4.1.1 SELECTION BASIS

Vertical steam drive (VSD), complemented by cyclic steam stimulation (CSS), is the proposed recovery process for the Carmon Creek Project. VSD with CSS is technically, economically and environmentally feasible for bitumen recovery in the resource development area. A number of alternative recovery processes were also reviewed for bitumen recovery in the resource development area (see Section 4.2), but were ultimately rejected as inappropriate or infeasible for the Carmon Creek Project, for economic or technical reasons.

Shell has sought recovery methods that maximize the resource recovery factor and the oil steam ratio, while reducing environmental impact. The average recovery factor within the resource development area, using VSD and CSS, is expected to be over 50%.

VSD is a commercially proven technology for bitumen recovery that is used worldwide and in Western Canada by other operators.

4.1.2 RESOURCE RECOVERY PROCESS

Shell’s planned subsurface development pattern consists of six vertical production wells in a hexagonal pattern. Each pattern will cover 3.4 ha within the Bluesky Formation. One dedicated vertical steam injector well will be added in the centre of the hexagon to create an inverted seven-spot well pattern. The goal of this recovery method is to drive fluid horizontally from the steam injector well to the producer wells, without relying on gravity or vertical flow, and to operate at low pressures.

The recovery process will begin by conditioning the reservoir. This will be done by injecting steam into the reservoir, through the six producer wells, for one CSS cycle. The steam from the CSS cycle will heat the bitumen to lower its viscosity, thereby allowing the bitumen to flow. When the CSS cycle is complete and the production wells have all been steam soaked once, the central steam injection well will begin to inject steam continuously. This steam injection process will push steam horizontally toward the producing wells, reducing the viscosity of the bitumen throughout the reservoir. Artificial lift will be used at the producing wells to:
4.1.2 RESOURCE RECOVERY PROCESS (cont’d)

- maintain them in a constant pumped-off condition
- act as the drive mechanism that moves the heated bitumen from the steam injection well to the producer wells

A single CSS cycle, combined with continuous steam injection at the central injection well, is expected to sustain production from a pattern for about one to two years. Then, as the produced fluids gradually cool down and production rates drop, the producing wells within the pattern will undergo further CSS cycles. The exact number of CSS cycles required to maximize recovery will vary between patterns and will be optimized to reflect each individual pattern’s steam flood performance. For the last CSS cycle on the producers, solvent might be added to the steam to enhance production rates. Once a threshold instantaneous oil steam ratio is reached, steam injection will end and production will continue until flow rates become uneconomic. A typical pattern is expected to remain in operation for about 10 years.

4.1.3 STEAM INJECTION

Steam is available at the wellhead at an average 70% quality and a maximum pressure of 14.3 MPa.

Steam injection rates vary between 50 and 250 t/d, depending on injectivity and maturity of the well.

Recent experience with vertical steam injectors confirms that there is sufficient injectivity below the formation fracture pressure, despite the high initial bitumen viscosity and relatively short open-hole exposure of vertical wells in the reservoir. Injectivity in the cold bitumen column can be established because of the presence of initial mobile water along the complete vertical interval in the Bluesky, resulting from bitumen shrinkage after biodegradation.

Vertical wells have the advantage of allowing a high degree of reservoir management to optimize operations and performance.

4.1.4 SURFACE HEAVE

VSD is a low-pressure process, and should result in minimal or no surface heave over the lifetime of a production pad.
4.2.1 RESOURCE RECOVERY CONSTRAINTS

High bitumen viscosity in the resource development area prevents the use of primary production as a viable means of resource recovery. Viscosity can be reduced significantly by heating the bitumen.

Overburden thickness within the resource development area is over 500 m. Therefore, surface mining is also not a viable recovery technique.

Since 1965, Shell has tested several potential thermal recovery methods at its Peace River leases. Two key findings led to the decision to proceed to recover bitumen in the resource development area using VSD, complemented by CSS:

- vertical permeability in the Bluesky is much lower than expected based on results from core analyses and logs. This low permeability is created by small-scale shale barriers that prevent vertical gravitational flow (rising steam, sinking bitumen), and eliminate any recovery technique that relies on gravity drainage

- steam injectivity with vertical wells is high enough to allow bitumen recovery within the Bluesky because of initial water mobility in the formation, even above the bottom water zone

4.2.2 SCOPE OF ALTERNATIVES

Shell began exploration of the bitumen resource in the Peace River area in the early 1950s, and initiated tests to extract bitumen in the 1960s. Between 1962 and 2008, Shell developed and tested a number of schemes to produce bitumen from its Peace River reservoir efficiently and cost effectively. The following methods were not selected for the project, based on technical, environmental or economic considerations.

To assess the methods and technologies considered for the project, data from the following recovery processes were considered:

- in situ combustion
- steam-assisted gravity drainage (SAGD)
- pressure cycle steam drive
- CSS with horizontal wells
- in situ upgrading
4.2.2.1 In Situ Combustion (1965)

In situ combustion was tested by Shell in 1965. Preheating by steam injection was required for self-ignition of the bitumen in place. A combustion front was apparently established, and bitumen was produced. This technology has not been proven to be economically feasible.

4.2.2.2 Steam-Assisted Gravity Drainage (1992 to 1997)

Shell implemented SAGD wells in the Peace River leases from 1992 to 1997. All pairs of SAGD wells under-performed economically and most of the wells were converted to CSS wells in 2004. The SAGD steam chambers would not rise, because of lower than expected vertical reservoir connectivity.

4.2.2.3 Pressure-Cycle Steam Drive (1979 to 2001)

The pressure-cycle steam drive concept was developed following extensive laboratory experiments between 1972 and 1974. The vertical well configuration used is the inverted seven-spot. In this recovery process, steam is injected into the bottom water zone (the lowest 4 m to 6 m of the 25 m-thick reservoir) at high injection rates and pressures.

Production rates at producers would vary between periods of low and high rates. This caused cycles of:

- high reservoir pressure during low production rates
- low reservoir pressure during high production rates

Expectations were that steam would be forced into the upper parts of the reservoir, and bitumen would be produced by gravity drainage. These expectations were not met during the large-scale development stage, and recovery was found to be uneconomic.

The Peace River in-situ pilot (PRISP, 1979 to 1992) consisted of 11 inverted seven-spots, and performed close to expectations. A large-scale expansion of the pilot (the Peace River Expansion Project, PREP, 1982 to 2001) included four clusters with 13 inverted seven-spots each (more than 200 wells). Because of interference between the clusters, project surveillance showed that it was not possible to operate one cluster at high pressure while depleting a neighbouring cluster. As a result, the performance of pressure-cycle steam drive was not economic.

4.2.2.4 Cyclic Steam Stimulation With Horizontal Wells (1996 to 2009)

Since 1996, Shell has drilled numerous horizontal wells with varying geometries for CSS applications. All wells were completed at the bottom of the reservoir (above the bottom water zone). Shell found that steam does not rise to higher parts of the reservoir, despite injection above fracture pressure, because of the presence of shale barriers. Therefore, bitumen recovery using this technology was not optimal for large-scale commercial development.
4.2.5 In Situ Upgrading (2004 to 2009)

The concept of in situ upgrading is to upgrade the bitumen in the reservoir and produce the light hydrocarbon ends to surface, while leaving coke and heavy-end bitumen in the subsurface. The required reservoir temperatures for upgrading are achieved by conductive heaters. A pilot with 18 heaters, eight observation wells, and three producers provided medium- to light-end oil products, confirmed the concept technically, but the economics were not favourable enough to choose this technology for the Carmon Creek Project.
5.1.1 SCOPE

The field facilities provided for the project include:

- vertical (deviated) steam injection wells
- vertical (deviated) production wells
- other well types
- well pads and associated facilities

All wells will be drilled from their surface well pad locations to respective subsurface targets.

5.1.2 VERTICAL STEAM INJECTION WELLS

With a large-scale development of inverted seven spot patterns, about one-third of the wells will be steam injection wells (see Section 4.1, Selected Recovery Process). These wells will be designed for steam injection only.

For further information on steam injection wells, see Section 5.3, Steam Injection Wells.

5.1.3 VERTICAL PRODUCTION WELLS

Although vertical production wells will primarily be used to produce bitumen, they will also have multiple steaming cycles to initiate bitumen production. The dedicated steam injection wells will begin steaming after all surrounding production wells have received at least one steam production cycle. Production wells that are not communicating with steam from the injection wells might require some additional steaming.

An electrically-driven conventional pump jack and reciprocating pump will be used to produce the reservoir fluids.

For further information on production wells, see Section 5.4, Production Wells.

5.1.4 OTHER WELLS

Other wells include:
### 5.1.4 OTHER WELLS (cont’d)

- produced water disposal wells
- regeneration wastewater disposal wells
- acid gas disposal wells
- observation wells
- saline groundwater source wells

For information on these wells, see Section 5.5, Other Wells.

### 5.1.5 WELL PADS AND ASSOCIATED FACILITIES

Wells will be drilled from well pads. The pad footprint will vary, depending on the number of wells per pad and on other environmental factors, such as:

- waterbody setback restrictions
- soil salvage requirements
- surface water control system designs

Pad facilities will be designed to accommodate a maximum of 52 development wells (36 production wells and 16 steam injection wells). Each well pad will contain an average of 45 wells.

Production from all producing wells will be collected and routed to the production manifolds on the pad, then routed through the production gathering system to one of the CPFs (see Section 5.6, Well Pads and Facilities).

Steam to the wells will be controlled and directed from the well pad’s steam metering manifold to the desired wells, using the pad flow lines.
5.2.1 DRILLING PROGRAM

5.2.1.1 Program Description

The drilling program for typical steam injection and production wells will be as follows:

1. Preset the conductor pipe 20 m measured depth (MD) below the surface.
2. Pressure-cement the conductor pipe in place.
3. Drill the wellbore to the target location in the Bluesky Formation with sufficient depth to allow complete access to the entire formation.
4. Run sour-service Grade L80 productive intermediate casing with metal-to-metal sealing connections to the total depth of the well.
5. Cement the casing to the surface using a thermal-grade cement.

The wellbore will be directionally drilled with a planned dogleg severity ranging from 2° to 12° per 30 m. The wellbore will be drilled with water-based drilling fluid. Fluid losses will be corrected using standard lost circulation materials.

Shell has plans in place to manage any well control problems that might arise during drilling operations. These plans cover:

- wellbore instability
- losses during cementing
- problems encountered when drilling through a gravel zone
- any losses or inflows when drilling into or near production-affected areas

5.2.1.2 Open-Hole Logging Waiver

Based on expected well density, not all wells will need a full suite of open hole logs. A separate waiver of the requirement to run a full suite of logs on all wells will be requested from the ERCB.
5.2.2 WELL CASING

5.2.2.1 Casing Grade and Cementation

The productive intermediate casing run from the surface into the Bluesky Formation will be a sour-service Grade L80 with metal-to-metal sealing connections. The casing string will be cemented to the surface with a thermal-grade cement.

5.2.2.2 Surface Casing Waiver

In subsurface areas where safety and environmental risks can be managed with drilling and operations practices, Shell will request the ERCB to waive the requirement for surface casing. The waiver request will follow the ERCB guidelines and will be the subject of a separate submission.

5.2.3 CASING INTEGRITY ASSURANCE

5.2.3.1 Integrity Assurance and Casing Monitoring Program

The sour-service Grade L80 productive intermediate casing will be fully cemented to the surface with a thermal-grade cement. During steam injection operations, the casing will be monitored for annular pressure changes that would indicate a loss of casing integrity.

When the production wells are not being injected with steam, they will be operated with a low bottomhole pressure to reduce or eliminate hydrocarbon losses from the wellbore. With a low bottomhole pressure, a casing failure in a water zone would result in an influx of groundwater into the wellbore, which would cause an anomalous production profile, (increased water-cut and lower wellhead temperatures). If this type of well profile occurred, a field response would be initiated to formally assess the integrity of the well.

Response plans will be consistent with existing operating practices to quickly address and resolve any up-hole loss in wellbore integrity.

Observation wells using passive seismic monitoring might be incorporated into well integrity assurance plans.

5.2.3.2 Reduced Cement-Bond Logging Waiver

Shell is confident that the combination of a thick caprock (60 m to 70 m of Wilrich Shale), a deeper reservoir and sound cementing practices will provide hydraulic containment of the Bluesky Formation for the wells being drilled for the project.

Shell intends to run cement bond logs on at least two wells on each pad and in all situations where cementing operations indicate that further validation is needed.

A waiver for a reduced number of wells with cement-bond logs, will be separately requested from the ERCB.
FIELD FACILITIES

APPLICATION FOR APPROVAL OF THE
CARMON CREEK PROJECT
VOLUME 1: PROJECT DESCRIPTION

STEAM INJECTION WELLS

5.3.1 COMPLETION METHOD

During completion, the productive intermediate casing will be perforated in the Bluesky Formation (see Figure 5-1). Selective limited entry perforating is proposed as a means to achieve uniform steaming across the Bluesky Formation.

Figure 5-1: Proposed Steam Injection Wellbore

The production tubing will be run inside the productive intermediate casing to a depth near the top of the Bluesky Formation. Having the tubing landed will allow for steam injection profile monitoring. No downhole packers will be included with the tubing string.

The tubing will be landed in the casing bowl and the final wellhead will be installed.
5.3.2 WELLHEAD DESIGN

The installed wellheads (see Figure 5-2) will be designed and pressure-rated to meet field production and steaming requirements.

Figure 5-2: Proposed Steam Injection Wellhead
5.4.1 COMPLETION METHOD

During completion, the productive intermediate casing will be perforated over the Bluesky Formation (see Figure 5-3). Production tubing will be run inside the casing and a pump seating nipple will be installed and landed at, or below, the base of the Bluesky Formation.

![Diagram of proposed vertical production wellbore]

**Figure 5-3: Proposed Vertical Production Wellbore**

Having the tubing and pump set below the perforations enhances gas separation during pumping, thereby improving production performance. No downhole packers or anchors will be included with the tubing string.

The tubing will be landed in the casing bowl and the final wellhead will be installed.
5.4.2 ARTIFICIAL LIFT

A conventional reciprocating rod pumping system will be used to pump fluids to the surface. During steaming operations, this pump will be unseated, the tubing will be flushed with clean water, and steam will be injected down the tubing casing annulus.

The pump system will typically be equipped with a pump-off controller, which will provide real-time data to the field and office network computers. The pump performance can then be assessed and optimized for each well.

5.4.3 WELLHEAD DESIGN

The installed wellheads will be designed and pressure-rated to meet field production and steaming requirements. Figure 5-4 shows a typical production wellhead. Although not shown, a master valve will be included on the wellhead for the first several years of cyclic steaming operation.

![Typical Production Wellhead](Figure 5-4: Typical Production Wellhead)
5.5.1 WATER DISPOSAL WELLS

5.5.1.1 Produced Water Disposal

Produced water from existing operations is currently disposed of into the Leduc Formation, using two disposal wells located in the project area. For the project, produced water will be reused for steam generation. However, the existing Leduc Formation disposal wells will be maintained for disposing of produced water during start-up, early operations, process upsets, and when produced water quantities exceed boiler feedwater requirements.

5.5.1.2 Regeneration Wastewater Disposal

One or two regeneration wastewater disposal wells will be drilled to dispose of wastewater from the water softening system. Because of water compatibility, separate wells are required to dispose of regeneration wastewater and produced water.

The new disposal wells will be drilled, completed and tested following all applicable requirements outlined in ERCB Directive 051, Injection and Disposal Wells – Well Classifications, Completions, Logging and Testing Requirements. Surface casing will be used, which will provide additional protection for the shallow groundwater intervals. The wastewater will be pumped using electric-driven water pumps. The wellhead injection pressure and the injection rate for each well will be monitored. The wellhead will be rated to design injection or bottomhole pressure, whichever is greater.

5.5.2 ACID GAS DISPOSAL WELLS

To manage SO2 emissions, Shell is including an amine unit to strip H2S from the produced gas. The resultant acid gas will be disposed of through deep well injection into the Leduc Formation.

One or two disposal wells will be drilled, completed and tested following all applicable requirements outlined in ERCB Directive 051, Injection and Disposal Wells – Well Classifications, Completions, Logging and Testing Requirements. Specific well design details will be provided in separate submissions to the ERCB. The acid gas will be compressed and dehydrated for transportation and injection into the disposal wells. The wellhead injection pressure and injection rate for each well will be monitored.
5.5.3 OBSERVATION WELLS

In addition to using the production and steam injection wells to monitor steam flood performance, a number of dedicated observation wells will also be drilled. Production wells can be logged with neutron logs by pulling the pump and rods. Fibre optics or thermocouples might be used in select production wells. By using the appropriate production wells for observation, data can be gathered in areas where questions about the drive performance arise. The injection wells might also be logged to track where the injected steam exits the well.

5.5.4 SALINE GROUNDWATER SOURCE WELLS

Saline groundwater will be supplied through dedicated saline groundwater source wells drilled into the Paddy–Cadotte interval. Having water available from these saline groundwater source wells will reduce dependency on river water for steam production.
5.6.1 WELL PADS

5.6.1.1 Number of Surface Well Pads

Within the initial development area, 18 well pads will be built. Within the resource development area, about 77 additional well pads will be required to maintain production to the end of the project’s 35-year operation. Each well pad will contain an average of 45 wells and will have a life cycle of about 10 years.

5.6.1.2 Well Pad Design

Each well pad will be about 160 m by 325 m. The final constructed well pad layout will be optimized to ensure that pads are the minimum size required to meet the drilling, well spacing and facilities piping requirements. Wells and associated facilities will be housed on each well pad (see Figure 5-5).

The well pads will be designed to contain modules capable of connecting with up to:

- 36 production wells
- 16 injection wells

This will ensure that a standard well pad design can be used for all the expected variations in the number of steam injection and production wells. Any unused well pad facilities will be isolated. Additional monitoring wells might also be located on the well pads.

Each well pad will have two rows of wells. Each row will be about 40 m apart. Adequate space will be provided around the perimeter of the well pads to store topsoil and conduct future workover operations. Shell plans to contain surface runoff on the well pads by constructing a combination of berms and ditches to ensure that surface water runoff is appropriately controlled during drilling and operations. For further information on the proposed industrial runoff control systems, see:

- Section 13, Water Management Plan
- the conceptual Conservation and Reclamation Plan in EIA Volume IIC
5.6.2 WELL PAD FACILITIES

The well pads will include production and steam injection wellheads. Other well-pad facilities will include:

- two production manifolds and one steam metering manifold
- steam distribution flow lines
- pump jacks on production wells
- a test separator
- an electrical power supply, including a motor control centre
- well pad control instrumentation
- a diluent injection system
- an inlet valve to the production gathering system and casing vent gas gathering system

Figure 5-6 shows a typical facility layout for a well pad.

Each well pad will be connected to the CPF by an above-ground:

- steam distribution pipeline
- production gathering system to collect produced fluids
- casing vent gas gathering system
- diluent supply pipeline

5.6.2.1 Piping Manifolds

Each well pad will include:

- two production manifold modules, which will enable some wells on the pad to be steamed while others are producing
- one steam metering module, which will allow the steam flow to each injection well to be measured

5.6.2.2 Steam Distribution Flow Lines

Steam supply to the wells will be controlled and directed from the well pad’s steam metering manifold using the well pad flow lines.

5.6.2.3 Pump Jacks

An electrically-driven conventional pump jack and reciprocating pump will be used to produce the reservoir fluids. The number of pump jacks installed will be equal to the number of production wells that have been drilled for a given pad, up to a maximum of 36.

5.6.2.4 Test Separator

Produced fluids (gas, bitumen and produced water) will be routed to a test separator on an individual well basis. Each pad will have a test separator package. Production from each well will be measured at the test separator according to ERCB accounting requirements.
Figure 5-5: Conceptual Production Well Pad Layout
5.6.2.5 Electrical Power Supply

Well pads will receive electrical power from the cogeneration facilities at each CPF. Electrical power will be provided to the well pads through an electrical distribution system.

Electrical transformers will step down the distribution line voltage of 25 kV, as required. Each pad will be equipped with a motor control centre to provide electrical switching and control at the pads.

5.6.2.6 Control Instrumentation

Well pads will be equipped with instrumentation to control and monitor well pad equipment and material flows. Each well pad will have an air compressor to supply the necessary instrument air.

A fibre-optic cable will be run on the above-ground pipe rack to connect the control systems at the well pads with the control systems at the CPF.

5.6.2.7 Diluent Injection

If required, diluent will be mixed with steam and injected into the wells at certain production cycles to facilitate fluid production.

5.6.2.8 Inlet Valve

Each well pad will have an inlet valve as the connection point to the production gathering system and casing vent gas gathering system.

5.6.2.9 Above-Ground Pipelines and Gathering Systems

Each well pad will be supplied with steam and diluent by above-ground pipelines.

Produced fluids from each well pad will be transported via the production gathering system to the CPF inlet.

Low-pressure casing vent gas will also be gathered in a dedicated, low-pressure, casing vent gas gathering system.

The above-ground pipelines and gathering systems will be insulated and mounted on a pipe rack that will generally follow the topography about 1 m to 1.5 m above the ground. Stand-alone above-ground pipeline corridors will be about 20 m wide.

Wildlife and heavy equipment crossings, such as those needed for fire-fighting equipment, will be installed, as needed.
CENTRAL PROCESSING FACILITIES

6.1.1 PURPOSE

Two central processing facilities (CPF 1 and CPF 2) will be constructed for the proposed development. They will be similar in size and will process produced bitumen, water and gas, and produce the steam needed for injecting into the bitumen reservoir. The two CPFs will be built within the initial development area, about three years apart, with processing from CPF 2 beginning about three years after the start of processing from CPF 1. Each facility will be capable of processing 6,300 m³/d (40,000 bbl/d) of bitumen.

6.1.2 MAJOR PROCESSES

Each CPF will process production from the field by:

- separating bitumen and water emulsion to meet the current sales oil pipeline specification
- treating produced water to enable it to be reused for steam generation
- treating saline groundwater and limited quantities of river water
- disposing of excess produced water
- treating produced gas to be used for fuel
- generating steam, using cogeneration and boilers, for injection into the reservoir

The cogeneration plants will supply electrical power for the facilities and for sale to the provincial power grid.

6.1.3 FACILITIES

Each CPF will include:

- cogeneration units and supporting boilers
- plant inlet separation facilities
- a bitumen emulsion treatment system
- a produced water treatment system
6.1.3 FACILITIES (cont'd)

- a river water softening system
- a regeneration wastewater disposal system
- a produced solids handling system
- a produced gas treatment (amine unit) and acid gas compression system
- storage tanks
- utilities

Steel-framed buildings will include:

- an oil treating building
- a warm lime softener building
- a river water softening building
- an evaporator and crystallizer building
- cogeneration buildings
- gas treating and compression buildings
- utilities buildings, including motor control centres
- control, warehouse and maintenance buildings

Other plant facilities not housed in buildings will include:

- tankage
- heat exchangers
- emergency flare systems
- pipe racks
- aerial coolers
- landfills for evaporator and warm lime softener waste streams
- sewage lagoons
- runoff and boiler blowdown ponds
- an electrical substation and switchyard

6.1.4 INTEGRATION WITH EXISTING PLANT

The existing Peace River Complex will continue to operate while CPF 1 is being constructed. Portions of the existing Peace River Complex will be used to support the start-up of CPF 1 to the extent practicable and according to the final design and operational requirements. The Peace River Complex processing facilities are expected to be decommissioned after CPF 1 has been started up.

6.1.5 CPF SITE SELECTION

The CPFs will be located about 3 km southeast of the existing Peace River Complex.

6.1.5.1 Site Selection Criteria

The selected site for the CPFs was chosen based on the following criteria:
• reducing the overall environmental impact, including selecting a site with:
  • sufficient area to avoid facilities encroaching on sensitive muskeg areas
  • suitable soil conditions, to reduce the required site preparation activities

• safety considerations, including ensuring that the selected site:
  • has sufficient area to allow for a plant layout that can be constructed and operated efficiently, which contributes to improved safety
  • would enable the construction camp to be located immediately adjacent to the site, thereby reducing travel exposure for the site
  • is remote from existing operations, reducing the degree of interference between the ongoing operations at Peace River and the construction of the new CPF

• proximity to the resource development area

6.1.5.2 Advantages of Selected Site

The site selected is adjacent to the initial development area and central to the overall future development areas. The CPFs will be located on thinner pay zone, which will reduce the impact if recovery efficiency is reduced as a result of production or drilling constraints under the CPF facilities.

The site is a large contiguous area, which:

• provides enough space to co-locate CPF 1 and CPF 2
• offers the potential for future expansion
• satisfies the selection criteria described previously

Figure 6-1 shows the plot plan for CPF 1 and CPF 2.
Figure 6-1: Central Processing Facility Plot Plan