CANADA-NEWFOUNDLAND and LABRADOR OFFSHORE PETROLEUM BOARD

STAFF ANALYSIS OF THE WHITE ROSE DEVELOPMENT PLAN AMENDMENT APPLICATION

SOUTH WHITE ROSE EXTENSION TIE-BACK

APRIL 26, 2013

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1.0 PURPOSE

The purpose of this staff analysis is to provide the Board with an assessment of Husky Oil Operations Limited (Proponent) proposed White Rose Development Plan Amendment (DPA) for the South White Rose Extension Tie-back project. This analysis considered safety, operations, environment, resource management and industrial benefits aspects of the DPA.

It should be noted that although no benefits plan amendment was required for this project the Board did ask the Proponent to provide a supplement to their approved White Rose benefits plan (Decision 2001.01). The analysis of this supplement is provided in this document.

2.0 EXECUTIVE SUMMARY

On October 2, 2012, the Proponent submitted to the Canada-Newfoundland and Labrador Offshore Petroleum Board (Board) on behalf of its co-venturers Suncor Energy and Nalcor Energy - Oil and Gas the following documents:

- White Rose Development Plan Amendment – South White Rose Extension Tie-back (September 2012)
- Concept Safety Assessment of South White Rose Extension Project

The documents describe the Proponent's plan to develop oil reserves from the South Avalon and South White Rose Extension (SWRX) pools via a subsea tie-back to the SeaRose FPSO. The total predicted recoverable oil from the SWRX tie-back project is estimated to be approximately 33 million barrels. The depletion strategy consists of a total of six development wells: two producers, one gas injector and one water injector into the SWRX Pool, as well as one producer and one gas injector into the South Avalon Pool. Secondary recovery of oil is planned through both gas and water injection.

The Proponent plans to tie the SWRX Drill Centre back to the existing production, water injection and gas lift flowlines from the North Amethyst Drill Centre and the Southern Drill Centre. Furthermore, a gas injection flowline from the North Drill Centre will tie-in directly to the SWRX Drill Centre. The Proponent is planning to start gas injection (in 2014) and oil production (in 2015) from SWRX and South Avalon pools.

The total estimated cost of this development is $1.2 billion and an estimated 877,500 person hours of employment will be generated in the Province as a result of the proposed project.

Staff reviewed the above documents for completeness and, in a letter dated November 15, 2012, requested additional information. In response to this letter, the Proponent submitted an updated Development Plan on January 15, 2013. Staff reviewed the updated document, and in a letter dated February 4, 2013, informed the Proponent that the document was complete. The updated Development Plan amendment (January 15, 2013) along with the Concept Safety Assessment constitute the "Application" and are the focus of this assessment.

The Application was posted on the C-NLOPB's website on February 5, 2013 for a 30 day comment period – no comments were received.

It should be noted that in September 2006, the Proponent submitted an amendment to the White Rose Development Plan for the tie-back of SWRX. The amendment was approved by the Board and both governments as per Decision 2007.02. In this Application the Proponent has decided to change the depletion strategy with respect to the development of SWRX and South Avalon pools. That is, the depletion plan for both pools is now expected to include gas injection in addition to oil production and water injection. The injection of gas represents a new depletion strategy; therefore the Board requested that another amendment be submitted for consideration.

Staff reviewed the Application to determine whether the proposed development would affect the benefits, resource management, safety, operations or environmental obligations and undertakings of the White Rose Development Plan (Decision 2001.01).

Benefits

The industrial benefits associated with the proposed changes to the depletion schemes for the South Avalon Pool and the South White Rose Pool (and gas storage in these pools) did not materially affect the basis of the Board's approval of the White Rose Benefits Plan (Decision 2001.01) or the subsequent approval of the SWRX (Decision 2007.02). As a result, the Proponent was not required to file a benefits plan amendment. Instead it was determined that a supplement to the benefits plan was appropriate.

The Proponent has committed to requiring the project management and engineering work to take place in the Province and re-affirmed its commitment to improving the participation of the local supply community by communicating contracting and procurement opportunities, requirements and specifications in a detailed and timely manner. As a means of following-up on the Proponent's commitment, staff have monitored, and will continue to monitor, the contracting activity associated with the engineering, procurement, construction and installation (EPCI) contract for the flow lines, risers, umbilicals, manifolds and ancillary subsea infrastructure.

With respect to employment, the Proponent is expected to abide by the first consideration principles in its approved White Rose benefits plan and staff will continue to monitor compliance in this matter.

In conclusion, staff determined that the information provided in the benefits supplement demonstrates the Proponent's ongoing commitment to its White Rose benefits plan and the conditions of its approval and that there are no further benefits matters that would adversely impact the Board's consideration of the Application.

Resource Management

Staff reviewed the resource management aspects of the Application and had the following conclusions:

- The geological understanding of the Northern Drill Centre (NDC) region has changed from the original White Rose development plan (Decision 2001.01) resulting in significantly less gas storage capacity. The remaining storage capacity is predicted to be filled as early as December 2013.

- The proposal to commence gas flooding in the SWRX and South Avalon Terrace is reasonable, as it will alleviate gas storage capacity concerns without negatively impacting oil production from these pools.

- There is good agreement between the Proponent and staff's volumetric assessment. The Proponent's estimate of OOIP in the SWRX Pool has increased from 14.5 MMm3 (91 MMbbls) to 15.4 MMm3 (97 MMbbls) since the original SWRX DPA submission (Decision 2007.02). The Board's estimate of OOIP has also increased from 13 MMm3 (83 MMbbls) to 14.6 MMm3 (91.8 MMbbls). These increases can be attributed to differences in the geological and reservoir modeling methodologies, the petrophysical analyses, and the parameters varied in the uncertainty analysis.

- The Proponent used the available geological and reservoir engineering information to develop reasonable reservoir simulation models for both the South Avalon and SWRX regions. Staff's analysis indicates that the current South Avalon and SWRX reservoir simulation models are sufficient in the context of this Application.

- Under the proposed depletion scheme, the Proponent's P50 recoverable oil estimate for SWRX has increased slightly from 4 MMm^3 (24 MMbbls) to 4.1 MMm^3 (25.8 MMbbls) since the original SWRX DPA approval (Decision 2007.02). Staff's assessment has shown a slight increase in recoverable oil estimate from 3.4 MMm^3 (21.6 MMbbls) to 3.5MMm^3 (22 MMbbls). Overall, there is good agreement between staff's and the Proponent's recoverable reserves.

- In the White Rose Decision Report (Decision 2001.01), the Proponent's P50 recoverable reserves for the South Avalon Pool were estimated at 37.1 MMm^3 (233.4 MMbbls) while staff's estimate was 32.9 MMm^3 (207 MMbbls). While no P50 recoverable reserve estimate was provided in the Application, a most likely deterministic recoverable estimate of 38.68 MMm^3 (243.28 MMbbls) was provided from reservoir simulation. This is an increase of an estimated 1.51 MMm^3 (9.52 MMbbls) compared to the water flood only depletion scheme currently employed. It should be noted that the staff's analysis focused on the Terrace portion of the South Avalon Pool. Staff are currently assessing and updating the overall reserve numbers for the White Rose asset.

- The largest risk to production under the proposed exploitation scheme is early gas breakthrough in either the SWRX or the South Avalon Terrace. The Proponent plans to mitigate this risk by installing an Inflow Control Device (ICD) completion for the proposed SWRX production wells. Gas breakthrough in the southern Terrace will be mitigated by a smart completion in the gas injector, which will permit the Proponent to control gas injection in either the East or West fault blocks.The Proponent will also have the ability to inject in only one of the pools should early gas breakthrough occur in the other.

- The Proponent must submit an updated exploitation scheme for Board approval prior to the initiation of any gas flooding in areas of the South Avalon Pool outside of the southern Terrace.

- Staff considers the Proponent's reservoir management plan for the South Avalon Pool to be reasonable and acceptable. However, the Proponent will be required to submit a report acceptable to the Board assessing the sealing nature of the fault separating the East and West blocks one year after the commencement of gas injection in the southern Terrace. If injection and pressure data from the gas injector indicate that the fault is sealing, the Proponent will have to apply for a subsurface gas storage license in the East fault block.

- Staff finds that the Proponent's reservoir management plan for the SWRX Pool to be reasonable. The Proponent plans to inject gas for a tentative period of 18 months prior to commencement of oil production from the pool. This period of "pre-injection" is necessary as the production flowlines and related subsea infrastructure will not be installed and commissioned in the SWRX Drill Centre until late 2014 or early 2015. If this planned period of "pre-injection" extends beyond 18 months, the Proponent will have to update the Board on their plans.

- Staff found that the SeaRose FPSO facilities can adequately handle additional production from the proposed exploitation scheme. The Application also provides sufficient flexibility to accommodate potential future development in the SWRX area, as the proposed drill centre can accommodate six additional wells if necessary.

From a resource management perspective, staff recommends approval of the Application subject to the following conditions:

1. The Proponent must submit a report acceptable to the Board assessing the sealing nature of the fault separating the East and West Fault blocks one year after commencement of gas injection into the southern Terrace.

2. Should the period of gas injection prior to oil production in the SWRX Pool extend beyond 18 months, the Proponent must submit a report acceptable to the Board detailing the activities to date and future plans for gas injection in the SWRX Pool.

Safety

Safety risks to personnel will arise during the various phases of the development, including the drilling program, the subsea flowline installation program and the diving program to tie in the flowlines to existing subsea infrastructure. Each of these programs requires a "Work Authorization" from the C-NLOPB and oversight by the Certifying Authority. A detailed safety assessment of each of these programs will be undertaken by the Board's Safety staff in accordance with established processes which are based on experience with similar work authorizations.

In general, the activities associated with the proposed development do not raise any new safety concerns from the staff's perspective particularly in view of the fact that the Proponent has demonstrated the ability to successfully execute such subsea development programs in the past.

The Proponent conducted a study to determine the impact on risk to the safety of personnel, facilities and equipment due to the SWRX project. The results of this assessment are provided in the report *Concept Safety Assessment of South White Rose Expansion Project, Atkins Report No. 5113311/003-RP-01 Rev 1*. The quantitative risk analysis did not raise any concerns regarding the resultant impact on the target levels for safety identified for the project in the original White Rose development safety studies. The study identified a number of recommendations for consideration as the project proceeds through the detailed engineering phase and the Application outlines the manner in which the Proponent plans to address each recommendation. The Proponent will be required to update the Board's Chief Safety Officer on the progress for addressing each of the recommendations prior to equipment tie-in.

Staff concludes that all of the safety matters arising from the Application can be managed in accordance with established processes and procedures. No safety concerns were identified that would preclude staff from recommending that the Board approve the Development Plan Amendment.

Operations

From an operational perspective, staff assessed the Proponent's approach to drilling and completions, installation, commissioning and operation of subsea equipment and modifications to the FPSO and its systems.

With respect to the drilling and completions, the Proponent has established systems and procedures used in the execution of drilling and completion activities in the White Rose and North Amethyst Fields. Staff will review the Proponent's well designs, cementing programs and drilling programs in the Approval to Drill a Well (ADW) review process.

Currently, the White Rose and North Amethyst Fields are being exploited using subsea technology. The Proponent is proposing to use the same development approach for SWRX; therefore, the installation, commissioning and operation of subsea equipment will utilize well templates and wellhead systems that are similar to those in both of these fields. This approach does not raise any new operational safety concerns as the Proponent has demonstrated the ability to successfully implement such programs.

No operational concerns were identified that would preclude staff from recommending approval of the Application. Activities in connection with this Application can be managed in accordance with established safety processes and procedures already in place for the White Rose and North Amethyst Fields.

Environment

Staff reviewed the Application to determine whether it raised any environmental concerns that were not previously assessed as part of the White Rose project. The construction of a new drill centre for the SWRX, installation of subsea equipment, and tie-back to the SeaRose FPSO had been assessed in the screening level environmental assessment completed for new drill centres in

2007.That assessment concluded that, with the application of mitigation measures, the implementation of a follow-up program and adherence to relevant C-NLOPB guidance material, significant adverse environmental affects associated with the project were not likely. The project as described in the current development plan amendment is consistent with the geographic scope, and description of project activities previously assessed in 2001 and 2007 and no further assessment is required for the construction of the excavated drill centre, installation of subsea equipment and tie-backs, and drilling and completions of wells at this location.

It should be noted that the *White Rose Oilfield Comprehensive Study Report* completed in 2001, contemplates production up to 2020. The Proponent will have to address this temporal scope issue by amending their environmental assessment documents prior to C-NLOPB authorizing any activity past 2020.

Staff concluded that there were no environmental concerns that would preclude staff from recommending approval of the Application.

Accordingly, staff recommends the following:

The Board approve the Application subject to the following conditions:

1. **The Proponent must submit a report acceptable to the Board assessing the sealing nature of the fault separating the East and West Fault blocks one year after commencement of gas injection into the southern Terrace.**

2. **Should the period of gas injection prior to oil production in the SWRX Pool extend beyond 18 months, the Proponent must submit a report acceptable to the Board detailing the activities to date and future plans for gas injection in the SWRX Pool.**

3.0 BACKGROUND

3.1 The Application

On October 2, 2012, Husky Oil Operations Limited (Proponent) submitted to the Canada-Newfoundland and Labrador Offshore Petroleum Board (Board) on behalf its co-venturers Suncor Energy and Nalcor Energy - Oil and Gas the following documents:

• White Rose Development Plan Amendment – South White Rose Extension Tie-back (September 2012)

• Concept Safety Assessment of South White Rose Extension Project

Staff reviewed the above documents for completeness and found that the September 2012 Development Plan amendment document was incomplete. In a letter dated November 15, 2012 staff requested additional information. On January 15, 2013, the Proponent submitted an updated Development Plan document titled "White Rose Development Plan Amendment – South White Rose Extension Tie-Back (January 15, 2013)" which addressed the issues raised in our November 15 letter. The Proponent's response to staff comments are found in Appendix I of the updated document. Staff reviewed this document to ensure that our comments were sufficiently addressed and, in a letter dated February 4, 2013, informed the Proponent that the documents were complete.

The updated Development Plan document dated January 15, 2013, and the Concept Safety Assessment document constitute the "Application" which is the focus of this analysis.

The Board determined that once we had a complete Application, it would be posted on the C-NLOPB's website for a 30 day comment period. So, on February 5, 2013, both documents were posted on the website until March 6, 2013 for public comment. However, no comments were received.

It should be noted that in September 2006, the Proponent submitted an amendment to the White Rose Development Plan for the development of the SWRX. Staff assessed this amendment and it was approved by the Board and the federal and provincial governments in Decision 2007.02. Since approval of this amendment, the Proponent decided to change the depletion strategy with respect to the development of SWRX and South Avalon pools. That is, the current anticipated depletion plan for both pools is now expected to include gas injection in addition to oil production and water injection. The injection of gas represents a new depletion strategy; therefore, the Board requested that another amendment be submitted for consideration. Thus the need for the current Application before the Board.

3.2 History/Context

The White Rose Field was discovered in 1984 by the drilling and testing of the Husky et al. Whiterose N-22 exploratory well. The field is located approximately 350 km east of St. John's, Newfoundland and Labrador on the eastern edge of the Jeanne d'Arc Basin, in water depths ranging from 115 to 130 metres. The White Rose Significant Discovery Area encompasses the adjacent North Amethyst Field, which was discovered in 2006 by the drilling of the Husky Oil et. al. North Amethyst K-15 well (Figure 3.1).

A note of clarification is required regarding the naming convention of the main reservoir within the White Rose Significant Discovery Area. The reservoir section was termed the "Avalon Formation" in the Proponent's White Rose Development Plan Application (2001), and in the Board's Decision 2001.01. However, current understanding indicates that the reservoir section lies upon the mid-Aptian unconformity, is middle Aptian-Albian in age, is an overall fining-upward package within a transgressive systems tract, and is more likely to be the Ben Nevis Formation. The terms "Ben Nevis" (BN) and "Ben Nevis Avalon" (BNA) are used interchangeably throughout this analysis.

The recoverable oil reserves, expressed at a 50 percent probability level, within the Ben Nevis Avalon Formation at the White Rose Field are currently estimated by the Board to be 36.3 MMm^3 (229 MMbbls). Pressure measurements and fluid contacts indicate that the oil and gas accumulation in the Ben Nevis Formation is divided into four separate oil pools, each with an associated gas cap: the South Avalon Pool, the North Avalon Pool, the West Avalon Pool, and the South White Rose Extension (SWRX) Pool (Figure 3.1).

The Board currently estimates, at a 50 percent probability, that the White Rose Field contains recoverable resources of $76.7 \times 10^9 \ m^3$ (2.7 TCF) of natural gas, and 13.8 MMm^3 (86 MMbbls) of natural gas liquids within the Ben Nevis Formation. However, this Application does not propose exploitation of these resources at this time.

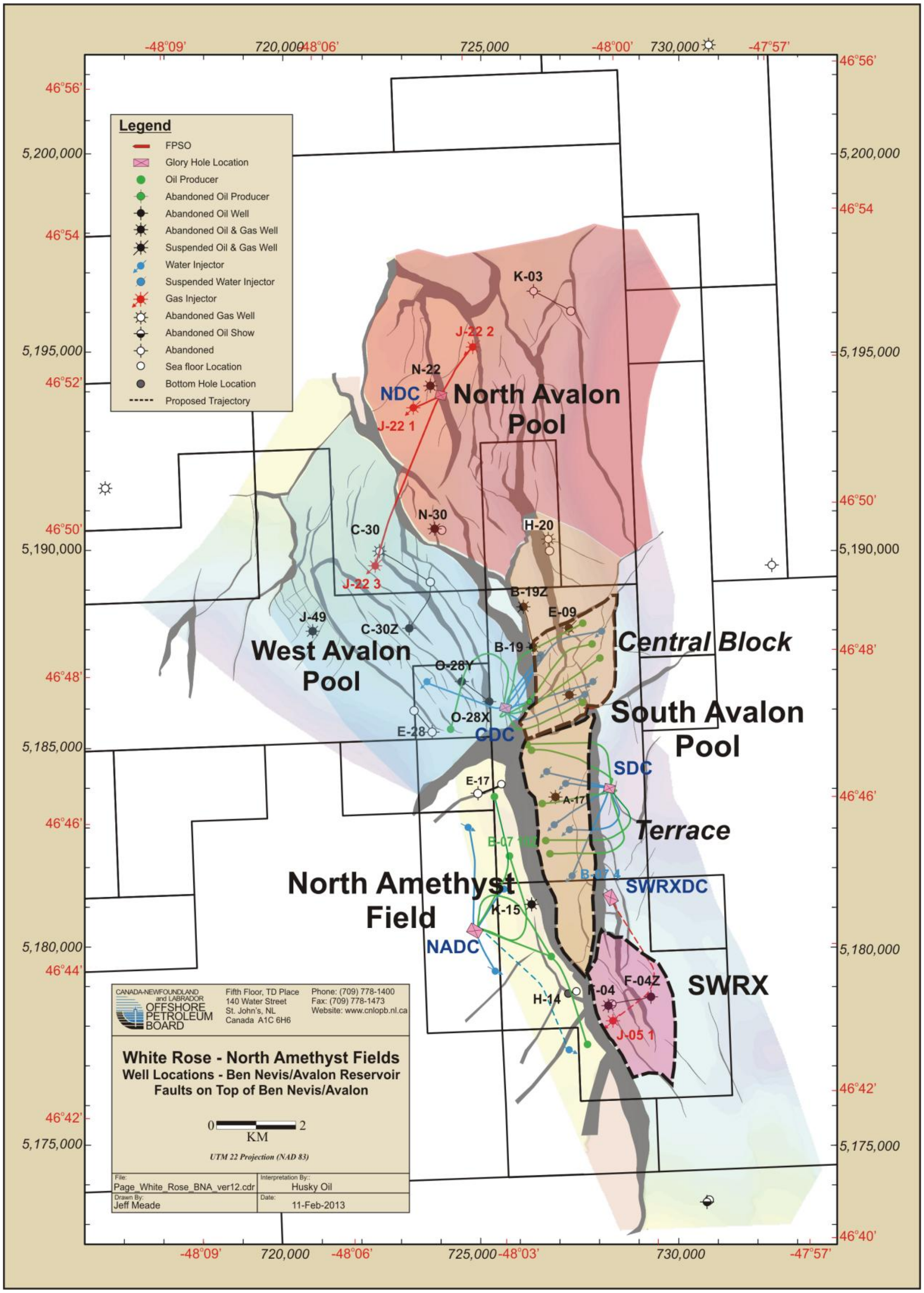

Figure 3.1: Map of the White Rose Development area, identifying well locations, drill centres, pool boundaries, North Amethyst Field and proposed SWRX Tie-back Development area.

At present, the White Rose Significant Discovery Area incorporates fourteen Significant Discovery Licences (SDLs). As well, there are five Production Licences (PLs) located in the White Rose Significant Discovery Area as indicated in Figure 3.2. PLs 1006 and 1007 are located in the White Rose Field. PLs 1009 and 1010 contain the West Avalon Pool while PL 1008 contains in the North Amethyst Field (Figure 3.2).

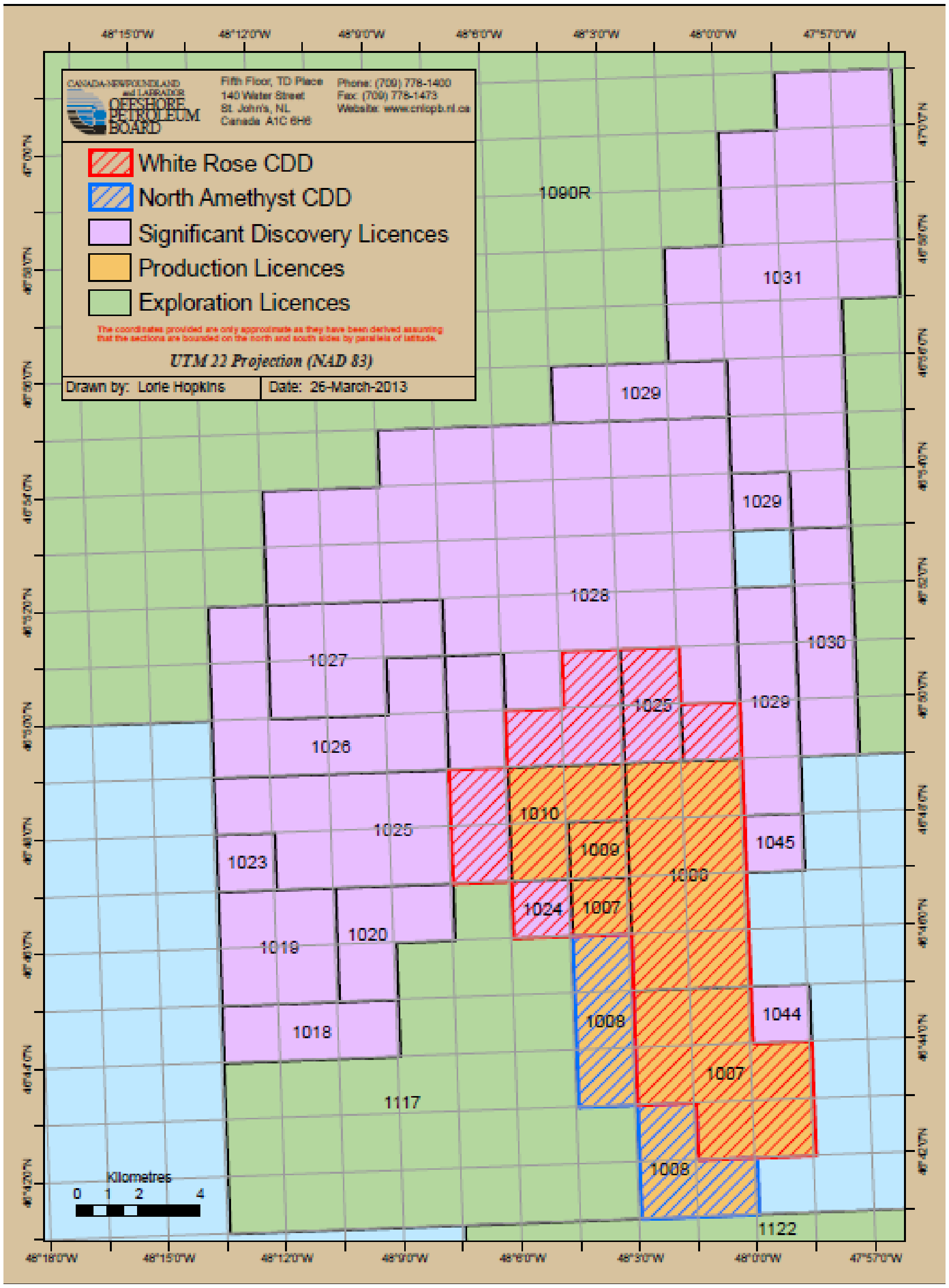

Figure 3.2: Map of the White Rose Significant Discovery Area, identifying exploration licences, significant discovery licences and production licences.

Commercial oil production from the White Rose Field began on November 12, 2005. As of February 28, 2013, 24 development wells have been drilled and 27.6 MMm^3 (173.5 MMbbls) of oil have been produced from the White Rose South Avalon Pool. Production from the North Amethyst Field (Decision 2008.03) began on May 31, 2010. Eight development wells have been drilled in the North Amethyst Field and 3.9 MMm^3 (24.7 MMbbls) of oil have been produced to date. Two development wells were drilled for the West White Rose Pilot Scheme (Decision 2010.01) with production commencing on September 5, 2011 and 0.48 MMm^3 (3.05 MMbbls) of oil produced to date. Twenty-three exploration or delineation wells have been drilled in the region to date, including two within the SWRX region. This drilling and production activity has provided a substantial quantity of information to assess reservoir and facility performance and to construct geological and reservoir simulation models.

Development of the SWRX Pool was approved by the Board in Decision 2007.02 and by the federal and provincial governments on September 7, 2007. The DPA proposed reservoir exploitation by water injection. The C-NLOPB estimated that 3.4 MMm^3 (21.6 MMbbls) of oil were recoverable from the SWRX Pool at that time.

The Application proposes a subsea tie-back to the SeaRose FPSO from an excavated drill centre south of the Southern Drill Centre (SDC) in the SWRX area (Figure 3.1). In addition to oil production and water injection capabilities, the SWRX Drill Centre (SWRXDC) will also have gas injection capability as it will be tied into a gas injection flowline from the Northern Drill Centre (NDC). The proposed SWRXDC will be tied back to the existing production, water injection and gas lift flowlines from the North Amethyst Drill Centre (NADC) and the SDC. The SWRXDC will produce oil from both the SWRX and South Avalon pools.

The development proposed in the Application requires an amendment of the approved White Rose Development Plan (Decision 2001.01) as the Proponent would like to incorporate gas flooding into the exploitation plan for the South Avalon and SWRX pools. This is a change to the depletion strategy approved in Decision 2001.01 and in Decision 2007.02 (SWRX).

4.0 RESOURCE MANAGEMENT

4.1 Resource Management Review

Staff reviewed the Application, which included the Proponent's seismic interpretations, geological models and reservoir simulation models. Staff also conducted a review of reservoir, geological, and production data and constructed a geological model for the South Avalon and SWRX pools. As of February 28, 2013, 27.6 MMm^3 (173.5 MMbbls) of oil (Figure 4.1) have been produced from the South Avalon Pool.

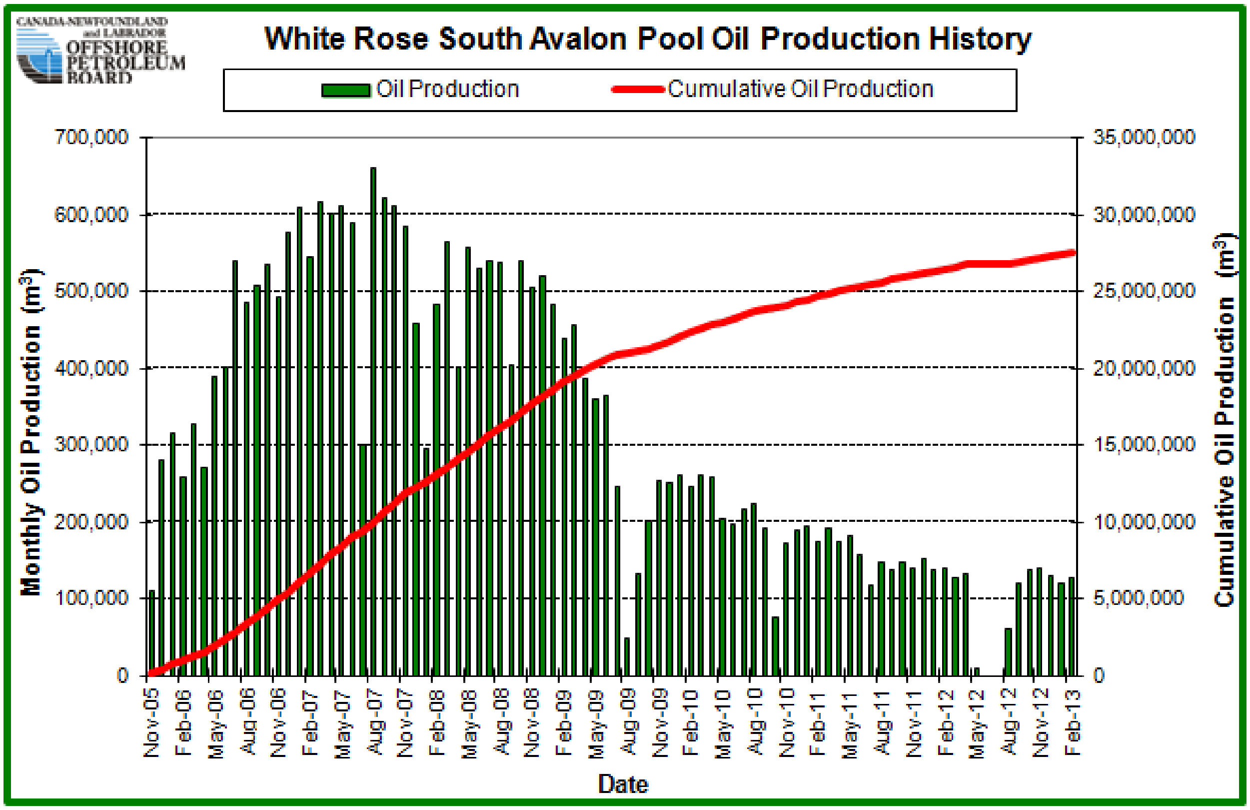

Figure 4.1: White Rose South Avalon Pool oil production history.

4.2 Gas Storage

The Northern Drill Centre (NDC) is the gas injection drill centre for the White Rose Field. To date, all White Rose gas injection wells (J-22 1, J-22 2 and J-22 3) are located in the Northern Drill Centre (NDC) as depicted in Figure 4.2. In the original Development Plan, the North Avalon Pool and area surrounding the NDC was identified as the best location to store produced gas from the White Rose Field. At that time, the Proponent's geologic modeling indicated the North Avalon Pool was capable of storing the estimated 5.5 billion m^3 of produced gas from the South Avalon Pool. However, subsequent drilling results found that the reservoir volume in the region was considerably smaller than originally anticipated.

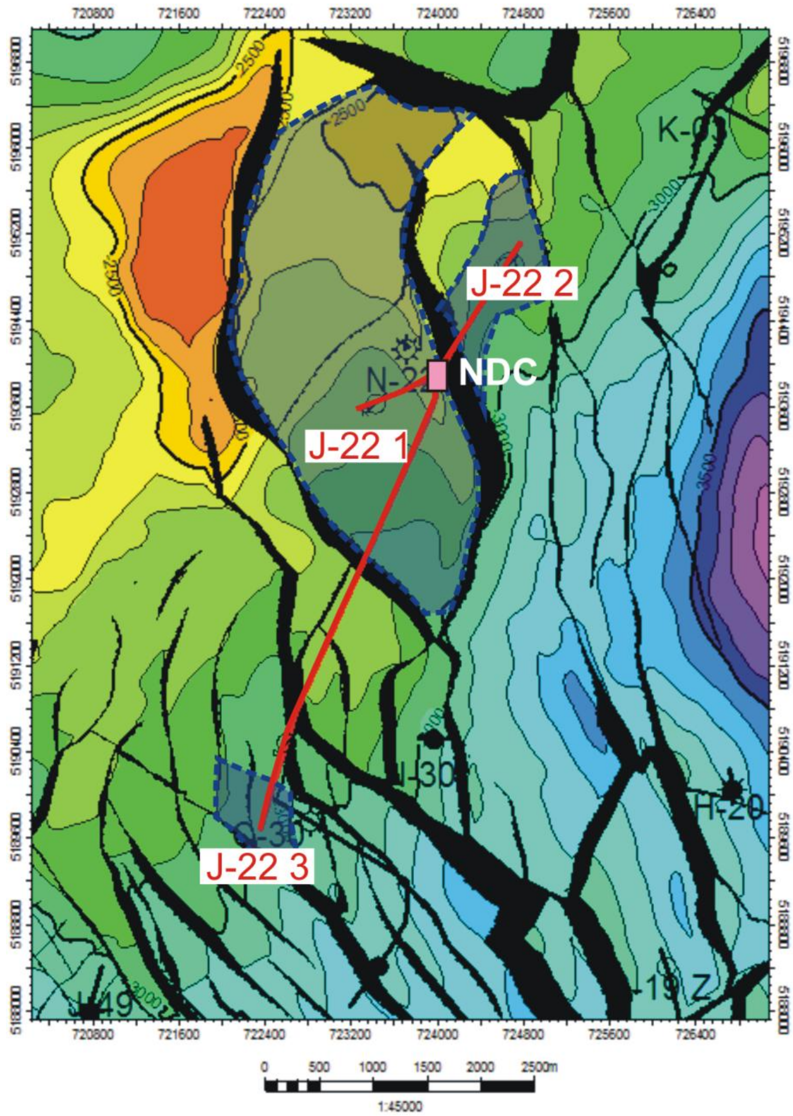

Figure 4.2: Northern Drill Centre gas injection well locations.

The majority of produced gas to date has been injected into J-22 1 (87%), which was the first gas injector drilled in the field. All subsequent wells drilled in the NDC region have encountered less reservoir quality sandstone and therefore have a reduced gas storage capacity. These wells include the J-22 2 and J-22 3 gas injectors and the K-03 delineation well. Both the J-22 2 and J-22 3 gas injectors encountered smaller then expected volume of connected reservoir and consequently, only slightly increased the gas storage capacity of the area. The K-03 delineation well found a limited amount of reservoir quality sandstone but did not encounter any hydrocarbons. The results from these wells have caused the Proponent to revise the geological interpretation of the North Avalon Pool and significantly reduce the original gas in place (OGIP) estimate for the pool. The reduction in OGIP, in addition to the isolated fault blocks in the region, has caused the Proponent to re-examine the suitability of the NDC region for gas storage.

The Application provided a table showing the expected storage capacity of the J-22 1, J-22 2 and J-22 3 gas injection wells. The table also included the volume of gas injected in each well to June 1, 2012 and the remaining gas storage capacity as a result of this injection. In order to assess the most up to date gas storage capacity, Staff has updated the volume of gas injected to February 28, 2013. The remaining storage capacity for each well and the field total are shown in Table 4.1.

Well	Current Estimated Storage Capacity (MMm^3)	Injected Gas as of February 28, 2013 (MMm^3)	Remaining Storage Capacity (MMm^3)
J-22 1	3,322	2,812	510
J-22 2	233	222	11
J-22 3	394	193	201
Total	**3,949**	**3,227**	**722**

Table 4.1: Remaining gas storage capacity (Source: modified from Husky).

As indicated in the table, approximately 3.2 billion m^3 of produced gas has been injected in the NDC to date. With the total storage capacity estimated to be 3.9 billion m^3, there is a remaining storage capacity of approximately 0.72 billion m^3 or 20% of the total expected capacity. This is a significant concern for the Proponent, as forecasts for the currently producing pools predict the remaining gas storage capacity could be full as early as December 2013.

Additional development within the White Rose asset has put further strain on the storage capacity remaining in the NDC region. The current estimated produced gas storage requirement for the White Rose asset is approximately 3 billion m^3. This estimate is based on the approved water flooding scheme for the South Avalon and SWRX pools (not the gas injection scheme proposed in the Application), plus production from the North Amethyst BNA, West White Rose pilot and proposed North Amethyst Hibernia developments. Assuming the current gas injection sites are filled to capacity, there will still be a shortage of gas storage space for the remaining 2.3 billion m^3 of gas forecasted to be produced. This shortage will also constrain any additional future development within the White Rose asset.

4.2.1 Gas Storage Strategy Base Plan

Adequate gas storage capacity has been a concern for the Proponent since the addition of the North Amethyst Field. Consequently, the Proponent has developed a Gas Storage Strategy for the White Rose asset. The objective of this strategy is to monitor and forecast gas storage capacity requirements and to investigate contingency storage options in order to ensure storage capacity is available for existing and future development of the White Rose area. The strategy will continue to evolve as the Proponent acquires new information through drilling and production activities.

As the gas storage capacity of the NDC area is insufficient for current and future development, the Proponent has identified a base case gas storage plan that can be implemented to help alleviate gas storage capacity concerns. The plan, which is the basis for this DPA submission, calls for gas injection and gas flooding of the SWRX and the South Avalon Terrace. The Proponent views the proposed SWRX tie-back as the next step in the White Rose Gas Storage Strategy and believes it has significant long-term potential for the life-of-field gas storage requirements.

Board staff considers the Proponent's plan to commence gas flooding in the SWRX and South Avalon Terrace pools to be reasonable, as it will alleviate gas storage capacity concerns without negatively impacting oil production. Further details on the Proponent's gas management plan can be found in Section 4.6.3.

4.2.2 Gas Storage Strategy Alternative Options

Should any issues arise with the proposed gas storage base plan, the Proponent has developed a contingency option which could be implemented in the short term if required. This option is to drill the J-22 4 gas injection well from the remaining drill slot in the NDC. A significant amount of work on well design for J-22 4 has been undertaken by the Proponent. The proposed well trajectory, depicted in Figure 4.3, is nearly horizontal, and connects multiple isolated fault blocks to increase the length of reservoir sand contact and maximize gas injection rates and storage capacity. However, as the reservoir in the area is thin, the well may not encounter enough reservoir sand to provide substantial gas storage capacity. The Proponent's gas storage capacity estimates of the area vary greatly, with the lower-end capacity being less than six months of gas storage. In this case, another gas injection location would be needed shortly after J-22 4 came online. In addition, drilling design work on the J-22 4 well trajectory indicates significant drilling risk due to the well complexity. As such, the Proponent believes the risks associated with drilling J-22 4 outweigh the potential increase in gas storage capacity and it is not the preferred gas storage option.

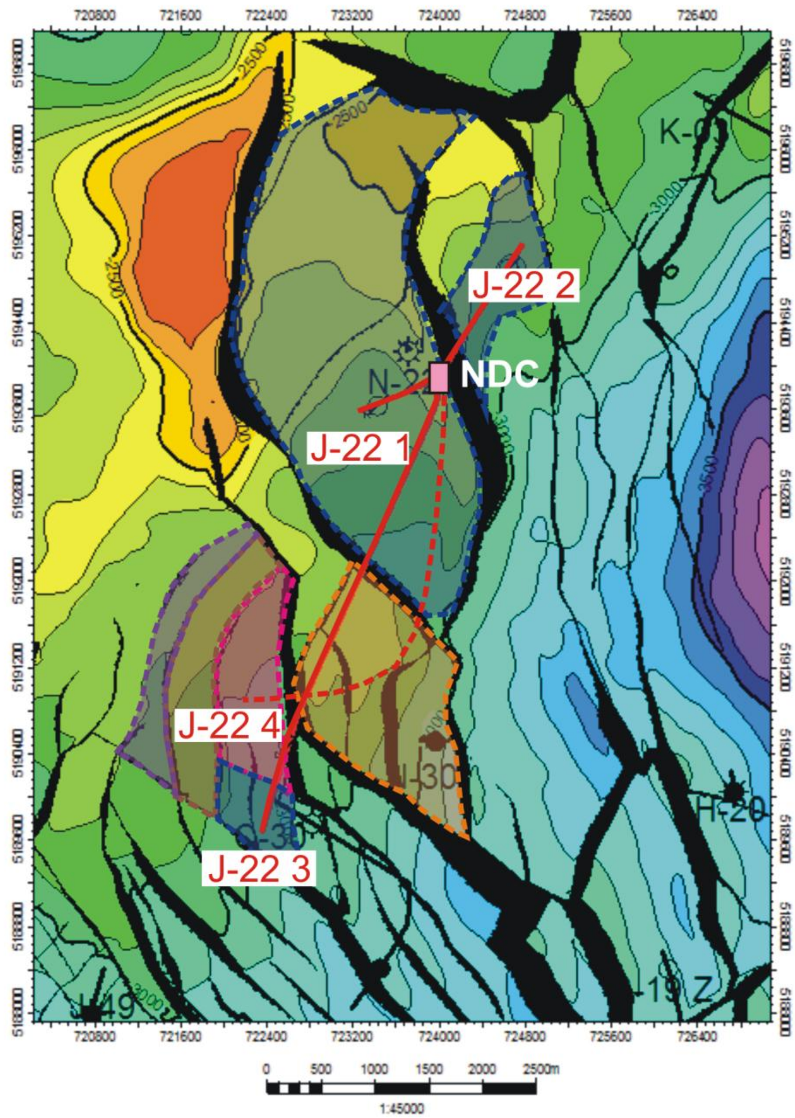

Figure 4.3: Proposed J-22 4 gas injection well trajectory.

The Proponent will continue to explore alternative plans and longer-term gas storage options for both contingency purposes and future developments. The potential alternative options include evaluation and delineation of near-field gas injection opportunities and also the evaluation of other gas enabled enhanced oil recovery schemes.

4.3 Geological/Geophysical/ Petrophysical Model Review

4.3.1 Regional Geology

In Decision 2001.01, the Proponent extensively detailed the regional geologic history of the Jeanne d'Arc Basin. As this discussion adequately describes the tectonic evolution of the White Rose region, a similar discussion is not required for this Application.

4.3.2 Geology of White Rose

The principal reservoir at White Rose Field consists of shallow marine, fine-grained, quartzose sandstones of the Ben Nevis Avalon Formation (BNA). This southwest-northeast trending sequence was likely deposited along a paleoshoreline located east of the field (Figure 4.4). The original White Rose Development Plan Application presented three main facies associations and identified diagenetic components in the formation:

1) Lower shoreface storm deposits consisting of well-sorted, very fine-grained, low angle laminated sandstones, massive sandstone, and parallel laminated sandstones. These deposits form the main reservoir rock type in the region.

2) Lower shoreface fair-weather deposits consisting of heavily bioturbated siltstone to silty sandstone, with primary structures rarely preserved.

3) Laminated and massive marine silty shale and shale deposits with minor bioturbated intervals, representing the distal component of White Rose region deposition.

4) Diagenetic components include calcite cement nodules that are round and laterally discontinuous or lenticular and associated with shell lag intervals, and locally present siderite nodules.

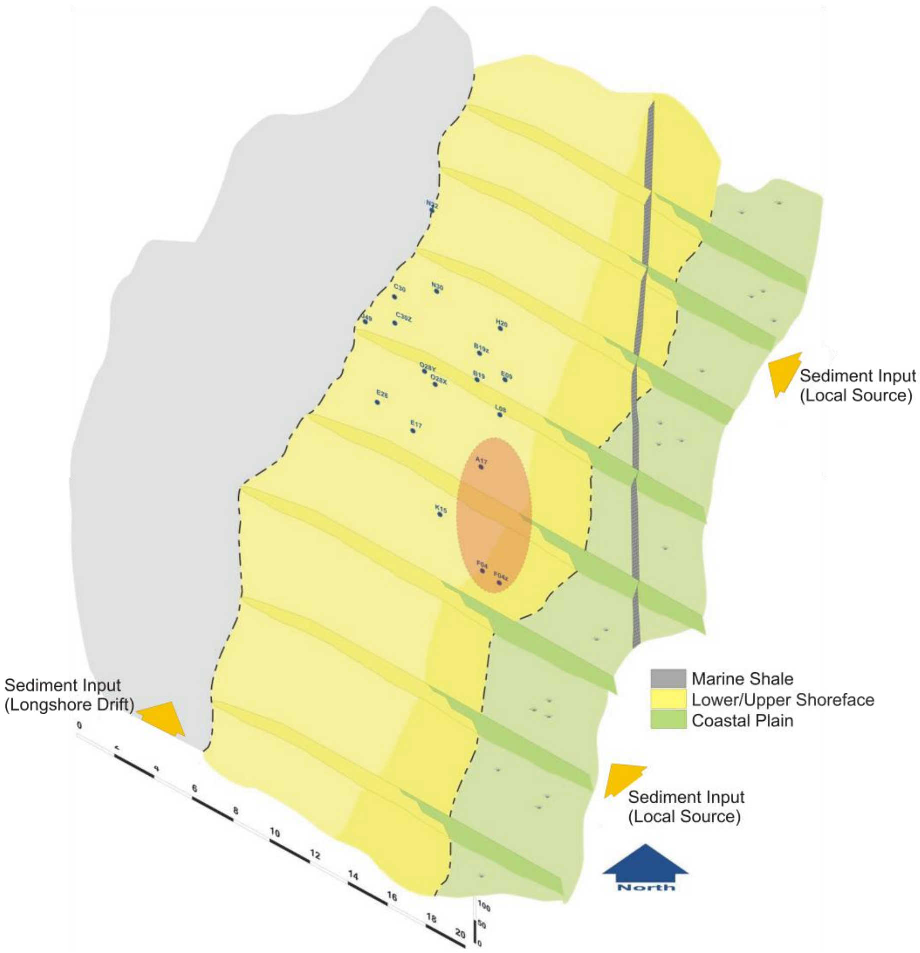

Figure 4.4: Schematic of aerial distribution of shoreface sandstones and early moving faults related to the initial phases of Ben Nevis deposition. The region of interest and the White Rose delineation wells are identified in relation to the paleogeography (Source: Husky, 2007).

The Proponent has incorporated these facies associations within the static reservoir model and reservoir simulations for the SWRX and South Avalon pools.

4.3.3 Geology of South White Rose and SWRX

Current geological understanding places the South Avalon and SWRX in a region of shallow marine lower shoreface deposition trending southwest-northeast (Figure 4.4). The Proponent has subdivided the Ben Nevis Avalon into several parasequence sets that correspond to coarsening upwards, backstepping cycles. These sequences are most evident in the moderately distal areas of the White Rose region but lose resolution in areas where the net-to-gross ratio is very high or very low. In these regions, which include the South Avalon Terrace and SWRX, the internal divisions are highly interpretational. The Proponent has incorporated the larger scale parasequence sets into their South Avalon and SWRX reservoir models.

The BNA is nearly completely offset by the fault separating the South Avalon Terrace from the SWRX, which permits different fluid contacts in the SWRX relative to those encountered in the Terrace region. The SWRX is structurally segregated into several fault blocks by post-depositional normal faults with throws ranging from <20m to 300 m.

4.3.4 Geophysics

Seismic data quality in the White Rose asset area is fair to good. While 2008 seismic data was available for both the South Avalon and the SWRX, the older vintage datasets were preferred by the Proponent, as the 2008 data contains a key-hole coverage gap in the region of the SeaRose FPSO. This data gap was problematic in the SWRX and South Avalon regions. Board staff reviewed this data and concurs with the Proponent.

The reservoir interval is imaged seismically as a low amplitude sequence indicative of a low impedance siltstone reservoir. The seismic interpretation is challenging given the low impedance contrast of the Ben Nevis Avalon reservoir and surrounding geology. Two main seismic markers define the reservoir interval in the South Avalon and SWRX pools: the top Ben Nevis Avalon (top reservoir) and the Mid-Aptian Unconformity (base reservoir). The top Ben Nevis Avalon Formation is a difficult seismic pick in the White Rose region because of the low impedance contrast. The Mid-Aptian Unconformity is a medium to high amplitude horizon mapped with a higher level of confidence. The Proponent supplied geophysically controlled horizon and fault interpretations of the South Avalon and SWRX regions. These interpretations were audited and verified by the Board's geophysical staff.

4.3.4 Petrophysics

Extensive data was acquired by the Proponent on the two delineation wells that were drilled to evaluate the SWRX of the White Rose Field. The data acquisition program included logs, cores and sidewall cores. A thorough, independent analysis has been untaken by Board staff on the data collected and these studies provide a technical basis to evaluate the validity of the Proponent's petrophysical results as submitted in the Application.

Board staff believes the petrophysical interpretation presented by the Proponent in support of this application is reasonable and is similar to staff's assessment with slight differences attributed to different methodology, assumptions and criteria used in interpreting the data. Overall, the Proponents's critical petrophysical parameters, such as porosity, water saturation and fluid contacts are aligned with those determined by Board staff.

4.3.5 Reservoir Geologic Model

Board staff constructed a detailed 3D geological model for the SWRX and South Avalon pools to estimate the in-place hydrocarbon resources. This model incorporated available geophysical, geological and reservoir engineering data.

The structural framework for the model is based on the fault and surface interpretation supplied by the Proponent. The model is limited vertically by the top Ben Nevis and the Mid-Aptian unconformity, and is subdivided by stratigraphic surfaces interpreted from well log and core data (Figure 4.5). Each stratigraphic zone was further subdivided by proportionally layering each interval. Overall, the average grid cell size is 50 x 50 x 1.4 m.

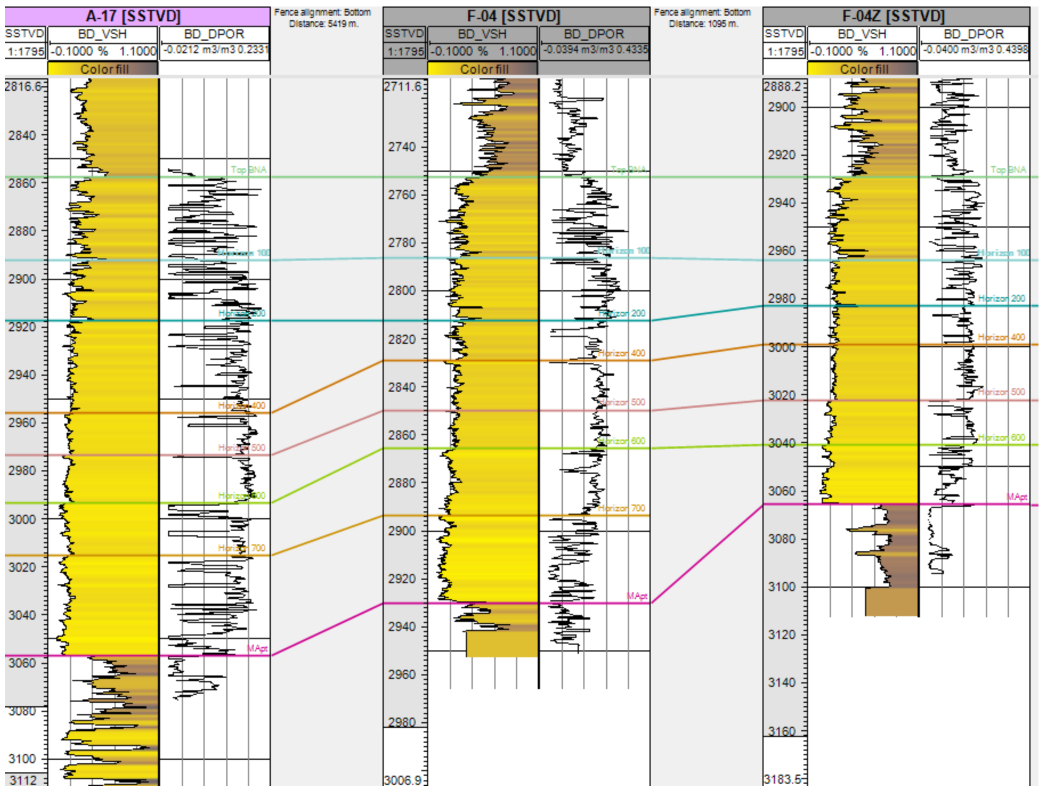

Figure 4.5: Stratigraphic well-section through the South Avalon and SWRX regions.

A hierarchical modeling approach was taken where the depositional environment and facies interpretations were used to guide the statistical populations of the petrophysical data. Core data and available literature on the Ben Nevis were used to interpret depositional environments and facies within the South Avalon and SWRX areas. The facies interpretations were calibrated to the log data within the cored intervals and then extrapolated through the reservoir interval at each well location. The interpretations were upscaled to the 3D grid and populated using a sequential Gaussian simulation algorithm. This statistical population was conditioned to the depositional environment model for each facies and zone.

Porosity, water saturation, and permeability were modeled for both pools. The property modeling process included upscaling the logs into the 3D grid (Figure 4.6), and analyzing the data by both zone and facies. The upscaled porosity data were conditioned to the facies model and populated through the grid using a sequential Gaussian simulation algorithm. Distribution curves obtained from histograms of the porosity data, filtered by facies and zone, were used to ensure that the input statistics were honoured in the distribution. The modeling parameters were set on a zone-by-zone basis.

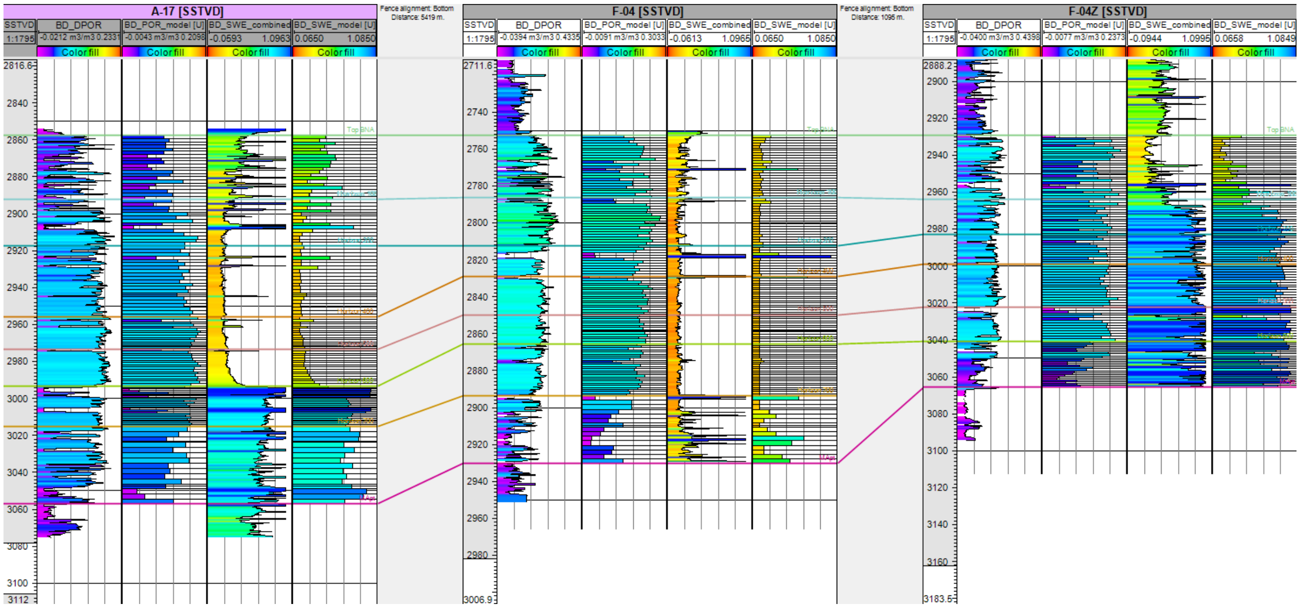

Figure 4.6: Comparison of log and upscaled porosity and water saturation data.

The water saturation data was upscaled to the grid, populated using a sequential Gaussian simulation algorithm, and co-kriged to the porosity model. The statistical population was also conditioned to the hydrocarbon contacts. A distribution curve obtained from a histogram of the water saturation values, filtered to the hydrocarbon zone, was used to ensure the input statistics were honoured.

The horizontal permeability data, obtained from the Board staff's petrophysical assessment, was upscaled and populated using sequential Gaussian simulation and co-kriged to the porosity model. The collocated co-kriging coefficient was obtained from the correlation function, which was estimated from a crossplot of upscaled permeability and porosity data.

4.4 Oil and Gas In Place

Board staff conducted an assessment of the in-place hydrocarbon resources in the SWRX and South Avalon pools. The resulting deterministic hierarchical geological model was used as a basis for the stochastic assessment. Multiple parameters were varied in the assessment, including facies, porosity, water saturation, hydrocarbon contacts and shrinkage.

A comparison of the Proponent's and the Board's volumetric oil-in-place (OOIP), original-gas-in-place (OGIP) (gas cap) and original-gas-in-place (OGIP) (solution) estimates for the South Avalon Terrace and SWRX, are shown in Table 4.2. These are probabilistic in-place resource estimates: P90 (downside case), P50 (most likely case) and P10 (upside case).

Overall, there is good agreement between the Proponent and the Board's volumetric assessment. The differences between the Proponent and Board staff OOIP and OGIP estimates can be attributed to differences in the geological and reservoir modeling methodologies, the petrophysical analyses, and the parameters varied in the uncertainty analysis. It should be noted that the Proponent's estimate of OOIP in the SWRX Pool has increased from 14.5 MMm^3 (91 MMbbls) to 15.4 MMm^3 (97 MMbbls) since the original SWRX DPA submission (Decision 2007.02). The Board's estimate of OOIP has also increased from 13 MMm^3 (83 MMbbls) to 14.6 MMm^3 (91.8 MMbbls).

	Pool	Units	P90		P50		P10	
			Husky	C-NLOPB	Husky	C-NLOPB	Husky	C-NLOPB
OOIP	SWRX	MMbbls	69.8	70.4	96.9	91.8	129.6	112
		MMm^3	11.1	11.5	15.4	14.6	20.6	17.8
	South Avalon Terrace	MMbbls	251.6	278	302	322	352.2	387.5
		MMm^3	40	44.2	48	51.2	56	61.6
Gas Cap OGIP	SWRX	GCF	190.7	134.2	236.6	155.4	300.2	190.7
		Gm^3	5.4	3.8	6.7	4.4	8.5	5.4
	South Avalon Terrace	GCF	268.4	247.2	346.1	293.1	459.1	363.7
		Gm^3	7.6	7.0	9.8	8.3	13	10.3
Solution Gas OGIP	SWRX	GCF	50.1	52.3	69.2	66.7	93.9	80.9
		Gm^3	1.42	1.48	1.96	1.89	2.66	2.29
	South Avalon Terrace	GCF	180.1	201.3	215.4	233.1	257.8	279
		Gm^3	5.1	5.7	6.1	6.6	7.3	7.9

Table 4.2: Comparison of Proponent and C-NLOPB probabilistic resources in place, South Avalon Terrace and SWRX.

4.5 Reservoir Engineering

Analysis of the reservoir engineering component of the Application included a review of the following items:

- Reservoir Pressures and Temperatures
- Fluid Characterization
- Injection Fluids
- Special Core Analysis
- Water Saturation Estimates

4.5.1 Reservoir Pressures and Temperatures

Two delineation wells, F-04 and F-04Z, have been drilled in the SWRX Pool to date. One delineation and ten development wells have been drilled into the Terrace region of the South Avalon Pool.

Reservoir pressures were obtained in many of the exploration, delineation and development wells drilled in the SWRX and South Avalon pools. A pressure-versus-depth plot for each pool is illustrated in Figure 4.7.

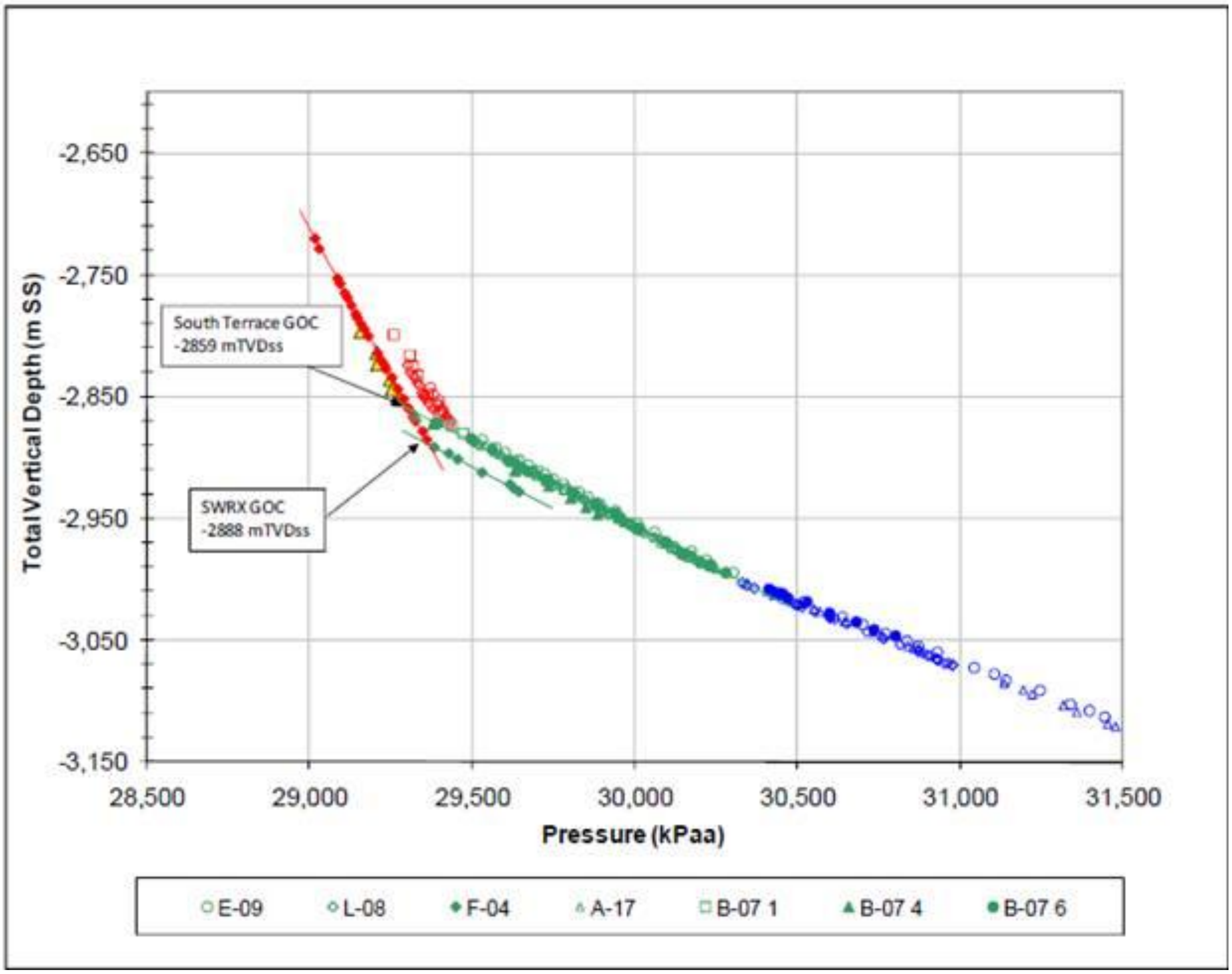

Figure 4.7: South Avalon and SWRX pressure versus depth (Source: Husky).

The fluid gradients and the hydrocarbon contacts encountered in several exploration, delineation and development wells including A-17, L-08, E-09, B-07 1 and B-07 6 define the South Avalon Pool. The hydrocarbon contacts and gradients encountered in the F-04 and F-04Z wells define the SWRX Pool.

The fluid gradients for gas, oil and water are listed in Table 4.3, and are similar to those encountered in the other areas of the White Rose Field.

Well	Reservoir Gas Gradient (kPa/m)	Reservoir Oil Gradient (kPa/m)	Reservoir Water Gradient (kPa/m)
A-17	1.71	6.96	9.71
L-08	2.11	6.98	9.69
E-09	2.28	7.09	9.81
B-07 1	2.13	6.84	N/A
B-07 4	2.06	6.92	N/A
B-07 6	N/A	7.18	10.22
F-04	2.06	7.23	N/A

Table 4.3: Proponent's South Avalon and SWRX fluid gradients .

There is good agreement between the Proponent's and the Board's gas-oil and oil-water contacts. The fluid contacts encountered in the SWRX and South Avalon Terrace wells are shown in Table 4.4.

Well	Formation	Contact	Subsea Depth (m SS TVD)
A-17	Ben Nevis	Gas-Oil Top of O-W Transition Bottom of O-W Transition	2874.7 2985.0 2999.5
L-08	Ben Nevis	Gas-Oil Top of O-W Transition Bottom of O-W Transition	2872.0 2989.0 3009.5
E-09	Ben Nevis	Gas-Oil Top of O-W Transition Bottom of O-W Transition	2871.8 2990.0 3009.5
B-07 1	Ben Nevis	Gas-Oil	2872.0
B-07 4	Ben Nevis	Gas-Oil	2858.9
B-07 6	Ben Nevis	Oil-Water	2998.5
B-07 11	Ben Nevis	Gas-Oil	2869.2
E-18 9	Ben Nevis	Gas-Oil	2892.7
F-04	Ben Nevis	Gas-Oil	2887.5
F-04Z	Ben Nevis	Oil-Water	2968.2

Table 4.4: Proponent's South Avalon and SWRX pools contacts.

The fluid contacts used in the Proponent's South Avalon reservoir simulation model, in the region of the proposed infill producer and gas injector, are consistent with the contacts for the B-07 4 (gas-oil) and the B-07 6 (oil-water) water injectors. The fluid contacts used in the Proponent's SWRX reservoir simulation are consistent with the fluid contacts for the F-04 (gas-oil) and F-04Z (oil-water) delineation wells.

Due to the number of wells and frequency of temperature monitoring in the South Avalon Terrace, the temperature gradient is well understood. The maximum recorded temperature in the South Avalon Terrace region was measured at 105^{o}C in the B-07 8 water injector. The Proponent used a reservoir temperature of 107^{o}C in the South Avalon reservoir simulation model, which is slightly higher than the estimated reservoir temperature for South Avalon. In the SWRX Pool, the maximum recorded temperature was 98^{o}C, recorded while logging the F-04 well. Taking into account the cooling due to mud circulation during the logging operation, the reservoir temperature in the SWRX is estimated at 101^{o}C by the Proponent. The Proponent used a reservoir temperature of 106^{o}C in the SWRX reservoir simulation model.

Board staff considers the Proponent's analysis and use of the pressure and temperature data to be reasonable and appropriate for the South Avalon Terrace and SWRX regions.

4.5.2 Fluid Data

The Proponent collected fluid samples from several wells in the South Avalon Terrace region, and from the F-04 well in the SWRX region. Due to operational challenges while logging, fluid samples were not obtained from the F-04Z well. Additionally, the F-04 well only captured bottom hole pressurized fluid samples from the gas zone. As there are no oil samples from the SWRX Pool, the oil properties are assumed to be the same as those of the South Avalon Pool.

The Application indicates that a detailed review of South Avalon PVT properties was conducted. From this work, new PVT tables were generated and these tables are now considered to be the most representative PVT dataset for the South Avalon Pool. This fluid analysis indicates a GOR of 128.5 m^3/m^3, a saturation pressure of 29,100 kPa and an initial oil formation volume factor of 1.359 m^3/m^3 for both the South Avalon and the SWRX regions.

Gas samples taken from the F-04 well indicate that the gas properties from the SWRX region are similar to those in the South Avalon Pool. No water samples were taken from the SWRX region; however, the water composition in the SWRX is considered to be comparable to that encountered in South Avalon.

Board staff considers the Proponent's oil, gas and water characterizations to be reasonable and appropriate. However, **the Proponent is expected to obtain oil and water samples from the SWRX Pool at the earliest opportunity to confirm that the assumptions made in this Application are valid.**

4.5.3 Injection Fluids

The Application proposes the continued development of the South Avalon Pool with water injection and the addition of gas injection to the southern portion of the Terrace region. The currently undeveloped SWRX region is planned to be produced using both water injection and gas injection support.

The South Avalon Pool is currently produced using a water flood depletion scheme. The injected water is treated sea water. The Proponent plans to continue using the same source and treatment methodology for injection water in the South Avalon and will apply this process to the SWRX as the formation water is anticipated to be the same as that in South Avalon. Board staff considers this approach to be reasonable. As with South Avalon, chemical injection is proposed to mitigate any scaling that may occur.

The Proponent plans to inject gas in the South Avalon Terrace and SWRX regions for both gas storage and pressure support. The injected gas will be lean gas with a composition consistent with that currently injected in the North Avalon Pool and used for gas lift in the South Avalon Pool. The injected gas will be sourced from the current gas injection system operating on the SeaRose FPSO.

Board staff considers the Proponent's plans for reservoir injection fluids to be reasonable and consistent with current water and gas injection practices on the SeaRose FPSO.

4.5.4 Special Core Analysis (SCAL)

The oil-water and gas-oil relative permeability curves used in both the South Avalon and SWRX models are based on core flood analysis of laminated sandstone samples from the White Rose L-08 well, and are used for all rock types contained in the models. The relative permeability endpoints for each of the five rock types (laminated sandstone, bioturbated sandstone, bioturbated siltstone, calcite and shale) are presented in the Application.

SCAL has been conducted on core from the F-04 well; however, the Proponent determined it was not representative of reservoir behaviour in the SWRX region. As the Proponent believes the SWRX and South Avalon reservoirs to be similar, and there has been an extensive amount of SCAL work done on South Avalon wells, the SCAL results from the South Avalon Pool have been incorporated into the SWRX model.

Board staff considers the Proponent's approach to incorporating SCAL data to be acceptable. However, the Proponent will be expected to provide a comparison of reservoir performance and the reservoir simulation model predictions in the Annual Resource Management Plan update once production from the SWRX region begins.

4.5.5 Water Saturation Estimates

The initial water saturation in the Proponent's South Avalon geological and simulation models was populated using the kriging method. Employing the kriging method in the South Avalon model resulted in initial water saturation values that demonstrated a good match to the initial water saturation observed on well logs, compared to those generated by using J functions.

For the SWRX Pool, the initial water saturation for the Proponent's simulation and geological models was estimated using J function curves. The curves were generated for each of the five rock types and were incorporated into the simulation and geological models.

Board staff found the Proponent's approach to water saturation estimation for both the South Avalon and SWRX pools to be reasonable.

4.6 Development Strategy

The Application outlines an updated depletion strategy for the South Avalon and the SWRX pools through a subsea tie-back to the SeaRose FPSO from an excavated drill centre (SWRXDC). Figure 4.8 depicts SWRXDC in relation to the hydrocarbon accumulation, the Terrace region, the SWRX and existing production and delineation wells.

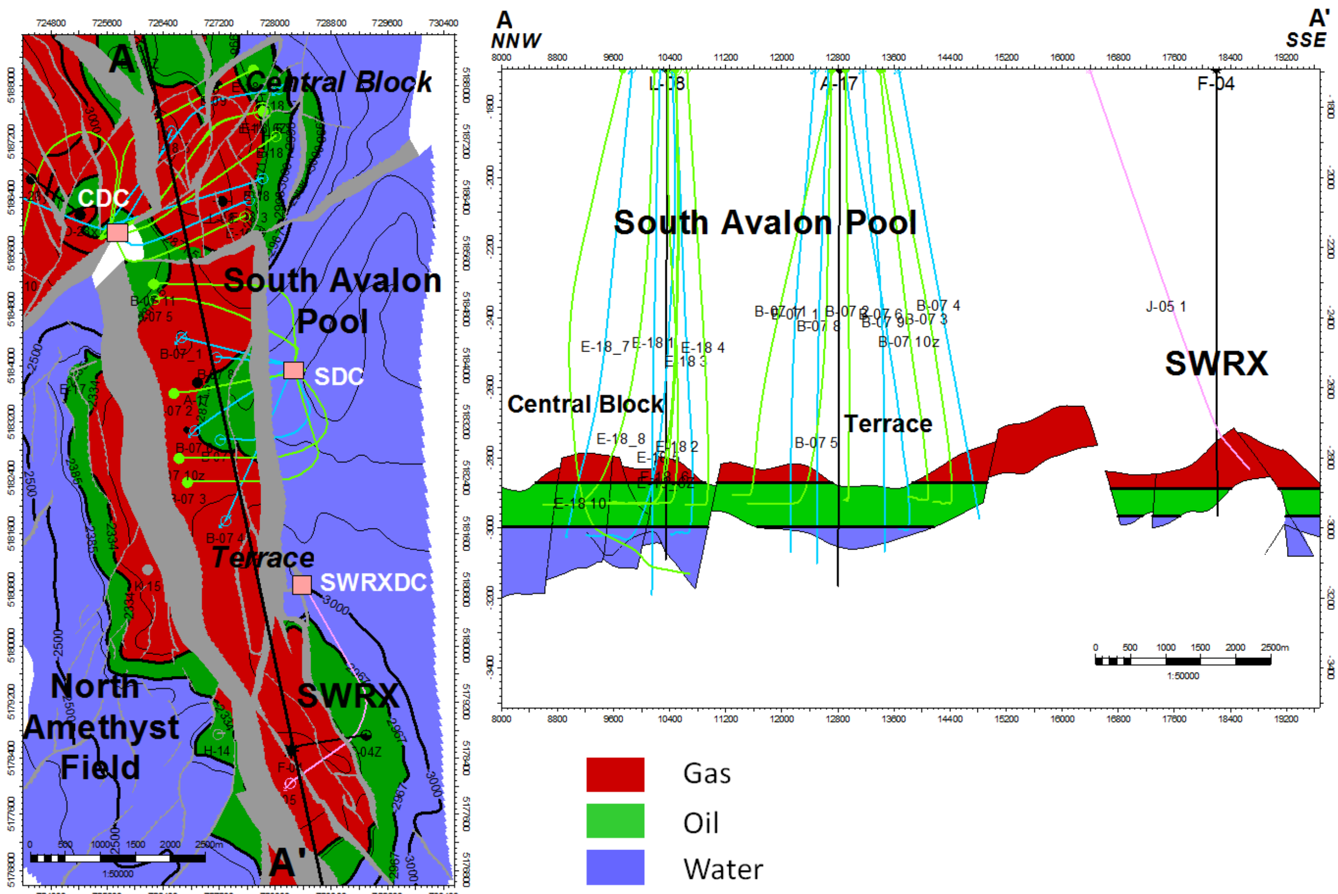

Figure 4.8: Hydrocarbon accumulations in relation to the development and delineation well locations, pools, and the drill centre locations.

4.6.1 Depletion Plan

4.6.1.1 South Avalon Pool Depletion Plan

The current mode of development for the South Avalon Pool, as approved by the Board in Decision 2001.01, is to maximize oil production through pressure support and secondary recovery from water injection. The approved Development Plan also requires the re-injection of produced gas into the North Avalon Pool for storage and conservation.

The Application outlines a plan to alter the depletion scheme for the South Avalon Pool by providing pressure support from both gas and water injection. The Proponent plans to implement this altered depletion plan for the nine existing horizontal oil producers and any potential infill wells drilled in the South Avalon Pool in the future. The purpose for this change is the shortage of remaining gas storage capacity in the White Rose asset, and the desire to enable enhanced oil recovery through gas injection to ensure oil production is maximized.

There are currently ten water injectors providing pressure support to the producers in the Central and Terrace blocks of the South Avalon Pool. Five of these water injection wells are horizontal and five are vertical. Water is injected into the water leg of the reservoir or directly into the oil zone in wells where no water was encountered. The water injectors sweep oil upward toward the horizontal producers by providing pressure support from below. Under the proposed scheme, gas will be injected into the structurally higher gas cap. This will provide another means of reservoir pressure support while also sweeping trapped or bypassed oil in the upper reservoir (“attic” oil) down toward the producers, which are generally located in the middle of the oil zone.

The proposed infill well will be a horizontal producer in the B-07 3 area. The proposed gas injector will be a highly deviated well in the south Terrace region in the vicinity of the B-07 4 well. The Proponent plans to drill and complete this well in two fault blocks. This gas injector will provide the Proponent with gas storage capacity and assist in sweeping oil towards the planned infill well and the currently producing B-07 3 and B-07 10Z wells.

Board staff concurs with the proposed plan to alter the depletion strategy in the South Avalon Pool to alleviate gas storage capacity concerns and provide enhanced oil recovery. However, the Proponent has only provided gas injection and oil, gas and water production forecast volumes for wells in the southern portion of the Terrace. As a result, the Application does not adequately assess the effects of gas injection in the northern Terrace or the Central Block of the South Avalon Pool. Therefore, **prior to the initiation of any gas flooding in areas of the South Avalon Pool outside of the southern Terrace, the Proponent must submit an updated exploitation scheme for Board approval.**

The practice of routinely assessing enhanced oil recovery schemes is consistent with the requirements of the *Newfoundland Offshore Petroleum Drilling and Production Regulations*. Staff are encouraged by the Proponent’s intention to pursue the enhanced oil recovery scheme outlined in the Application. Staff believes the Proponent should be allowed to proceed with the proposed gas injection scheme in the southern Terrace because reservoir simulation predicts it will lead to an increase in ultimate oil recovery to 38.68 MMm^3 (243.26 MMbbls) for the South Avalon Pool. This estimate is higher than the expected recoverable of 37.16 MMm^3 (233.76 MMbbls) under the current water flood scheme, which results in an estimated incremental oil recovery of 1.51 MMm^3 (9.52 MMbbls) for the South Avalon Pool.

4.6.1.2 South White Rose Pool Depletion Plan

The DPA originally approved by the Board for the SWRX Pool in Decision 2007.02 called for pressure support from water injection and storage of produced gas in the North Avalon Pool. Due to the need for gas storage capacity, as discussed in Section 4.2, the Proponent now wishes to alter the approved depletion plan to permit pressure support from gas injection into the large gas cap in the structurally higher F-04 fault block. A cross-section of the gas cap in the F-04 fault block is depicted in Figure 4.9.

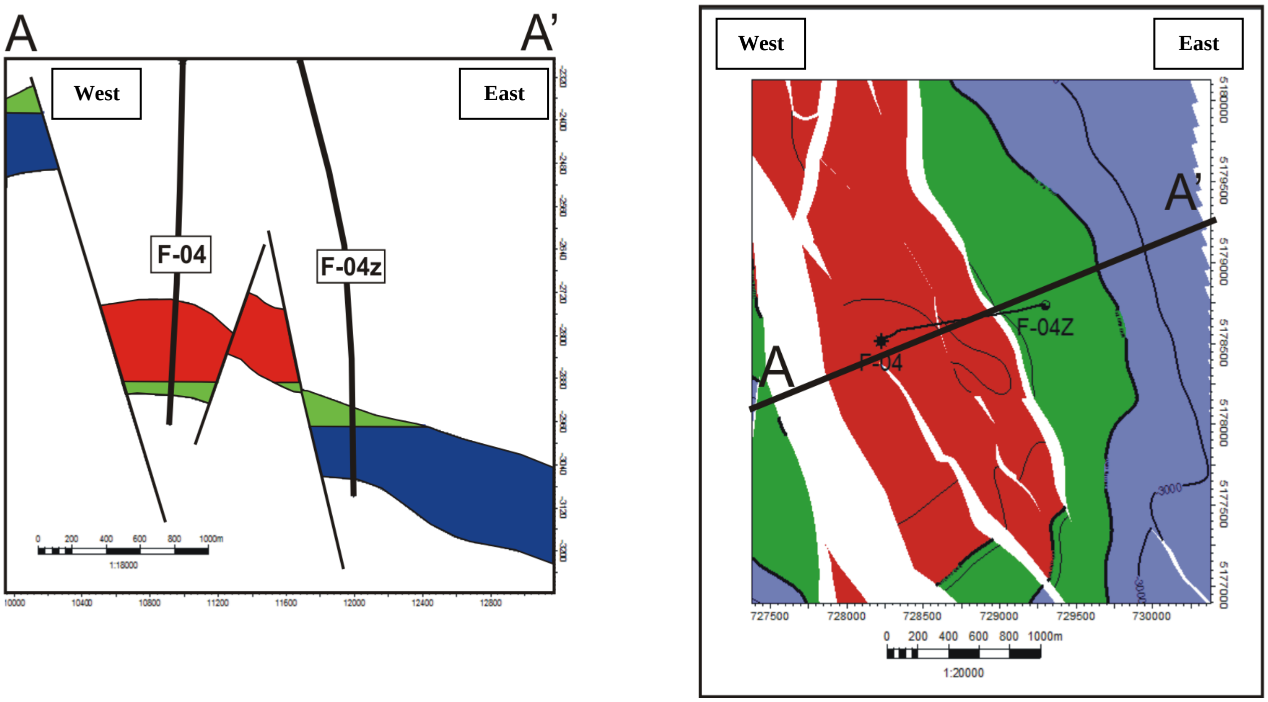

Figure 4.9: SWRX Pool cross-section.

Injection into the F-04 block gas cap will be achieved by drilling a deviated gas injector to support the horizontal producer. The gas injector (J-05 1) is currently being drilled. Gas will be injected into two separate fault blocks as shown in Figure 4.10.

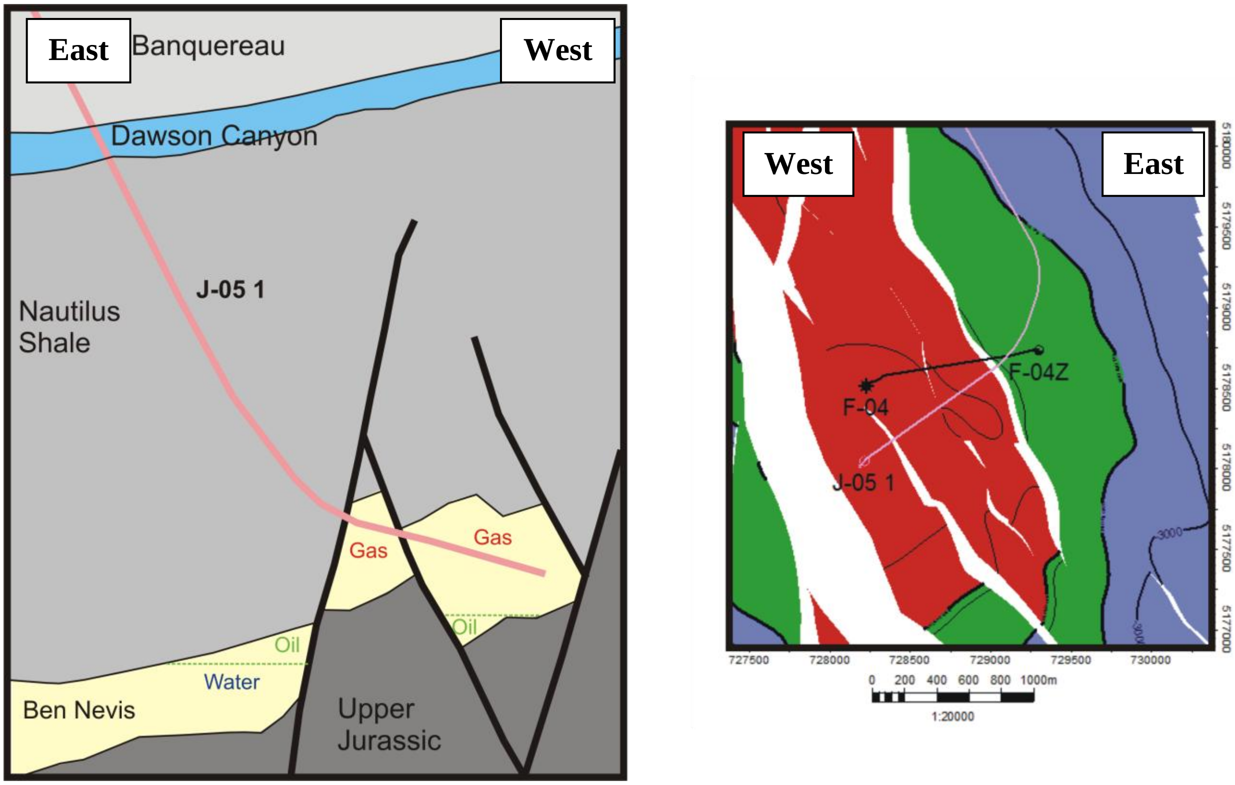

Figure 4.10: J-05 1 Gas injector schematic (Source: modified from Husky).

Pressure support for the horizontal producer in the F-04Z fault block will be provided by water injection into the water leg. As discussed in the previous SWRX DPA (Decision 2007.02), the Proponent believes that a regional aquifer could exist in the area of the F-04Z block. This aquifer may be able to provide full or partial pressure support to the block. However, as the sustainability of water encroachment and the connectivity of the water volume are not definitive at this time, the Proponent plans to drill a water injector in the F-04Z fault block to ensure oil recovery is maximized through adequate pressure support.

The Proponent's reservoir simulation model for the proposed depletion plan predicts an ultimate oil recovery of 3.82 MMm^3 (24 MMbbls) from the SWRX Pool, which is the same as the estimated recovery in the original SWRX DPA (Decision 2007.02). Therefore, staff recommends that the Proponent should be permitted to proceed with the plan outlined in the Application, as this will alleviate gas storage concerns for the White Rose asset without negatively impacting oil recovery from the SWRX Pool.

4.6.2 SWRX Drill Centre Development Scenario

The proposed development scenario for the SWRXDC calls for six wells in total. The drill centre will have expansion capability for an additional six to accommodate potential future development.

Two wells will be drilled from the SWRXDC into the southern Terrace region of the South Avalon Pool. The first well will be a horizontal infill production well, and the second is planned as a highly deviated gas injection well.

The Proponent's base case plan for SWRX Pool development consists of one horizontal producer and one deviated gas injector in the F-04 fault block, and one horizontal producer and one water injector in the F-04Z fault block for a total of four wells. There is potential for an oil production and water injection pair to be added in the southern area of the SWRX Pool. This area is more structurally complex and requires a better understanding before development can proceed. As new wells are drilled, and understanding of the SWRX Pool improves, the Proponent will evaluate the feasibility of developing the southern portion of the pool.

The proposed locations of the development wells under the SWRX Drill Centre development scenario are shown in Figure 4.11.

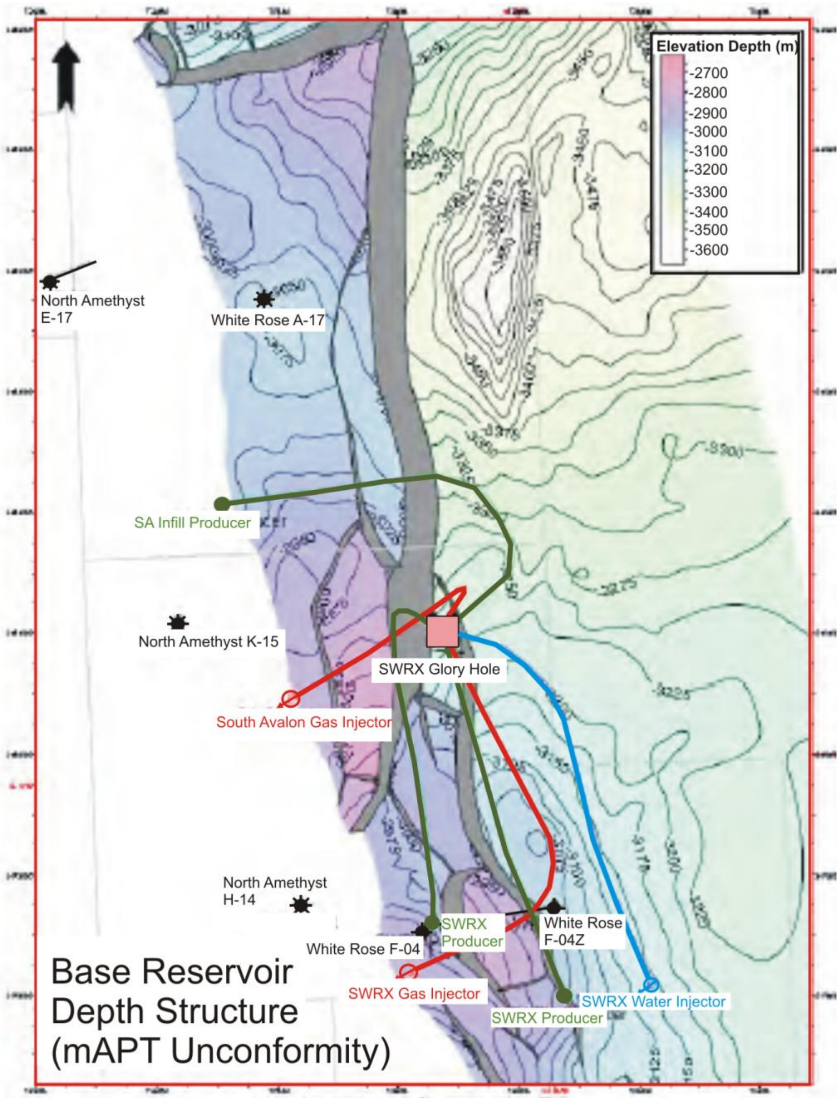

Figure 4.11: SWRX Drill Centre proposed development wells (Source: modified from Husky).

The Proponent provided a preliminary drilling schedule for the six proposed development wells. On November 30, 2012 the Proponent received ministerial approval to proceed with the drilling of the SWRX gas injector prior to the Board's approval of this DPA Application. That well, J-05 1, was spud on February 18, 2013 and drilling operations are ongoing.

The tentative spud dates of the remaining development wells are as follows:

1. South Avalon Terrace infill oil producer – 2014
2. South Avalon Terrace gas injector – 2014/2015
3. SWRX oil producer (F-04 fault block) – 2014/2015
4. SWRX oil producer (F-04Z fault block) – 2015/2016

5. SWRX water injector – 2015/2016

4.6.3 Reservoir Management Plan

The Proponent indicated that the reservoir management plan for the South Avalon Pool will remain unchanged. Pressure in the pool will continue to be maintained above bubble point, and the Proponent will also endeavor to maintain a voidage replacement ratio between 1.0 and 1.2. A portion of production in the southern Terrace region from the B-07 3 well, the B-07 10Z well and the proposed infill well will be voidage replaced by gas injection. In addition, the current Data Acquisition Plan for the White Rose Field will continue to be adhered to in accordance with the requirements of the *Newfoundland Offshore Petroleum Drilling and Production Regulations*.

The Proponent plans to install a smart gas injector completion for the proposed gas injection well in the southern Terrace, as this area contains two distinct fault blocks. These sub-units are referred to as the East and West fault blocks and are illustrated in Figure 4.12.

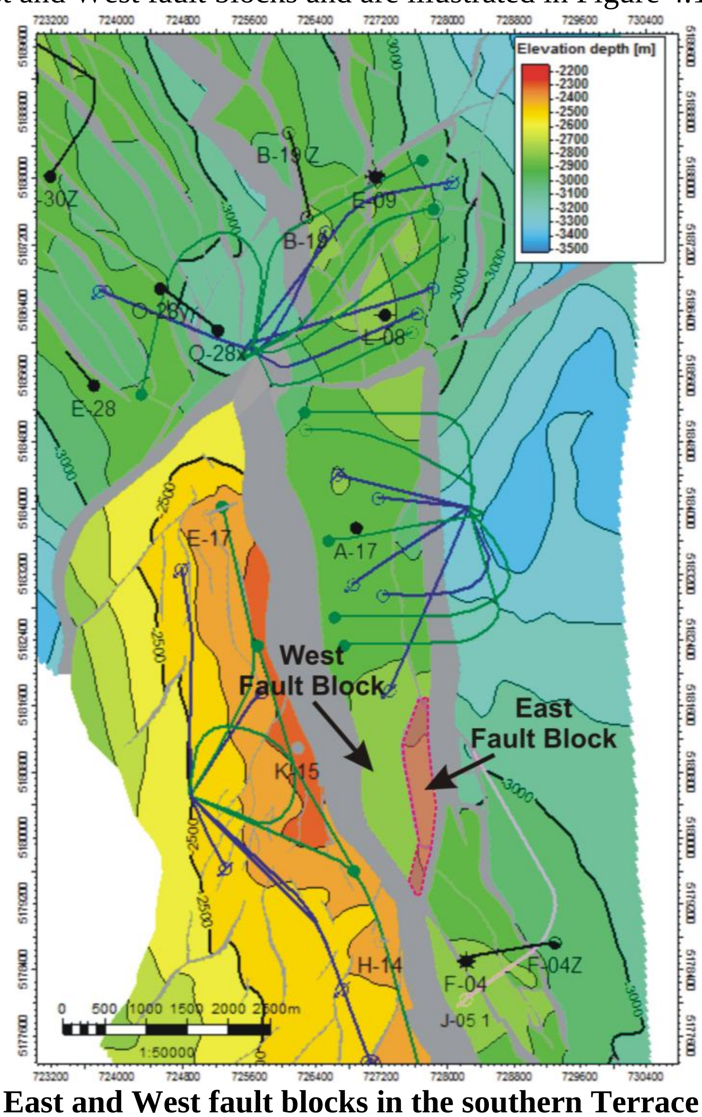

Figure 4.12: East and West fault blocks in the southern Terrace gas cap area.

Utilizing a smart well completion will allow the Proponent to independently inject gas into the East and West fault blocks or to inject gas into both blocks concurrently. If the fault separating these blocks is sealing, use of the smart completion could possibly provide up to three years of gas storage within the East fault block, as the Proponent will have the capability to inject gas into the heel section of the well only. In that case, this period of gas injection would have no impact on South Avalon Terrace pressure maintenance and subsequent voidage replacement. After cessation of the initial injection period in the East fault block, the smart completion could be used to hydraulically open the toe section of the well to permit gas injection into the West fault block. Once gas injection into the West fault block begins, gas flood support would be provided to the production wells in the southern portion of the Terrace. Monitoring and adjustment of the water and gas injection and production rates will be carried out by the Proponent to ensure that a voidage replacement ratio between 1.0 and 1.2 is maintained.

Board staff considers the Proponent's plans for reservoir management in the South Avalon Pool to be reasonable. However, if the fault separating the East and West fault blocks is sealing, the gas initially injected in the heel section of the injector will not aid in gas flooding the production wells in the southern Terrace region. Consequently, this injection would be considered gas storage, not gas flooding. The sealing nature of this fault will not be known until the Proponent is able acquire adequate injection and pressure data. As a result, **the Proponent will be required to submit a report acceptable to the Board assessing the sealing nature of the fault separating the East and West blocks one year after the commencement of gas injection in the southern Terrace.** If injection and pressure data from the gas injector indicates that the fault is sealing, the Proponent will have to apply for a subsurface gas storage license in the East fault block.

> **Condition 1: The Proponent must submit a report acceptable to the Board assessing the sealing nature of the fault separating the East and West Fault blocks one year after commencement of gas injection into the southern Terrace.**

The proposed reservoir management plan for the SWRX Pool is consistent with the plan for the South Avalon Pool and the other producing pools in the White Rose area. Reservoir pressure will be maintained above bubble point and a voidage replacement ratio between 1.0 and 1.2 will continue to be targeted in order to maximize ultimate field recovery. Data acquisition for the SWRX Pool will be in accordance with the current Data Acquisition Plan for the White Rose Field.

A smart completion will not be used by the Proponent in the SWRX gas injector in the F-04 fault block (J-05 1). The Proponent plans to inject gas for a tentative period of 18 months prior to commencement of oil production from the pool. This period of "pre-injection" is necessary as the production flowlines and related subsea infrastructure will not be installed and commissioned in the SWRXDC until late 2014 or early 2015. The Proponent's SWRX reservoir simulation model showed no adverse effects on oil recovery from the "pre-injection" period.

Produced gas from both the South Avalon and SWRX pools will be re-injected via the gas injection wells proposed under this scheme or the existing gas injection wells in the North Avalon Pool.

Staff finds the Proponent’s reservoir management plan for the SWRX Pool to be reasonable. If the Proponent’s planned period of “pre-injection” extends beyond 18 months due to operational or other issues, the Proponent will have to update the Board on their plans.

> **Condition 2: Should the period of gas injection prior to oil production in the SWRX Pool extend beyond 18 months, the Proponent must submit a report acceptable to the Board detailing the activities to date and future plans for gas injection in the SWRX Pool.**

For the proposed production wells, the Proponent will consider utilizing subsea multiphase flow meters (MPFM) to apportion produced fluids back to each SWRX well/drill centre. This will be in conjunction with existing test separation facilities. Staff notes this is an important aspect for future subsea field allocations and will require the Proponent to address appropriate meter provisions in the Flow System Approval Application process.

4.6.4 Full Field Performance

The SeaRose FPSO facility is currently handling production from the South Avalon Pool, the North Amethyst Pool and the West White Rose Pilot Project. As the Proponent wishes to add more production from the proposed development scheme, they conducted an assessment of the implications of increased production on the full field performance to determine if there were any issues with the SeaRose FPSO production and injection capabilities. The SeaRose FPSO production and injection constraints used for this assessment are as follows:

- Total Liquids – 33,000 m^3/day (208,000 bbls/day)
- Total Water Injection – 44,000 m^3/day (277,000 bbls/day)
- Water Injection per excavated drill centre – 30,000 m^3/day (189,000 bbls/day)
- Produced Water – 28,000 m^3/day (176,000 bbls/day)
- Gas Compression – 4.2 MMm^3/day (148 MMscf/day)
- Lift Gas – 1.6 MMm^3/day (56 MMscf/day)
- Lift Gas per excavated drill centre – 1.19 MMm^3/day (42 MMscf/day)

The Proponent used simulation models in conjunction with vertical flow performance tables for the existing and proposed production wells to predict production and pressure performance for the full field. Profiles for full field oil production, produced water, water injection, total liquid production, total gas production and gas lift, and gas utilization were included in the Application and are shown in Figures 4.13 to 4.18.

The Proponent has extended field life to 2030 for the full field production profiles. Production to 2030 would extend field life five years beyond the original twenty-year design life of the SeaRose FPSO. Further work will be required by the Proponent to assess feasibility and impacts of field life extension beyond 2025. (Note: There is an extended shut down scheduled for 2022.)

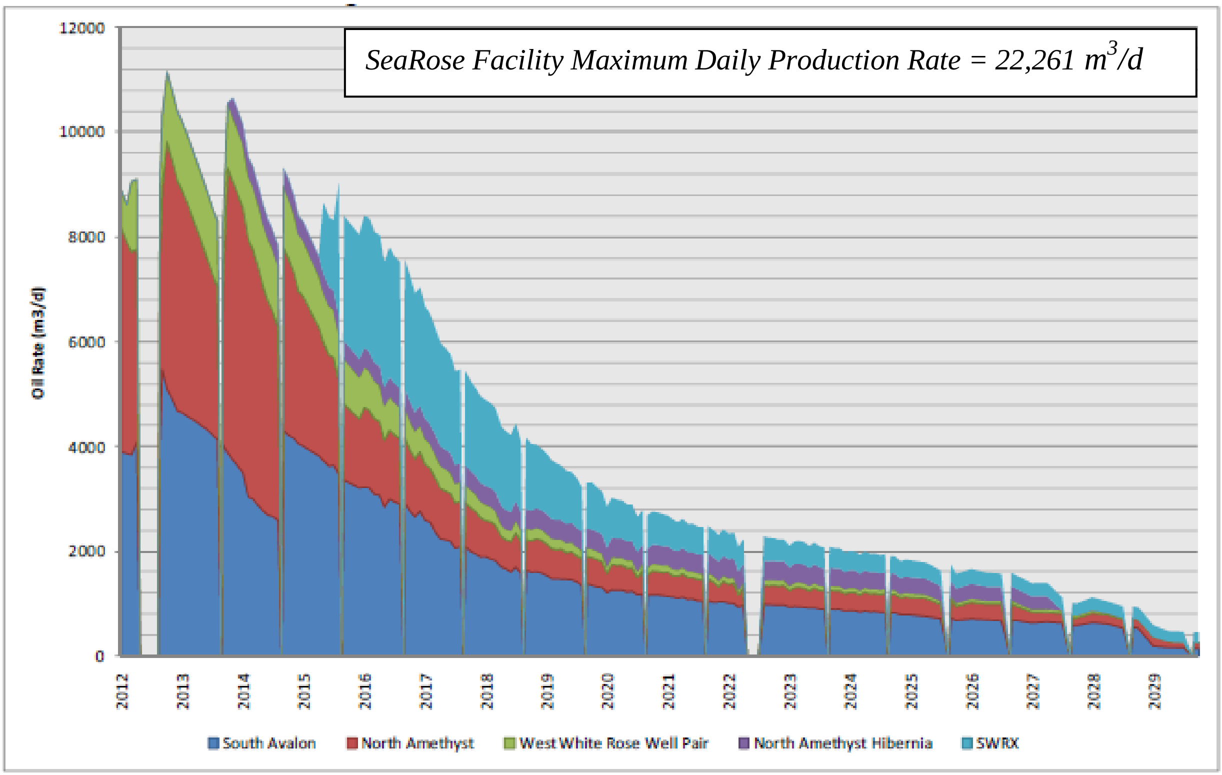

Figure 4.13: Full field oil production profile (Source: Husky).

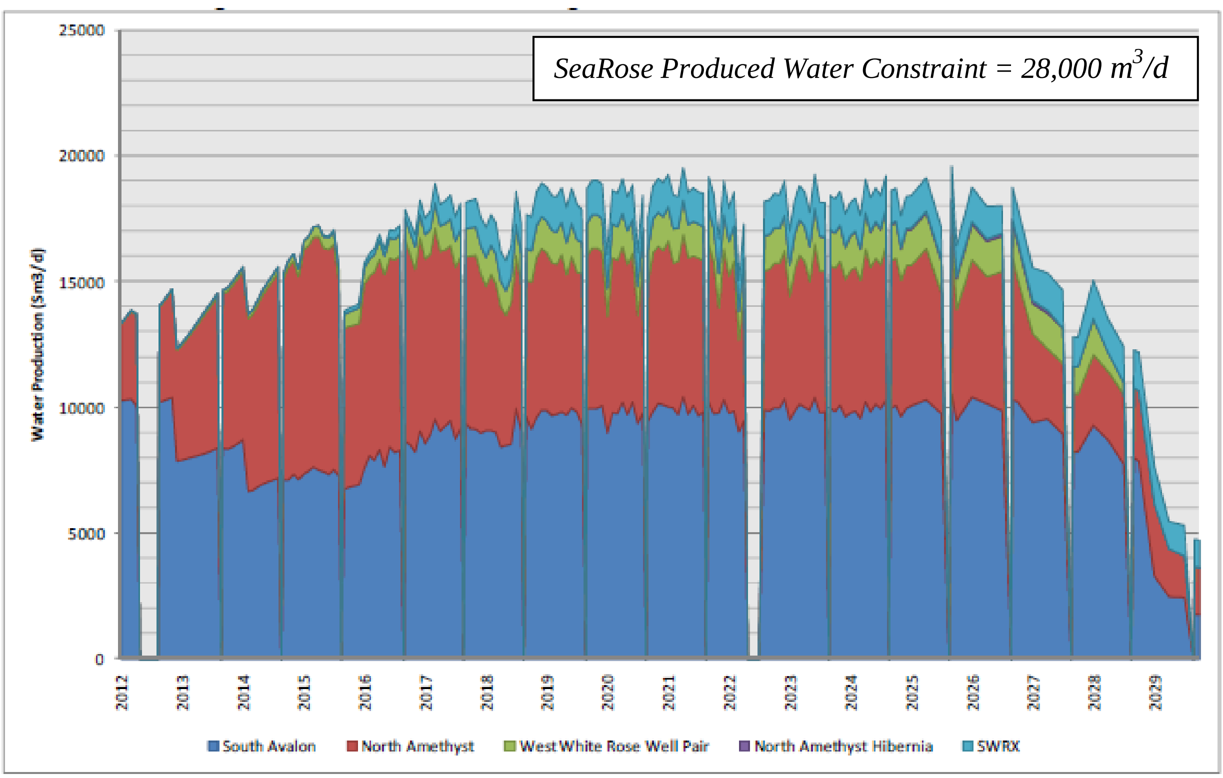

Figure 4.14: Full field water production profile (Source: Husky).

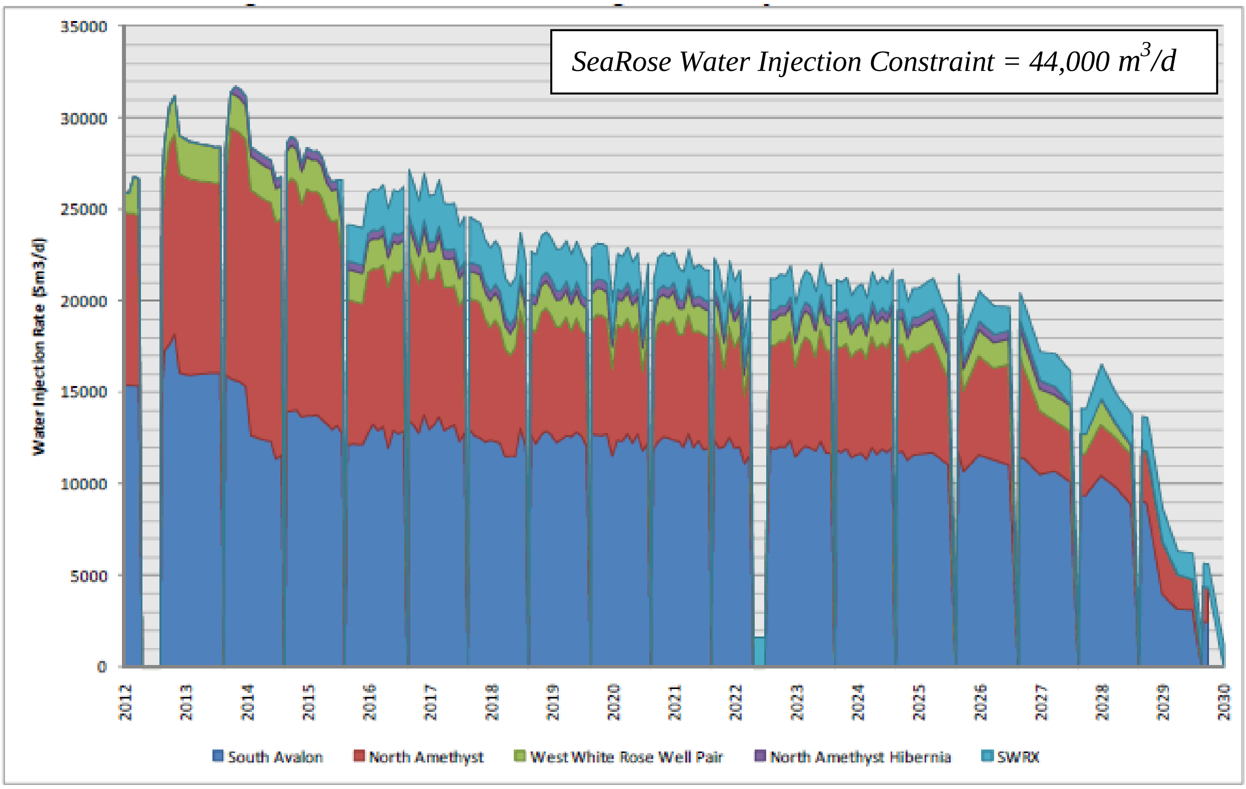

Figure 4.15: Full field water injection rate (Source: Husky).

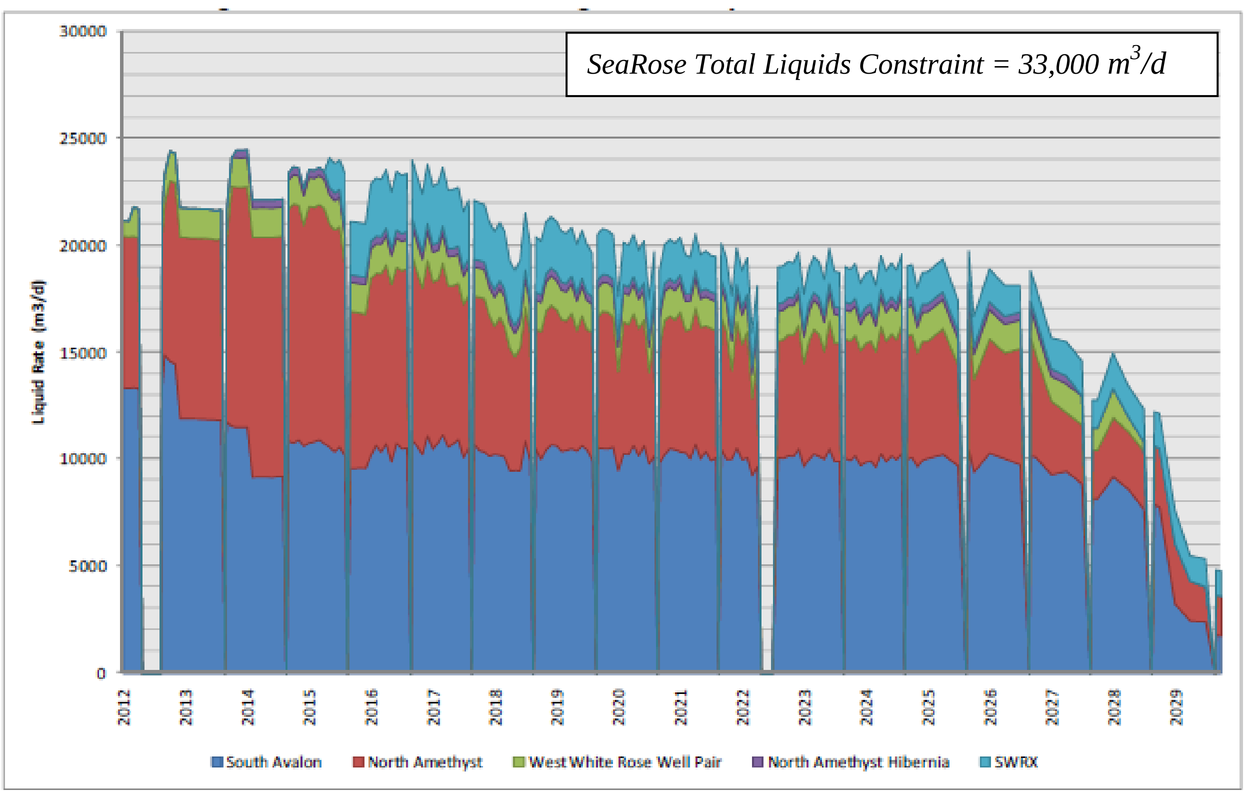

Figure 4.16: Full field total liquid rate (Source: Husky).

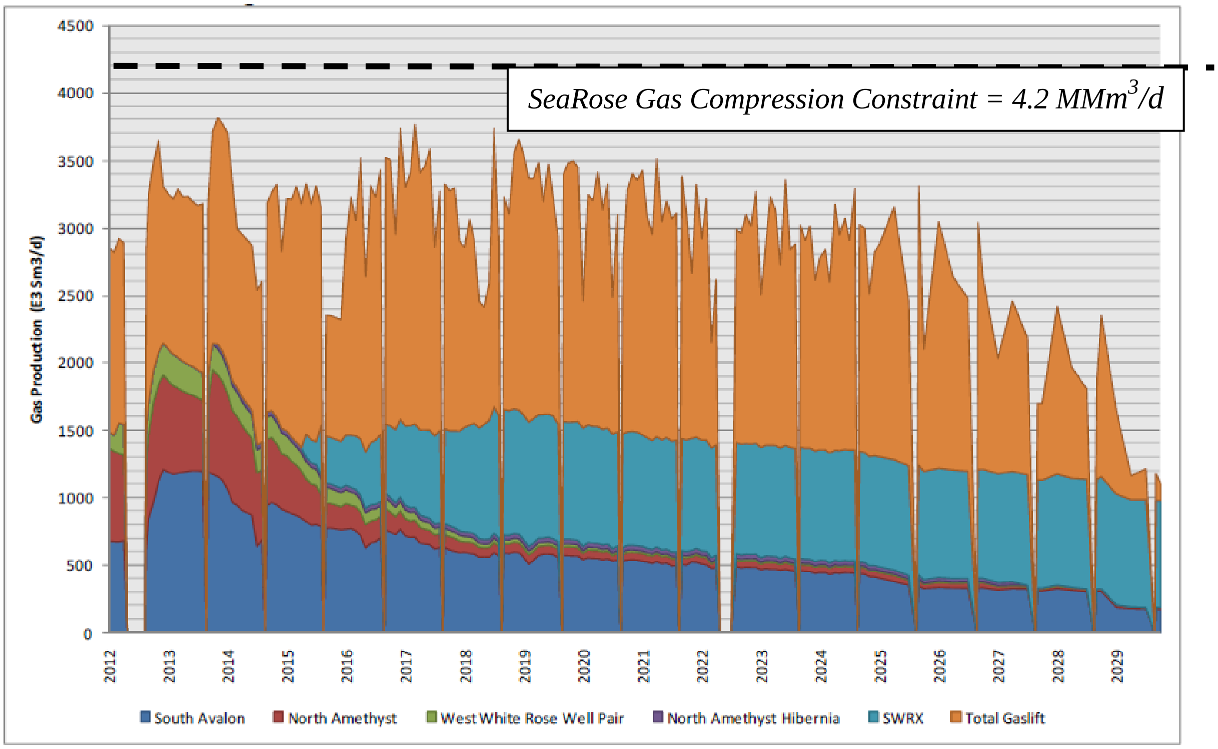

Figure 4.17: Full field gas production and gas lift profile (Source: Husky).

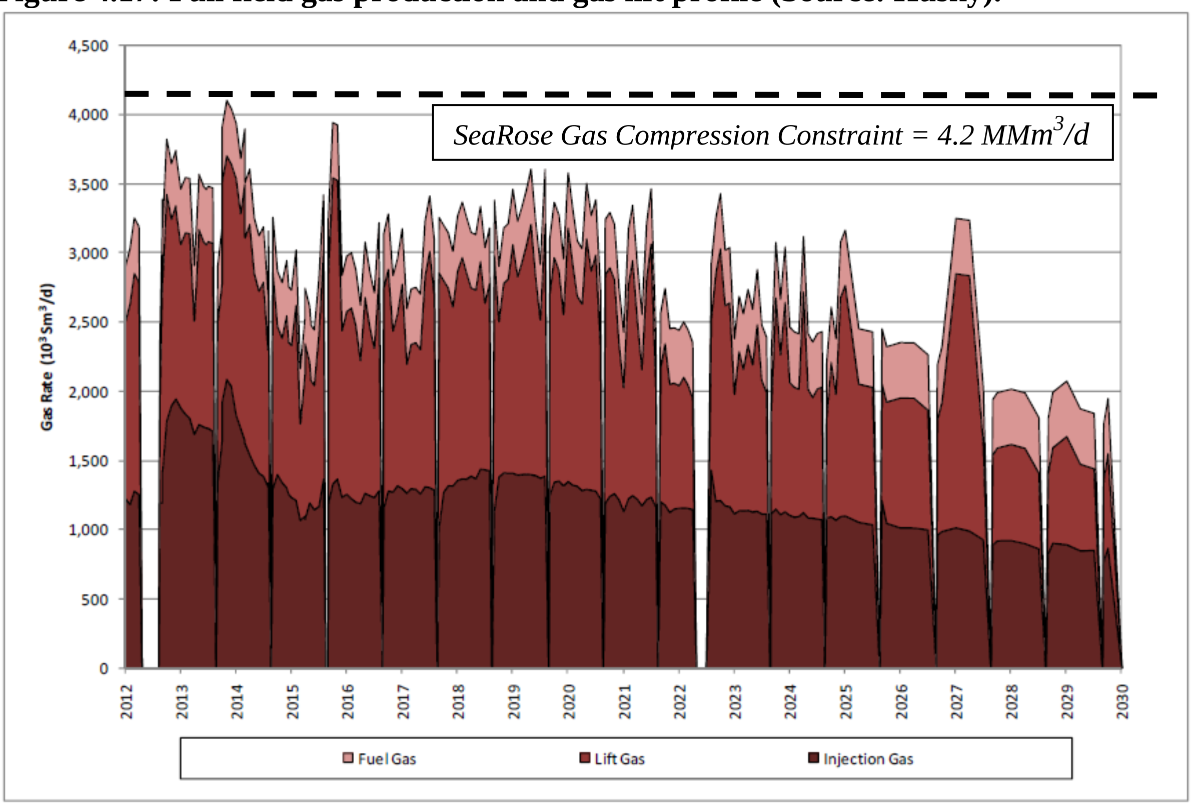

Figure 4.18: Full field gas utilization profile (Source: Husky).

Table 4.5 shows the data from the full field oil production profile of Figure 4.13 in tabular format. It should be noted that the rates shown in Table 4.5 are not an exact match to those shown in Figure 4.13, as they are averaged out over the year.

Year	South Avalon Oil Production Rate (sm3/d)	North Amethyst Oil Production Rate (sm3/d)	West White Rose Well Pair Oil Production Rate (sm3/d)	North Amethyst Hibernia Oil Production Rate (sm3/d)	SWRX Oil Production Rate (sm3/d)	Total Oil Production Rate (sm3/d)
2012	2,654.5	2,442.8	718.8	0.0	0.0	5,816.1
2013	3,889.6	3,638.5	1,170.8	56.6	0.0	8,755.4
2014	3,068.6	3,708.4	1,091.5	334.0	0.0	8,202.4
2015	3,329.6	1,872.9	861.2	328.3	1,229.9	7,621.9
2016	2,724.6	1,200.9	594.1	333.4	2,236.2	7,089.2
2017	2,020.7	837.5	371.5	333.6	1,725.3	5,288.6
2018	1,560.6	573.9	222.8	332.5	1,315.2	4,005.0
2019	1,311.3	491.6	169.7	337.2	886.6	3,196.3
2020	1,113.5	400.7	133.5	332.1	628.4	2,608.2
2021	995.2	372.0	116.8	333.3	491.3	2,308.6
2022	678.9	240.9	76.1	248.9	311.3	1,556.1
2023	841.5	320.9	91.4	316.6	370.8	1,941.1
2024	772.3	318.5	80.2	294.1	314.0	1,779.1
2025	611.7	260.5	63.7	240.3	246.8	1,423.0
2026	574.9	251.6	60.2	221.2	215.6	1,323.5
2027	516.8	140.6	47.4	82.6	197.5	984.9
2028	480.7	143.1	19.1	0.0	187.0	829.8
2029	136.4	103.3	0.0	0.0	162.0	401.7
2030	0.0	0.0	0.0	0.0	0.0	0.0

Table 4.5: Full field oil production average yearly rates (Source: modified from Husky).

Table 4.6 shows the data from the full field gas utilization profile of Figure 4.18 in tabular format. It should be noted that the rates shown in Table 4.6 are not an exact match to those shown in Figure 4.18, as they are averaged out over the year.

Year	Gas Injection Rate	Gas Lift Rate	Gas Fuel Rate
	10^3 sm^3/day	10^3 sm^3/day	10^3 sm^3/day
2012	950.23	914.69	400.00
2013	1,667.11	1,240.95	400.00
2014	1,365.89	1,301.62	400.00
2015	1,053.35	1,149.94	400.00
2016	1,147.50	1,218.40	400.00
2017	1,171.84	1,250.65	400.00
2018	1,267.52	1,316.18	400.00
2019	1,262.65	1,407.53	400.00
2020	1,173.98	1,408.43	400.00
2021	1,098.12	1,126.22	400.00
2022	831.05	845.69	400.00
2023	1,040.22	1,031.23	400.00
2024	1,005.96	957.00	400.00
2025	907.71	894.68	400.00
2026	828.90	750.18	400.00
2027	790.13	948.42	400.00
2028	735.35	533.33	400.00
2029	705.50	542.80	400.00

Table 4.6: Full field gas utilization average yearly rates (Source: Husky).

Staff reviewed the full field profiles to determine if there was any cause for concern regarding SeaRose FPSO facility handling capabilities. Based on facility constraints of the SeaRose FPSO, staff concluded that there are not any significant issues with fluid handling capacities. However, one SeaRose FPSO facility constraint which has potential to cause concerns is gas compression. As depicted in Figure 4.18, total gas injection, fuel gas and gas lift all remain below the SeaRose FPSO gas-handling capacity (4.2 MMm^3/day) for the life of field, but the peak volume of approximately 4.1 MMm^3/day in late 2013 is close to the SeaRose FPSO gas handling capacity. However, this rate is predicted only for a short period of time, and the Proponent will have the options of cutting back on oil production or gas lift rate to deal with any short-term issues.

Testing of the gas compression system was recently conducted on the SeaRose FPSO to ensure the system is capable of meeting future gas compression requirements for the White Rose asset without requiring a system upgrade. The testing found the gas compression system capable of meeting the design basis rate requirement of 4.2 MMm^3/d at 40,000 kPa discharge pressure, and therefore no upgrade of the system is required.

Although the gas handling requirement is within the facility gas compression capability, issues could arise in the future if there is earlier than anticipated gas breakthrough in either of the SWRX or South Avalon Terrace pools. The Proponent plans to mitigate this risk by installing an

Inflow Control Device (ICD) completion for the proposed SWRX production wells. These ICD completions have been successful in delaying breakthrough in other areas of the field, as they create uniform drawdown along the horizontal length of the producers. Gas breakthrough in the southern Terrace will be mitigated by the smart completion in the gas injector, which will permit the Proponent to control gas injection in either the East or West fault blocks. The Proponent will also investigate installation of an ICD completion for the proposed producer in the southern Terrace. Finally, as a gas injection well is planned for each pool, the Proponent will have the flexibility to inject in either pool, should earlier than anticipated gas breakthrough occur in one of them.

4.7 Reservoir Simulation

To support this Application, the Proponent submitted updated reservoir simulation models for the South Avalon and SWRX Pools.

The Proponent's South Avalon reservoir simulation model is history matched to the actual production volumes up to June 1, 2011. The model assumed the B-07 11 infill well would start production on September 1, 2012. The actual start date for this well was August 17, 2012. It also assumed the Terrace infill producer would start production on July 1, 2014, and gas injection in the Terrace would begin on November 1, 2014.

The SWRX reservoir simulation is a predictive model that assumes gas injection in the region will begin in November 2013. The gas injection well, J-05 1, is currently being drilled and should be online by this date. The first oil producer is expected to be online in May 2015, followed by the second oil producer and water injector in November 2015. The model assumes production from the SWRX Pool until 2030.

A further description of the reservoir simulation models, including grid size, active cell count and other model properties, can be found in Section 6.4 of the Application.

While no full field model was submitted, the current SeaRose FPSO facility constraints were considered for the full field forecast. These facility constraints are listed in Section 4.6.4.

Overall, the Proponent's reservoir simulation models and the assumptions used are reasonable and appropriate, and are consistent with modeling constraints used in the past by the Proponent.

4.7.1 Oil Production Results and Forecasts

As the South Avalon reservoir simulation model is a history-matched model, oil production up to June 2011 matches actual production from the White Rose Field. Production beyond June 2011 shows a continual decline in production rate with increases in 2012 and 2014 due to the B-07 11 and Terrace infill wells coming online. Following the drilling of the Terrace infill well, the model indicates a steep decline in production until 2017, after which the rate stabilizes to a more gradual decline for the remainder of field life, until 2031. The reservoir simulation model indicates total production from the South Avalon field to be 38.7 MMm^3 (243.4 MMbbls). The original White Rose Development Plan (Decision 2001.01) oil production forecast was 36.2 MMm^3 (230 MMbbls) for 15 years.

Figure 4.19 shows the oil production rate and cumulative production from the South Avalon reservoir simulation model. The South Avalon Pool includes the Terrace and Central blocks.

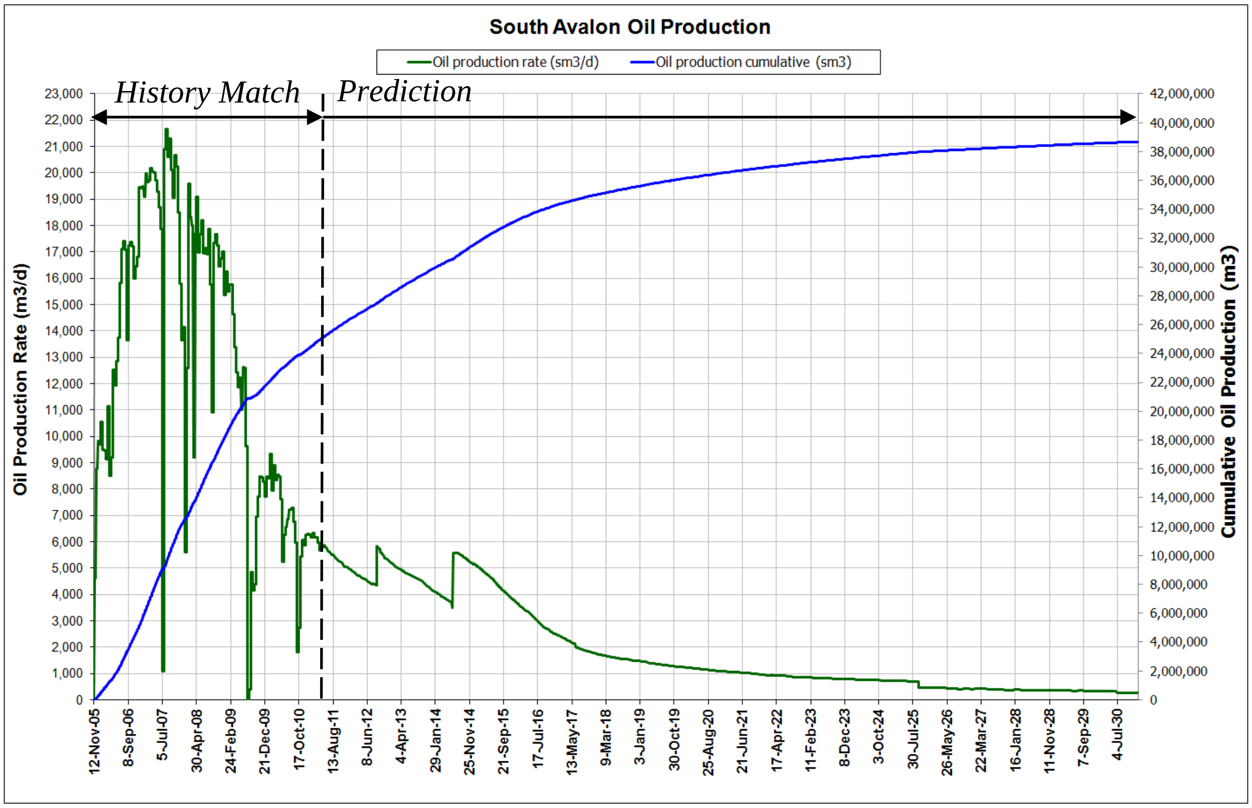

Figure 4.19: South Avalon oil production rate and cumulative – base case.

Production from the SWRX indicates an initial production of approximately 1500 m^3/d when the first well is drilled, which will increase to 2900 m^3/d when the second producer is drilled. The model indicates a fairly steep decline rate over five to six, years after which production from the SWRX declines slowly for the remainder of the field life. Using the Proponent's exploitation scheme (one gas injector, two producers and one water injector), the reservoir simulation model suggests that ultimate recovery from the SWRX region will be 3.82 MMm^3 (24.03 MMbbls). Figure 4.20 shows the oil production rate and cumulative production from the SWRX reservoir simulation model.

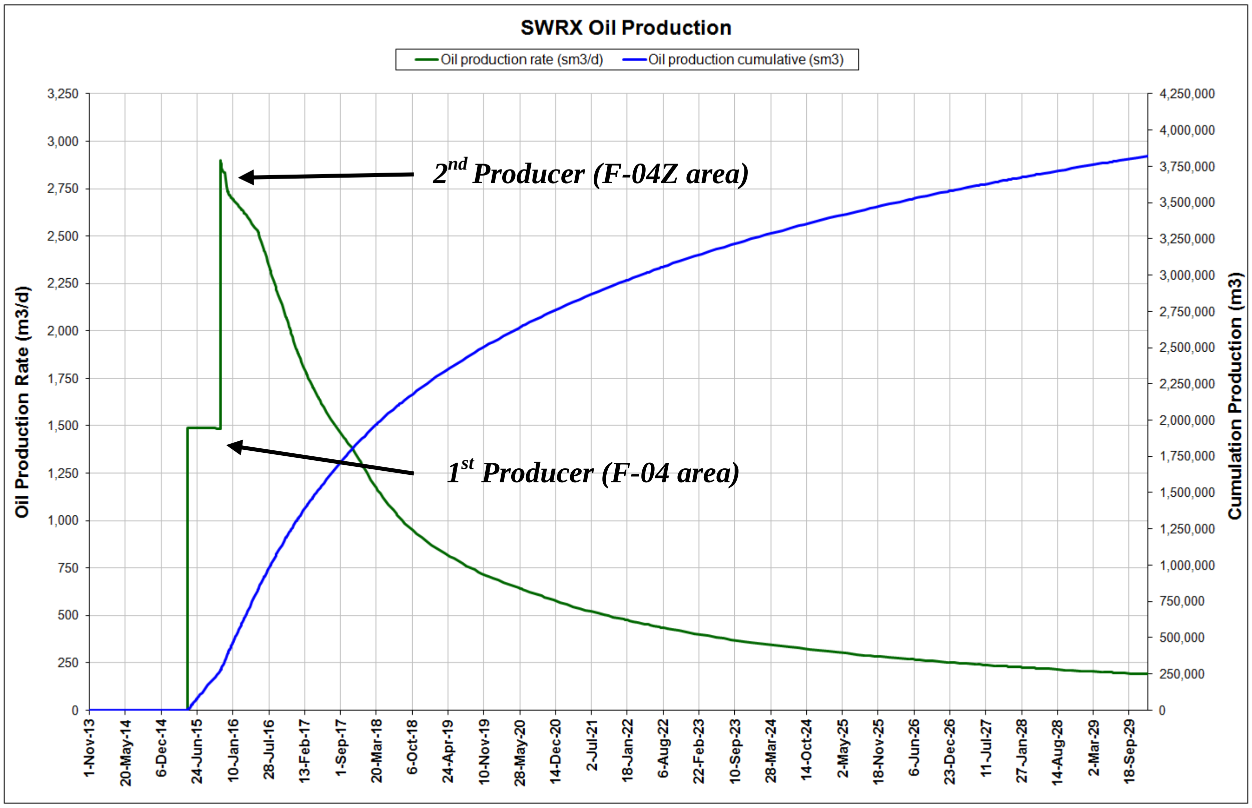

Figure 4.20: SWRX oil production rate and cumulative – base case.

Board staff finds the Proponent's approach to reservoir simulation and the resulting oil production forecasts to be reasonable.

4.7.2 Gas Production Results and Forecasts

One concern staff has with the implementation of a gas injection exploitation scheme in the South Avalon and the SWRX regions is the SeaRose FPSO's capacity to handle increased gas production. According to the submitted South Avalon reservoir simulation model, future gas production from South Avalon will peak in July 2015 with a rate of 1.81 MMm^3/d. Figure 4.21 shows gas production and injection rates and cumulative volumes for the South Avalon Pool based on the submitted reservoir simulation model.

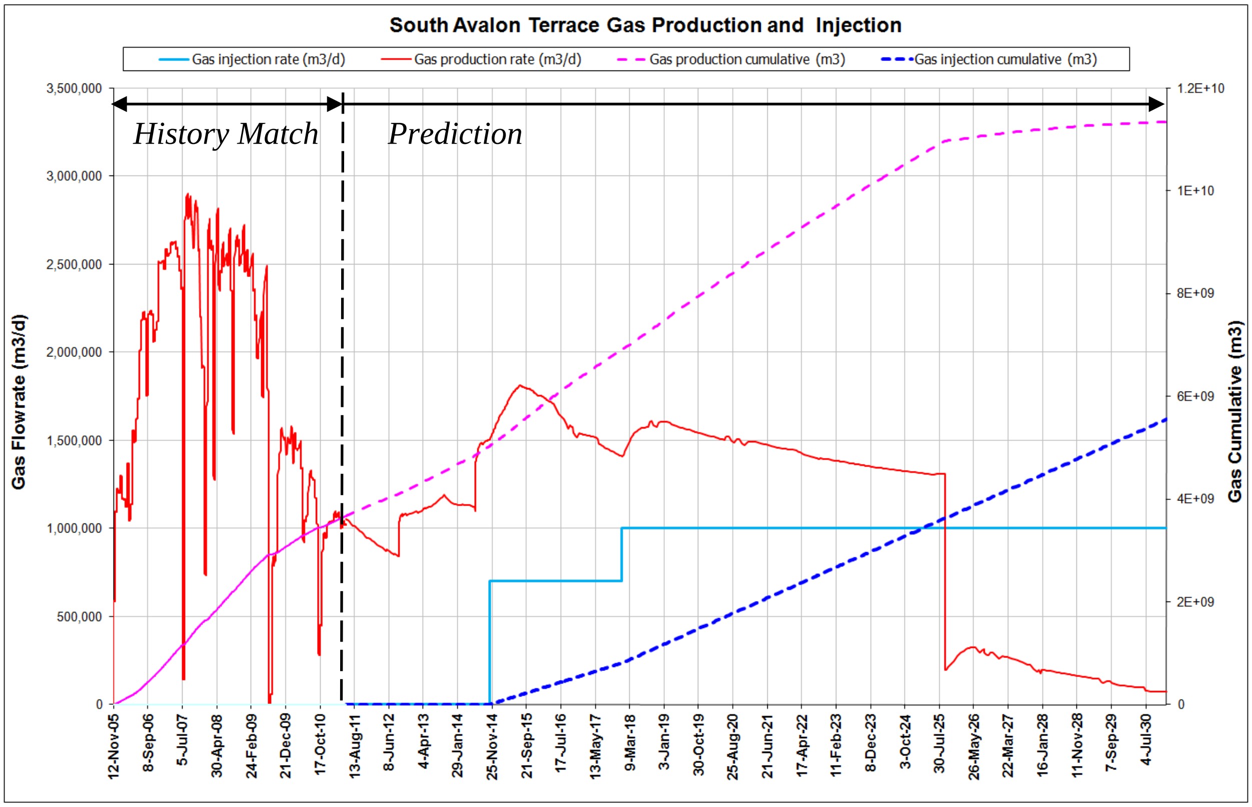

Figure 4.21: South Avalon gas production and injection rates and cumulative – base case.

In the SWRX region, the submitted reservoir simulation model indicates that peak gas production will occur toward the end of the field life and reach a maximum rate of 0.74 MMm^3/d. Peak gas injection of 1.0 MMm^3/d will occur when the gas injector comes online at the start of the field life, at which time it is anticipated that all gas from the White Rose asset will be injected into the SWRX region. Over the course of the SWRX field life, the reservoir simulation model predicts the injection of 1.2 times the amount of gas produced from the region, which indicates the importance of the SWRX to the gas management strategy of the White Rose asset as a whole. Figure 4.22 shows gas production and injection rates and cumulative volumes for the SWRX, based on the submitted reservoir simulation model.

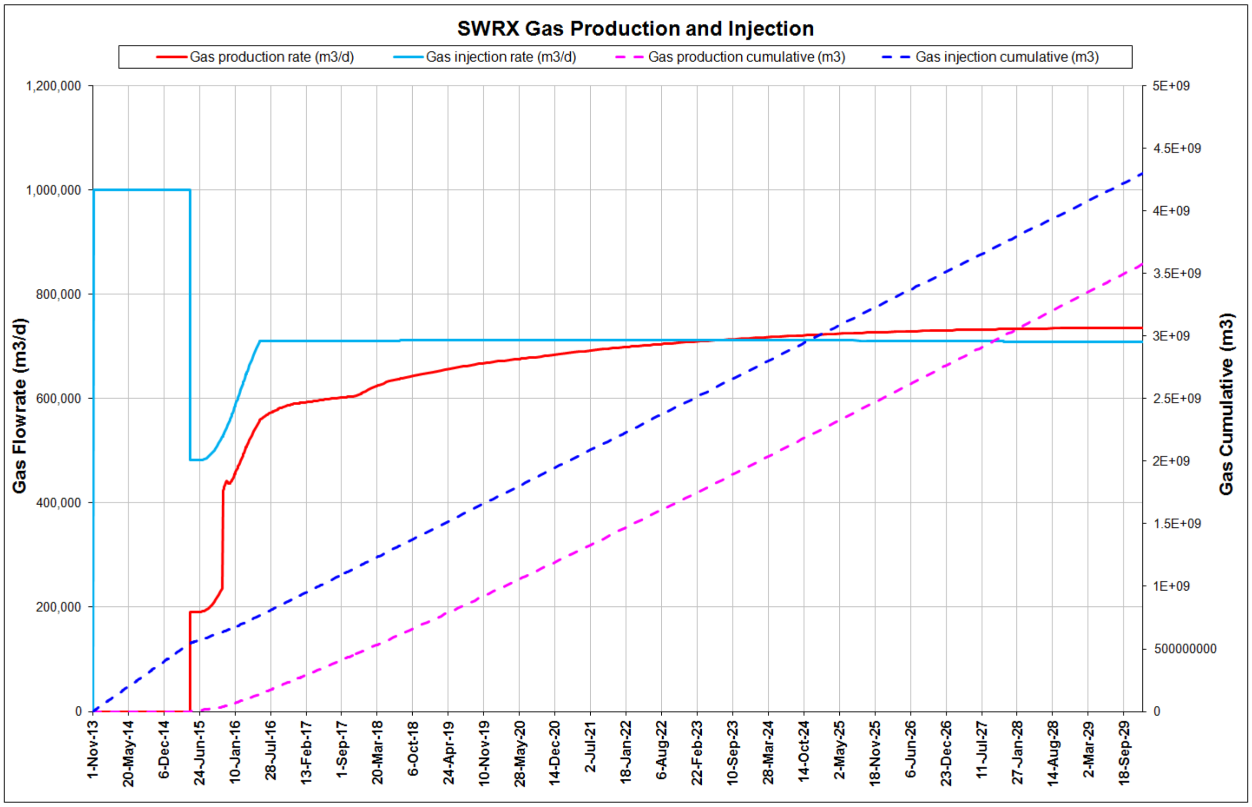

Figure 4.22: SWRX gas production and injection rates and cumulative – base case.

Combining the South Avalon and SWRX gas compression requirements indicates that the capacity of the SeaRose FPSO is more than adequate to handle gas from these developments. However, the submitted simulation models did not take other White Rose developments, such as the West Pool, North Amethyst BNA or North Amethyst Hibernia, into account.

4.7.3 Reservoir Pressure Results and Forecasts

When plotting reservoir pressure from the South Avalon simulation model, the pressure remains relatively consistent over the life of the field. However, there is a slight peak following the Terrace gas injector coming online and then a significant ramp up late in field life as production drops off, but gas injection continues in. Figure 4.23 displays South Avalon reservoir pressure for the life of the field.

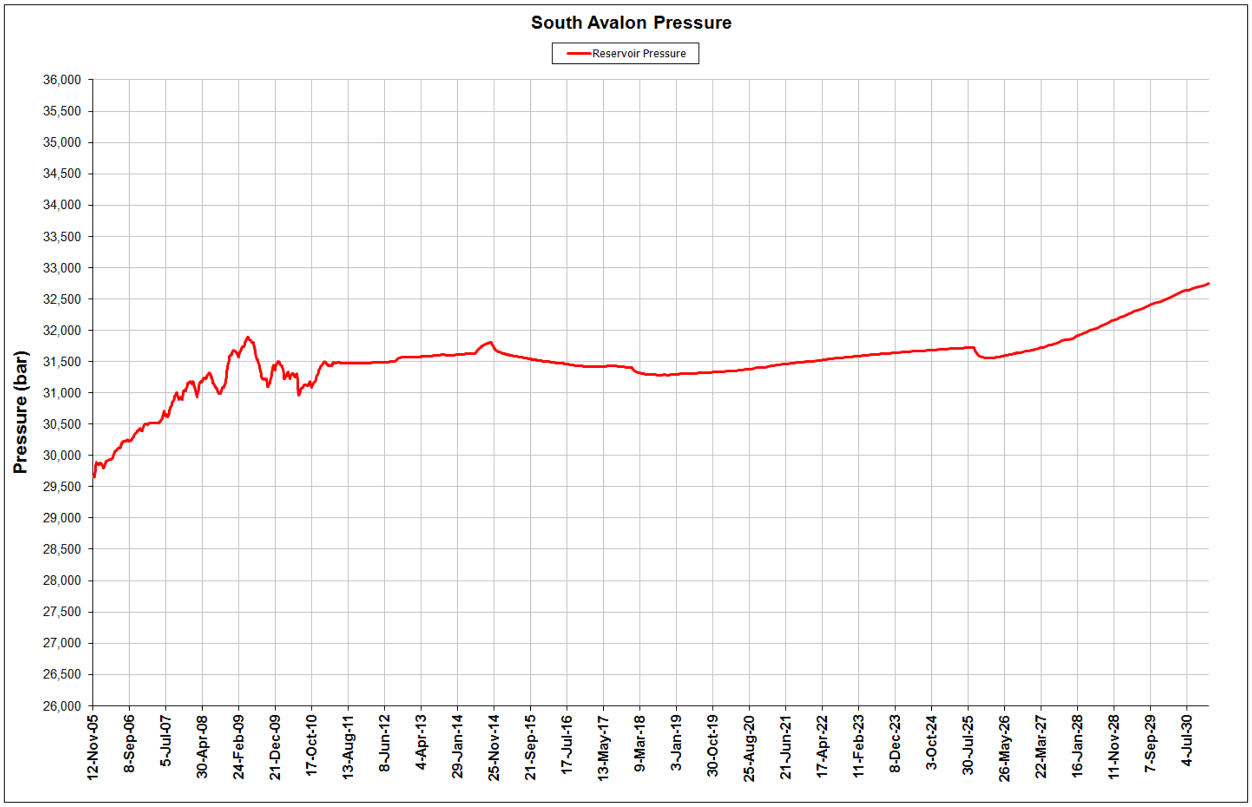

Figure 4.23: South Avalon reservoir pressure – base case.

When plotting reservoir pressure from the SWRX simulation model, pressure increases initially as the gas injector comes online and peaks just as production begins. Although pressure drops off slightly over the field life, it remains higher than initial reservoir pressure. Based on the Proponent's reservoir simulation model, there are no concerns with the maintenance of voidage or reservoir pressure using the proposed development scheme. Figure 4.24 displays SWRX reservoir pressure for the life of the field.

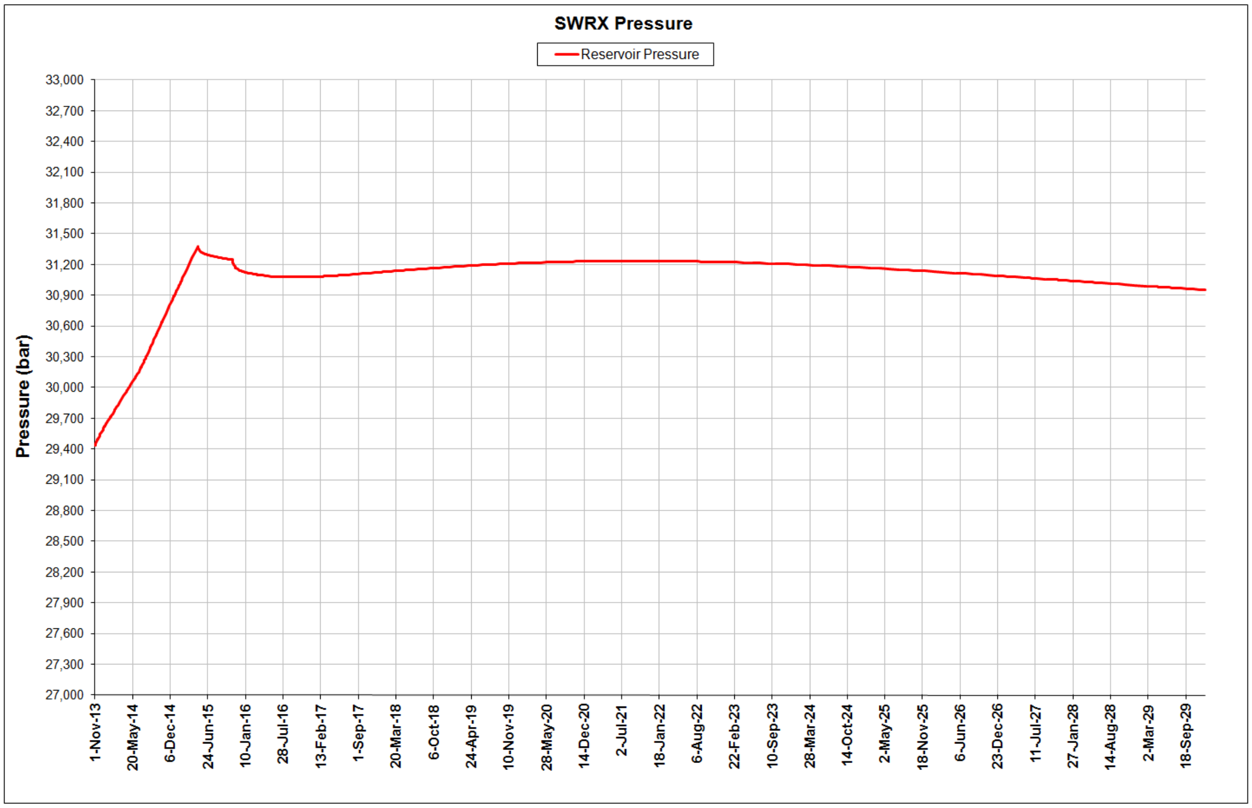

Figure 4.24: SWRX reservoir pressure – base case.

4.7.4 Reservoir Simulation Alternate Cases

In order to evaluate the Proponent's reservoir exploitation scheme, and more specifically to determine the impact of gas injection on ultimate oil recovery in the South Avalon Terrace region and SWRX area, alternate simulation cases were run.

Board staff were able to achieve a reasonable approximation of the submitted South Avalon simulation model. An alternative case that disabled the South Avalon Terrace gas injection well was also run. The results from this case indicated that the impact of gas injection on ultimate oil recovery is an additional 1.95 MMm^3 (12.27 MMbbls).

Re-running the Proponent's SWRX reservoir simulation model gave an exact repeat of the submitted results. Therefore, there was high confidence that any modifications made by Board staff to investigate the effects of changes in the exploitation scheme would sufficiently assess the impact of those changes. The first alternate case tested the impact of the planned gas injection well. In this case, the gas injector was removed but the two oil producers and one water injector, as described in the proposed exploitation scheme, were included. This case yielded an ultimate oil recovery of 3.21 MMm^3 (20.19 MMbbls), which suggests that the implementation of gas injection as planned will result in an additional oil recovery of 0.61 MMm^3 (3.84 MMbbls). Figure 4.25 compares the oil production rate and cumulative oil production with gas injection (solid line) and without gas injection (dashed line).

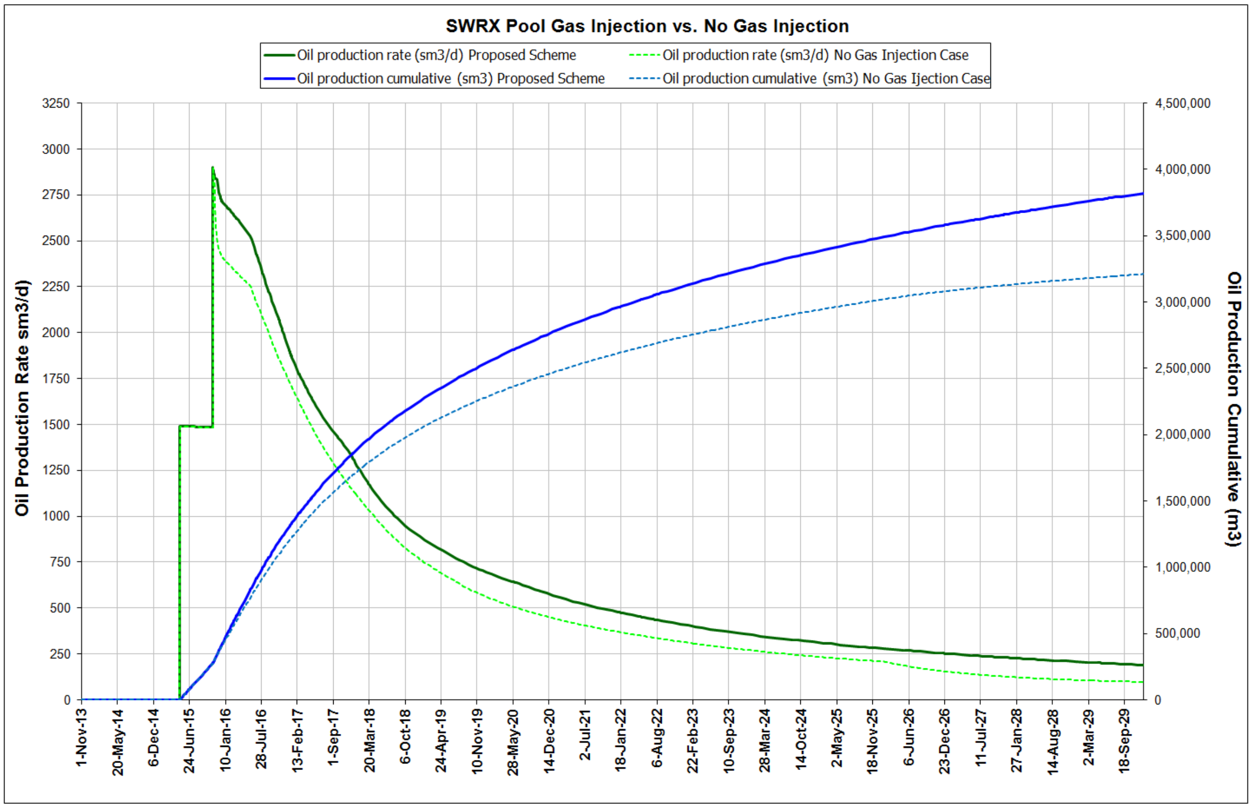

Figure 4.25: SWRX production rate and cumulative – base case vs. no gas injection.

In 2006, the Proponent submitted a DPA addressing development of the SWRX using an exploitation scheme with three producers and two water injectors. Using the Proponent's current reservoir model, a case was run using the proposed production and water injection wells with the addition of a water injector to the F-04 block and the removal of the proposed gas injector. Ultimate oil recovery in this case was 3.52 MMm^3 (22.14 MMbbls) which is 0.3 MMm^3 (1.89 MMbbls) less than recovered with the proposed depletion strategy. Figure 4.26 compares the oil production rate and cumulative with the proposed exploitation scheme (solid line) and the alternate case with two water injectors (dashed line).

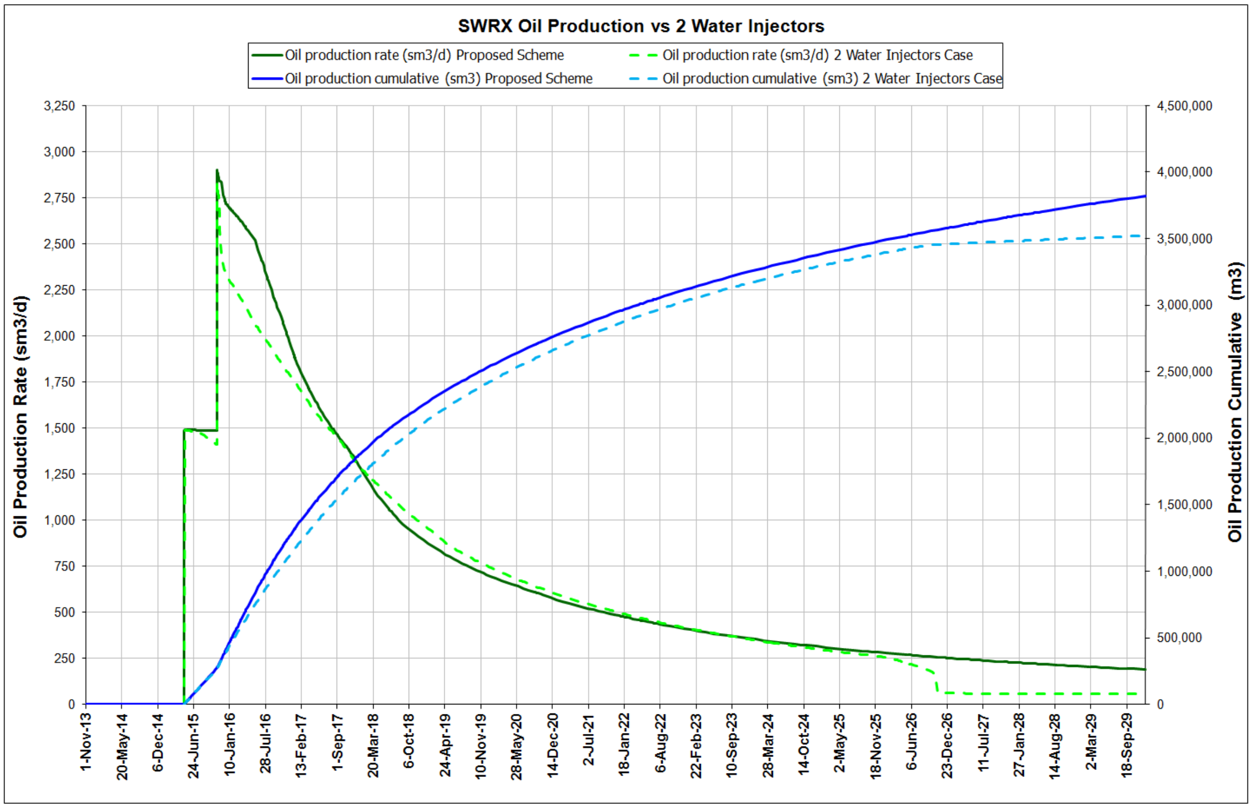

Figure 4.26: SWRX production rate and cumulative – base case vs. two water injectors.

Based on alternate cases run on the SWRX reservoir simulation model, the proposed exploitation scheme with two oil producers, one gas injector and one water injector has the highest ultimate recovery of all the cases examined. While the difference in ultimate recovery in all cases is not significant, the proposed scheme has the added benefit of alleviating gas storage capacity concerns within the White Rose asset.

4.7.5 Reservoir Simulation Summary

The Proponent used the available geological and reservoir engineering information to develop reasonable reservoir simulation models for both the South Avalon and SWRX regions. The models and cases submitted provide an adequate overview of these development areas, but do not address other developments in the White Rose asset, most notably North Amethyst and West White Rose. Staff's analysis indicates that the current South Avalon and SWRX reservoir simulation models are sufficient in the context of this Application.

4.8 Reserve Estimates

The Application presented a deterministic estimate of 3.82 MMm^3 (24 MMbbls) for the most likely recoverable oil for the SWRX Pool. This estimate corresponds to 25% of the P50 probabilistic oil-in-place estimate. For the South Avalon Pool, the deterministic estimate of the incremental recoverable oil is approximately 1.51 MMm^3 (9.52 MMbbls) under the proposed scheme. Furthermore, the cumulative recovery of the proposed scheme was shown to be 38.68 MMm^3 (243.28 MMbbls), compared to a cumulative recovery of only 37.16 MMm^3 (233.76 MMbbls) for the previously approved water flood scheme.

The Application also contained probabilistic recoverable reserve estimates for the South Avalon Terrace and SWRX pools. Table 4.7 summarizes the Proponent's and staff's low, expected and high case recoverable estimates for these regions.

Pool	Units	P90		P50		P10	
		Husky	C-NLOPB	Husky	C-NLOPB	Husky	C-NLOPB
SWRX	MMbbls	16.2	15.2	25.8	22.0	38.6	30.2
	MMm^3	2.6	2.4	4.1	3.5	6.1	4.8
South Avalon Terrace	MMbbls	115.2	119.5	123.2	128.8	133.5	147.2
	MMm^3	18.3	19	19.6	20.5	21.2	23.4

Table 4.7: Comparison of Proponent and C-NLOPB probabilistic reserve estimates, South Avalon Terrace and SWRX areas.

Board staff did not construct independent reservoir simulation models. Rather, the Board's recoverable oil estimates were calculated by using low, medium and high case recovery factors in conjunction with the staff's OOIP estimates. The recovery factors chosen were based on a combination of the Proponent's reservoir simulation results, South Avalon Pool production performance and staff's geologic and engineering knowledge.

Both the Proponent's and staff's reserve estimates for the SWRX Pool have slightly increased since the initial DPA was approved in Decision 2007.02. At that time, the Proponent estimated P50 recoverable reserves for SWRX to be 3.8 MMm^3 (24 MMbbls), while staff estimated P50 recoverable reserves to be 3.4 MMm^3 (21.6 MMbbls).

In the White Rose Decision Report (Decision 2001.01), the Proponent's P50 recoverable reserves for the South Avalon Pool were estimated at 37.1 MMm^3 (233.4 MMbbls) while the staff's estimate was 32.9 MMm^3 (207 MMbbls). While no P50 recoverable reserve estimate was provided in this Application, a most likely deterministic recoverable estimate of 38.68 MMm^3 (243.28 MMbbls) was provided from reservoir simulation.

Staff recognizes that the overall reserve numbers for the White Rose asset need to be reassessed and updated, and this work is currently ongoing.

It is also worth noting that the Proponent's current deterministic recoverable oil estimates for the South Avalon and SWRX pools result from the reservoir simulation models producing out to 2030. As discussed, the current design life of the SeaRose FPSO is twenty years, to 2025. The deterministic recoverable oil estimates presented in the Application cannot be recovered without the addition of five more years of production. **Additional work by the Proponent will be required in order to assess the feasibility and impact of extending the field life beyond 2025.**

4.9 Conclusions and Recommendation

There is currently a shortage of gas storage space within the White Rose Field. The remaining gas storage capacity within the Northern Drill Centre region could be filled as early as December 2013, and is inadequate for the forecasted volumes of produced gas from current production and future development. In order to continue oil production without causing a gas resource waste issue, a change in the Proponent's gas utilization strategy is required. The Proponent has outlined a plan that uses gas flooding in the southern Terrace and SWRX areas to support oil production. The Proponent has demonstrated that gas injection in these areas will help to alleviate gas storage issues without negatively impacting ultimate oil recovery from the South Avalon and SWRX pools.

Under the proposed scheme, the Proponent's P50 recoverable oil estimate for SWRX has increased slightly from 4 MMm^3 (24 MMbbls) to 4.1 MMm^3 (25.8 MMbbls) since the original SWRX DPA approval (Decision 2007.02).

The exploitation plan for the South Avalon Pool includes drilling an infill production well and a gas injection well in the southern portion of the Terrace block. The gas injection will provide pressure support to the planned infill and existing production wells, which will help recover unswept "attic" oil in the reservoir. Reservoir simulation indicates that the proposed wells will increase ultimate recoverable oil from the South Avalon Pool by an estimated 1.51 MMm^3 (9.52 MMbbls). The potential for a significant volume of unswept "attic" oil in the South Avalon Pool was identified an issue which would have to be addressed prior to end of field life in the White Rose Decision Report (Decision 2001.01). The proposed plan for the southern Terrace addresses the concerns raised in Decision 2001.01, as it provides a means to exploit the unswept "attic" oil and increase ultimate oil recovery from the area.

The largest risk to production under the proposed exploitation scheme is early gas breakthrough in either the SWRX or the South Avalon Terrace. The Proponent plans to take steps during the implementation of the exploitation plan to help mitigate this risk. The Proponent will also have the ability to inject in only one of the pools should early gas breakthrough occur in the other.

Staff found the Proponent's geological and reservoir simulation modeling to be reasonable and appropriate. The reservoir simulation indicates that the SeaRose FPSO facilities can adequately handle additional production from the proposed exploitation scheme. The Application also provides sufficient flexibility to accommodate potential future development in the SWRX area, as the proposed drill centre can accommodate six additional wells if necessary.

The following list summarizes some of staff's expectations and requirements as the proposed project progresses.

- The Proponent is expected to obtain an oil sample from the SWRX Pool at the earliest opportunity to confirm that the fluid property assumptions made in the Application are valid.
- Prior to the initiation of any gas flooding in areas of the South Avalon Pool outside the southern Terrace, the Proponent must submit an updated exploitation scheme for Board approval.
- The production forecasts and deterministic recoverable oil estimates presented in the Application assume an extension of field life by five years. The Proponent will be required to perform additional work to assess the feasibility and impact of extending the field life beyond 2025.

Staff concurs with the proposed Application from a resource management perspective, and recommend approval, subject to the following conditions:

1. The Proponent must submit a report acceptable to the Board assessing the sealing nature of the fault separating the East and West Fault blocks one year after commencement of gas injection into the southern Terrace.

2. Should the period of gas injection prior to oil production in the SWRX Pool extend beyond 18 months, the Proponent must submit a report acceptable to the Board detailing the activities to date and future plans for gas injection in the SWRX Pool.

5.0 SAFETY

The safety review of the Application focused on the Proponent's plans for tying an oil producer and gas injector for the South Avalon pool and two oil producers, a gas injector and a water injector for the South White Rose Extension Pool back to the SeaRose FPSO.

The Proponent's plan is to excavate a new South White Rose Extension (SWRX) Excavated Drill Center and install the necessary subsea equipment to support the six new development wells. The flowlines for this new SWRX drill center will be tied back to the existing production, water injection and gas lift flowlines that connect the North Amethyst Drill Center (NADC) and the Southern Drill Center (SDC). The SWRX drill center will have a gas injection flowline that ties-in directly to the Northern Drill Center (NDC), as well as an electro-hydraulic umbilical that ties into the SDC. The development wells will be drilled utilizing a semi-submersible drilling installation. This plan is consistent with the approach approved in the original White Rose development plan.

Consistent with this approach, the Proponent is planning to use an excavated drill center as the means of protecting the subsea templates, wellheads, production trees and manifolds against scouring icebergs and critical equipment will have clearance from potential iceberg scour consistent with the practice applied in the other drill centers. This is an acceptable methodology for subsea developments as approved in the original White Rose development plan and associated amendments.

5.1 Construction and Installation Phase

Safety risks to personnel will arise during the various construction and installation phases of the development, including the drilling program, the subsea flowline installation program and the diving program to tie in the flowlines to existing subsea infrastructure. Each of these programs will require a "Work Authorization" from the C-NLOPB as specified by the Atlantic Accord Act and will also require oversight by the Certifying Authority. A detailed safety assessment of each of these programs will be undertaken by the Board's Safety staff in accordance with established processes and procedures. The safety assessment process systematically examines the adequacy of the Proponent's safety plan for each proposed activity to confirm that the Proponent has identified all hazards and has adequately addressed each identified hazard. The safety standards pertaining to facilities, equipment, policies, procedures, training and competency of personnel for each of the proposed construction and installation activities are firmly established based on experience with similar work authorizations. In general, the construction activities associated with the proposed extension do not raise any new safety concerns from the staff's perspective particularly in view of the fact that the Proponent has demonstrated the ability to successfully execute such programs in the past.

Staff will, however, require the Proponent to specifically address the following matters in their associated work authorization submissions:

- a summary of simultaneous operations issues and mitigations;
- outline the risks and mitigations associated with conducting the mid-line tie-ins to the existing NADC to SDC production, water injection and gas lift flowlines; and

- a summary of the specific modifications that will be made to the NDC manifold to allow for the Gas Injection flowline connection and tie-in of control jumpers.

5.2 Drilling and Completions

The drilling and completions activities will be carried out using existing White Rose processes and systems, with the exception that larger conductor casing sizes will be used to support increased load capacity. Drilling hazards and mitigative measures are covered by the Proponent's existing Quantitative Risk Analysis (QRA) and Safety Plan for drilling operations. The incremental impact of this additional well operation activity was also further reviewed by the Proponent; this is commented in the next section of this analysis. In addition, the final design of the drilling program of each well, and the completion design and installation, will be reviewed during the Approval to Drill a Well (ADW) process.

5.3 Risk Analysis

The Proponent conducted a study to determine the impact on risk to the safety of personnel, facilities and equipment due to the SWRX tie-back. The study looked at the incremental impact of the construction, installation, drilling and completion aspects of the program as well as impact on the SeaRose FPSO from the facility modifications. The results of this assessment are provided in the report *Concept Safety Assessment of South White Rose Expansion Project, Atkins Report No. 5113311/003-RP-01 Rev 1* issued to Husky Oil Operations Ltd. dated August, 2012. The quantitative risk analysis did not raise any concerns regarding the resultant impact on the target levels for safety identified for the project in the original White Rose development safety studies. The study identified a number of recommendations for consideration as the project proceeds through the detailed engineering phase and the Application outlines the manner in which the Proponent plans to address each recommendation. As part of the approval of this Application, the Proponent will be required to update the Board's Chief Safety Officer (CSO), prior to equipment tie-in, on the progress for addressing each of the recommendations. The Proponent will also be required to keep staff informed of the detailed schedule for the project, including a schedule for any ongoing or future safety studies.

The Atkin's study also noted that the assessment is based on the use of the Global Santa Fe (GSF) Grand Banks as this MODU has performed operations at the White Rose Field in the past. Should a different MODU be used, the assessment should be reviewed and updated to ensure that the specific MODU risk is assessed. In such circumstance, the Proponent will be required to submit the revised assessment for consideration by the CSO.

5.4 Modifications to Facilities

The Proponent has confirmed that an upgrade will be required to the subsea master control station software and to the SeaRose FPSO integrated control and safety system but will be similar in nature to that required for the previous North Amethyst and West Pilot Scheme projects. Also, minor modifications will have to be made to the hydraulic power unit, as well as the methanol and chemical injection systems. Any modifications will require an independent assessment by the Certifying Authority and approval by both the CSO and the Certifying Authority pursuant to sub-section 67(1) of the *Newfoundland Offshore Petroleum Installation Regulations*. In this regard, the "scope of work" for the Certificate of Fitness will have to be modified by the Proponent to capture any modifications that are required to any of the systems or facilities as a result of the SWRX Tie-back and to include any new subsea systems and flowlines to be installed in connection with the expansion.

The Application notes a deterministic resource depletion profile that extends out to 2030; however, the Proponent has clearly stated that the end of field life is not tied to this date and that this depletion profile is not a statement of intent to operate to a specific date beyond the current design life of the original equipment which is to 2025. As well, the issue of any potential Life of Facility Extension is not a current or near term consideration. Facility life beyond 2025 has not been considered at this point in time and the current approval only covers a Facility Life to 2025.

It will also be necessary for the Proponent to integrate any modifications into existing systems, policies and procedures and to provide any necessary training to personnel in respect of any new systems or upgrades. Such efforts must be complete prior to operation of the SWRX tie-back development wells and prior to operation of any topsides equipment modified as a result of this program.

5.5 Existing Plans and Procedures

The Proponent's ice management plan will need to be amended in due course to expand the ice management zone around the SeaRose FPSO to include the facilities in the SWRX excavated drill center. Modifications to the SeaRose FPSO safety zone have already been addressed. All operational changes, including any necessary updates to the SeaRose Safety Plan must be effected in accordance with the Proponent's management of change process.

5.6 Conclusions and Recommendations

All of the safety matters arising from staff's review of the Application can be managed in accordance with established processes and procedures. No safety concerns were identified that would preclude staff from recommending that the Board approve the Development Plan Amendment.

Staff will ensure that the following matters will be followed up with the Proponent in due course as the project proceeds:

1) The Proponent is to specifically address the following matters in their associated work authorization submissions for the construction and dive programs:
   - a summary of simultaneous operations issues and mitigations;
   - outline the risks and mitigations associated with conducting the mid-line tie-ins to the existing NADC to SDC production, water injection and gas lift flowlines; and
   - a summary of the specific modifications that will be made to the NDC manifold to allow for the Gas Injection flowline connection and tie-in of control jumper.

2) Prior to equipment tie-in to existing infrastructure, the Proponent must confirm to the CSO the manner in which the recommendations arising from the Atkin's report have been addressed.

3) At an appropriate stage in the detailed engineering design phase, the Proponent must update staff of the detailed schedule for the project, including a schedule for any ongoing or future safety studies.

4) The scope of work of the Certifying Authority in respect of the White Rose project must be amended to include a review of any new subsea systems and flowlines to be installed as well as any modifications to either the SeaRose FPSO or existing subsea systems.

5) Prior to operation of the SWRX Tie-back development wells and prior to operation of any topsides equipment modified as a result of this program, the Proponent must have updated all related facility description, operation and maintenance procedures and documents affected by this expansion program and must have completed all necessary training for operation and maintenance personnel in respect of any new systems or upgrades. Such efforts must be confirmed as complete, to the satisfaction of the CSO, prior to operation of the SWRX Tie-back development wells and prior to operation of any topsides equipment modified as a result of this program.

6) As a matter of course, updates to the SeaRose Safety Plan reflecting the SWRX Tie-Back must be submitted to the CSO for approval. Any necessary changes to the ice management plan, the safety zone around the SeaRose FPSO and any other operational updates to existing plans, processes and procedures must be made by the Proponent in accordance with the established management of change process.

6.0 OPERATIONS

The operations review of the Application focused on an assessment of the Proponent's plans for the SWRX project in order to determine whether it raised any new operational issues.

6.1 Drilling and Completions

Operational risks to personnel and equipment will arise during the various phases of development, including the drilling and completions programs. These activities will be carried out using the Proponent's existing White Rose and North Amethyst field processes and systems. In particular, drilling hazards and mitigative measures are covered by the Proponent's existing Quantitative Risk Analysis (QRA), the Proponent's Drilling and Completions Operations Manual and their drilling contractor's Operational Integrity case. Any final well designs, cementing programs, and drilling programs will be reviewed during the Approval to Drill a Well (ADW) process. The completion design and installation plan will be outlined and assessed in the completion program as part of the ADW.

6.2 Subsea Equipment Installation, Commissioning and Operation

The Proponent received Ministerial approval to drill the first well in the SWRX excavated drill center, J-05 1, and is proceeding with that program. This well is the first planned gas injector to be drilled outside the Northern Drill Centre (NDC). The Proponent plans to drill one more gas injector in the SWRX drill center to target the South Avalon Pool.

The SWRX development will utilize well templates and wellhead systems that are similar as those used for the other wells in the White Rose and North Amethyst Fields. The first gas injector is planned to be completed prior to the installation of subsea manifolds, control equipment and flowlines. The SWRX Drill Center will be tied back to the existing production, water injection and gas lift flowlines to the North Amethyst Drill Centre (NADC) and the Southern Drill Centre (SDC). The final connection location will be either midline or at the end of the drill centers pending final routing reviews. A gas injection flowline from the NDC will tie-in directly to the SWRX Drill Centre as well as an electro-hydraulic umbilical from SDC to SWRX.

The installation activities associated with the SWRX do not raise any new operational safety concerns from the staff's perspective as the Proponent has demonstrated the ability to execute such programs successfully in the past.

6.3 Modifications to Installation

As the project moves into the detailed engineering phase, modifications will be made to the various control systems on board the SeaRose FPSO, including minor modifications to the Integrated Control and Safety System (ICSS) and Master Control Station (MCS) software. The Proponent will use the existing management of change process for the modifications on the SeaRose FPSO.

The SeaRose FPSO as a production installation encompasses all equipment for the production of oil or gas, including separation, treatment and processing facilities, equipment and facilities used in support of production operations, landing areas, heliports, storage areas or tanks and personnel accommodations, and subsea production system, loading system, and facilities related to marine activities.

It is the responsibility of the Proponent to ensure the SWRX Tie-back project, including the production installation, comply with the regulations and that the project can be conducted safely without polluting the environment. Furthermore, the Proponent is required to have a valid Certificate of Fitness. The Certificate of Fitness provides an independent third party assurance and verification that the installation, during the term of the certificate, is fit for purpose, functions as intended, and remains in compliance with the regulations without compromising safety and polluting the environment.

Following the issuance of the Certificate of Fitness, the Certifying Authority surveys the installation periodically to verify the continued integrity of the installation. In addition, all modifications/repairs to the installation that affects its strength, stability, integrity, operability, safety or regulatory compliance need to be reviewed and accepted by the Certifying Authority to ensure the continued validity of the certificate.

6.4 Safety Analysis

The Proponent will utilize existing systems and processes for assessing any identified risks related to activities associated with the development of the SWRX. These processes include the Proponent's procedure for management of change and their east coast risk management process.

6.5 Existing Plans and Procedures

The Proponent's existing systems and processes for assessing risks of planned operations, modifications or changes will be used in relation to the implementation of the SWRX Tie-back project. The Proponent's existing operations and maintenance policies and procedures, ice management plan, contingency plans, logistical support, communications, vessel surveillance and production safety protocols will also apply to the implementation of this project. These documents were used, and continued to be used, for the development and operation of the White Rose and North Amethyst Fields.

6.6 Conclusions and Recommendations

The Proponent plans to use existing policies and procedures for the SWRX Tie-back project which are already in place for the White Rose and North Amethyst projects. Review of the Proponent's drilling plans will be conducted during the Approval to Drill a Well (ADW) process. The Proponent's ADWs will require the review of operations staff and approval by the Board.

The Proponent has stated they will use their existing Certifying Authority, Det Norske Veritas (DNV), during the design, fabrication, installation, and commissioning phases of the project.

This is consistent with procedures that currently exist with the White Rose and North Amethyst projects.

No operational concerns were identified which would preclude staff from recommending approval of the Application. Activities in connection with this application can be managed in accordance with established safety processes and procedures already in place for the White Rose and North Amethyst Fields.

7.0 PROTECTION OF THE ENVIRONMENT

7.1 Environmental Assessment

Staff reviewed the Application to determine whether it raised any environmental concerns that were not previously assessed as part of the *White Rose Oilfield Comprehensive Study Report*[1] completed in 2001, in the documents submitted by the Proponent in support of the new drill centres environmental assessment[2,3], in the C-NLOPB's *New Drill Centre Construction and Operations Program CEA Act Screening*[4] or in C-NLOPB Decisions 2001.01, 2007.02, 2008.03.

It was determined that the proposed construction of a new drill centre for the South White Rose Extension (SWRX) with a capacity of up to 16 wells, installation of subsea equipment, and tie-back to the SeaRose FPSO had been assessed in the screening level environmental assessment completed for new drill centres in 2007.[5,6,7] That assessment concluded that, with the application of mitigation measures, the implementation of a follow-up program and adherence to relevant C-NLOPB guidance material, significant adverse environmental affects associated with the project were not likely. The project as described in the Application is consistent with the geographic scope, and description of project activities previously assessed in 2001 and 2007 and no further environmental assessment is required for the construction of the excavated drill centre, installation of subsea equipment and tie-backs, and drilling and completions of wells at this location.

The temporal scope related to production operations and related well interventions and workovers at the SWRX site, as described in the Application, extends beyond the temporal scope assessed in the 2001 *White Rose Comprehensive Study Report* and in the 2007 *Screening Report* for five additional drill centres. Temporal scope in the 2001 White Rose Comprehensive study is set out as start-up and first oil at approximately the fourth quarter of Year 3 with production operations ending by Year 18.[8] With first oil in November 2005, a fifteen year production life would close temporal scope in 2020. The 2007 *Environmental Assessment Addendum*[9] and the

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[1] Husky Oil Operations Limited, *White Rose Comprehensive Study Report*, April 2001, 94 p.
[2] LGL Limited, September 2006, *Husky White Rose Development Project: New Drill Centre Construction & Operations Program Environmental Assessment*. LGL Rep. SA883. Rep. by LGL Limited, St. John's, NL, for Husky Energy Inc., Calgary, AB. 299 p. + Appendices.
[3] LGL Limited, January 2007, Husky White Rose Development Project: New Drill Centre Construction & Operations Program Environmental Assessment Addendum. LGL Rep. SA883a. Rep. by LGL Limited, St. John's, NL, for Husky Energy Inc., Calgary, AB. 126 p. + Appendices.
[4] C-NLOPB, April 2007, *Husky White Rose Development Project: New Drill Centre Construction and Operations Program, CEA Act Screening Report*, 38 p.
[5] LGL Limited, September 2006
[6] LGL Limited, January 2007
[7] C-NLOPB, April 2007
[8] Husky Oil Operations Limited, April 2001, page 25
[9] LGL, January 2007, page 6

Screening Report[10] state that "Production operations associated with these five new drill centres would occur between 2009 and 2020" and that "Effects of activities associated with production operations using the new drill centres have been assessed 'year-round' for the period 2009-2020."[11]A review of C-NLOPB Decision 2001.01 indicates on page 75, "The forecast predicts that … it will take 15 years to recover the oil reserves." This is consistent with the field life described in the 2001 *White Rose Oilfield Comprehensive Study*.

The Proponent will have to address temporal scope issues by amending their environmental assessment documents prior to C-NLOPB authorizing any activity past 2020. While the "Life of field" issue may not be critical in respect of the near-term work described in the development plan amendment application, the C-NLOPB will not be able to authorize or approve any activity that extends beyond the assessed project temporal scope.

7.2 Environmental Effects Monitoring

The Proponent has an ongoing environmental effects monitoring program to meet the Canadian Environmental Assessment Act requirements for a follow-up program. Amendment of the program to account for additional drill centres was required in Decision 2007-02 by Condition 2007-02.01:

> **The Proponent, no later than six months prior to commencing drilling operations at the SWRX drill centre, shall submit for the approval of the Chief Conservation Officer an amended Environmental Effects Monitoring program design that considers drilling and production activities associated with the SWRX drill centre.**

That condition was restated in Decision 2008-03 approving the "Development Plan - North Amethyst Satellite Tie-back to SeaRose FPSO" where condition 2008-03.01 required a revised EEM plan prior to commencing drilling operations.

The Proponent's EEM program was revised accordingly and accepted by the C-NLOPB in 2008.

7.3 EPP for Drilling and Production Operations

Environmental protection plans (EPPs) currently exist for production operations at the White Rose Field using the SeaRose FPSO and associated equipment and for drilling operations using the MODUs "GSF Grand Banks" and "Henry Goodrich".

At the time of application for or amendment of the Proponent's operations authorization for the SWRX, the relevant EPPs must be reviewed by the Proponent to determine if any updates or revisions are required. Staff expects the Proponent to submit the results of this review, and any necessary amendments to its drilling EPP(s) and/or its production EPP with its application for an Operations Authorization or amendment.

[10] C-NLOPB, April 2007, page 2
[11] C-NLOPB, April 2007, page 119

7.4 Decommissioning and Abandonment

In the Application, page 84, the Proponent states that "The decommissioning and abandonment of the SWRX facilities will be in accordance with the established White Rose Decommissioning and Abandonment Plan." The Proponent has a decommissioning and abandonment plan on file with the C-NLOPB (Husky Document No. WR-S-90-X-PG-00001-001), but that plan does not include information related to SWRX or other developments beyond the original scope of the White Rose Project. Under Subsection 6(k) of the *Newfoundland Offshore Petroleum Drilling and Production Regulations*, the Proponent is required to provide a decommissioning and abandonment plan with an application for an authorization. The Proponent should review its decommissioning and abandonment plan to ensure that the plan addresses all aspects of the proposed development plan amendment, that all developments operated by the Proponent in association with White Rose and North Amethyst are described by the plan, and that the plan is acceptable in respect of any related application for an operations authorization.

7.5 Conclusion

No environmental concerns were identified that would preclude staff from recommending approval of the Application.

8.0 INDUSTRIAL BENEFITS

The Board's development plan guidelines indicate that any development plan amendment should be accompanied by an assessment of the impact that the amendment will have on the approved benefits plan. In this case, it was determined that the industrial benefits associated with the proposed changes to the depletion schemes for the South Avalon Pool and the South White Rose Pool (and gas storage in these pools) did not materially affect the basis of the Board's approval of the White Rose Benefits Plan (Decision 2001.01) or the subsequent approval of the South White Rose Extension (Decision 2007.02). As a result, the Proponent was not required to file a benefits plan amendment and instead it was determined that a supplement to the benefits plan was appropriate. The Proponent provided this supplement in section 10.0 of the development plan amendment document.

A summary of the activities associated with the Application and staff's assessment of the supplemental benefits information follows.

Summary of Proposed Activities

The industrial benefits associated with the installation or modification of the subsea infrastructure, the drilling of wells and the other activities associated with the proposed amendment have previously been described either as part of the original White Rose benefits plan approved in 2001 or as part of the benefits plan review for the South White Rose Extension (SWRX) accepted in 2007.

The additional activities associated with the current development plan amendment may be summarized as follows:

- project management and engineering activities including front-end engineering design, detailed design engineering, procurement, construction management, hook-up and commissioning of the subsea flow lines, risers, umbilicals and ancillary equipment;
- drilling and completion activities associated with additional gas injection wells in either the SWRX Pool or the South Avalon Pool;
- construction of additional manifold structures;
- modification of the gas injection manifold in the northern drill center to allow for a gas injection flow line connection to the SRWX drill center;
- installation, hook-up and commissioning of a gas injection flow line from the northern drill center to the SWRX drill center which would also include a flow line tie in structure for possible future tie-in of a gas injection line to the proposed wellhead platform;
- installation, hook-up and commissioning of a gas injection manifold and module in the SWRX drill center;
- installation, hook-up and commissioning of an extension to the control umbilical from the southern drill center to the SWRX drill center and the installation of a subsea distribution control unit in the SWRX drill center; and
- minor modifications to the SeaRose FPSO topsides respecting software modifications, hydraulic power units and the pressure ratings of the methanol and chemical injection systems.

Project Costs

Total capital expenditures for the proposed project are estimated at $1.2 billion, as follows:

Activity	Cost (in Millions)
Project Management & Engineering	$70
Drilling & Completions (6 wells)	$590
Excavated Drill Center Construction	$40
Subsea System	$495
FPSO Modifications	$5
TOTAL	**$1,200**

The proposed project will not materially affect the overall operating expenditures for the White Rose project other than costs that may be incurred from time-to-time for any additional inspection, maintenance or repair activities.

8.1 ANALYSIS

Employment

An estimated 877,500 person-hours of employment will be generated in the Province as a result of the proposed project.

Project Component	Estimated Person-Hours
Project Management	240,000
Drilling & Completions	500,000
Excavated Drill Center	30,000
Subsea System	100,000
FPSO Modifications	7,500
TOTAL	**877,500**

This estimate includes the project management activities associated with the front-end engineering design, detailed engineering, procurement, construction, hook-up and commissioning as well as the employment associated with drilling and completion activities. Also included is employment associated with the construction of the excavated drill center including ROV inspection services and marine support services as well as the fabrication of subsea components locally and the testing and installation of the subsea infrastructure, which will also occur locally. The work associated with modifications to the software and instrumentation onboard the FPSO and any upgrades that may be necessary to the hydraulic power units, methanol and chemical injection systems are also included.

In terms of the project management activities as well as the drilling and completion activities and any necessary FPSO modifications, the Proponent has suggested that very few “new hires” will be required. This is because most of this work can be completed by current staffing levels within the Proponent and its contractors. Nevertheless, new opportunities may arise as the project is executed, possibly in the areas of engineering personnel, marine technicians and office support staff. Furthermore, because the fabrication of certain subsea components will be completed in the Province, there will be opportunities for trades such as welders, electricians and pipe fitters. The Proponent has also identified opportunities during the testing and installation phases for inspectors, marine personnel, divers and logistic coordinators. In each case, the Proponent and its contractors are obligated to abide with the approved White Rose benefits plan as it relates to first consideration for Newfoundland and Labrador (NL) residents. Staff will continue to monitor the Proponent's compliance with this matter in accordance with the established monitoring and reporting systems.

Staff is aware that non-local vessels will have to be used to excavate the drill center and to install the subsea infrastructure. When bringing in any non-local vessels, such as a dredging vessel, a subsea flow line installation vessel or a diving support vessel, staff reviews the crewing model as well as the proposed crew list to confirm that the principle of first consideration for training and employment of NL residents is being followed. The objective is to ensure that crewing levels for NL residents and other Canadians are at least on par with that achieved in the past for programs of a similar nature and duration. This occurred in respect of the dredging vessel used to excavate the SWRX drill center in 2012 and will be undertaken in respect of any vessel(s) to be mobilized later in 2013 or subsequently to install the subsea infrastructure.

Contracting and Procurement

The contracting and procurement opportunities described in the benefits plan supplement are consistent with the opportunities previously described in either the original White Rose benefits plan or the subsequent benefits plan assessment report for the SWRX tie-back project. Each of these opportunities are discussed below.

Excavated Drill Center

The construction of the excavated drill center was addressed in the 2007 development plan amendment. The contracting and procurement activity associated with the drill center, as well as the sub-contracting opportunities, was discussed in detail in the benefits assessment report accompanying this amendment. Following a competitive bidding process, this contract was awarded to an international offshore dredging company and this work was completed by the Cristobal Colon dredging vessel in the third quarter of 2012.

Engineering, Procurement and Construction

The opportunities associated with the engineering, procurement, construction and installation of the subsea infrastructure have also been described in both the original White Rose benefits plan and, more specifically, in the benefits report provided with the SWRX (2007) amendment. Of particular note is the fact that, in the SWRX benefits plan assessment report, the Proponent committed to requiring the project management and system engineering work to take place in the Province and re-affirmed its commitment to improving the participation of the local supply community by communicating contracting and procurement opportunities, requirements and specifications in a detailed and timely manner. These undertakings are aligned with the Board's expectations and are applicable to the current project under consideration.

As a means of following-up on the Proponent's commitment in this area, staff monitored the contracting activity associated with the engineering, procurement, construction and installation (EPCI) contract for the flow lines, risers, umbilicals, manifolds and ancillary subsea infrastructure. This matter was monitored by staff in accordance with established procedures.
Following a competitive bidding process, the contract was awarded to Technip Canada's local office in St. John's who confirmed that the project management and engineering services, as well as the sub-contracting and procurement activity would be conducted locally. In addition, at staff's request, the Proponent provided a description of the sub-contracting process associated with this matter which was examined to verify that the process was aligned with the full and fair opportunity and first consideration provisions of the legislation. In particular, staff confirmed that:

- all sub-contracting and procurement opportunities were advertised through appropriate media;
- all sub-contracting and procurement activity was carried out in accordance with conventional competitive bidding processes; and
- in consideration of the infrastructure, expertise and capabilities that have been established in the Province by the supply and service sector, the provision of goods and services that are being provided locally are within expectations.

Some examples of the latter point include: use of the marine base and associated facilities at Bay Bulls, fabrication of subsea structures and spools locally; miscellaneous steel fabrication will be awarded locally; pre-commissioning services will be performed by a local vendor; inspection services will be provided by a local engineering and marine surveying company; supply of diving and ROV personnel will be through a local company; and, the supply of marine personnel will be through a local company.

Drilling and Completion

In consideration of the ongoing need for drilling, completion and production related services, the Proponent confirmed that the scope of work associated with contracts previously awarded provide for the continuation of these contracts for the current project. Specifically, services in respect of drilling and completion, marine support vessels, helicopter support, shorebase facilities, warehouse facilities and communication services can be met by current service providers. This approach was reviewed and accepted by staff as being reasonable and appropriate in consideration that the approach taken to provide full and fair opportunity and first consideration in respect of the original contracting and procurement approach for these services was reviewed and found to be consistent with the legislation.

Other Opportunities

The Proponent identified that a number of key elements such as the fabrication of the manifolds and foundations, flow line end manifolds, temporary guide bases, rigid spools, control jumpers, subsea control distribution units as well as the subsea integration test will all occur locally.

Diversity Plan

In response to the Board's conditions of approval of the original White Rose benefits plan, the Proponent developed a Diversity Plan to address and promote employment diversity. This plan not only applies to the Proponent, but to its contractors and sub-contractors for both the White Rose and North Amethyst projects.

Staff has observed the implementation of this plan and notes that the Proponent has successfully executed this plan over the past number of years. For instance, the Proponent has established a diversity committee and holds annual diversity forums with participation from representatives of designated groups in an ongoing effort to advance the diversity agenda. The Proponent reports on its initiatives and its progress in annual diversity reports which it makes available on its website.

Research and Development

In the original White Rose benefits plan, the Proponent signified that they would abide by the legislation and the guidelines with respect to research and development (R&D) and education and training (E&T).

Notwithstanding that no specific R&D projects have been identified to date for this project, the Proponent affirmed that they are continuing to support capacity development of R&D/E&T in the Province as well as the continued use of local facilities and institutions for any R&D/E&T work.

Staff has observed that the Proponent has diligently abided with its R&D obligations including the fact that a full time R&D coordinator is assigned to oversee ongoing R&D/E&T expenditure obligations.

Benefits Agreement

In 2007, the Government of Newfoundland and Labrador signed the White Rose Expansion Project Framework Agreement (the benefits agreement) with the White Rose project participants. This agreement covers West White Rose, South White Rose and North Amethyst. It explicitly addresses the need to undertake the project management, engineering, procurement and fabrication activities associated with the expansion activities in the Province together with the need to provide web-based access to procurement opportunities and activities.

While the Board is not party to this agreement, the Province requested that the Board monitor compliance with the benefits terms. The Board's oversight of this matter is performed as part of the monitoring and reporting systems established for the White Rose project. If any areas of non-conformance are identified, the Board's role is to notify the Province who is responsible for resolving the matter in accordance with the provisions of the agreement.

Staff has not identified any areas of non-compliance with the benefits agreement to date. In particular, the activities in relation to the SWRX project are consistent with the terms of the benefits agreement. This was confirmed by staff in consultation with Provincial officials by way of the ongoing monitoring of benefits and by way of the contract designation process previously described.

8.2 CONCLUSION

Staff has determined that the information provided in the benefits supplement demonstrates the Proponent's ongoing commitment to its benefits plan and the conditions of its approval. Staff's experience to date with the Proponent's compliance with the legislation has been positive.

The monitoring and reporting systems established for the White Rose project provide a mechanism for staff to verify the Proponent's ongoing commitment to its benefits plan undertakings. In particular, staff will ensure that employment statistics in relation to the project are included in the quarterly and annual benefits reports for the White Rose project and staff will continue to monitor contracting and procurement activity on an ongoing basis in relation to the full and fair opportunity and first consideration provisions of the legislation.

Based on its analysis of this matter, no benefits related matters that adversely impact the Board's consideration of the proposed development plan amendment have been identified.

Appendix A: Glossary and Terminology used in Reserves and Resources Definitions

Glossary

bbls (Barrels)
1 bbl = 0.15898 m3

C-NLOPB
Canada-Newfoundland and Labrador Offshore Petroleum Board.

Certifying Authorities
Bodies licensed by the Board to conduct examination of designs, plans and facilities and to issue Certificates of Fitness.

Completions
The activities necessary to prepare a well for the production of oil and gas or injection of a fluid.

Delineation well
A well drilled to determine the extent of a reservoir.

Development well
A well drilled for the purpose of production or observation or for the injection or disposal of fluid into or from a petroleum accumulation.

Fault
In the geological sense, a break in the continuity of rock types.

Flooding
The injection of water or gas into, or adjacent to, a productive formation or reservoir to increase oil recovery.

FPSO
Floating production, storage and offloading facility, a floating production installation.

Injection
The process of pumping gas or water into an oil-producing reservoir to provide a driving mechanism for increased oil production.

Logging
A systematic recording of data from the driller's log, mud log, electrical well log, or radioactivity log.

m3
Cubic metre. 1 m3 = 6.2898 bbls

MODU
Mobile Offshore Drilling Unit

Permeability
A measure of how well a rock can transmit fluid (i.e. water or hydrocarbon). Is primarily determined by the size of the pore spaces and their degree of interconnection.

Parasequence
Relatively conformable depositional units bounded by surfaces of marine flooding, surfaces that separate older strata from younger and show an increase in water depth in successively younger strata. Parasequences are usually too thin to discern on seismic data, but when added together, they form sets called parasequence sets that are visible on seismic data.

Parasequence set
A succession of genetically related parasequences that form a distinctive stacking pattern, and that are typically bounded by major marine flooding surfaces and their correlative surfaces. Parasequence sets are usually classified as progradational, aggradational or retrogradational.

Petrophysics
The science and application of measuring borehole rock properties and establishing relationships between these properties.

Porosity
Fraction of pore space in a rock. Pore space can include openings between grains or fractures, and may contain hydrocarbons or water.

Pool
A natural underground reservoir containing or appearing to contain an accumulation of petroleum that is separated or appears to be separated from any such other accumulation

Produced water
Water associated with oil and gas reservoirs, that is produced along with the oil and gas.

Production well
A well drilled and completed for the purpose of producing crude oil or natural gas.

Reserves
The volumes of hydrocarbons proven by drilling, testing and interpretation of geological, geophysical and engineering data, that are considered to be recoverable using current technology and under present and anticipated economic conditions.

Reservoir
A porous, permeable rock formation in which hydrocarbons have accumulated.

Reservoir pressure
The pressure of fluids in a reservoir.

Sandstone
A sedimentary rock composed of detrital grains of sand size particles.

Seismic
Pertaining to or characteristic of earth vibration. Also, process whereby information regarding subsurface geological structures may be deduced from sound signals transmitted through the earth.

TERMINOLOGY USED IN RESERVES AND RESOURCES DEFINITIONS

Assessment of the discovered oil and gas "Reserves" and "Resources" in oil and gas fields is an important function of the Canada Newfoundland Offshore Petroleum Board. The following definitions are used by the Board:

"Discovered resources" is used to describe those volumes of hydrocarbons that have been assessed to be technically recoverable, but have not been fully delineated and/or have uncertain economic viability. The volume of discovered resources includes that proven by drilling and testing and the interpretation of geological, geophysical or other information, and deemed to be technically recoverable. (For example, the natural gas and natural gas liquids in the Hibernia and Terra Nova fields, and the oil, natural gas and natural gas liquids in the undeveloped fields offshore Newfoundland and Labrador, are referred to as discovered resources.)

"Reserves" is used to describe the portion of the oil-in-place or gas-in-place volumes identified by drilling and testing and the interpretation of geological and geophysical information, that are considered to be recoverable using current technology, and under present and anticipated economic conditions. (For example, the oil at Hibernia and Terra Nova classified as reserves.)

Since the assessment of reserves depends on the interpretation of data available at a given time, the reserves are further classified by the Board to reflect the uncertainty in the interpretation and the lack of detailed geological and reservoir data. The following classifications are used by the Board:

Proven Reserves
Hydrocarbons that have been confirmed by drilling and testing, or where sufficient geological and geophysical data exist to project the existence of hydrocarbons in adjacent fault blocks. A high confidence level is placed on recovery of these hydrocarbons.

Probable Reserves
Hydrocarbons that are projected to exist in fault blocks adjacent to those that have been tested by wells and into which the geologic trends may extend. Also, where fluid contacts have not been defined within the area drilled, these contacts may reasonably be projected to exist. However, additional drilling is required to substantiate the existence of hydrocarbons. These hydrocarbons may reasonably be expected to be recovered under normal operating conditions yet have a degree of risk, either geologic or reservoir performance related, associated with their exploitation.

Possible Reserves
Hydrocarbons that may exist based on geophysics and the extension of geologic trends. However, due to the lack of adjacent wells located within the region and reservoir engineering and geologic data, these hydrocarbons cannot be assigned a lower risk classification.

The same classifications are used for both resources and reserves. However the primary difference in the case of discovered resources is the uncertainty as to the economic viability. In terms of the probabilistic approach the Board classifies P90 as proven, P50 as proven plus probable and P10 as proven plus probable plus possible. The P90 term implies a 90 percent probability of the value in question at least being realized. The P50 numbers are used for planning purposes as there is a 50 percent probability of that number being realized. The P10 estimates provide an upside potential but with only a 10 percent chance of being realized. There is always uncertainty in reserves estimation, particularly prior to production in offshore areas, as there are very few wells and no production experience. At this stage the objective is to define the reserves range and establish a base case for proceeding with development. As development wells are drilled and production information is acquired, the oil and gas-in-place estimates will be better defined and the recovery efficiency better understood. The estimates will change between the various categories as development proceeds, but generally should be within the range of the original estimate.