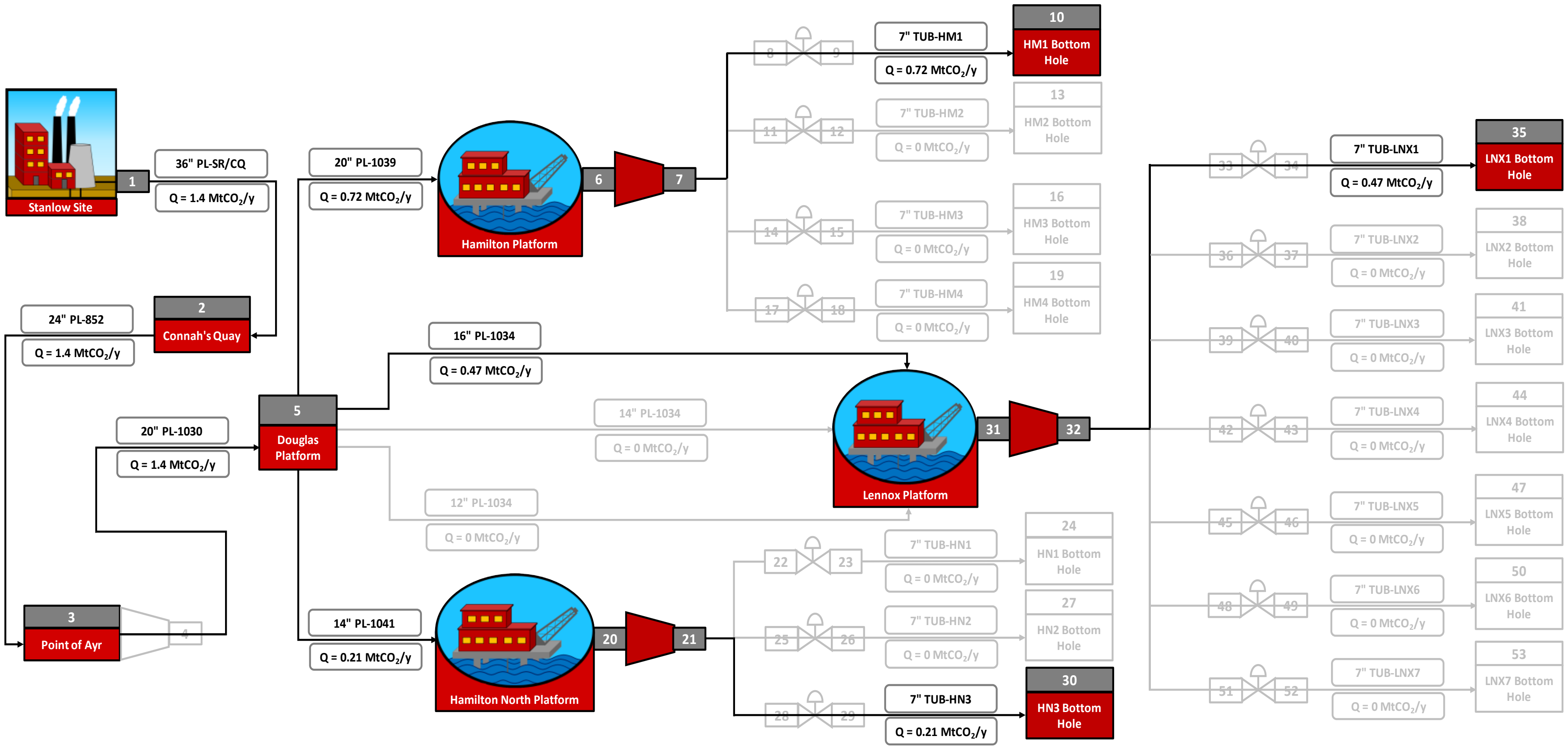


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-32.

Table C-32 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-32.

CO_2 Flow Properties	1	2	3	5	31	32	35
Pressure (barg)	34.8	34.7	34.6	34.5	33.0	83.1	111.0
Fluid Temperature (°C)	20.0	0.5	2.1	5.1	3.9	40.0	51.1
Fluid Density (kg/m^3)	80.9	95.0	92.9	90.1	85.4	265.7	376.3
CO_2 velocity (m/s)	0.3	0.2	0.6	0.9	1.4	2.6	1.8

Figure C-33 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 34 barg, CO_2 Injection Rate of 1.4 $MtCO_2$/year.

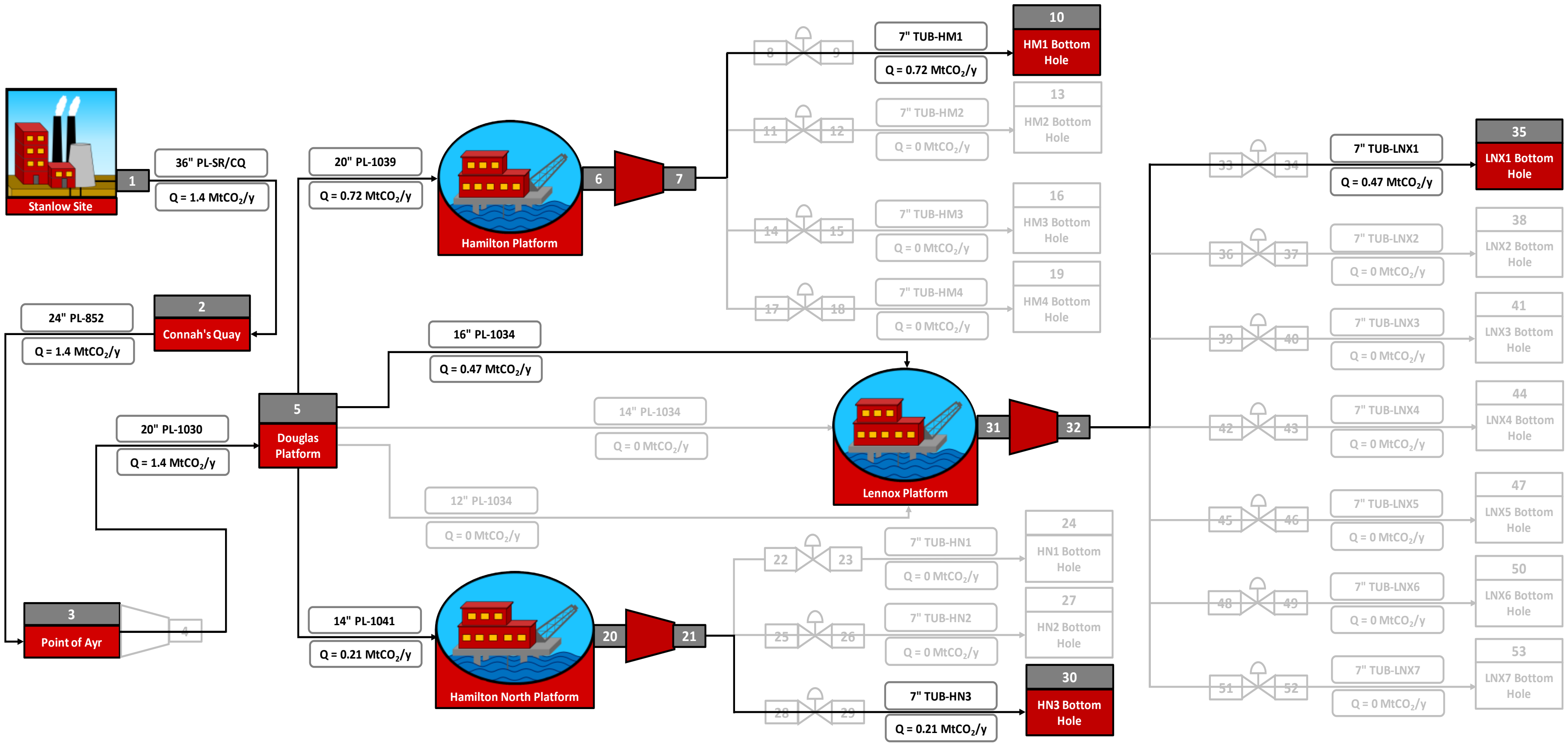


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-33.

Table C-33 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-33.

CO_2 Flow Properties	1	2	3	5	6	7	10	20	21	30	31	32	35
Pressure (barg)	35.0	34.8	33.9	29.1	28.0	43.6	34.1	28.0	28.0	34.0	28.0	38.3	34.0
Fluid Temperature (°C)	20.0	5.6	2.7	2.2	3.0	40.0	25.8	3.8	40.0	32.2	4.0	40.0	30.8
Fluid Density (kg/m³)	81.3	90.9	89.8	73.0	69.1	93.9	75.6	68.7	55.5	72.2	68.6	79.9	73.1
CO_2 velocity (m/s)	1.0	0.9	2.0	3.9	2.4	13.2	16.4	1.7	6.3	4.9	1.3	10.1	11.1

Figure C-34 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 96 barg, CO_2 Injection Rate of 1.4 $MtCO_2$/year.

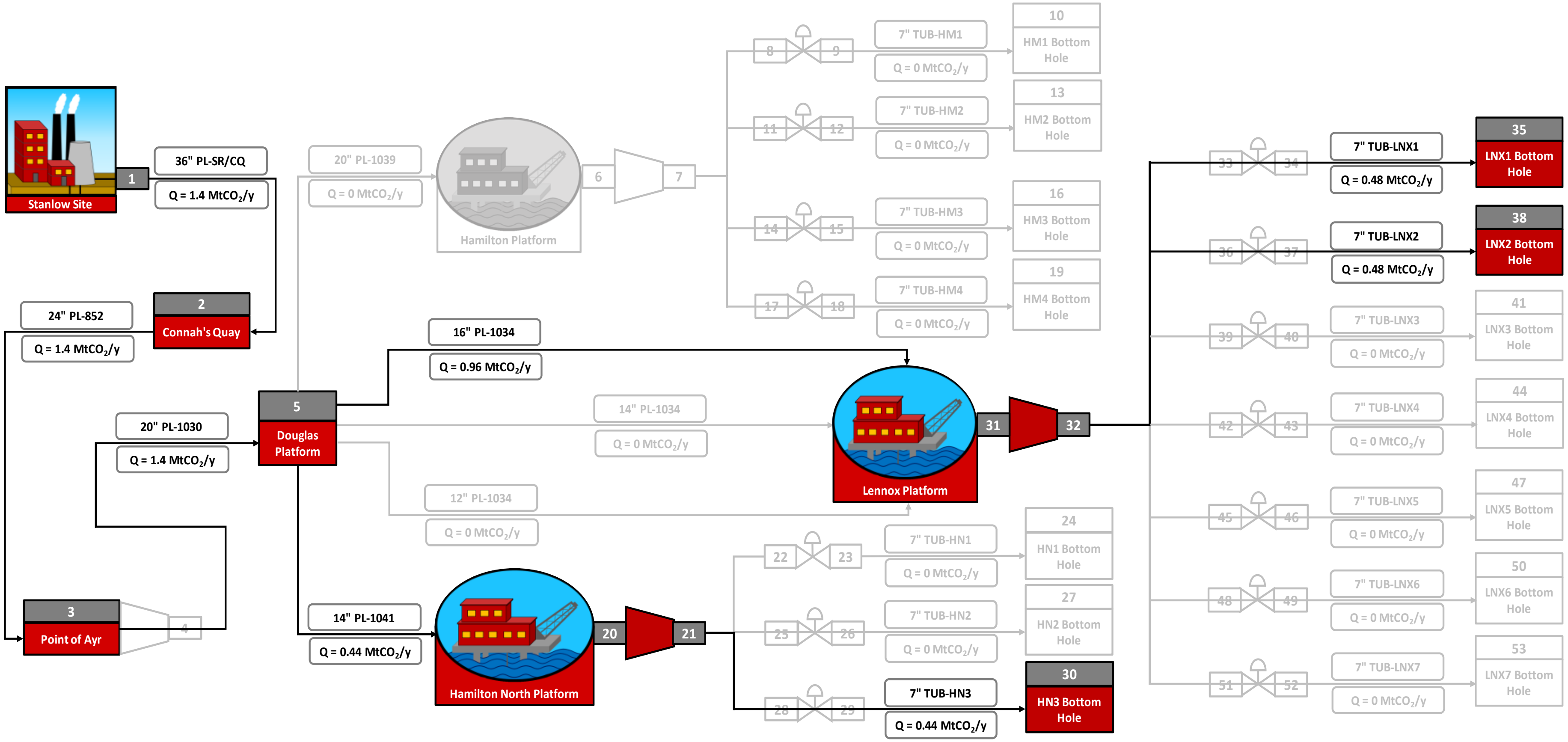


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-34.

Table C-34 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-34.

CO_2 Flow Properties	1	2	3	5	6	7	10	20	21	30	31	32	35
Pressure (barg)	35.0	34.8	33.9	29.1	28.0	73.8	96.0	28.0	67.1	96.0	28.0	75.7	96.0
Fluid Temperature (°C)	20.0	5.6	2.7	2.2	3.0	40.0	50.8	3.8	40.0	47.5	4.0	40.0	49.2
Fluid Density (kg/m^3)	81.3	90.9	89.8	73.0	69.1	207.3	284.0	68.7	175.8	303.1	68.6	217.8	294.1
CO_2 velocity (m/s)	1.0	0.9	2.0	3.9	2.4	6.0	4.4	1.7	2.0	1.2	1.3	3.7	2.7

Figure C-35 Simultaneous Injection to Hamilton North and Lennox Sites, Bottom-hole Pressure of 106 barg, CO_2 Injection Rate of 1.4 $MtCO_2$/year.

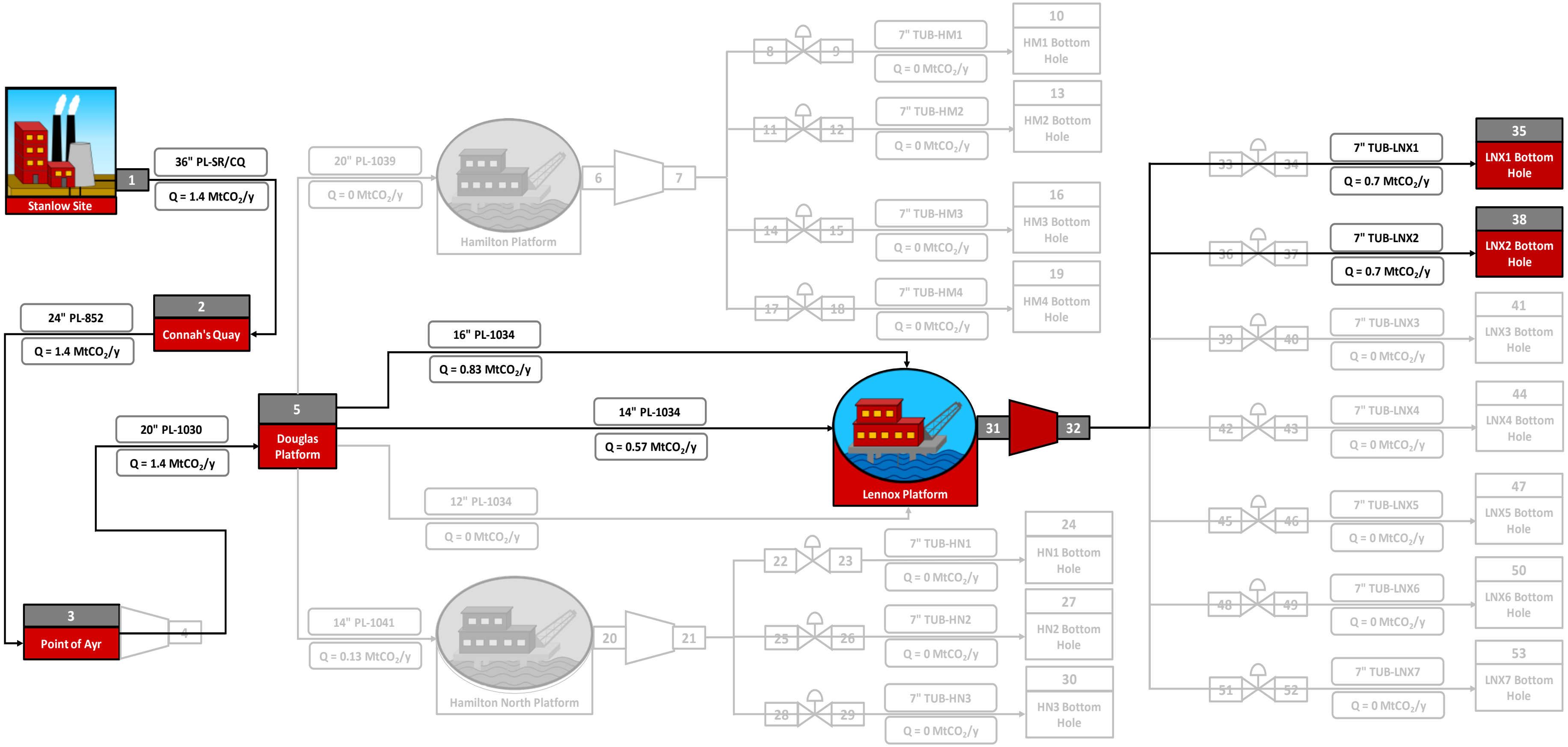


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-35.

Table C-35 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-35.

CO_2 Flow Properties	1	2	3	5	20	21	30	31	32	35	38
Pressure (barg)	34.7	34.6	33.7	28.8	24.0	74.9	106.0	24.0	81.3	106.0	106.0
Fluid Temperature (°C)	20.0	5.5	2.7	2.2	1.2	40.0	53.1	2.8	40.0	51.1	51.1
Fluid Density (kg/m^3)	80.6	90.0	88.9	72.0	57.8	213.4	327.9	57.1	252.1	344.2	344.2
CO_2 velocity (m/s)	1.0	0.9	2.0	4.0	4.9	3.6	2.3	3.8	3.3	2.4	2.4

Figure C-36 Injection to Lennox Reservoir only, Bottom-hole Pressure of 111 barg, CO_2 Injection Rate of 1.4 $MtCO_2$/year.

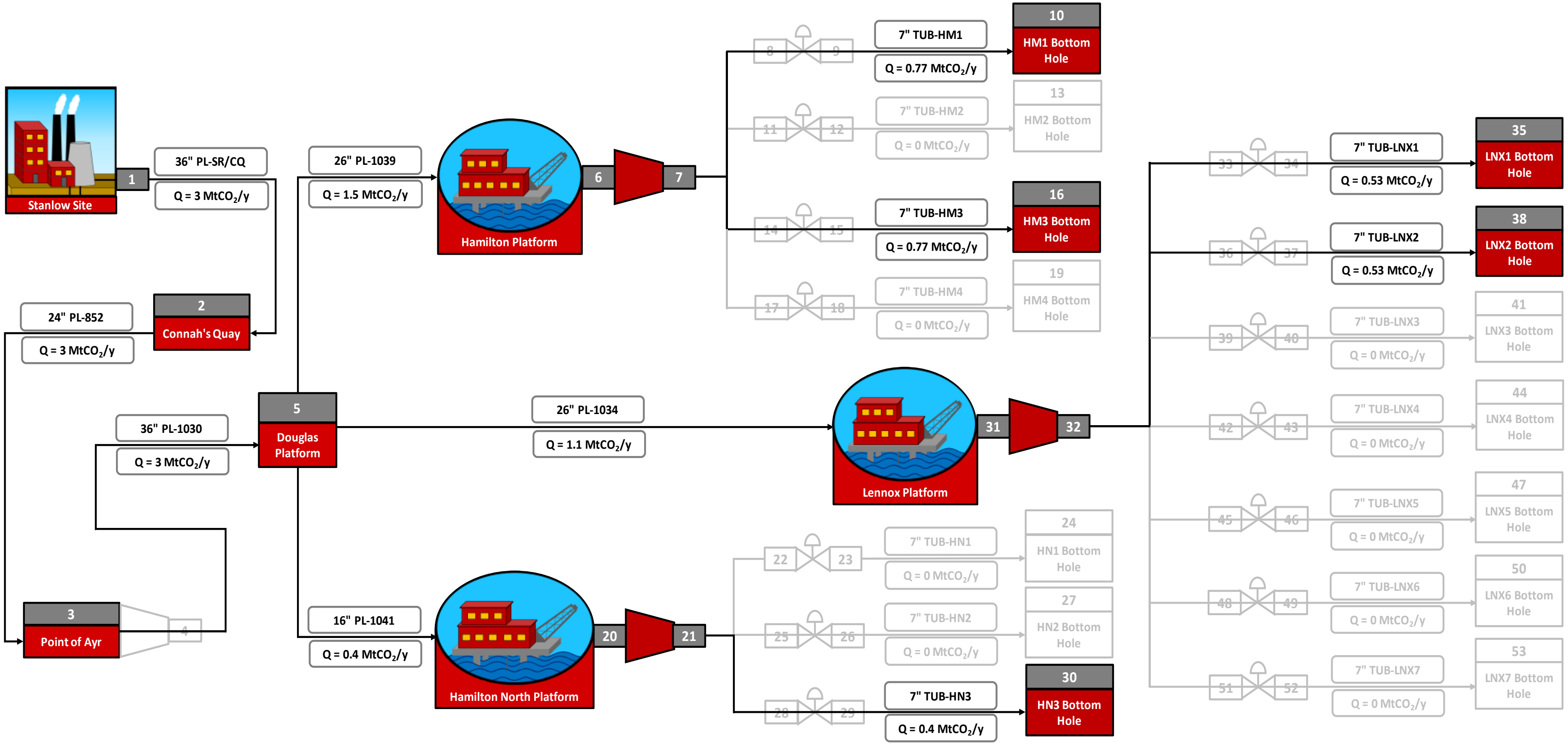


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-36.

Table C-36 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-36.

CO_2 Flow Properties	1	2	3	5	31	32	35	38
Pressure (barg)	34.7	34.6	33.7	28.8	24.0	81.3	106.0	106.0
Fluid Temperature (°C)	20.0	5.5	2.7	2.2	2.8	40.0	51.1	51.1
Fluid Density (kg/m^3)	80.6	90.0	88.9	72.0	57.1	252.1	344.2	344.2
CO_2 velocity (m/s)	1.0	0.9	2.0	4.0	3.8	3.3	2.4	2.4

Figure C-37 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 27 barg, CO_2 Injection Rate of 3 $MtCO_2$/year.

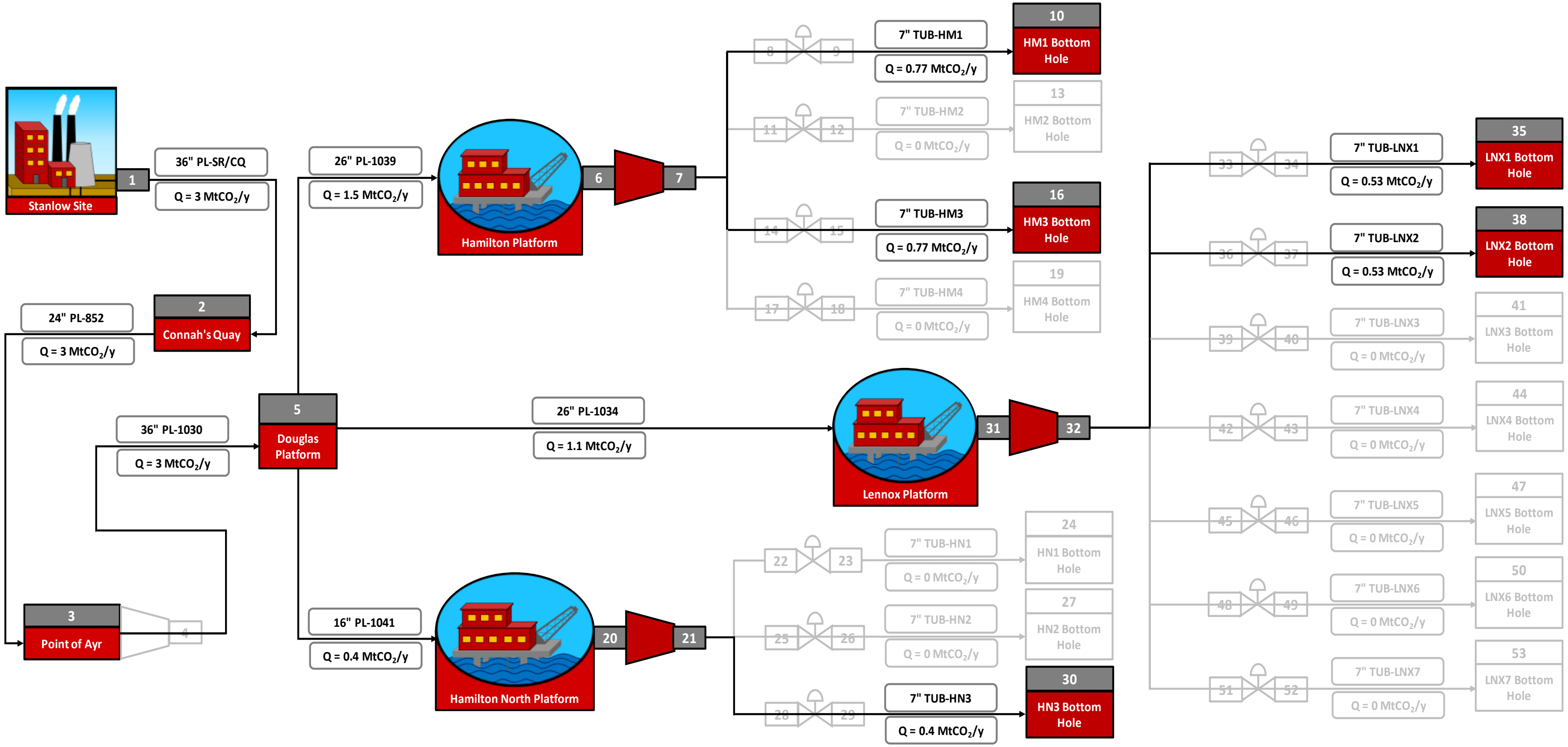


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-37.

Table C-37 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-37.

CO_2 Flow Properties	1	2	3	5	6	7	10	16	20	21	30	31	32	35	38
Pressure (barg)	34.9	34.4	29.9	29.4	28.5	42.6	27.0	27.0	28.5	26.9	27.0	28.5	36.9	27.0	27.0
Fluid Temperature (°C)	20.0	10.4	2.2	4.1	3.3	40.0	20.2	20.2	3.7	40.0	31.5	4.0	40.0	26.7	26.7
Fluid Density (kg/m^3)	81.2	85.7	75.6	72.8	70.5	91.2	59.6	59.6	70.3	52.9	55.4	70.2	76.5	57.1	57.1
CO_2 velocity (m/s)	2.2	2.0	5.2	2.3	2.5	14.5	22.2	22.2	1.7	12.6	12.0	1.6	11.8	15.9	15.9

Figure C-38 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 96 barg, CO_2 Injection Rate of 3 $MtCO_2$/year.

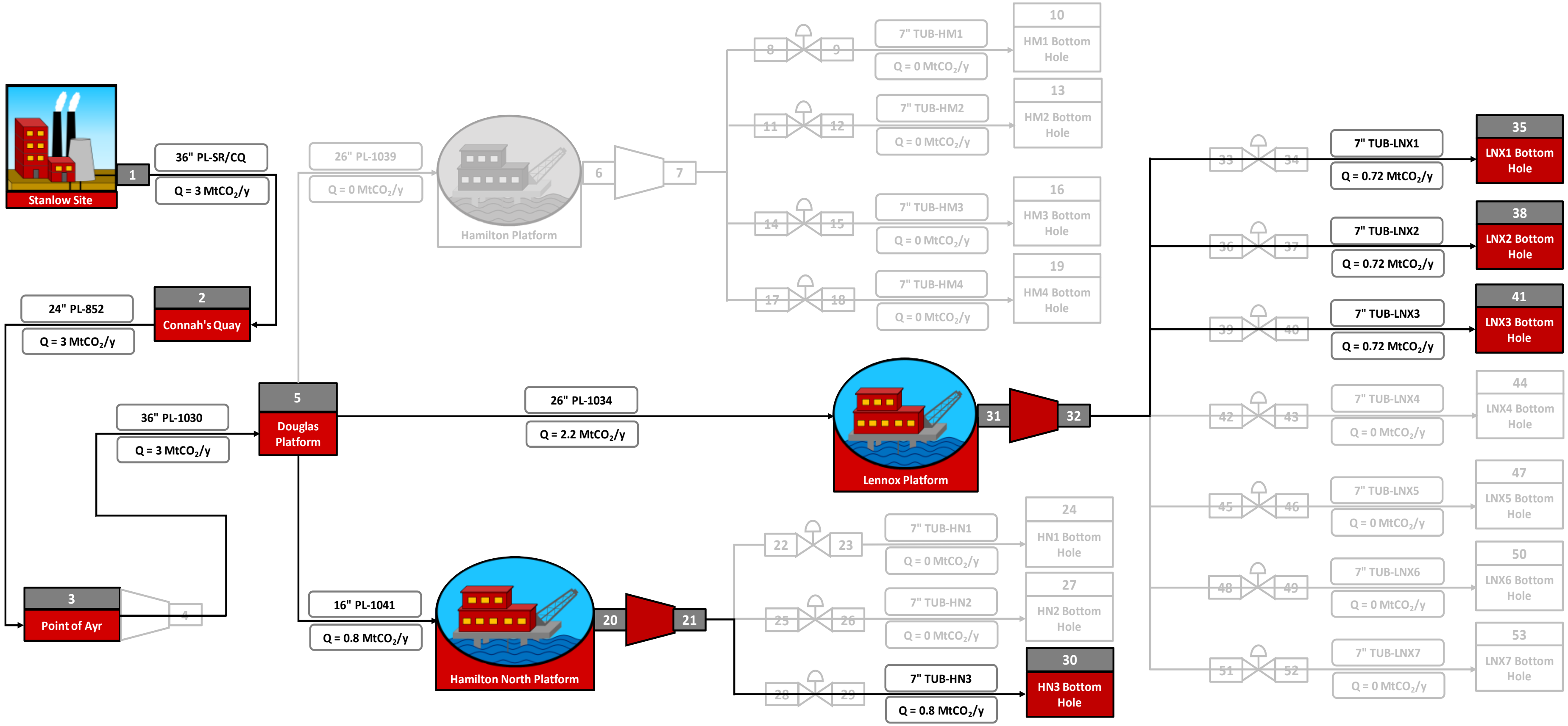


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-38.

Table C-38 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-38.

CO_2 Flow Properties	1	2	3	5	6	7	10	16	20	21	30	31	32	35	38
Pressure (barg)	34.9	34.4	29.9	29.4	28.5	74.4	96.0	96.0	28.5	69.2	96.0	28.5	76.4	96.0	96.0
Fluid Temperature (°C)	20.0	10.4	2.2	4.1	3.3	40.0	50.8	50.8	3.7	40.0	50.6	4.0	40.0	49.4	49.4
Fluid Density (kg/m^3)	81.2	85.7	75.6	72.8	70.5	210.5	284.3	284.3	70.3	184.8	284.2	70.2	221.5	292.6	292.6
CO_2 velocity (m/s)	2.2	2.0	5.2	2.3	2.5	6.3	4.7	4.7	1.7	3.6	2.3	1.6	4.1	3.1	3.1

Figure C-39 Simultaneous Injection to Hamilton North and Lennox Sites, Bottom-hole Pressure of 106 barg, CO_2 Injection Rate of 3 $MtCO_2$/year.

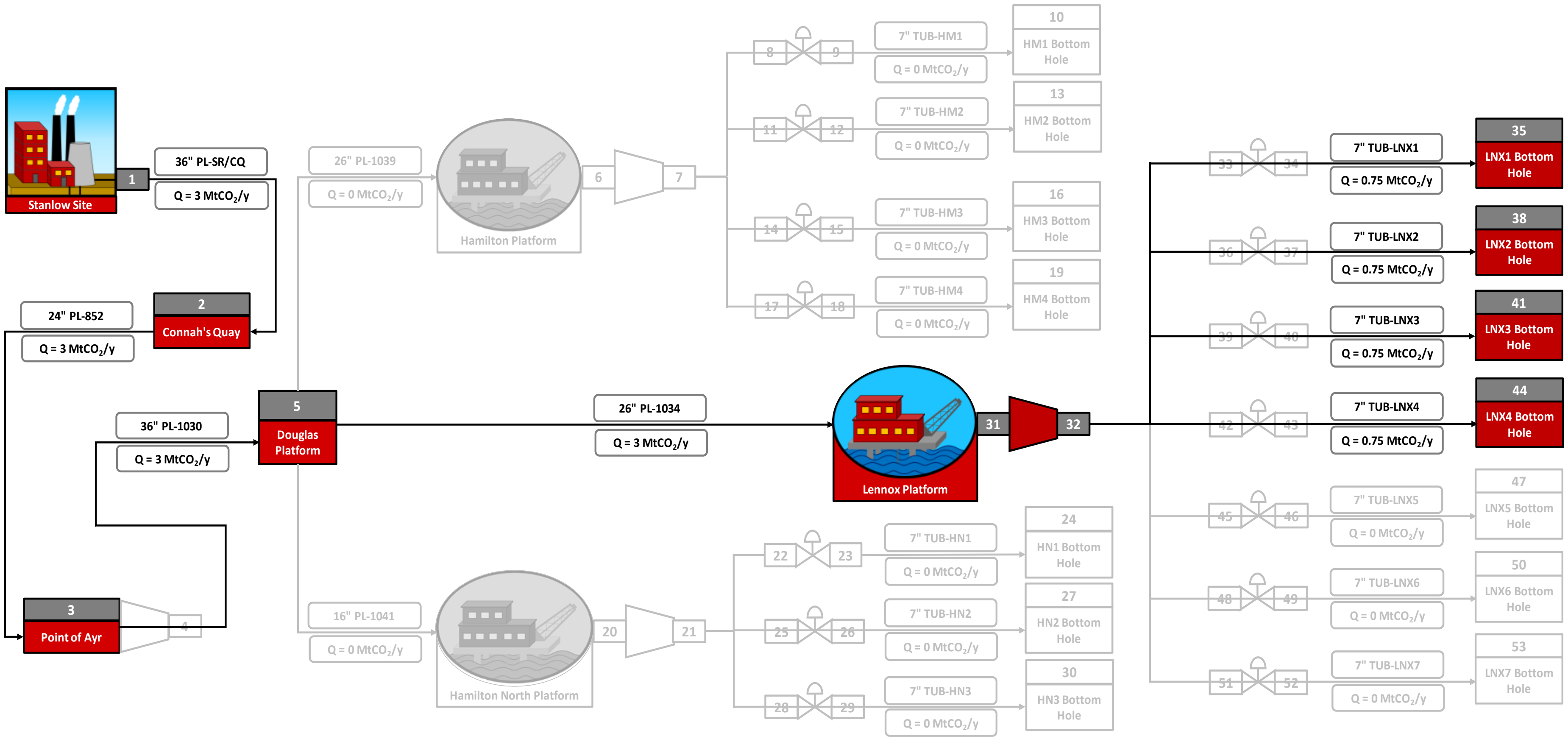


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-39.

Table C-39 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-39.

CO_2 Flow Properties	1	2	3	5	20	21	30	31	32	35	38	41
Pressure (barg)	35.0	34.6	30.0	29.6	27.0	78.6	106.0	27.0	84.1	106.0	106.0	106.0
Fluid Temperature (°C)	20.0	10.4	2.2	4.1	2.5	40.0	54.2	2.6	40.0	51.3	51.3	51.3
Fluid Density (kg/m^3)	81.6	86.2	76.2	73.5	66.2	234.8	320.7	66.2	272.1	342.8	342.8	342.8
CO_2 velocity (m/s)	2.1	2.0	5.1	2.3	3.8	6.1	4.4	3.6	4.6	3.6	3.6	3.6

Figure C-40 Injection to Lennox Reservoir only, Bottom-hole Pressure of 111 barg, CO_2 Injection Rate of 3 $MtCO_2$/year.

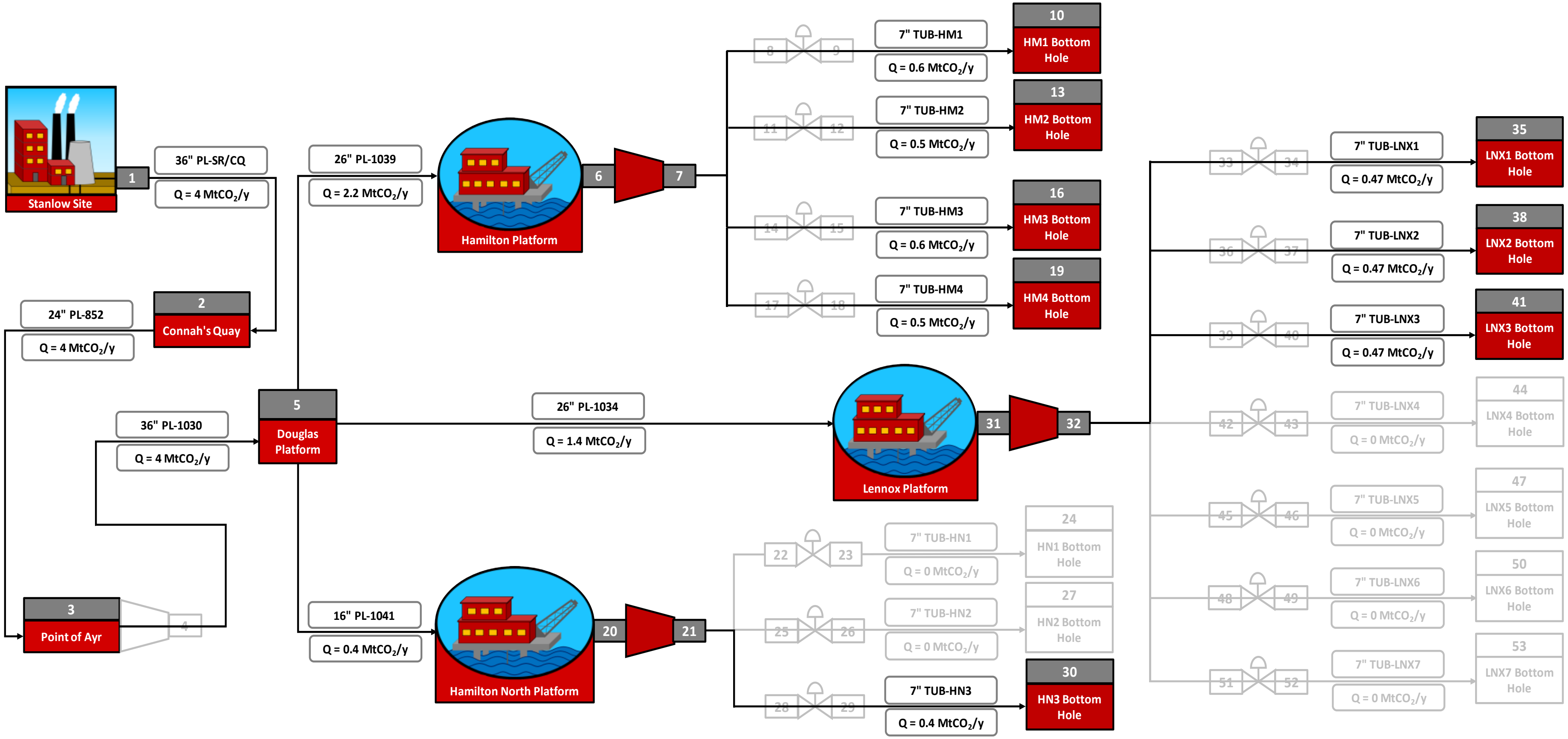


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-40.

Table C-40 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-40.

CO_2 Flow Properties	1	2	3	5	31	32	35	38	41	44
Pressure (barg)	34.8	34.3	29.7	29.2	24.5	86.8	111.0	111.0	111.0	111.0
Fluid Temperature (°C)	20.0	10.4	2.1	4.1	0.5	40.0	51.9	51.9	51.9	51.9
Fluid Density (kg/m^3)	80.9	85.4	75.2	72.5	59.5	293.9	369.3	369.3	369.3	369.3
CO_2 velocity (m/s)	2.2	2.1	5.2	2.3	5.6	4.4	3.5	3.5	3.5	3.5

Figure C-41 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 16 barg, CO_2 Injection Rate of 4 $MtCO_2$/year.

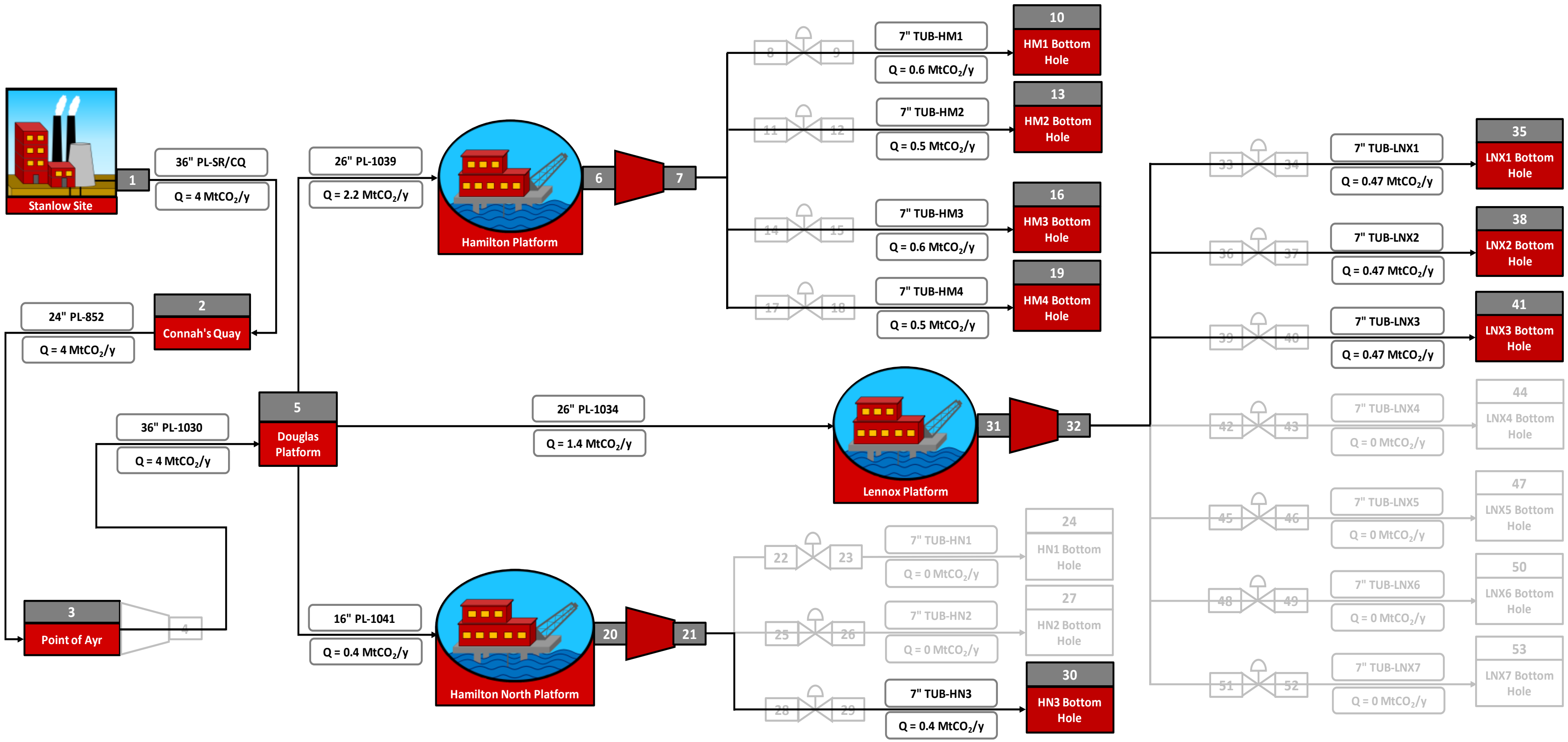


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-41.

Table C-41 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-41.

CO_2 Flow Properties	7	2	3	5	6	7	10	13	16	19	20	21	30	21	32	35	38	41
Pressure (barg)	34.8	33.9	24.9	23.4	22.0	31.5	16.0	16.0	16.0	16.0	22.0	25.2	16.0	22.0	28.8	16.0	16.0	16.0
Fluid Temperature (°C)	20.0	11.7	-1.5	2.0	1.7	40.0	18.9	17.2	18.9	17.2	3.4	40.0	24.8	3.6	40.0	23.5	23.5	23.5
Fluid Density (kg/m³)	80.8	83.1	61.4	55.7	51.9	63.4	33.8	33.9	33.8	33.9	51.3	49.2	32.8	51.3	57.2	32.9	32.9	32.9
CO_2 velocity (m/s)	2.9	2.8	8.5	4.1	4.6	15.6	29.3	24.9	29.3	24.9	3.1	17.9	26.9	2.9	13.4	23.3	23.3	23.3

Figure C-42 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 96 barg, CO_2 Injection Rate of 4 $MtCO_2$/year.

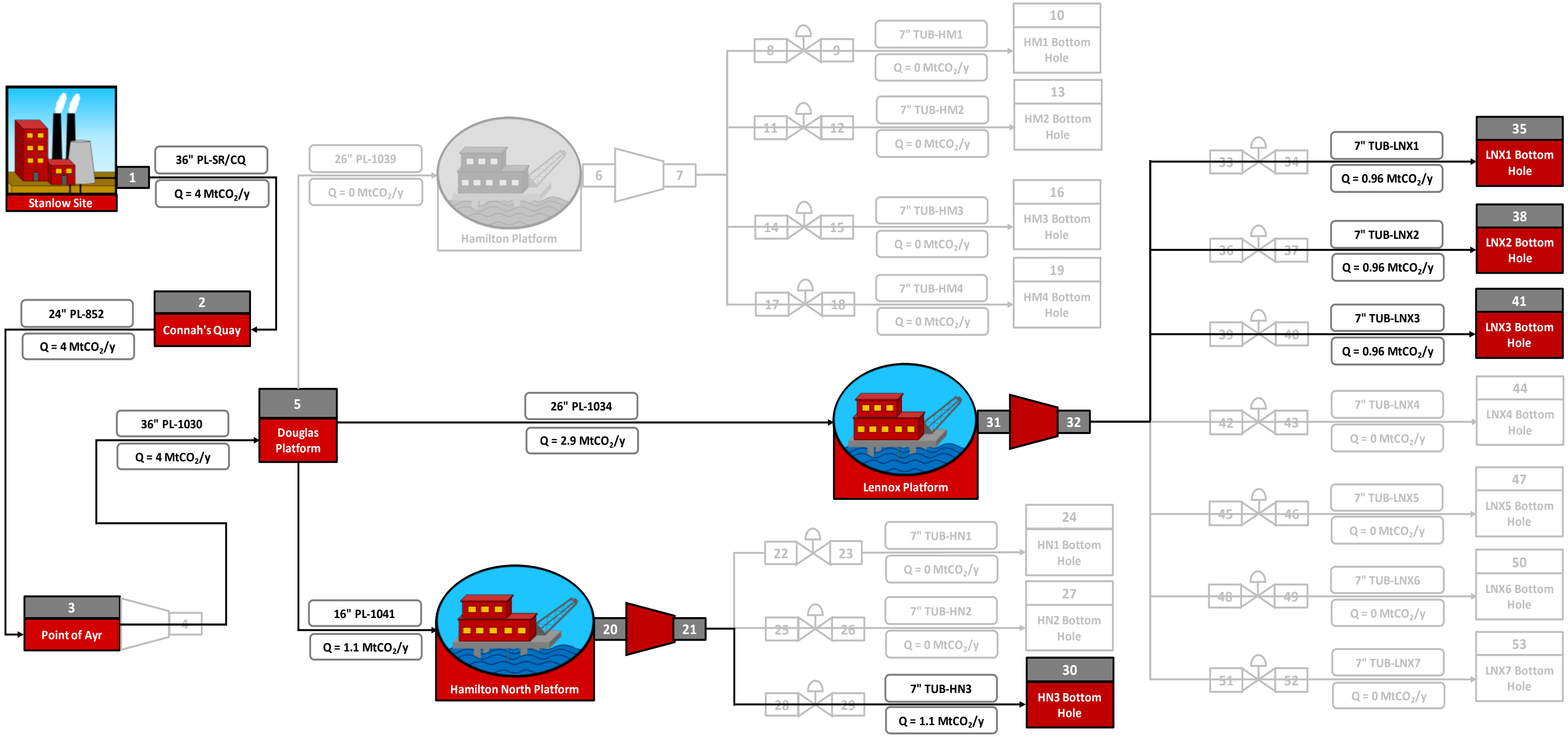


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-42.

Table C-42 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-42.

CO_2 Flow Properties	1	2	3	5	6	7	10	13	16	19	20	21	30	31	32	35	38	41
Pressure (barg)	34.8	33.9	24.9	23.4	22.0	72.3	96.0	96.0	96.0	96.0	22.0	70.4	96.0	22.0	75.4	96.0	96.0	96.0
Fluid Temperature (°C)	20.0	11.7	-1.5	2.0	1.7	40.0	50.9	47.3	50.9	47.3	3.4	40.0	51.6	3.6	40.0	49.1	49.1	49.1
Fluid Density (kg/m³)	80.8	83.1	61.4	55.7	51.9	199.6	283.7	306.6	283.7	306.6	51.3	190.6	279.1	51.3	215.8	294.7	294.7	294.7
CO_2 velocity (m/s)	2.9	2.8	8.5	4.1	4.6	5.3	3.7	2.5	3.7	2.5	3.1	4.6	3.2	2.9	3.6	2.6	2.6	2.6

Figure C-43 Simultaneous Injection to Hamilton North and Lennox Sites, Bottom-hole Pressure of 106 barg, CO_2 Injection Rate of 4 $MtCO_2$/year.

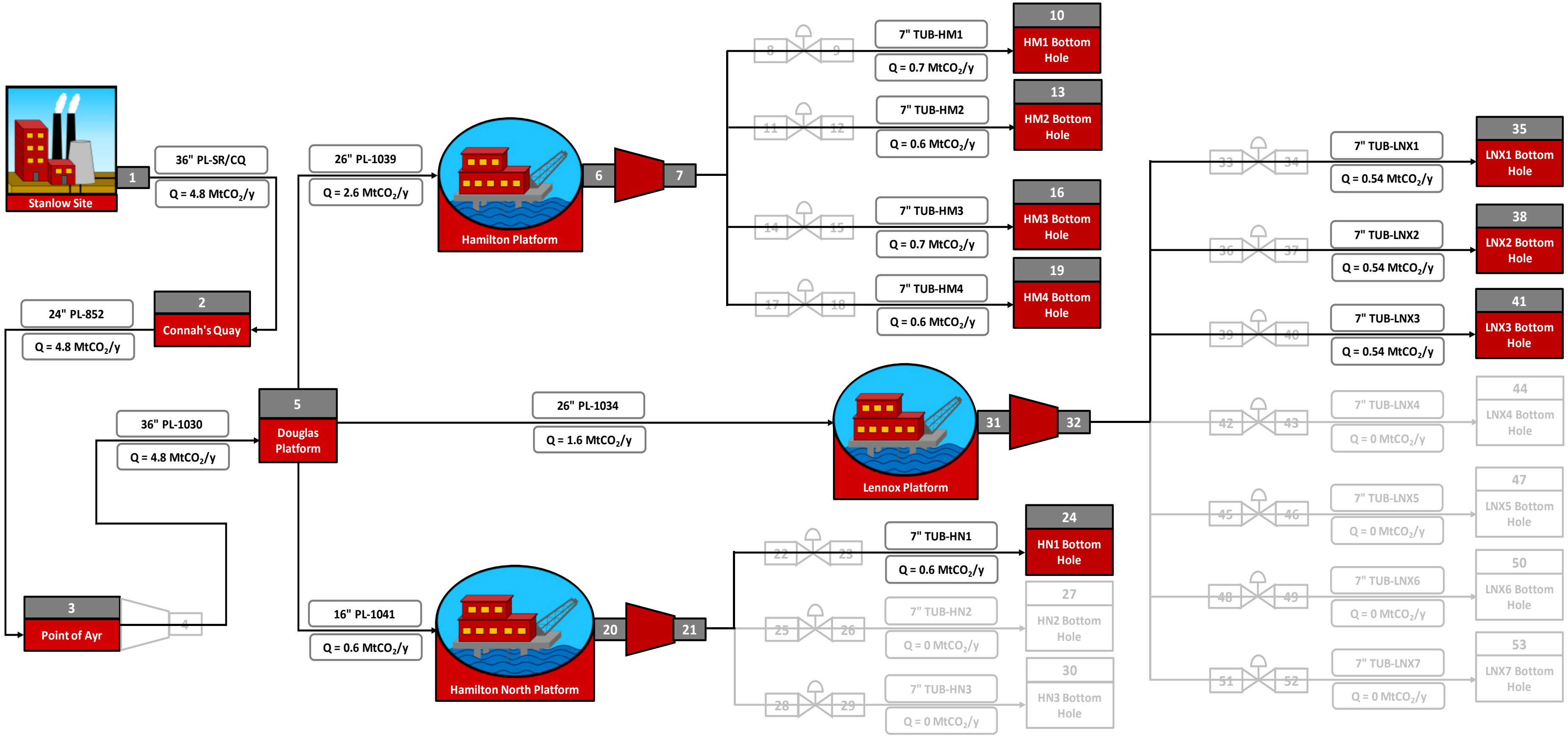


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-43.

Table C-43 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-43.

CO_2 Flow Properties	1	2	3	5	20	21	30	31	32	35	38	41
Pressure (barg)	35.0	34.1	25.2	23.7	18.0	81.4	106.0	18.0	87.1	106.0	106.0	106.0
Fluid Temperature (°C)	20.0	11.7	-1.3	2.0	-0.5	40.0	53.5	-0.5	40.0	50.2	50.2	50.2
Fluid Density (kg/m³)	81.4	83.8	62.3	56.7	41.8	253.1	325.5	41.8	296.8	351.9	351.9	351.9
CO_2 velocity (m/s)	2.9	2.8	8.3	4.0	8.1	7.5	5.8	7.7	5.6	4.7	4.7	4.7

Figure C-44 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 19 barg, CO_2 Injection Rate of 4.8 $MtCO_2$/year.

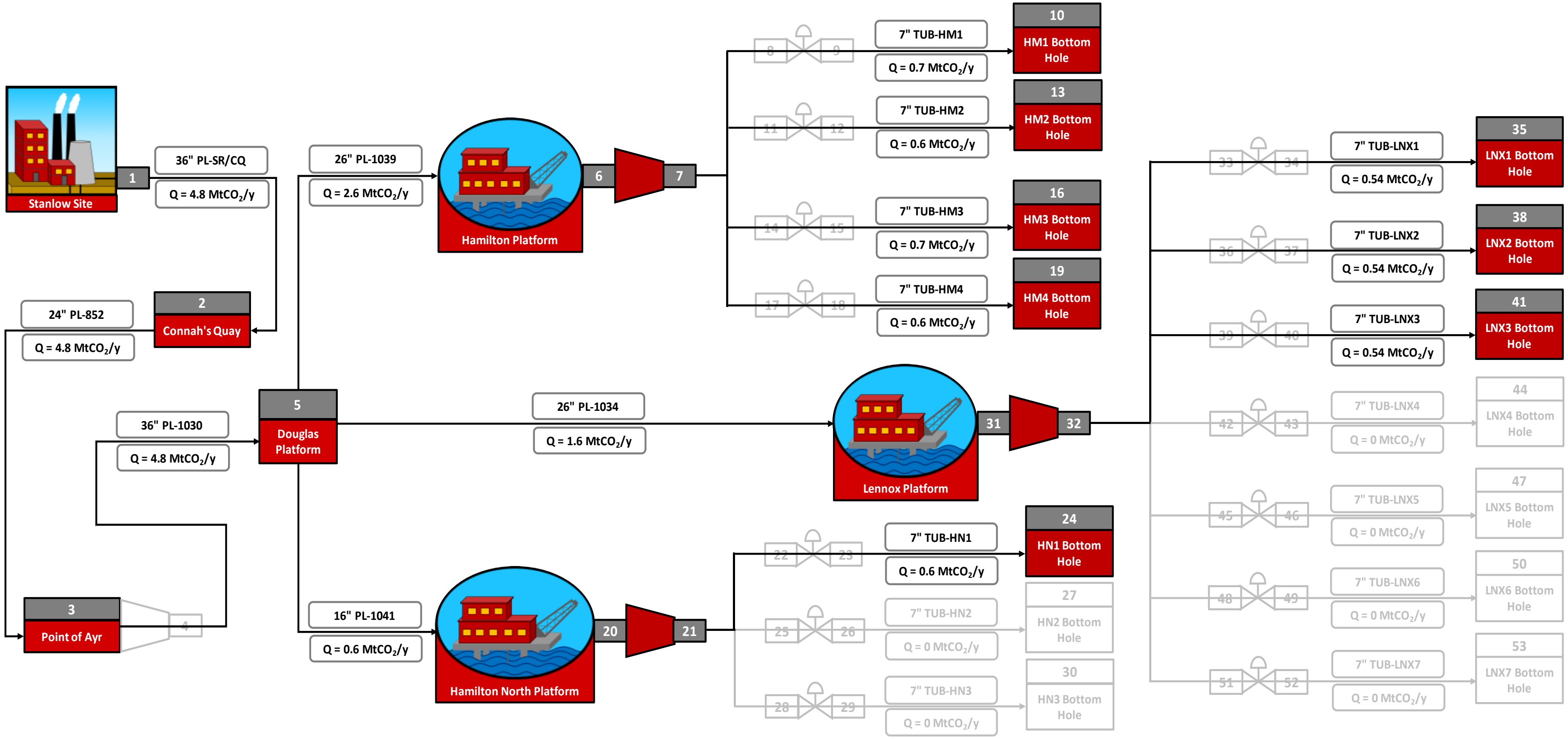


Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-44.

Table C-44 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-44.

CO_2 Flow Properties	1	2	3	5	6	7	10	13	16	19	20	21	24	31	32	35	38	41
Pressure (barg)	34.9	33.7	19.1	15.8	13.0	37.1	19.0	19.0	19.0	19.0	13.0	33.4	19.0	13.0	34.0	19.0	19.0	19.0
Fluid Temperature (°C)	20.0	12.3	-7.4	-1.9	-1.7	40.0	17.1	15.2	17.1	15.2	2.6	40.0	20.8	2.7	40.0	22.3	22.3	22.3
Fluid Density (kg/m³)	81.2	81.9	46.4	36.4	29.6	77.1	41.1	41.2	41.1	41.2	29.0	67.8	40.2	29.0	69.4	39.7	39.7	39.7
CO_2 velocity (m/s)	3.5	3.4	13.4	7.5	9.7	15.4	29.1	24.7	29.1	24.7	6.5	15.5	26.3	6.2	13.2	23.1	23.1	23.1

Figure C-45 Simultaneous Injection to Hamilton Main, Hamilton North and Lennox Sites, Bottom-hole Pressure of 96 barg, CO_2 Injection Rate of 4.8 $MtCO_2$/year



Note 1: Components of the offshore system (pipelines, wells, compressors and chokes) not in operation are greyed out.
Note 2: Key operating conditions at numbered reference locations of the above network (grey-shaded boxes with numbers) are given in Table C-45.

Table C-45 Key Flowing Parameters Corresponding to Operating Scenario Presented in Figure C-45.

CO_2 Flow Properties	1	2	3	5	6	7	10	13		19	20	21	24	31	32	35	38	41
Pressure (barg)	34.9	33.7	19.0	15.8	13.0	73.8	96.0	97.0	98.0	99.0	13.0	70.2	96.0	13.0	76.5	96.0	97.0	98.0
Fluid Temperature (°C)	20.0	12.3	-7.4	-1.9	-1.7	40.0	50.9	47.7	50.9	47.7	2.6	40.0	52.3	2.7	40.0	49.4	49.4	49.4
Fluid Density (kg/m³)	81.2	81.9	46.4	36.4	29.6	207.5	283.8	303.2	283.8	303.2	29.0	189.1	275.4	29.0	222.1	292.5	292.5	292.5
CO_2 velocity (m/s)	3.5	3.4	13.4	7.5	9.7	6.1	4.4	3.1	4.4	3.1	6.5	5.6	3.8	6.2	4.1	3.1	3.1	3.1

Appendix D INPUT DATA

The main input data used for the simulations presented in this note is taken from the Flow Assurance Design Premise (Ref. 11). Key or additional data is described in this Appendix.

D-1 Simulation Software

The analysis undertaken in this study was performed using OLGA dynamic multiphase flow simulator version 2018.1.1.

Thermodynamic calculations have been performed using Multiflash version 7.0

D-2 CO_2 Mixture Composition

All steady state simulations are based on the composition of the CO_2 mixture with a high H_2 content (2 mol%) (Ref. 1).

D-3 Reservoir Pressures

As the initial pressures of depleted storage reservoirs differ between fields, it is assumed that each storage site will be brought online in the following order (Ref. 12 and to be confirmed during FEED):

1. Hamilton Main with the initial reservoir pressure of 4.5 barg;
2. Lennox with the initial reservoir pressure of 9 barg, once Hamilton Main reservoir pressure reaches 9 barg;
3. Hamilton North with the initial reservoir pressure of 13.8 barg, once Hamilton Main and Lennox reservoirs pressures reach 13.8 barg.

The maximum reservoirs pressures that can be expected at the end of the project life, when storage reservoirs reach their full capacity (assumed to be below the fracture pressure of the cap-rock), are presented in Table D-1 (Ref. 12):

Table D-1: Maximum Reservoir Pressures of Storage Reservoirs

Storage Site	Maximum Reservoir Pressure barg	Fields in Operation
Hamilton Main	96	Hamilton Main, Hamilton North & Lennox
Hamilton North	106	Hamilton North & Lennox
Lennox	111	Lennox

D-4 Well Data

D-4.1 Well Stock

Table D-2 shows the numbers of wells at each field available for CO_2 injection. The number of available wells to be confirmed in FEED.

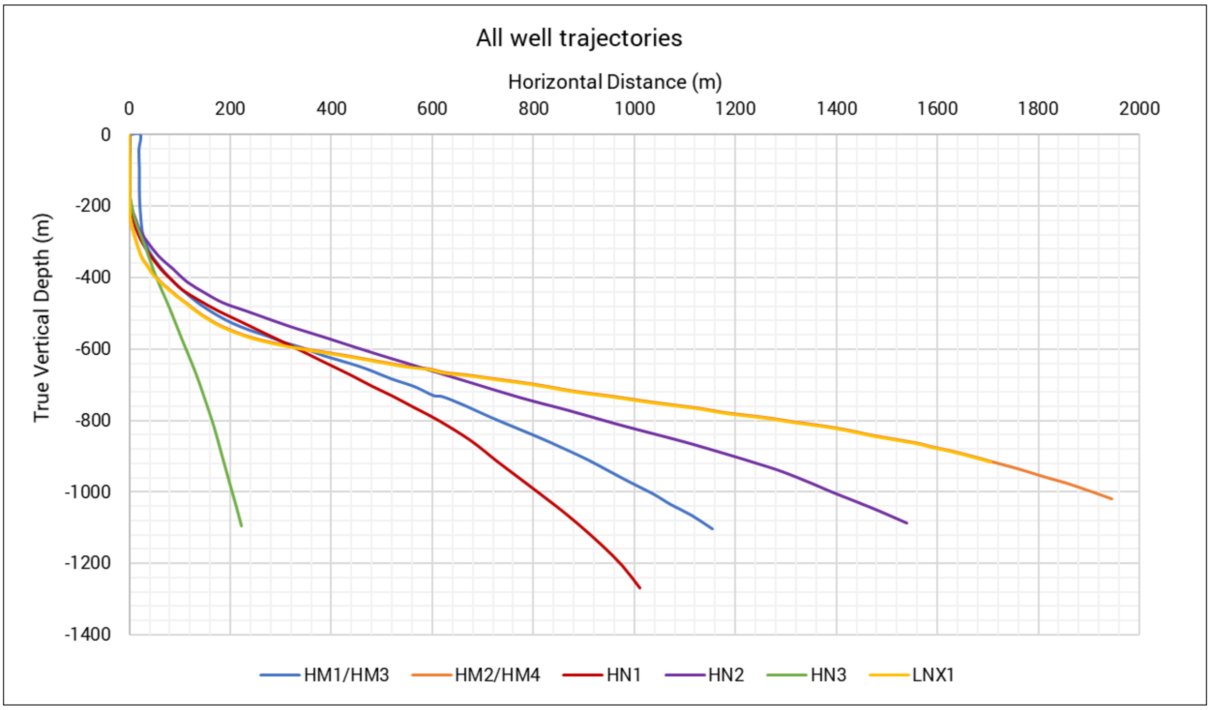
Table D-2: Available Wells at Each Platform

Field	Number of Wells
Hamilton	4
Hamilton North	3
Lennox	7

D-4.2 Well Trajectories

Figure D-1 presents the assumed well trajectories for the wells in Hamilton Platform (HM1 to HM4), Hamilton North (HN1 to HN3) and Lennox wells (LNX1 to LNX7). All the Lennox wells have been assumed to be identical.

Figure D-1: Well Trajectories at Hamilton, Hamilton North and Lennox Fields



D-5 Design / Operating Limits

Design and Operating margins to be confirmed in FEED.

D-5.1 Onshore and Offshore Pipelines

Table D-3: Gas Phase Design / Operating Constraints for the Pipelines

	Gas	Rationale
MAOP	35 barg	To avoid liquid dropout at 0°C
Minimum Normal Operating Pressure	5 barg	Minimum start reservoir pressure
Maximum Velocity	20 m/s	Reduce risk erosion and vibration (some debris is expected used pipelines at start of operation). High velocity promotes increased Joule-Thomson cooling
Maximum Operating Temperature	20 °C	Environmental Constraint
Minimum Operating Temperature	-10 °C	No margin on minimum design temperature

Table D-4: Liquid Phase Design / Operating Constraints for the Pipelines

	Liquid	Rationale
MAOP	125 barg	To honour design pressure
Minimum Normal Operating Pressure	97 / 84 barg	To avoid gas breakout after extended shutdown (high / low H_2 content)
Maximum Velocity	5-12 m/s	Unlikely to be high. It is anticipated this will not be an issue
Maximum Operating Temperature	20 °C	Environmental constraint (likely to be lower, circa 15 °C to avoid gas breakout after extended shutdown)
Minimum Operating Temperature	-10 °C	No margin on minimum design temperature (unlikely to reach low temperatures as minimum Joule-Thomson cooling expected)

D-5.2 Injection Wells

Table D-5: Design / Operating Constraints in Injection Wells

	Limit	Rationale
MAOP / Design Pressure	98 - 113 barg	Initial reservoir production pressure
Minimum Normal Operating Pressure	5 barg	Minimum start reservoir pressure

Maximum Velocity	30 m/s	Reduce risk erosion and vibration (some debris in used pipelines at start of operation). High velocity promotes increased Joule-Thomson cooling. Material likely to be more resistant to erosion. High velocities risk to damage formation.
Design Temperature	31 - 60 / -10 °C	Reservoir Temperature and/or to match pipeline design temperature
Minimum Operating Temperature	0 / 4 °C	0 °C at wellhead but arrival temperature at bottom hole > 4 °C to avoid thermal stresses in the formation

Appendix E ABOUT HYNET PHASE 1: INDUSTRIAL CCUS PROJECT

E-1 General Background

The HyNet project is located in the North West of England. This project aims to produce hydrogen from natural gas feedstock using reforming processes, capture the resulting carbon dioxide (CO_2) and transport it offshore for underground storage. The produced hydrogen will be transported to industrial consumers via newbuild pipeline. Additionally, hydrogen will be blended with natural gas to materially reduce the carbon intensity of domestic heat.

This phase (Phase 1: Industrial CCUS) of the project focuses also on capturing some of the emissions from Stanlow Refinery (Essar) and Ince Fertiliser Plant (CF Fertilisers), and transporting the carbon dioxide offshore, using a combination of new and existing repurposed infrastructure, to store it in the depleted Hamilton gas field. Also, provisions are made for the inclusion of CO_2 from other sources including Project Bright SNG and from other waste plants.

As Government procedures on CCUS and hydrogen deployment are still being formulated, consideration has been given to the approach of focusing on a subset of the proposed HyNet Project in the first instance, which provides material industrial emissions reduction, creates expandable CCUS infrastructure and is in line with the HMG commitment.

Figure E-1 below presents the schematic of HyNet Project. Figure E-2presents the Phase 1 of Hynet Project (Industrial CCUS).

Figure E-1: HyNet Full Project Schematic

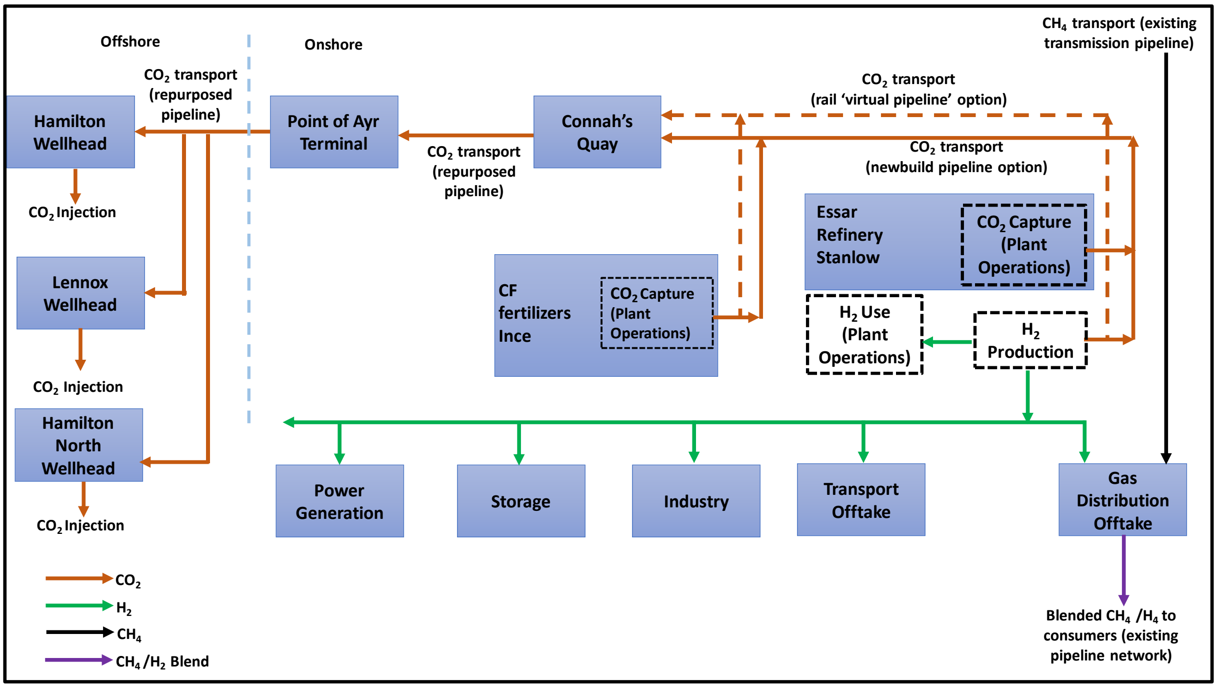
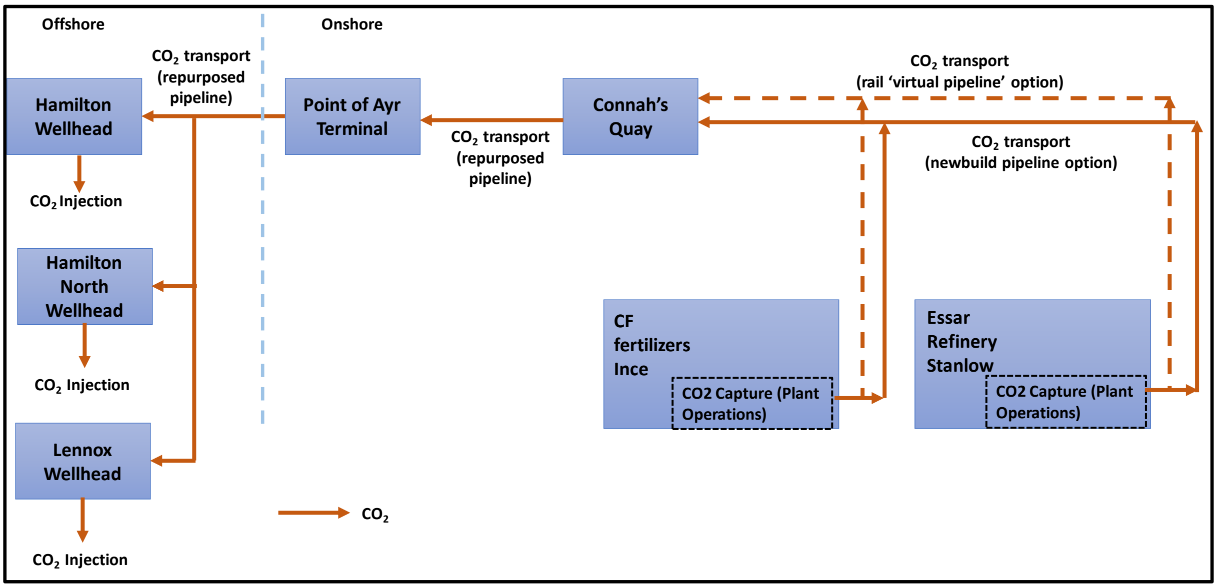


Figure E-2: HyNet Phase 1 Project Schematic



E-2 Project Development Description

For the purposes of the pre-FEED it is assumed that the hydrogen production plant will be located adjacent to the Stanlow Refinery and that new-build industrial facilities with CO_2 capture will be located at Protos.

CO_2 emissions captured from the Ince Fertiliser Plant and Stanlow Refinery will be transported along a new-build pipeline which will connect the Ince Fertiliser Plant with Stanlow site and then run from Stanlow site to the north of Chester, and then north to Connah's Quay. At Connah's Quay the new-build pipeline will connect to the existing natural gas import pipeline, currently owned and operated by Eni.

The existing onshore natural gas import pipeline (PL852) will be re-purposed to become a CO_2 export pipeline and will transport the CO_2 to the existing Point of Ayr gas terminal. From the Point of Ayr gas terminal, the existing offshore natural gas import pipeline (PL1030 / P908) will be re-purposed to become a CO_2 export pipeline and will transport the CO_2 to the Douglas complex. From Douglas complex, CO_2 will be transported along re-purposed natural gas pipelines initially to the Hamilton platform (PL1039) for injection into the Hamilton reservoir, to the Hamilton North Platform for injection to the Hamilton North reservoir, and subsequently to the Lennox platform (PL1035) for injection into the Lennox reservoir. Compression facilities may be required along the pipeline route. The baseline configuration includes compression plants adjacent to, or co-located at Stanlow and at Point of Ayr. Figure E-3 below shows the map of the HyNet Project Phase 1.

Figure E-3: HyNet Phase 1 Map