7 DEVELOPMENT DRILLING AND COMPLETIONS

The White Rose oilfield was discovered in 1988 with the drilling of the E-09 well. Since that time, four additional delineation wells were drilled into the White Rose structure. They are L-08, A-17, N-30, and H-20. The first three of these wells were suspended. H-20 was abandoned. However, since they did not include options for iceberg protection, at present there are no plans for them to be used in the development of the White Rose oilfield.

7.1 Development Drilling

The project base case currently identifies the need for 15 wells, however, there is potential for up to 25 wells required to develop the South Avalon reservoir, of which 10 to 14 will be producing wells, six to eight will be water injection wells, and two to three will be gas injection wells.

Initially, up to 10 wells will be drilled before field production will commence. Plans call for the wells to be drilled in clusters or through templates located in glory holes. Semi-submersible MODUs will be used to drill and complete these wells before the arrival of the FPSO. The remainder will be drilled in parallel with production operations to meet the depletion plan objectives.

7.1.1 Tentative Drilling Schedule

The current plan is to start drilling 24 months prior to First Oil. Subject to ongoing petroleum engineering studies, it is anticipated that up to 10 producing and injection wells will have been drilled and completed before the arrival of the FPSO. Details on the drilling sequence are provided in Table 7.1-1.

Water injection wells, which are the deepest, are drilled first to capture as much information about the block as possible before the producers are drilled. Their trajectory/location is not as critical as would be the case for production wells.

7.1.2 Drilling Hazards

There were no significant operational problems encountered during the drilling of the White Rose delineation wells. However, typical potential problems that may be encountered during development drilling, and which will be addressed within the well design and contingency planning, are discussed below.
Table 7.1-1  Drilling Sequence Details

<table>
<thead>
<tr>
<th>No.</th>
<th>Well Name</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>B14W1</td>
<td>Information to locate Block 14 producer (w/pilot)</td>
</tr>
<tr>
<td>2</td>
<td>B7W1</td>
<td>Information to locate Block 7 producer</td>
</tr>
<tr>
<td>3</td>
<td>Gas #1</td>
<td>Time used to locate Block 7 and 14 producers</td>
</tr>
<tr>
<td>4</td>
<td>B7P1</td>
<td>No. 1 producer</td>
</tr>
<tr>
<td>5</td>
<td>B3W1</td>
<td>Information to locate Block 3 producer</td>
</tr>
<tr>
<td>6</td>
<td>B14P1</td>
<td>No. 2 producer</td>
</tr>
<tr>
<td>7</td>
<td>B7P2</td>
<td>No. 3 producer</td>
</tr>
<tr>
<td>8</td>
<td>B3P2</td>
<td>No. 4 producer</td>
</tr>
<tr>
<td>9</td>
<td>B3P1</td>
<td>No. 5 producer – “First Oil”</td>
</tr>
<tr>
<td>10</td>
<td>B1W1</td>
<td>Information to locate Block 1 producers (w/pilot)</td>
</tr>
<tr>
<td>11</td>
<td>Gas #2</td>
<td>Second gas injector</td>
</tr>
<tr>
<td>12</td>
<td>B1P2</td>
<td>No. 6 producer</td>
</tr>
<tr>
<td>13</td>
<td>B6W1</td>
<td>Information to locate Block 6 producer</td>
</tr>
<tr>
<td>14</td>
<td>B1P1</td>
<td>No. 7 producer</td>
</tr>
<tr>
<td>15</td>
<td>B6P1</td>
<td>No. 8 producer</td>
</tr>
</tbody>
</table>

7.1.2.1  Shallow Gas

Although there has been no occurrence of shallow gas in any of the wells drilled so far in the White Rose field, indications of gas chimneys and seismic anomalies have been identified on some site surveys in the field. A shallow gas accumulation could cause uncontrolled well flow if encountered prior to setting the surface casing and installing the blow out preventer (BOP) stack. The only concern raised by the 1997 shallow 3-D reprocessed data is the presence of a gas chimney centred on the crest of the White Rose Diapir that extends in a small area toward southwest. No delineation or development drilling is planned at this time on or near this area affected by gas contamination of low porosity sediments.

Husky Oil has shallow gas preparedness and drilling procedures in its East Coast drilling policy document. The policy includes drilling riserless prior to running the stack and conducting winch-off drills prior to spudding. This policy will be reviewed for development drilling, addressing issues such as the cuttings conveyance system.

7.1.2.2  Hole Instability

Borehole shear failures occur in planes that contain the minimum and maximum principal stresses (that is, perpendicular to the intermediate stress). The different types of borehole failures that occur in isotropic and anisotropic rock can manifest as a result of mud weight and insitu stresses. The failure mode shifts as the intermediate stress shifts between the axial, tangential, and radial directions.
On high angle development wells, the shales will be exposed to drilling for longer periods of time and hole instability could be accentuated. Hole cleaning issues could become significant if hole instability increases.

Hole instability on White Rose is currently not considered a high drilling risk. To date, the only indications of potential stability problems occurred in the 311-mm hole section, with hole fill seen towards the total depth (TD) of the section. This phenomenon could be an indicator of a stressed formation and could have a more pronounced impact if the section was inclined.

The mud type and properties, the casing seat selection and any pilot hole design would all be impacted by the presence and mitigation of hole instability problems.

Proposals have been requested for a study into well bore stability at White Rose. The initial part of the study was to determine, using data obtained to date, the potential for instability in the White Rose formations and, if required, to provide recommendations on any additional data that could be collected in the 2000 Delineation Drilling Program.

### 7.1.2.3 Formation Pressure

Neither abnormal pressure nor lost circulation have been apparent in the White Rose wells. Pore pressures in the Avalon sands are between 29 and 30 MPa, depending on depth. The sands have a normal pressure gradient of 10.1 kPa/m.

### 7.1.2.4 Well Control

Industry-accepted drilling practices will be followed in order to minimize the risk of well control incidents or kicks. This includes such activities as continuous monitoring of drilling mud weight while drilling, hole monitoring, carefully designed casing programs and frequent BOP tests.

### 7.1.2.5 Differential Sticking

Differential sticking across any permeable zones may occur in high-angle wells. Tight control of drilling fluid properties, the use of synthetic-based fluid, and good tripping practices will be applied so as to minimize this problem.
7.1.3  Basis of Well Design

This section presents the basis of well design for the White Rose development wells. The basis of design takes into account experience from previous wells and the functional requirements for the development wells. Well design will evolve over the pre-production project phases, and subsequently over the life of the field, in order to take advantage of equipment development, new techniques and drilling experience.

7.1.3.1  Casing and Hole Sizes

The casing geometry will dictate the conduit size and setting depths. Once the casing has been set the flexibility of the operations are limited. The areas considered in developing the basis of casing design were:

- Completion Design: The tubing size, completion components, metallurgical requirements, and the tree configuration all impact on the casing design.

- Well Trajectory: The shape of the well bore will influence casing wear and connection types.

- Casing Seat: The two main critical casing seats are the surface casing and production casing points. The surface casing seat determines the available kick tolerance for the remainder of the well. Under the current design case, the 900-m TVD BRT depth provides enough kick tolerance to reach the well TD. The production casing seat selection could be critical for gas shut-off if the casing point is within the reservoir section. This will be further influenced by the vertical depth control and any pilot hole requirements.

- Contingency: The requirement to carry a casing string contingency will impact the casing design. Issues which influence this design feature are the minimum acceptable hole size through the reservoir, areas of identified drilling risks, pilot hole requirements, batch drilling and the need to have flexibility in the directional profile, formation evaluation, drilling performance, long lead times, and material stocks.

Wells will have an average horizontal departure of 4,000 m and a horizontal section through the reservoir of between 2,000 to 2,500 m. Well profiles have a preliminary maximum design build rate of 3°/30 m.
A 914-mm conductor hole will be drilled to approximately 250 m below the rotary table on the drilling rig and a 762-mm conductor casing will be run and cemented to seafloor. A 406-mm hole is then planned to approximately 800 to 900-m below rotary table. The 340-mm surface casing will be cemented to the sea floor.

The 311-mm main hole will then be drilled to either the top of the Avalon Formation or possibly to some deeper depth in high-angle or horizontal wells. The production casing will be set at this point. The depth in high-angle wells will depend upon sealing off the gas cap in the reservoir.

The upper section of the 244-mm production casing may have to be increased in diameter to accommodate the surface controlled subsurface safety valve (SCSSV).

A 216-mm hole will be drilled to TD and either a 178 or 140 mm liner will be run (cemented or uncemented). The well may also be completed open hole. Additional well completion details are discussed in Section 7.2, including an illustration of the well casing profiles for a 140 mm tubing string.

**Drilling Fluid Program**

The mechanism of formation damage in the reservoir will be one of the main drivers of the drilling and completion fluid design.

The drilling fluids used will be optimized to reduce fluid loss, to control rheology, and maintain hole stability. The drilling fluid program will be similar to that used on the past delineation wells. Seawater with prehydrated gel muds or polymer muds are planned for the top intervals of the well to the surface casing setting depth.

A water or synthetic-based system will be used for the intermediate hole, depending on the well profile. The intention would be to use water-based mud (WBM) systems in this hole section as long as the well bore stability and drag are acceptable. Synthetic-based muds (SBMs) are the most reliable method of managing hole stability and they also provide lubricity to lower drilling string torque and drag.

One of the objectives of the ongoing core and fluids studies is to identify the most likely damage mechanism(s) for the Avalon Formation. Once the mechanism(s) has been isolated, mud formulations will be tested to ensure that the fluid selected has minimal damaging characteristics or that any damage can be easily cleaned up and treated.
The mud system will also have to be tested and evaluated on the other design aspects. There will be a need to balance the fluid design against all the well design requirements.

**Cementing Program**

The cementing program will be similar to that used on past delineation wells. Conductor and surface casings will be cemented to the seafloor. The production casing will be cemented high enough to prevent future casing instability and to isolate permeable zones. To ensure a leak-off path for trapped fluid expansion during production, production casing will not be cemented into the previous shoe.

**Well Control System**

The selection of the BOP equipment will be part of the MODU bid evaluation. Typically, a 476-mm, 69 to 103 MPa BOP equipped with four rams (including shear rams) and an annular preventer will be installed on a 476-mm wellhead run with the surface casing, and used for the remainder of the well. The BOP system typically has capacity to exceed the known pressure in the White Rose field by a factor of two. This approach is taken to be able to address any unexpected pressure which could occur.

**7.1.3.2 Wellhead Design**

The selection of a subsea wellhead system is still ongoing. The choice of either template or clustered wells is not finalized. Subsea well protection for template and cluster wells will be by dredged glory holes. On satellite wells, drilled glory holes and caisson systems are being considered.

**Directional Drilling**

Plans call for drilling in clusters of approximately six wells. Wells will have an average horizontal departure of 4,000 m and a horizontal section through the reservoir of between 2,000 to 2,500 m. Well profiles have a preliminary maximum design build rate of 3°/30 m. Horizontal wells are being considered in the pay zone to provide increased productivity. Kick-off elevation and well profiles will be customized for each well.

On the main hole of the directional wells, mud pulse telemetry directional tools will be used. The survey intervals and the type of surveying system used will be sufficient to assure accurate entry into the target and avoid collision with adjacent wells, and will provide adequate wellbore positioning information to reliably target a relief well, if required.
7.2 Well Completions

The White Rose development well completions will be designed to maximize well productivity while maintaining necessary standards of risk and well integrity.

7.2.1 Production Wells

Current reservoir depletion studies indicate that horizontal wells will provide the best exploitation alternative for White Rose. It is anticipated that up to 15 to 25 new drill production and injection wells, located in up to four drill centres, will be required for the White Rose oilfield development. The suspended discovery well E-09 and 1999 delineation wells A-17, L-08, N-30 and H-20 are not being considered for completion as production or injection wells at this time.

7.2.1.1 Completion Configuration and Tubing Size

Tubing size requirements are a function of a well’s production or injection capacity. Considerations of the well requirements over the life of the field can determine whether monobore or conventional completions are best used. Conventional completions have production casing (liner) across the zone of interest with a production packer and smaller internal diameter (ID) tubing to surface. A conventional completion which may be applied in oil wells that require only 140 mm tubing with a 178 mm liner is illustrated in Figure 7.2-1.

Monobore completions have tubulars, downhole equipment and tree components with a similar ID to allow full wellbore access to larger diameter wellbore equipment. The production casing is landed above the formation of interest with a tie back liner over the completed zone as shown in Figure 7.2-2. This type of completion may be employed where a 178-mm flow path is required to facilitate higher production or injection rates where friction pressure loss from high velocity fluids is a concern.

7.2.1.2 Wellbore Isolation Measures

SCSSVs will be used to prevent flow of formation fluids to surface in the event of a wellhead failure. The White Rose development wells will have tubing-retrievable SCSSVs, which are an integral part of the completion tubing string and allow for larger diameter tool access into the bottom of the wellbore. The tubing-retrievable SCSSVs will also be designed to permit the insertion of wireline-retrievable insert SCSSVs to provide a means of maintaining isolation barriers without pulling the tubing string.
Figure 7.2–1  140 mm Conventional Production Well Completion

- 762mm Casing
- 340mm Casing
- 140mm Tubing
- 244mm Casing
- 178mm Liner
- Subsurface Safety Valve
- Chemical Injection Mandrel
- Pressure & Temp Gauge
- Gas Lift Mandrel
- PBR
- Packer
- Tie Back Seal
- Liner Hanger Packer
- Liner Hanger
Figure 7.2–2 178 mm Monobore Production Well Completion

762mm Casing

340mm Casing

178mm Tubing

244mm Casing

178mm Liner

Subsurface Safety Valve

Chemical Injection Mandrel

Pressure & Temp Gauge

Gas Lift Mandrel

PBR

Packer

Tie Back Seal

Liner Hanger Packer

Liner Hanger
Completions will be designed to have two independent annular barriers between the formation and the seafloor. The well tubulars, SCSSVs and production packer located just above the completed zone is the primary annular barrier system separating the formation from the annulus. The hydraulically operated annular master valve on the subsea tree functions as the second annular barrier by automatically closing if there is a loss of control line hydraulic pressure to the valve.

7.2.1.3 Well Production Performance

Well performance modelling based on the reservoir properties of the discovery and delineation wells has been conducted for both flowing and artificial lift (gas lift) scenarios. The flowing well model suggests that initial oil rates of between 2,800 and 4,200 m³/d are possible from horizontal production development wells completed with 140-mm tubing. A well with average reservoir properties should flow at 3,600 m³/d oil prior to water or gas breakthrough. The flowing well performance at various water cuts with the two inflow performance lines illustrating the range of productivity expected is shown in Figure 7.2-3 for a 2,000 m horizontal production well.

7.2.1.4 Artificial Lift

Water associated with White Rose oil production is expected to increase over the project life of the development. The flow modelling referred to above indicates that oil wells will require artificial lift when water cut exceeds 40 percent. Gas lift will be a readily available means of artificial lift, with gas compression facilities required for the reinjection of produced gas. Gas lift also has the advantage over other means of artificial lift due to its high reliability and efficiency. This is critical for subsea wells where reliability and efficiency are important for effective operation. To avoid the high cost of working over wells later in their producing life, gas lift side pocket mandrels will be included in the initial completion design for oil wells. This ability to control flow from the initial completion will enable greater flexibility in reservoir depletion management. The effect of gas lift on a well producing at 80 percent water cut is illustrated in Figure 7.2-4. As shown in Figure 7.2-4, high water cut wells with superior reservoir properties are still capable of up to 2,500 m³/d liquid (500 m³/d oil) at an injection gas rate of 400 10³m³/day.
Figure 7.2–3  Flowing Well Performance Curve – 2,000 m Horizontal Well, 140 mm Tubing
Figure 7.2–4 Gas Lift Well Performance 140 mm, 80% Water Cut, 2,000 m Horizontal Well

- Gas Lift Rate = 0 m³/day
- GLR = 400 x 10³ m³/day
- GLR = 200 x 10³ m³/day
- GLR = 600 x 10³ m³/day
- Hz Well IPR: Perm = 90, Skin = 0
- Hz Well IPR: Perm = 60, Skin = 10
7.2.1.5 Completion Program

Prior to the start of production, all wells in a given glory hole will likely be batch completed after being drilled and temporarily suspended. White Rose development wells prior to First Oil will be batch completed to take advantage of operational efficiencies. A simplified summary of the operations involved in a typical completion is outlined below for a 140-mm monobore completion. At the end of batch drilling operations, the wells will be left with appropriate barriers in place.

1. Inspect wellhead and retrieve external debris cover.
2. Run in drilling BOP and riser. Connect to subsea tree.
3. Pressure test BOP and subsea tree.
4. Pull wellhead plug and bridge plug.
5. Clean out to liner top. Clean out to bottom of liner.
6. Run casing scrapers over 244-mm casing and 140-mm liner.
7. Circulate well to clear brine to remove drilling fluid and cement cuttings.
8. Run permanent production packer on work string.
9. Circulate annulus to packer fluid prior to setting packer hydraulically.
10. Run in 140-mm tubing, complete with packer seal assembly, expansion assembly, gas lift side-pocket mandrels, permanent downhole gauges, tubing-retrievable SCSSVs and control line.
11. Stab into polish bore receptacle and land tubing hanger.
12. Pressure test packer and SCSSV.
14. Flow well for a short clean up and snub out guns.
15. Clean up and test well.
16. Displace drilling riser to water.
17. Remove drilling BOP and riser.
18. Install debris cover.

7.2.1.6 Tubing Materials and Accessories

White Rose reservoir fluids sampled to date have indicated CO₂ levels of between 1 and 2 mole percent and H₂S levels of up to 12 ppm. National Association of Corrosion Engineers (NACE) requirements for using materials that are resistant to erosion and corrosion will form the basis for production equipment specifications. Tubulars will be designed with consideration of life of field conditions.
7.2.1.7 Production Trees

Production trees will be located in open glory holes for iceberg scour protection. Installation will be through the moonpool of the drilling and completion MODU. As with all subsea facilities, production trees will be selected to provide diverless installation, operation, inspection and maintenance. The trees will be either vertical or horizontal types capable of installation on the 476 mm wellheads. The subsea tree schematics in Figures 7.2-5 and 7.2-6 illustrate the tree valve and equipment components for a typical production well. Vertical subsea trees have valves located in line vertically over the production or injection bores (Figure 7.2-5). Horizontal trees have tubing hanger plugs as vertical barriers and the master valves are located on the side outlets (Figure 7.2-6).

Provisions for gas lift and chemical injection complete with remotely operated barrier valves will be incorporated into the tree design. The production trees will also have a data cable path for the permanent downhole gauges. Subsea tree controls will also enable lock out from the FPSO during workover operations to prevent accidental operation of equipment when the workover vessel is connected to the wellhead.

The production subsea tree equipment will be rated to at least 34.5 MPa based on a maximum expected pressure at surface of 23.1 MPa. The maximum surface pressure was calculated from the original reservoir pressure with gas filled tubing.

7.2.1.8 Perforating

Alternatives of open hole, slotted liner or cemented liner completions are being studied to determine the method most suitable for the White Rose development. Where a cemented production liner is used the selection of a perforating system will be based on criteria that will deliver the optimal productivity within acceptable risk levels.

The most likely perforating system will be tubing conveyed perforating (TCP) type, deployed on either coiled tubing or a work string. The coiled tubing system enables perforating underbalanced and snubbing the guns without killing the well. The work string system allows longer intervals to be perforated in one operation but may require killing the well prior to removal of the guns. Perforating interval selection will be designed to minimize the potential for water and gas coning.
Figure 7.2–5  Vertical Subsea Tree

- **Primary Valve**
- **Secondary Valve**
- **Check Valve**
- **Lockdown**
- **Seal**
- **Gauge**
- **Injection Mandrel**
- **Hydraulic Line**
- **Electrical Line**
- **Chemical Injection Upper (production wells only)**
- **Surface Controlled Subsurface Safety Valve**
- **Chemical Injection Lower (production wells only)**
- **Down Hole Pressure**
- **Gas Lift Mandrel (gas lift wells only)**
- **Packer/Liner Top PBR**
Figure 7.2–6 Horizontal Subsea Tree

- Chemical Injection Upper (production wells only)
- Surface Controlled Subsea
  - Chemical Injection Upper (production well only)
  - Down Hole Pressure Temperature Gauge
- Gas Lift Mandrel (gas lift wells only)
- Down Hole Pressure Temperature Gauge
- Gas Lift Mandrel (gas lift wells only)
7.2.1.9 Packers and Accessories

To ensure the completions can adequately accommodate all thermal and load forces, permanent hydraulically set production packers will be run. The production packers use polished bore receptacles and seal assemblies to control pipe stress and facilitate workovers. Any monobore completions can also have hydraulically set liner top packers.

7.2.1.10 Completion Fluids

Separate completion fluids will be used for cleaning out the well after drilling, providing a benign environment in the packer annulus and for perforation operations. The well is cleaned out at the start of completion operations to ensure clean casing surfaces for packer seals and to remove any debris which could impair production equipment operations. This fluid will be seawater-based and facilitates circulating up cement cuttings and contamination remaining after the liner cement job. Viscous polymer gelled fluid pills may be required to sweep the hole clean to total depth, especially over the horizontal sections.

Corrosion-inhibited and oxygen-scavenged fluid is circulated into the annulus between the completion tubing and production casing above the production packer to prevent corrosion of the completion equipment.

The perforating fluid provides a predetermined measure of hydrostatic head which controls the initial direction of flow after perforating. Work is ongoing to determine whether an overbalanced or underbalanced perforating system will be used for White Rose development wells. If an underbalanced system is used where flow is into the wellbore, then either a nitrogen cushion or an oil-based fluid will be used. An overbalance system will likely employ a clean brine fluid. The perforating fluid will also be designed to prevent any adverse fluid interaction with the formation.

7.2.1.11 Sand Control

Current reservoir rock material strengths data indicate that sand production should not be a problem. However, any well completion programs will be designed to mitigate sand production.
7.2.2 Injection Wells

7.2.2.1 Well Designs

Current water injection well design is for continuous injection of 2,000 to 6,000 m³/day of seawater per well, with a maximum of up to 9,000 m³/day. To ensure adequate capacity, it is likely the water injection wells will be horizontal, with 178-mm monobore completion or 140-mm conventional completion. As mentioned previously, gas injection wells are required to facilitate conservation and possibly aid reservoir pressure maintenance. The gas injection wells will be designed for continuous injection of 1,000 to 3,000 10³m³/d gas per well, with a maximum of up to 4,000 10³m³/day gas.

Water injection and gas injection well performance plots for typical development conditions are illustrated in Figures 7.2-7 and 7.2-8.

7.2.2.2 Injection Christmas Trees

For project equipment synergy and to simplify completions and workovers, injection trees will likely be similar in specifications and design to the production trees. Gas injection trees may be required to be rated to 69 MPa.

7.2.2.3 Tubing and Connections

Studies are ongoing to determine appropriate materials and connection type for injection well tubing. Efforts will be made to design injection fluid processing such that downhole equipment can be as standard as possible. The tubulars will be designed with consideration of life of field conditions.

7.2.2.4 Wellbore Isolation Measures

SCSSVs on injection wells will be similar in design and specification as production wells SCSSVs.

7.2.2.5 Liners and Packers

Injection packers serve to isolate the annulus from injection fluids and pressures. White Rose injection packers will be permanent design with polished bore receptacles to provide for thermal movement of the tubing. As an added precaution, corrosion resistant material will be used on exposed surfaces of the injection packers.
Figure 7.2–7  Inflow vs Outflow for 2,000 m Horizontal Gas Injection Well
Figure 7.2–8  Inflow vs Outflow for 500 m Horizontal Gas Injection Well
7.2.2.6 Completion Fluids

Unless perforating design differs from the producing wells, the completion fluids will be the same for the injection wells.

7.3 Well Interventions

7.3.1 Major Workovers

Operations that involve replacing or removing items such as subsea trees, control lines, tubing, SCSSVs, and packers are considered major workovers. These types of workovers require mobilization of a semi-submersible drilling rig with a riser and BOP system for removal of the completion equipment. It is an objective of the completion design to reduce the number of major workovers during life of field conditions for the well.

7.2.2 Minor Workovers

Wireline and coiled tubing operations are considered to be minor workovers. However, because the wells are subsea, operations require mobilizing either a workover vessel or a semi-submersible drilling unit.

Statistics on subsea developments suggest that approximately one minor workover per well will be required every four to seven years. Operations such as installing or removing plugs, gas lift valves, chemical injection valves and downhole gauges are considered to be minor workovers, as are other interventions that do not require removal of the completion string.