STAFF ANALYSIS
OF THE
WHITE ROSE PRODUCTION VOLUME INCREASE
DEVELOPMENT PLAN
AMENDMENT APPLICATION

ISBN # 978-1-897101-22-3

Table of Contents

List of Figures

1.0 EXECUTIVE SUMMARY

On September 29, 2006, Husky Oil Operations Limited (Proponent) submitted the document *White Rose Development Plan Amendment Production Volume Increase (September 2006)* (the Document) to the Canada-Newfoundland and Labrador Offshore Petroleum Board (Board) on behalf of the owners in Production Licence (PL) 1006. The Document proposes to increase both the Annual Oil Production Rate (AOPR) and Facility Maximum Daily Production Rate (FMDPR) from 100,000 barrels of oil per day (bopd) (15 900 m^3/d) as stated in the approved White Rose Development Plan Decision 2001.01 to 140,000 bopd (22 261 m^3/d). Any approval to increase the FMDPR must be made by both the Chief Safety Officer (CSO) and Chief Conservation Officer (CCO). The AOPR requires Board approval as well approval from Governments (fundamental decision)

Staff reviewed the Document and advised the Proponent that it constituted a Development Plan Amendment Application (the Application) and that additional information would be required to complete the Application. This information was subsequently submitted by the Proponent. The Board made the Application and the additional information available to the public for comment on the Board's website for the period December 15, 2006 to January 19, 2007. The Board received one comment during this period and Staff considered this during its review of the Application.

Staff reviewed the Application to determine whether the proposed production rate increase would affect the environmental commitments or impact the approved Benefits Plan in the White Rose Development Plan Decision 2001.01. The Application does not involve any major modification to the facilities. Staff determined that this increase does not affect the approved White Rose Benefits Plan. The proposed rate change also does not raise any new environmental issues.

The Proponent's engineering studies (and the scope of the Certifying Authority's (CA's) independent review of the matter) support a maximum rate of 140,000 bopd (22 261 m^3/d) for the SeaRose FPSO. But no assessment has been provided to suggest that any higher capacity is appropriate. Therefore, based on the information provided in the Application and from the CA, the Chief Safety Officer (CSO) will set the Maximum Safety Related Capacity (MSRC) at 140,000 bopd (22 261 m^3/d).

Notwithstanding that ultimate oil recovery from the South Avalon Pool is not sensitive to production rates up to a daily rate of 140,000 bopd (22 261 m^3/d), Staff's analysis indicates that a Facility Maximum Daily Production Rate (FMDPR) of 140,000 bopd (22 261 m^3/d) appears to be near the limit of the production capacity of the developed area of the field. Staff concluded that it is not appropriate to approve a FMDPR beyond 125,000 bopd (19 875 m^3/d) until the Proponent demonstrates by testing that such rates are acceptable to the CSO and CCO. The Proponent has indicated such testing could occur as early as April 2007.

In order to achieve an Annual Oil Production Rate (AOPR) of 140,000 bopd (22 261 m^3/d) as requested by the Proponent, the process facilities must be capable of producing in excess of 140,000 bopd (22 261 m^3/d) to account for down time. However, reservoir simulation studies which examine production rates in excess of 140,000 bopd (22 261 m^3/d) has not been conducted by the Proponent as part of this Application. Accordingly, an AOPR equal to 140,000 bopd (22 261 m^3/d) should not be approved. However, an increase to the AOPR from 100,000 bopd (15 900 m^3/d) to 125,000 bopd (19 875 m^3/d), to coincide with the current FMDPR, is acceptable. Once the Proponent has demonstrated a FMDPR beyond 125,000 bopd (19 875 m^3/d), the AOPR can be increased between 125,000 bopd (19 875 m^3/d) and 140,000 bopd (22 261 m^3/d) to coincide with the FMDPR. That is, Staff's reservoir simulation shows that ultimate recovery is not affected by increase production up to 140,000 bopd (22 261 m^3/d).

Accordingly, the following is recommended:

1. The Board approve an AOPR of 45.6 million barrels (7.25 million m^3) based on an average daily oil production rate of 125,000 bopd (19 875 m^3/d).

2. The Board approve an increase of the AOPR beyond 125,000 bopd (19 875 m^3/d) when the Proponent can demonstrate that a FMDPR beyond 125,000 bopd (19 875 m^3/d) is acceptable to the CSO and CCO in accordance to the following:

   (a) The MSRC established by the CSO for the SeaRose FPSO shall be 140,000 bopd (22 261 m^3/d), subject to concurrence by the CA. The Proponent must ensure that the necessary controls are in place such that the MSRC of 140,000 bopd (22 261 m^3/d) is not exceeded.

   (b) The maximum total liquids processed by the SeaRose FPSO shall not exceed 207,900 barrels per day (33 050 m^3/d) unless otherwise approved by the CSO.

   (c) Field performance testing must be conducted in a safe and controlled manner to confirm the feasibility of operating beyond the current approved rate of 125,000 bopd (19 875 m^3/d). This testing must be done in accordance with a testing program approved by the Certifying Authority. The results of this testing program must be submitted for acceptance by the CSO and the CCO prior to increasing production beyond 125,000 bopd (19 875 m^3/d).

   (d) All necessary updates to the *SeaRose* Safety Plan must be submitted to and approved by the CSO prior to increasing steady state production beyond 125,000 bopd (19 875 m^3/d).

2.0 BACKGROUND

2.1 The Application

On September 29, 2006, Husky Oil Operations Limited (Proponent) submitted the document *White Rose Development Plan Amendment Production Volume Increase (September 2006)* (the Document) to the Canada-Newfoundland and Labrador Offshore Petroleum Board (Board) on behalf of the ownership of Production Licence (PL) 1006. The Document proposes to increase both the Annual Oil Production Rate (AOPR) and Facility Maximum Daily Production Rate (FMDPR) from 100,000 bopd (15 900 m^3/d) as stated in the approved White Rose Development Plan (Decision 2001.01) to 140,000 bopd (22 261 m^3/d).

The effect of these proposals is to increase the AOPR from the current approved rate of 100,000 bopd (15 900 m^3/d) to 140,000 bopd (22 261 m^3/d) and the FMDPR from the current rate of 125,000 bopd (19 875 m^3/d) to 140,000 bopd (22 261 m^3/d). The proposed increase in the AOPR means that the authorized maximum annual production will increase from 36.5 million barrels (5.8 million m^3) to 51.1 million barrels (8.12 million m^3).

It should be noted that the Proponent received approval from the Chief Safety Officer and the Chief Conservation Officer on September 29, 2006 to increase the FMDPR from 100,000 bopd (15 900 m^3/d) to 125,000 bopd (19 875 m^3/d).

2.2 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, on the eastern edge of the Jeanne d’Arc Basin in an area where the water depth ranges between 115 and 130 meters. Following the discovery, eight additional wells were drilled to define the structure and three seismic surveys were conducted. This information helped to confirm the presence and extent of hydrocarbons in the Ben Nevis Formation.

A note of clarification is required regarding the naming convention used in the Application. The reservoir section was termed the “Avalon Formation” in the Proponent’s original application, and in the Board’s Decision 2001.01. It is now believed the reservoir section lies upon the mid-Aptian unconformity, is middle Aptian-Albian in age, and is an overall fining-upward package within a transgressive systems tract, and is now interpreted to be the “Ben Nevis Formation”.

The total recoverable oil reserves in the White Rose Field are estimated, and expressed at a 50 percent probability level by the Board, to be 283 million barrels (45 million m^3). Most of the hydrocarbons are contained in the Ben Nevis Formation. Pressure measurements and fluid contacts indicate that the oil and gas accumulation in the Ben Nevis Formation are 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) (See Figure 2.1). The South Avalon Pool is currently being developed and the Proponent has stated that plans are underway to develop reserves in the North, West and Southern Extension pools.

In terms of natural gas and natural gas liquids, the Board estimates, at a 50 percent probability, that the White Rose Field contains recoverable resources of 2.7 TCF (76.7 x 10^9 m^3), and 96 million barrels (15.3 million m^3) respectively, however, the Proponent does not propose in this Application to exploit these resources at this time.

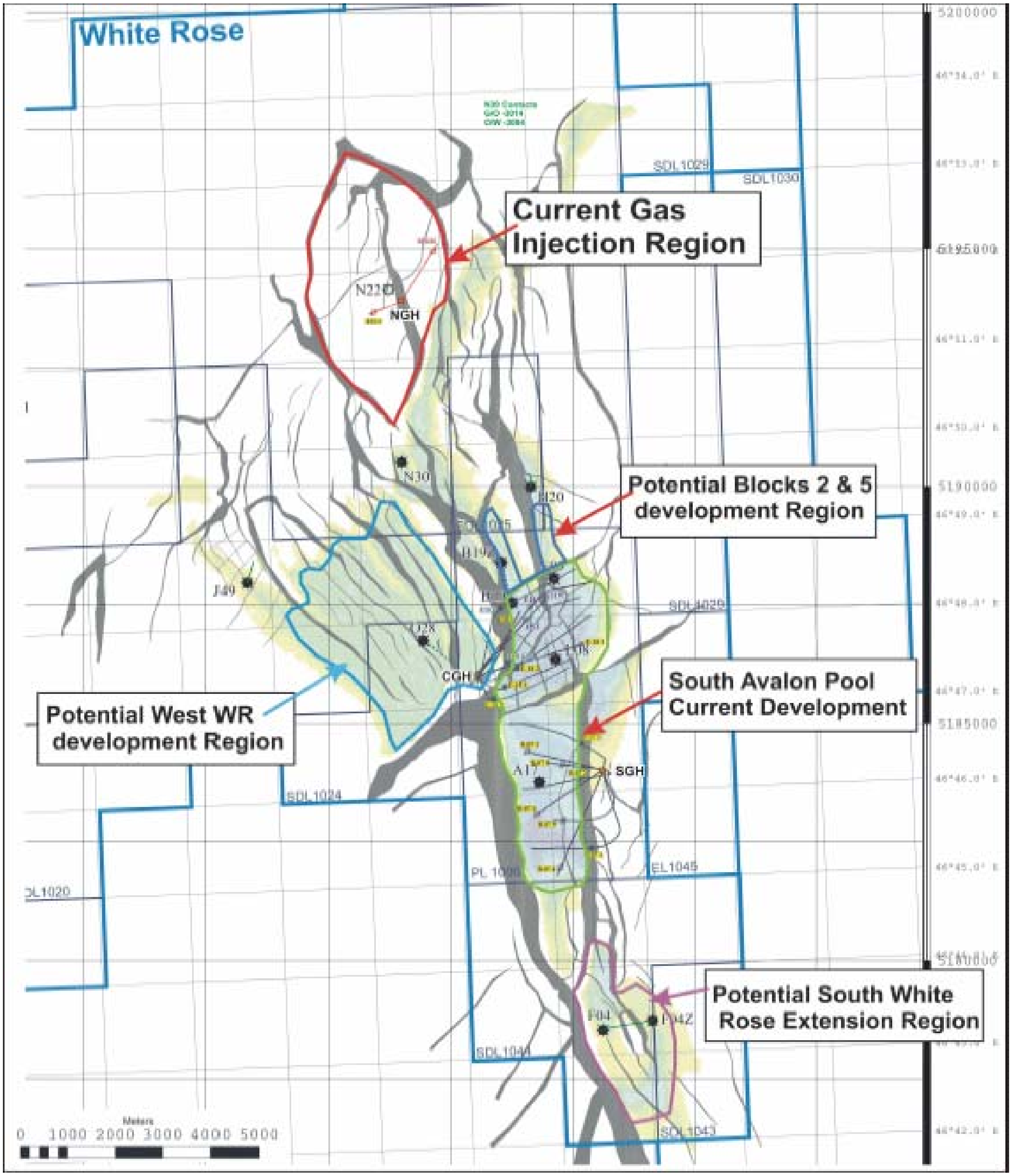

Figure 2.1: Map illustrating the location of the South Avalon Pool in relation to other delineated pools in the White Rose Region (Source: Husky)

Since the approval of the original Development Plan, 14 development wells have been completed in the South Avalon Pool; the original development plan proposes 21 wells for depletion. There have also been six delineation wells drilled in the field; two in the west pool, two in the northern area of the south pool, and two in the southern area of the south pool. Staff is currently assessing the impact of production and drilling information on recoverable resource/reserve estimates.

Commercial oil production began at the SeaRose FPSO on November 12, 2005. As of December 31, 2006, 34.5 million barrels of oil has been produced at the South Avalon Pool (See table 2.1 below).

Table 2.1 White Rose Oil Production Summary

Year	**Barrels**	**m^3**
2005	2,465,781	392,028
2006	32,051,559	5,095,773
Total	34,517,340	5,487,801

At present, the White Rose Significant Discovery Area incorporates fourteen Significant Discovery Licences (SDL) with two different interests owners – Husky at 72.5% and Petro-Canada at 27.5%. This percentage breakdown also applies to PL1006 (See Figure 2.2).

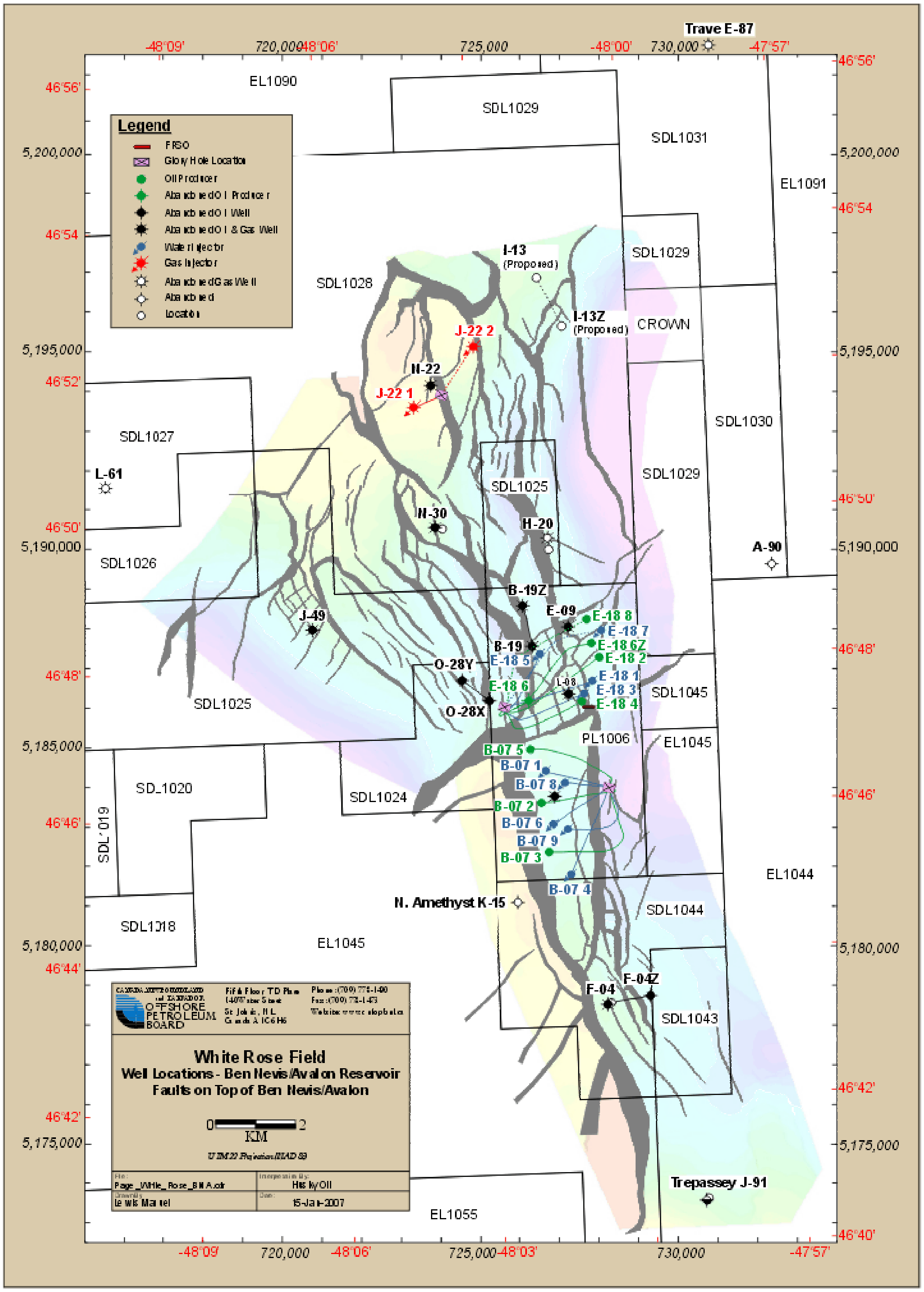

Figure 2 2: Land and Well Locations - White Rose Field (Source: C-NLOPB)

2.3 Fundamental Decision

Production rates are addressed in the *Newfoundland Offshore Area Petroleum Production and Conservation Regulations* Part V Section 34.

> ***"An operator shall produce petroleum from a pool or field in accordance with good production practices to achieve maximum recovery of petroleum from the pool or field and at the applicable rate specified in the approved development plan for that pool or field."***

The AOPR in the approved White Rose Development Plan Decision 2001.01 is 100,000 bopd (15 900 m3/d) and is based on the approved depletion scheme for the South Avalon Pool. The proposed rate increase to 140,000 (22 260 m^3/d) is deemed to be an amendment to Part I of the White Rose Development Plan. As the production rate constitutes an amendment to Part I of the plan, it is a fundamental decision and will require the approval of the appropriate Federal and Provincial Ministers.

Following the submission of the Document, the Proponent was advised in a letter dated October 26, 2006, that it is a Development Plan Amendment Application and additional information would be required to complete the Application. On November 20, 2006, the Proponent submitted the requested supplementary information. After reviewing the supplementary information, the Board wrote the Proponent on December 4, 2006 indicating that further information was required. On December 6, 2006, the Proponent submitted that information and on December 11, 2006, the Board advised the Proponent that the Application was complete.

The following documents constitute the Proponent's Application:

- White Rose Development Plan Amendment Production Volume Increase (September 2006);
- White Rose Development Plan Amendment Production Volume Increase Supplemental Information (November 2006);
- White Rose Development Plan Amendment Production Volume Increase Supplemental Information #2 (December 2006); and,
- White Rose Field Development SeaRose Metering For 140,000 bopd Case

The Application was posted for public comment on the Board's website for the period December 15, 2006 to January 19, 2007. One comment was received from the public and is contained in Appendix A. This comment was considered during the review of the Application and a response is provided in Section 7.0.

2.4 Production Rates

The setting of maximum allowable oil and gas production rates is an important aspect of the Board's responsibilities under the Accord legislation. The rates proposed by Operators are assessed by Staff to ensure they are within safe operating limits for the facilities and will not adversely affect oil and gas recovery. In addition, Staff monitors production from fields and reservoirs to ensure that levels are consistent with the approved annual production rates and that good oil field practices are being observed. It is important for all stakeholders to understand clearly how certain rates are defined and administered.

In the White Rose Development Plan Decision 2001.01, the Board examined four different rates. These included the Maximum Safety Related Capacity (MSRC), the Facility Maximum Daily Production Rate (FMDPR), the Annual Oil Production Rate (AOPR), and Well Rates. The definitions are stated below for reference.

Maximum Safety Related Capacity:

The Maximum Safety Related Capacity (MSRC) is the maximum oil or gas rate at which the platform may be operated. It is determined taking into account the safe operating limits of pressure relief, blow-down and flare systems, piping and equipment vibration, noise limits, cavitations, corrosion and erosion parameters. It provides a safety margin above the facility maximum daily production rate authorized for the facility, to allow for operational upsets. The MSRC is expressed in cubic metres per day and is established by the Board's Chief Safety Officer (CSO). This rate will be established based on operating performance and may not be exceeded.

Facility Maximum Daily Production Rate:

The Facility Maximum Daily Production Rate (FMDPR) is defined as the oil or gas production rate at which the facility can maintain stable production operations with sufficient reserve capacity to accommodate operational upsets without exceeding the MSRC of the platform. Typically, this is the design production rate for the processing facility, and it may be revised after production begins based on operating experience. There may be minor deviations above this rate during production operations, but these would only be of short duration. The Board's CSO and Chief Conservation Officer (CCO) approve the FMDPR. In approving this rate, these Officers give consideration too safety and resource management issues.

Annual Oil Production Rate (AOPR):

The Annual Oil Production Rate is the maximum annual oil or gas off-take rate authorized for a reservoir or field. It is approved by the Board as part of the Development Plan. This rate is defined by the plateau level of the production forecast and is based on the depletion strategy adopted for the field. This rate is usually expressed as an annual average daily production rate, in cubic metres per day. In approving this rate, the Board must be satisfied that it will not adversely affect oil or gas recovery. Any increase in this rate requires an amendment to the Development Plan. Such amendments also require the approval of both Ministers.

Well Rates:

The Board may require Operators to assess the impact of production rate of development wells on recovery efficiency and submit the results for review. The Board may set production rate limitations on wells to prevent waste. These limitations may be varied, as production information is acquired. The CCO establishes well rate limitations on behalf of the Board.

3.0 CANADA-NEWFOUNDLAND AND LABRADOR BENEFITS

Staff reviewed the Application to assess any potential impact with respect to the White Rose Benefits Plan provisions prescribed by subsections 45(1), 45(3), and 45(4) of the Accord legislation.

Section 45(1) defines a Benefit Plan as a plan for *"the employment of Canadians and, in particular, members of the labour force of the Province and, subject to paragraph (3)(d), for providing manufacturers, consultants, contractors and service companies in the Province and other parts of Canada with a full and fair opportunity to participate on a competitive basis in the supply of goods and services used in any proposed work or activity referred to in the benefits plan."*

Section 45(3) provides that a Benefits Plan shall contain provisions intended to ensure that:

a) *before carrying out any work or activity in the offshore area, the corporation or other body submitting the plan shall establish in the Province an office where appropriate levels of decision-making are to take place (para 45(3)(a));*
b) *consistent with the Canadian Charter of Rights and Freedoms, individuals resident in the Province shall be given first consideration for training and employment in the work program for which the plan was submitted and any collective agreement entered into by the corporation or other body submitting the plan and an organization of employees respecting terms and conditions of employment in the offshore area shall contain provisions consistent with this paragraph (para 45(3)(b));*

c) *expenditures shall be made for research and development to be carried out in the Province and for education and training to be provided in the province (para 45(3)(c)); and*

d) *first consideration shall be given to services provided from within the Province and to goods manufactured in the Province, where those services and goods are competitive in terms of fair market price, quality and delivery (para 45(3)(d)).*

Section 45(4) provides that the Board *"may require that any benefits plan include provisions to ensure that disadvantaged individuals or groups have access to training and employment opportunities and to enable such individuals or groups or corporations owned or cooperatives operated by them to participate in the supply of goods and services used in any proposed work or activity referred to in the benefits plan (ss 45 (4))."*

3.1 Development Plan Amendment – Benefits Review

The Proponent indicates that ultimate recovery is insensitive to daily production rates up to 140,000 bopd (22 261 m^3/d). Further, the Proponent states that field production profiles for the cases evaluated are similar toward the end of the production profile. Therefore, the effect on field life due to increased production rate is minimal.

Specifically, in Section 6.4, Field Peak Rate Sensitivities, the Proponent indicates that "…the figures show that cumulative oil production is virtually identical for each of the cases evaluated, suggesting that ultimate recovery is insensitive to daily oil production rates up to 22,261m3/d."

Also, Section 6.4.1, Impact on Field Life, indicates that "Since the end of field life will be determined by technical and economic factors at a future date, and since the field production profile for all three cases are similar toward the end of the production profile, the effect on field life due to increased production rate is minimal."

The Proponent also reviewed the results from FPSO performance testing, including a study of options for de-bottlenecking the topsides process plant and capacity testing of selected process streams and support systems. The Proponent concluded by further analysis that no material changes are required to the FPSO for an increase in production rates up to 140,000 bopd (22 261 m^3/d).

Specifically, in Section 3.3, Performance Test Summary and Conclusions, the Proponent indicates that "With a few operational adjustments and minor modifications, it will be possible to increase the production to 22,261m3/d oil (140,000 bpd) …"

Also, in Section 5.0, Flow Metering, the Proponent states "No modifications are required to the existing Tier 1 metering systems…".

Finally, in Section 10.0, Canada-Newfoundland and Labrador Benefits, the following is stated:

> "The proposed Amendment to the White Rose Plan involves only a change in the annual oil production rate approved in Decision 2001.01, and does not involve any major modifications to the facilities or changes in personnel. Therefore, the Amendment does not have any material effect on the approved White Rose Benefits Plan."

3.2 Discussion

The Application indicates the effect on field life due to an increased production rate is minimal. Staff analysis shows that although the production plateau has been shortened by the rate increase, the cumulative oil production and the life of the project has not changed substantially in terms of what is in the original Development Plan. Section 4.4 of this analysis supports this conclusion.

3.3 Benefits Plan Amendment

The Proponent states that the Amendment does not involve any major modifications to the facilities or changes in personnel, and does not have any material effect on the approved White Rose Benefits Plan.

The authority in the Accord Act, which addresses Benefits Plan approval, is contained in Section 45(2). This section of the Act requires that *before the Board may approve any development plan pursuant to subsection 139(4) … a Canada-Newfoundland and Labrador Benefits Plan shall be submitted to and approved by the Board, unless the Board directs that the requirement need not be complied with.*

Subsection 139(5) provides that no amendment of a Development Plan shall be made unless it is approved by the Board consistent with subsections 139(2) to 139(5) with such modifications as the circumstances require. Before approving an amendment to a Development Plan under 139(5), the Board must apply subsections 139(2) to (4) (specifically 139(4)). Subsection 45(2) provides that before the Board may approve any Development Plan pursuant to 139(4), a Benefits Plan shall be submitted to and approved by the Board. The combined effect of subsections 45(2) and 139(4), (5) and (6) requires the Board to determine the appropriateness of the Benefits Plan before approving an amendment to the Development Plan.

3.4 Advice

In this regard, Staff agrees with the Proponent's analysis and recommends that an Amendment to the approved White Rose Benefits Plan is not required.

4.0 RESOURCE MANAGEMENT

Staff conducted a review of reservoir, geologic and production data acquired from the White Rose Field to date as well as the data in the Application.

4.1 Geological/Geophysical Model Review

The Proponent continues to work on the geologic model for the White Rose Field, which is typical for any field under production. The geologic interpretation of the South Avalon Pool has changed very little since the original Development Plan and Staff believes that the geological model used by the Proponent for the reservoir studies is reasonable.

4.2 Petrophysics

The Proponent has conducted a comprehensive logging and coring program while drilling the exploration, delineation and development wells in the White Rose Field. In this Application, the Proponent summarized the reservoir net to gross, porosity and permeability for the gas, oil and water zones of all wells in the approved development area and for the White Rose F-04 and White Rose F-04Z delineation wells south of the developed region. The Proponent supplied supplemental information on the methodology, assumptions and criteria used to calculate the net to gross, porosity and permeability.

Staff conducted an independent review of this petrophysical data. In the White Rose Field, the Proponent's petrophysical interpretation matches Staff's assessment with slight differences attributed to different methodology, assumptions and criteria used in interpreting the data. For example, porosities reported by the Proponent for the oil zone in the F-04 well and the oil and water zones in the F-04Z well in the South White Rose Extension (See Figure 2.1) region range in value from 1.5-3.0 porosity units higher than those interpreted by Staff, however such differences did not have any material effect on the Application.

Based on its analyses, Staff believes the interpretation presented by the Proponent in support of this application is reasonable.

4.3 Reservoir Production and Simulation Model Review

Staff reviewed the reservoir simulation report submitted in support of the Application.

For background information the following events have occurred at the White Rose Field, since the initial White Rose Development Plan:

- Fourteen development wells (six oil producers, seven water injectors and one gas injector) have been completed; Six delineation well have been drilled.
- Since first commercial oil production, in excess of 34.5 million barrels (5.4 million m^3) (See Figure 4-1) of oil have been produced from six wells in the south and central blocks of the South Avalon Pool;
- Water injection in the field was initiated at first oil production in November 2005 from six injectors and has since increased to seven injectors;
- Gas injection in the North Avalon storage reservoir was initiated on May 5, 2006; and,
- Facility capacity testing up to 125,000 bopd (19 875 m^3/d) was conducted in July 2006.

These events have provided additional information to assess reservoir and facility performance and will be used to review and update geologic and reservoir simulation models. Staff acknowledges the Proponent has conducted a comprehensive assessment of this information in support of this Application.

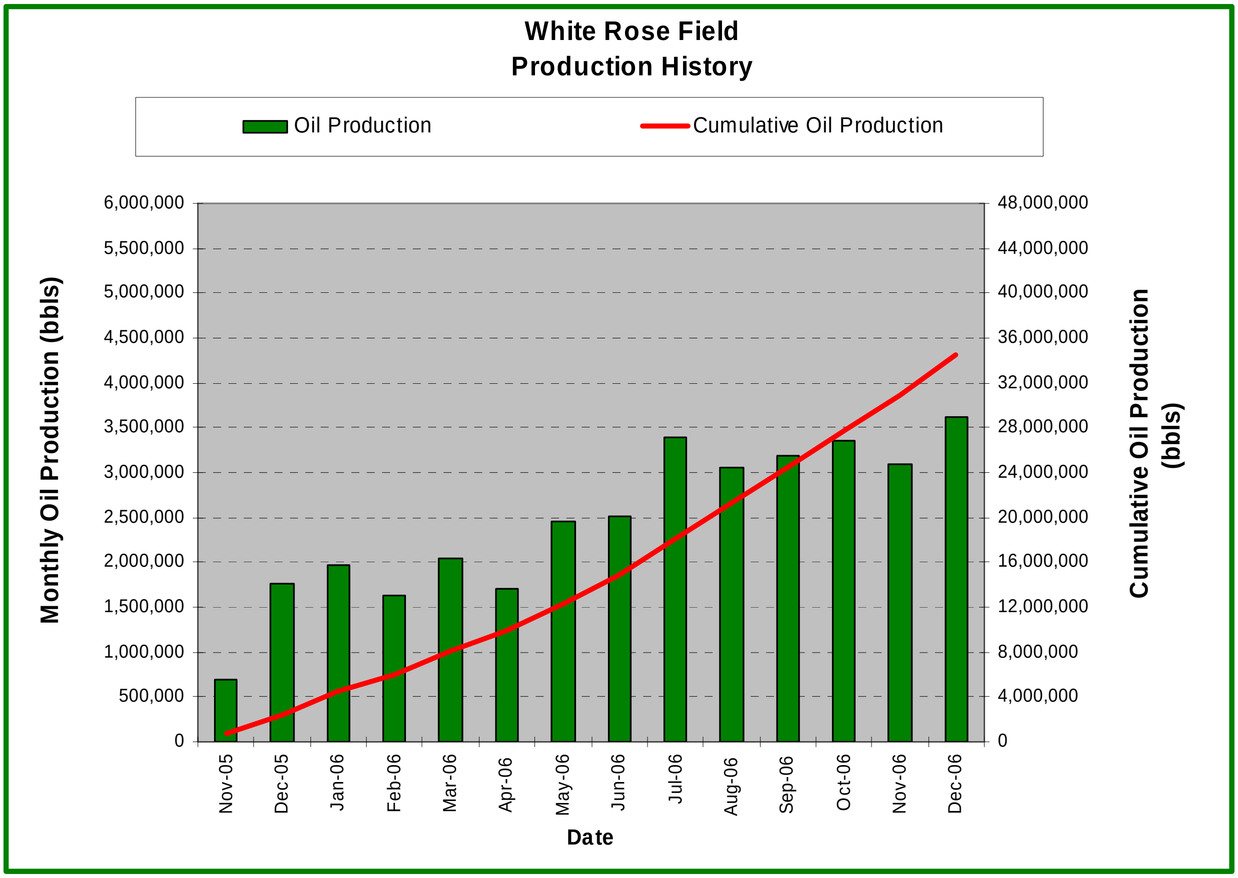

Figure 4. 1: White Rose Production History (Source: C-NLOPB)

Staff conducted a review of the production data from the first ten months of operations. This information was used to analyze the Proponent's history match of the first seven months reservoir simulation. A history match uses actual production and pressure data to assess the geological and reservoir simulation models.

The comparison of actual versus simulation oil production shows that the White Rose Field production at the end of the history match period (late July 2006) has been following the simulation prediction. Early actual production did not match the simulation prediction due to normal operational start up issues (See Figure 4-2).

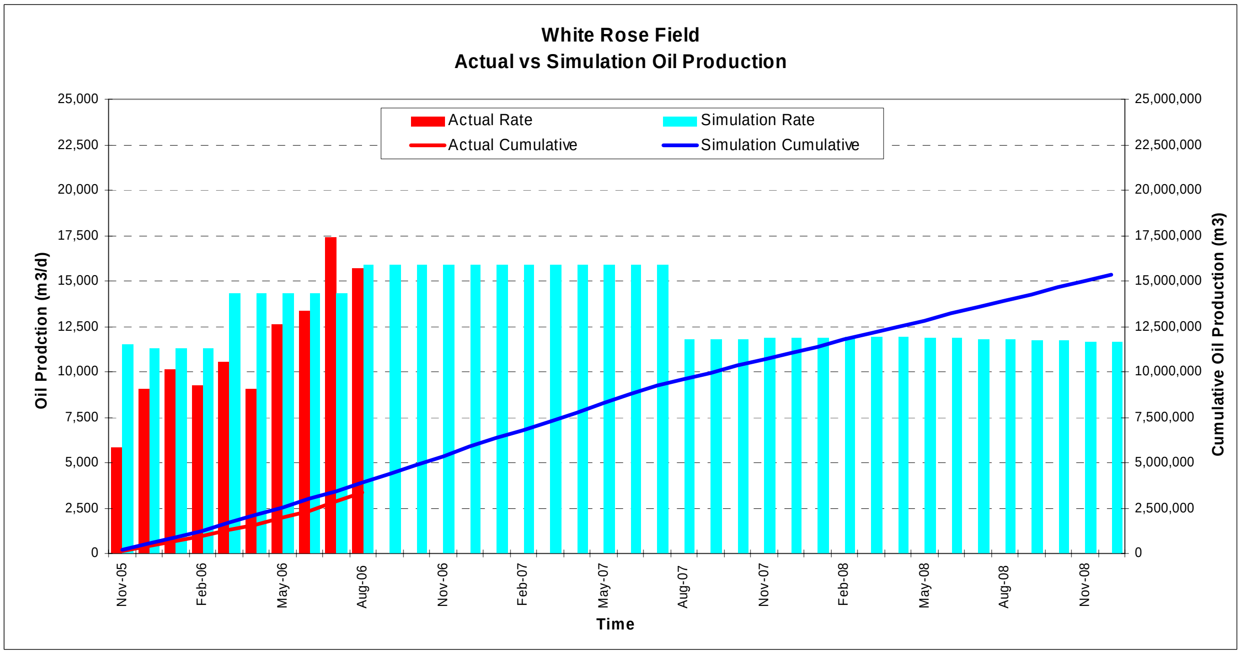

Figure 4. 2: White Rose Field Actual vs. Simulation Oil Production Date (Source: C-NLOPB)

Staff believes that the Proponent has achieved a good history match of the pressure data acquired from the wells B-07 3, B-07 5, E-18 2 and E-18 4 (See Figure 4.3). The production performance of these wells were found to match the original simulation models. Figures 4.4 and 4.5 support this conclusion

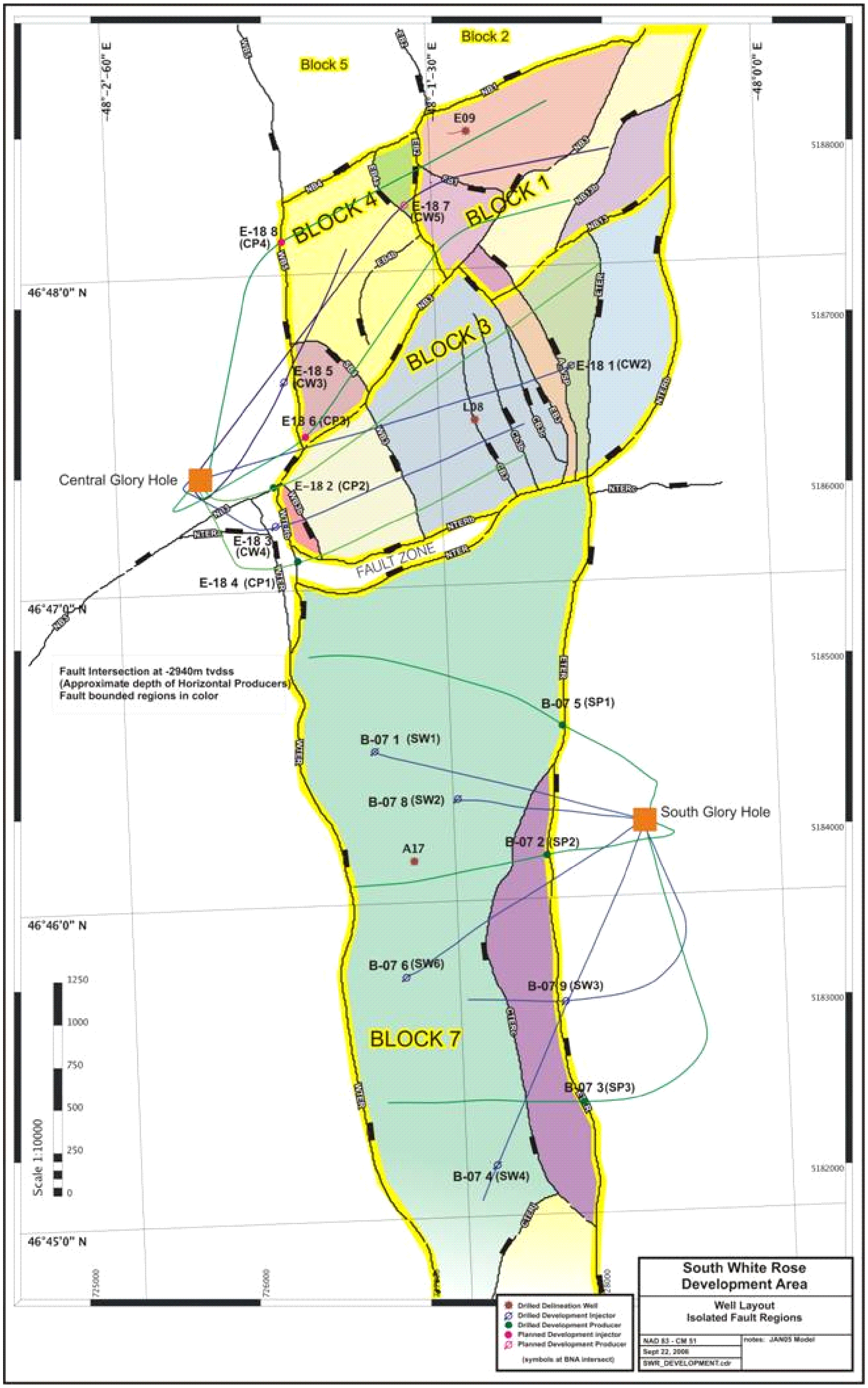

Figure 4. 3: Current Development Region and Wells in the South Avalon Pool (Source: Husky)

For example, Figure 4-4 shows the comparison of actual production from B-07 3 well with the simulation oil production. After initial start up operations, the actual data tracks the simulation.

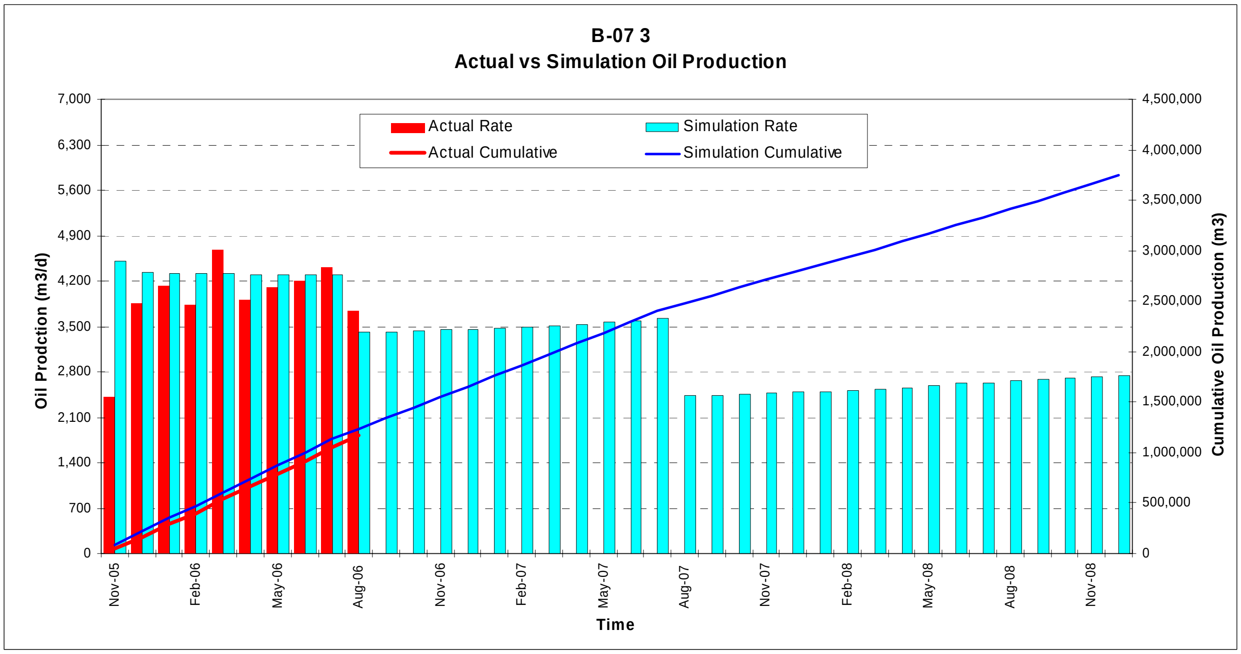

Figure 4. 4: B-07 3 Actual vs. Simulation Oil Production (Source: C-NLOPB)

The B-07 2 well showed a slight difference between the actual and simulated production. At this well, the actual production performance (rates and bottom-hole pressures) were found to be less than that predicted from the simulation model (See Figure 4-5). It was determined by the Proponent that the contributing length in the well model B-07 2 needed to be adjusted to account for the overestimation of production in the Eclipse Reservoir simulation model. This adjustment provided a better history match with the actual production and pressure data from the first seven months of production data. Staff believes that the Proponent has made the appropriate corrections to the reservoir simulation in terms of the productivity of the B-07 2 well.

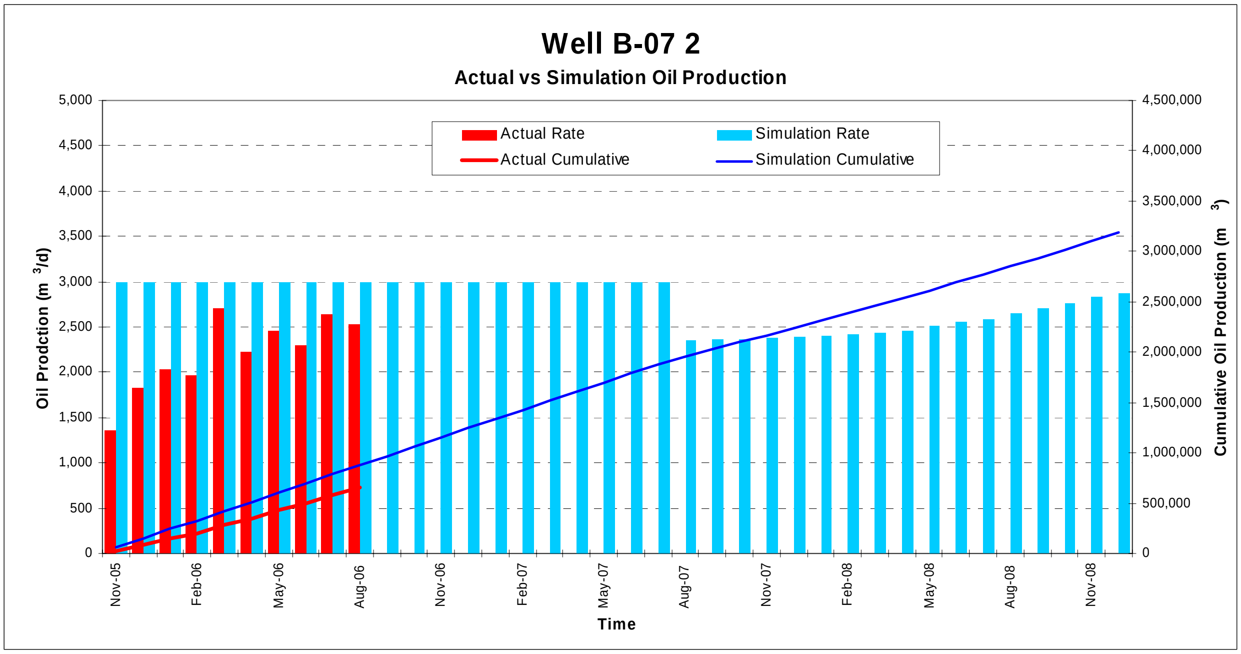

Figure 4. 5: B-07 2 Actual vs. Simulation Oil Production (Source: C-NLOPB)

Other properties that were examined and adjusted in the Proponent's Eclipse simulation model include:

- a revision in the Pressure-Volume-Temperature properties of the White Rose Field fluid data;
- a change in the Gas/Oil Contact in the southern region of Block 7 of the White Rose Field; and,
- adjustment to some of the internal faults of Block 3, Block 4 and Block 1 from sealing to non-sealing in the reservoir simulation model.

Staff concurs with the Proponent's adjustments to their Eclipse simulation model. These are normal adjustments in the life of a field development as production data becomes available.

Staff also acknowledges the sensitivity studies conducted with the adjusted simulation model to assess the impact of individual well rates on oil recovery in the South Avalon Pool.

Figure 4-6 shows the average annual oil production rate forecast for each of the rate sensitivities evaluated by the Proponent for the South Avalon Pool development area (sealing faults case).

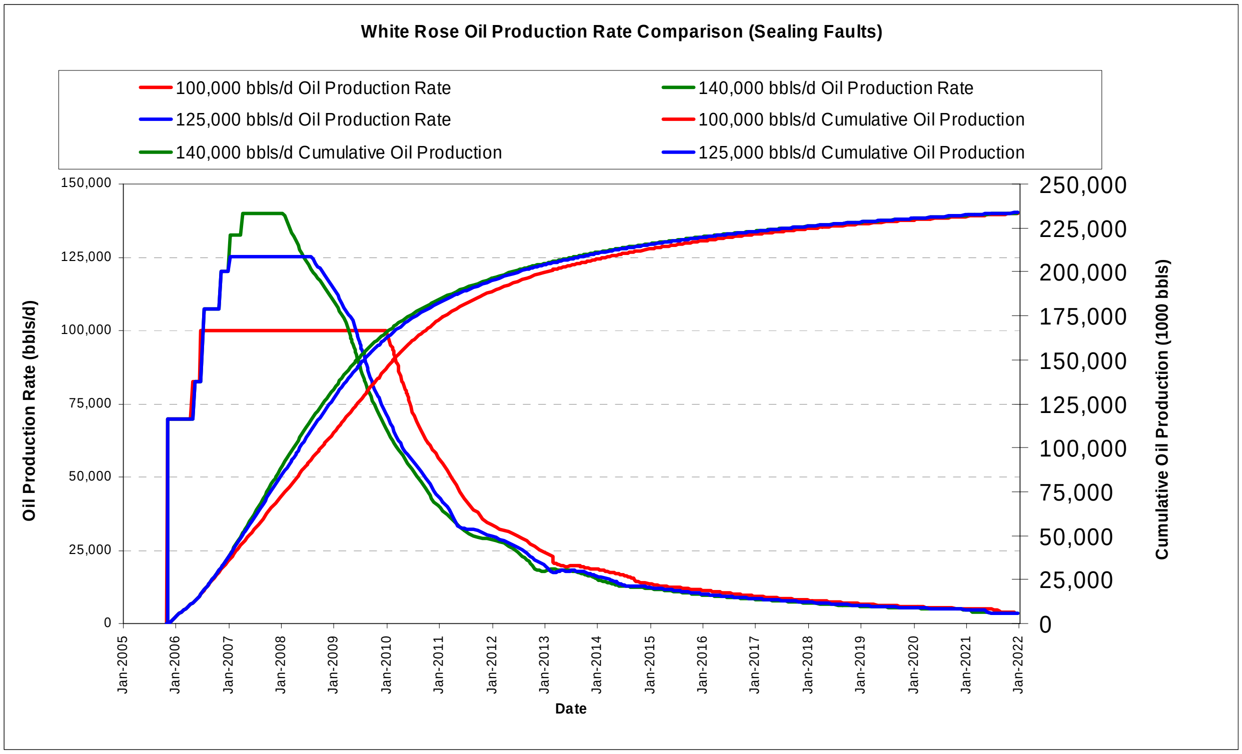

Figure 4. 6: White Rose Oil Production Rate Comparison (Sealing Faults) (Source: C-NLOPB)

Figure 4-7 illustrates the average annual oil production rate forecast for the same rate sensitivities with a geological feature of non-sealing faults.

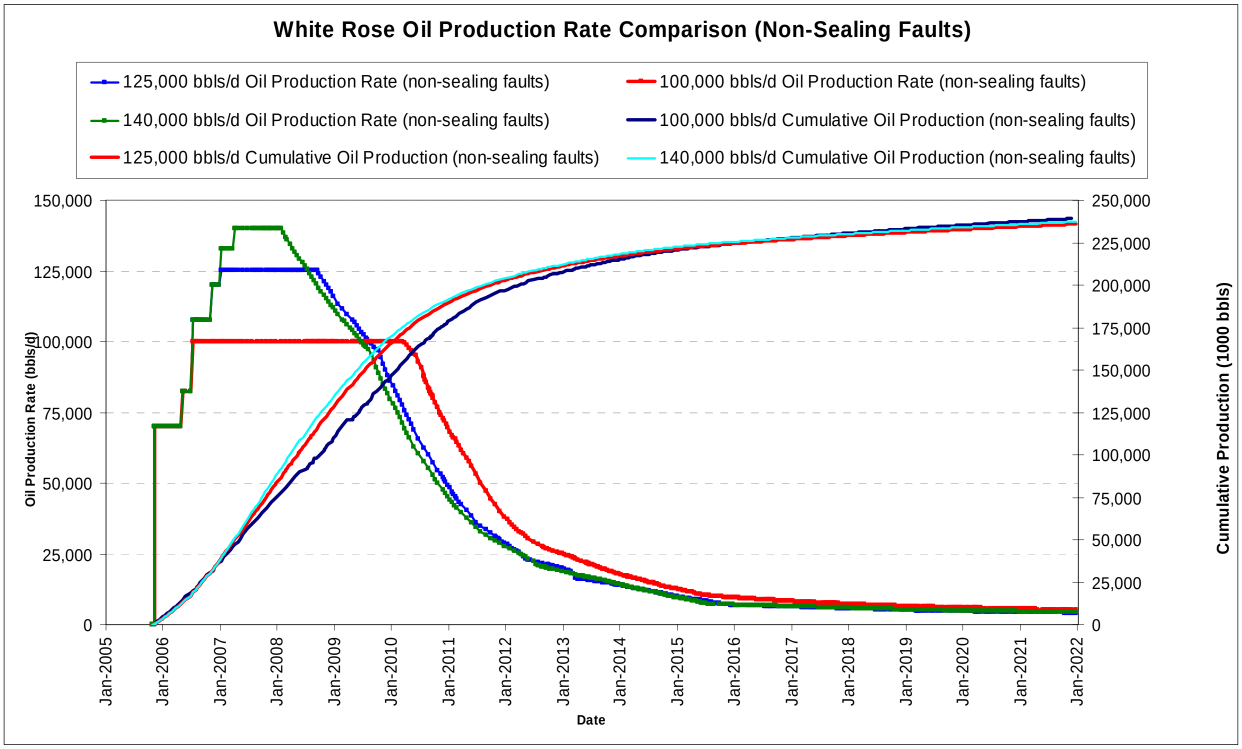

Figure 4. 7: White Rose Oil Production Rate Comparison (Non-Sealing Faults) (Source: C-NLOPB)

As seen from Figure 4-7, “non-sealing faults” simulation results are similar as the “sealing faults” simulation results.

Based on this review, Staff concurs with the Proponent that these studies suggest ultimate oil recovery from the South Avalon Pool is not sensitive to production rates up to a daily rate of 140,000 bopd (22 261 m^3/d).

From the information provided, a Facility Maximum Daily Production Rate (FMDPR) of 140,000 bopd (22 261 m^3/d) appears to be near the limit of the production capacity of the developed area. To achieve an AOPR of 140,000 bopd (22 261 m^3/d), the process facilities must be capable of producing in excess of 140,000 bopd (22 261 m^3/d) to account for down time. Also reservoir simulation studies which examine production rates in excess of 140,000 bopd (22 261 m^3/d) need to be conducted by the Proponent. This has not been done to date. The Proponent has tested the oil production capacity of the production facilities up to 125,000 bopd (19 875 m^3/d) and plans further testing when sufficient production capacity is available. It should be noted, based on test results and information provided by the Proponent, that on September 29, 2006, the CCO and CSO approved a Facility Maximum Daily Production Rate (FMDPR) of 125,000 bopd (19,875 m^3/d) and the facility has been producing above 100,000 bopd (15 960 m^3/d) since approval (See Figure 4.1).

The reservoir simulation model is an important tool to assess the reservoir performance and optimize depletion schemes to maximize recovery. However, the model is only as good as the data used to construct it. It is important that a comprehensive data set continues to be acquired to verify the reliability and to update the model. With higher production rates, the displacement process of fluids in the reservoir is occurring at a faster pace. Therefore, timely acquisition of data becomes important to ensure a comprehensive assessment of pressure maintenance and fluid movement across faults.

Staff believes that a robust data acquisition program is necessary to obtain information to monitor the water flood and update the reservoir simulation models. This includes running production logs in selected development wells to assess inflow performance of the various sandstone units and running production and saturation logs following water breakthrough when conditions are such that reliable information can be acquired.

Uncertainties with the geologic interpretation, oil-in-place estimates and communication between sandstone units and across faults are not unusual for most field developments. As development wells are drilled and additional data acquired, the geological and reservoir models will be updated and advanced to assist Staff in assessing these uncertainties. These uncertainties are not expected to alter the conclusions of the Proponent’s analysis respecting rate sensitivities nor Staff’s assessment of the Application.

Staff notes that the production performance of the White Rose Field, to date has been in good agreement with the reservoir simulation predictions. While there is uncertainty, the oil-in-place estimates in the South Avalon Pool have been within original Development Plan predictions (i.e. 698 million barrels or 111 million m^3).

Staff also note that the oil process and gas compression systems are operating stable at this time. In August 2006, Staff participated in an audit of the flow system and flow calculation and allocation procedures and no major issues were identified with either the system or the procedures.

4.4 Production Forecast and Impact on Life of Field

The estimate of the impact of a production rate increase on the ultimate life of field for an offshore development is not an exact science. It is based on predictions and forecasts from computer simulations. Many variables have to be considered, including:

- refinement of in-place estimates and recovery factors as more information on the reservoir becomes available through development drilling and well performance;
- improvement in the recovery from advances in drilling technology and field management techniques over the life of the project;
- the price of hydrocarbons toward the end of the field life will significantly impact when the economic limit of the development is reached; and,
- tie-in of other pools or fields found in proximity to the existing production facility to permit additional production. In the case of White Rose, tie-ins from the White Rose southern extension, White Rose west, North Amethyst and other opportunities are expected to be considered for exploitation in the future.

As a general rule, in offshore field developments, these factors have resulted in a significantly longer life of field than estimated at the time the projects were approved.

For the White Rose project, Figure 4.6 shows the projected life of field for the original Development Plan Approval rate of 100,000 bopd (15 890 m^3/d), 125,000 bopd (19 875 m^3/d) and at the maximum requested rate of 140,000 bopd (22 261 m^3/d) based on full field depletion scenarios.

Figure 4.6 shows the effect of the proposed production rate increase on the life of the South Avalon Pool is minimal. Staff's simulation prediction shows that the end of life for this pool remains January 2022 and ultimate recovery is unchanged at 234 million barrels (37.2 million m^3).

The simulation results also indicated the following:

- The maximum field water rate achieved in all of the reservoir simulation sensitivities occurred at the end of the project at 21 000 m^3/d when water production is expected to be at its highest. This is within the design requirements for the SeaRose FPSO of 28 600 m^3/d.
- The total gas production rate does not exceed the design rate of 4.2 10^6 m^3/d for the SeaRose FPSO at any of the simulated oil production rates. (See Figure 4.8)
- The total water injection rate does not exceed the design rate for the SeaRose FPSO of 46 000 m^3/d at any of the simulated oil production rates. (See Figure 4.9)
- The total fluid production does not exceed the design rate for the SeaRose FPSO of 33 050 m^3/d at any of the simulated oil production rates. (See Figure 4.10)

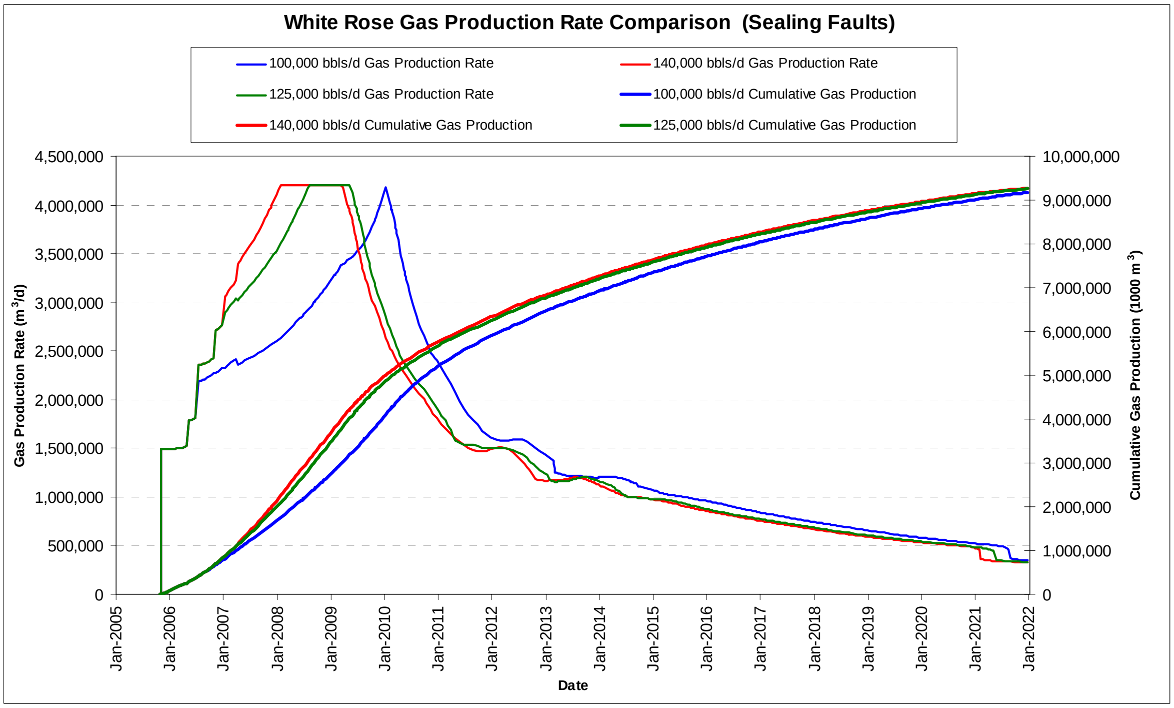

Figure 4. 8: White Rose Simulation Gas Production Rate Increase Comparisons (Source: C-NLOPB)

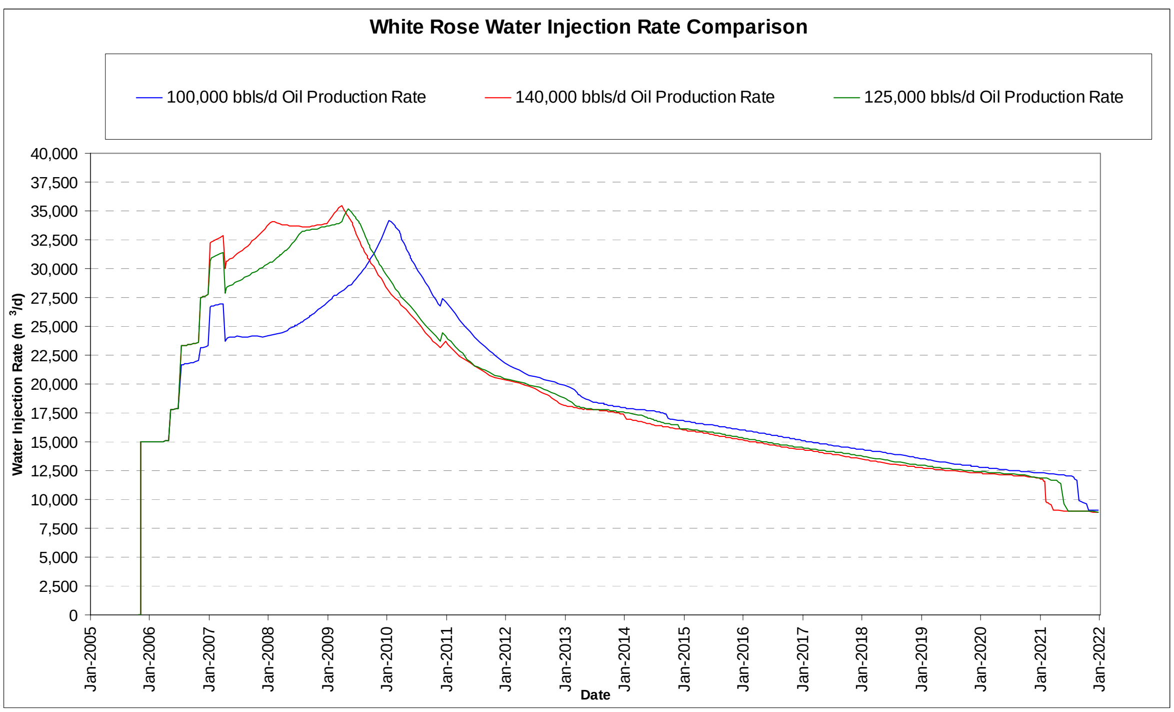

Figure 4. 9: White Rose Simulation Water Injection Rate Increase Comparison (Source: C-NLOPB)

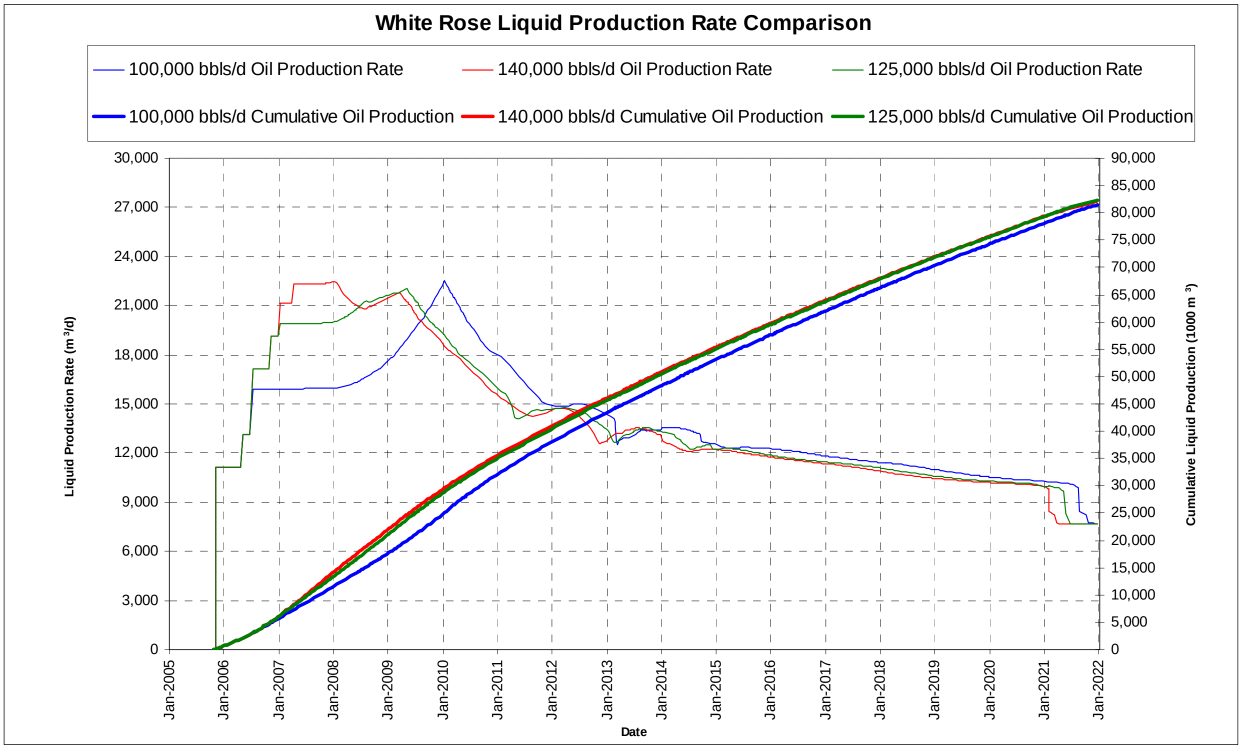

Figure 4. 10: White Rose Simulation Fluid Production Rate Increase Comparison (Source: C-NLOPB)

4.5 Conclusions

The conclusions from the Staff's analysis are as follows:

1. The geologic interpretation of the South Avalon Pool has changed very little since the original Development Plan. The geological model used by the Proponent for the reservoir studies is reasonable.
2. The reserves in the South Avalon Pool remain unchanged from that stated in the original Development Plan (i.e. 200-250 million barrels of oil).
3. Staff believes that the Proponent has achieved a good history match with the production data provided. The Proponent's adjustments to the reservoir simulation model were assessed to be reasonable and appropriate.
4. An increase of the AOPR from 100,000 bopd (15 900 m^3/d) to 125,000 bopd (19 875 m^3/d) is appropriate.

5. Notwithstanding that ultimate oil recovery from the South Avalon Pool is not sensitive to production rates up to a daily rate of 140,000 bopd (22 261 m^3/d), Staff's analysis indicates that a Facility Maximum Daily Production Rate (FMDPR) of 140,000 bopd (22 261 m^3/d) appears to be near the limit of the production capacity of the developed area of the field. Therefore, it is not appropriate to approve a FMDPR or an Annual Oil Production Rate (AOPR) beyond 125,000 bopd (19 875 m^3/d) until the Proponent demonstrates by testing that such rates are acceptable to the CSO and CCO.

4.6 Advice

Staff recommends that:

1. The Board approve an AOPR of 45.6 million barrels (7.25 million m^3) based on an average daily oil production rate of 125 000 bopd (19 875 m^3/d) subject to the following:
   - the CCO may at any time reduce the production rate if reservoir performance differs significantly from predictions in the Proponent's Application and the CCO has reason to believe that production at the approved rate may cause waste.
2. The Board approve the ability to increase the AOPR beyond 125,000 bopd (19 875 m^3/d) but less than 140,000 bopd (22 261 m^3/d) when the Proponent can demonstrate that a FMDPR beyond 125,000 bopd (19 875 m^3/d) is acceptable to the CSO and CCO.

5.0 OPERATIONS AND SAFETY

The Board's Chief Safety Officer (CSO) and Chief Conservation Officer (CCO) on September 29, 2006 approved an increase in the Facility Maximum Daily Production Rate from 100,000 bopd (15 900 m^3/d) to 125,000 bopd (19 875 m^3/d). The current Application is seeking a further increase to 140,000 bopd (22 261 m^3/d).

Although each application must be assessed on its own merit taking into consideration the unique features and layout of the production process facilities, there are a number of common safety related issues that must be reviewed to confirm that there are no impediments to a flow rate increase. These include:

(a) a detailed engineering analysis of the original design assumptions and design criteria used in the selection of each of the components of the production flow and process system to identify any potential limitations on the system and to confirm that the flow rate is within the design limits of each component;

(b) a comprehensive hazard and operability analysis of the process flow system and related utility support services to identify any safety related issues from an operability point of view; and

(c) an independent third party review and assessment of the matter from an engineering perspective – this is required to be performed by the Certifying Authority (CA) in relation to the Certificate of Fitness for the installation.

Notwithstanding the favourable outcome of engineering studies and operability analysis, experience has shown that it is often not possible to adequately identify all potential safety hazards based on studies alone. For this reason, any application for a rate increase must also be supported by field tests conducted under close supervision by experienced field personnel. Such tests must be done in a controlled manner whereby production is slowly increased on a short-term basis and critical parameters are recorded. The critical issues to be monitored and recorded during such tests are identified from the various engineering studies undertaken to determine potential bottlenecks.

5.1 Analysis

A review of these matters was performed in the context of the Application by Staff. This review focused on the adequacy and completeness of the Proponent's approach to the matter from a safety perspective.

To support the Application, the following studies, analyses and field trials were performed by the Proponent:

(a) a debottlenecking study;
(b) a piping vibration analysis;
(c) a process train performance test;
(d) a main power generator performance test; and
(e) a review of previous safety studies performed in relation to the White Rose development project that were sensitive to the risks associated with a higher production rate including the quantitative risk analysis, the temporary refuge impairment analysis, the fire risk analysis, the inert gas dispersion analysis, the ship collision analysis, and the cargo pump room explosion analysis.

These studies identified a number of issues that needed to be addressed and closed out as part of the implementation phase of increasing production to 140,000 bopd (22 261 m^3/d). The critical issues identified from the Staff's safety review of the Application included the following:

(a) Performance testing has been successfully completed at a rate up to 125,000 bopd (19 875 m^3/d) and the results from this testing have been used to simulate conditions expected at 140,000 bopd (22 261 m^3/d) – there is a need to perform further field trials to confirm the capacity to operate at rates higher than 125,000 bopd (19 875 m^3/d);

(b) The Proponent identified the need to more closely examine several debottlenecking issues required to operate at higher rates up to 140,000 bopd (22 261 m^3/d);

(c) Although the CA had been engaged by the Proponent to review and assess this matter in accordance with the protocols established by the Certificate of Fitness process for the *SeaRose FPSO*, there remained a number of outstanding issues within the purview of the CA that warranted further progress by the Proponent prior to Staff making a final determination respecting the feasibility and safety of the proposed rate increase;

(d) The Proponent's engineering studies (and the scope of the CA's independent review of the matter) are based on a maximum throughput of 140,000 bopd (22 261 m^3/d). These studies support that the facility can handle up to 140,000 bopd (22 261 m^3/d), but no assessment has been provided to suggest that any higher capacity is appropriate.

(e) The Proponent's engineering studies identified that the velocities in the crude oil lines are higher than the allowances specified in the API RP 14E standard specified in the C-NLOPB regulations. This may be an issue in relation to piping erosion and vibration. The Proponent has indicated, however, that the velocities are within the allowances of the Norwegian NORSOK guidelines.

(f) The Proponent acknowledges the intention to operate the plant within the existing total liquids limit of 207,900 barrels per day (33 050 m^3/d) as identified by the various engineering analysis provided in support of the Application.

(g) Revisions will be required to the *SeaRose FPSO* Safety Plan to reflect updated information associated with the proposed increase in the facility's capacity from 125,000 bopd (m^3/d) to 140,000 bopd (22 261 m^3/d).

In consideration that the CA review of the matter was only partially complete and there remained a number of outstanding engineering issues in relation to the ongoing studies, Staff requested the Proponent to provide an update to these matters. The Proponent's update on February 2, 2007 indicated that these matters were being satisfactorily progressed in a diligent manner. The CA's review of the matter had progressed to the point that "conditional release" (i.e. approval with certain limitations) was expected by the end of February 2007. Staff concluded that the engineering matters associated with the rate increase were being adequately addressed within the CA's scope of review and that there are no outstanding safety related matters within this scope that would preclude Staff from progressing the review of the Application.

In its February 2, 2007 response, the Proponent also confirmed its intention to proceed with field performance testing when the requisite number of oil production wells are completed. The Proponent estimates that this test may be performed as early as April 2007.

The Proponent's engineering studies, and the scope of the CA's independent review of the matter support a maximum rate of 140,000 bopd (22 261 m^3/d) but no assessment has been provided to suggest that any higher capacity is appropriate. Therefore, the CSO will set the MSRC at 140,000 bopd (22 261 m^3/d).

The current approved FMDPR is 125,000 bopd (19 875 m^3/d). The Proponent may test steady state production above the current rate of 125,000 bopd (19 875 m^3/d) provided that the Proponent allows for sufficient reserve capacity such that the MSRC rate of 140,000 bopd (22 261 m^3/d) is not exceeded. Based on the test results, the Proponent could propose an FMDPR beyond the current rate of 125,000 bopd (19 875 m^3/d) for the approval of both the CSO and the CCO.

Finally, the Proponent confirmed its undertaking to seek equivalency from the CSO respecting the proposed use of the Norwegian NORSOK guidelines instead of the criteria specified in API RP 14E as providing an equivalent level of safety regarding the velocities in the crude oil lines, and to update the *SeaRose FPSO* Safety Plan in a timely manner to reflect the rate increase from 125,000 bopd (19 875 m^3/d) to 140,000 bopd (22 261 m^3/d).

5.2 Conclusions

Based on the safety review conducted by Staff it has been concluded that the information provided supports setting the MSRC at 140,000 bopd (22 261 m^3/d). As well, the FMDPR should remain at 125,000 bopd (19 875 m^3/d) until such time as testing proves that a higher rate is appropriate. Any higher FMDPR must have sufficient reserve capacity to accommodate operational upsets without exceeding the MSRC.

5.3 Advice

Staff recommend that the CSO approve a MSRC of 140,000 bopd (22 261 m^3/d) in accordance with the following:

(a) The MSRC established by the CSO for the SeaRose FPSO shall be 140,000 bopd (22 261 m^3/d), subject to concurrence by the CA. The Proponent must ensure that the necessary controls are in place such that the MSRC of 140,000 bopd (22 261 m^3/d) is not exceeded.

(b) The maximum total liquids processed by the SeaRose FPSO shall not exceed 207,900 barrels per day (33 050 m^3/d) unless otherwise approved by the CSO.

Staff further recommends that the FMDPR not be increased beyond the current approved rate of 125,000 bopd (19 875 m^3/d) until the following conditions have been met to the satisfaction of the CSO:

(a) The Proponent must submit the requisite documentation in the form of a regulatory query respecting the proposed use of the Norwegian NORSOK guidelines instead of the criteria specified in API RP 14E as providing an equivalent level of safety regarding the velocities in the crude oil lines as it pertains to the piping erosion and vibration analysis. The regulatory query must be approved by the CSO prior to increasing production beyond 125,000 bopd (19 875 m^3/d).[1]

(b) Field performance testing must be conducted in a safe and controlled manner to confirm the feasibility of operating beyond the current approved rate of 125,000 bopd (19 875 m^3/d). This testing must be done in accordance with a testing program approved by the Certifying Authority. The results of this testing program must be submitted for acceptance by the CSO and the CCO prior to increasing production beyond 125,000 bopd (19 875 m^3/d).

(c) All necessary updates to the *SeaRose* Safety Plan must be submitted to and approved by the CSO prior to increasing steady state production beyond 125,000 bopd (19 875 m^3/d).

[1] On March 1, 2007, the Proponent submitted documentation indicating that the fluid velocities in the crude oil lines were within the specification of API RP 14 E and that a regulatory query was not required.

6.0 ENVIRONMENTAL AFFAIRS

Staff reviewed the Proponent's Application to determine if the production rate increase raises any new environmental issues. Based on the information provided, it is apparent that all activities fall within the scope of the Comprehensive Study review conducted under the Canadian Environmental Assessment Act for the White Rose Project in 2000. These activities include produced water and drilling discharges. Accordingly, there are no environmental issues or concerns in relation to the Application. The public comments received in relation to the produced water and the frequency of batch spills have been satisfactorily addressed in Section 7.0.

7.0 PUBLIC COMMENTS

The Board decided to make the Application available to the public for comment on the Board's website for the period December 15, 2006 to January 19, 2007. Staff only considered those comments that were received and related to the merits of the Application. In this regard, only one comment was considered (See Appendix A).
The manner in which this comment has been addressed is outlined below:

1. Will the C-NLOPB re-evaluate the increased production when the FPSO begins to generate produced water (and to continue to do so as the volume of produced water increases)?

   The White Rose Comprehensive Study states, (pg 335),"The peak field produced water is estimated at a maximum of 30,000 m^3/d." Husky's Supplemental Information November 2006, (pg 23), states "Based upon predictions from the ECLIPSE reservoir simulation model, the maximum anticipated produced water discharge rate for the White Rose South Avalon Pool is approximately 22,000 m^3/d." The Peak produced water estimate of 30,000 m^3/d, as stated in the White Rose Comprehensive Study, is the maximum flow the White Rose Project can discharge. The proponent will need to complete an addendum to the White Rose environmental assessment before the C-NLOPB would consider increasing the maximum produced water rate beyond 30, 000 m^3/day.
2. Specifically, is the 24-hour average oil content for produced water at or below the 2007 target Waste Treatment Guidelines? (Relevant to this request is the Terra Nova production increase – where are the data on oil content discharges related to produced water – did the Terra Nova experience a decrease in the ability to meet 2007 target Waste Treatment Guidelines with increased daily oil production?)

   All Operators are required to maintain the oil content of their produced water at or below the maximums stated in the Offshore Waste Treatment Guidelines, August

2002. It is the Operator’s responsibility to ensure they maintain the oil content of their produced water at or below the maximums. For the White Rose project the maximum oil content for produced water is 30 mg/L volume weighted average over 30 days and 60 mg/L daily average.

Exceeding the maximum oil content is a spill in accordance with section 161(1) of the Atlantic Accord Implementation Act (federal). The regulatory response to the spill infraction is based on the severity of the event, which could mean actions such as suspension of operations or prosecution.

3. What is the relationship between frequency of batch spills and increased daily production? In the White Rose EA (2001 pg 416), it was noted that “Developing predictions of frequencies for such spills is difficult at this time because the design of the loading/lifting system has not been finalized.” Providing an update on this issue would be important for this request because of the expected increased frequency of offloading.

   Staff concluded that it would be appropriate for the Proponent to address this comment. The Proponent’s response is in Appendix B. The Proponent concludes that while “the increased frequency of offloading operations may increase the potential for a spill from the offloading operations, the likelihood of such an event occurring is considered to be very low”. Staff agree with the Proponent’s analysis and conclusions on the matter.

Appendix A: Public Comments

January 7 2007

C-NLOPB
140 Water St.
St. John's NL

To Whom It May Concern:

Please consider the following comments on the production volume increase for the White Rose Project:

1. The test in July 2006 did not include produced water discharges

- Will the C-NLOPB re-evaluate of the increased production when the FPSO begins to generate produced water (and continue to do so as the volume of produced water increases)? Specifically, is the 24 hour average oil content for produced water at or below the 2007 target Waste Treatment Guidelines? (Relevant to this request is the Terra Nova production increase – where are the data on oil content discharges related to produced water – did the Terra Nova experience a decrease in the ability to meet 2007 target Waste Treatment Guidelines with increased daily oil production?)

2. What is the relationship between frequency of batch spills and increased daily production? In the White Rose EA (2001 pg 416), it was noted that "Developing predictions of frequencies for such spills is difficult at this time because the design of the loading/lifting system has not been finalized." Providing an update on this issue would be important for this request because of the expected increased frequency of offloading.

Regards,

Dr. Gail Fraser
Assistant Professor
Faculty of Environmental Studies
York University
4700 Keele St.
Toronto, ON M3J 1P3

Appendix B: Husky Letter

Husky Energy

Suite 901, Scotia Centre
235 Water Street
St. John's, NL, Canada
A1C 1B6

Phone: (709) 724-3900
Fax: (709) 724-3915

File #:
Initials:

January 19th, 2007

JAN 22 2007
RECEIVED
Canada-Newfoundland and Labrador
Offshore Petroleum Board

Canada-Newfoundland and Labrador Offshore Petroleum Board
5th Floor, TD Place
140 Water Street
St. John's, NL
A1C 6H6

Ref. No.: HUS-CPB-DG-LTR-00005

Attention: Mr. John Crocker

File No.: 1219

Dear Mr. Crocker:

Subject: Response to Comment from Dr. Gail Fraser on Husky's Production Volume Increase DPA

Following is Husky's response to the comment from Dr. Gail Fraser related to the relationship between frequency of batch spills and increased daily production:

The offloading hose on the SeaRose FPSO is used periodically to transfer the produced oil from the cargo storage tanks to a shuttle tanker. From the perspective of the White Rose Quantitative Risk Assessment, the offloading hose has been considered as a flexible riser and the release frequency has been found from PARLOC 2001 - '*The update of Loss of Containment Data for Offshore Pipelines*', which is a database of generic riser failures across all pressure ranges. The total frequency of release from the offloading hose is taken to be 5.70E-03 per annum, or once in every 175 years, within the safety assessments. This frequency of release, however, is based on continuous pressurization and operation of the offloading hose. As the hose will only actually be in use during offloading activities, the remainder of the time it will be isolated and stored onboard the FPSO. Therefore the frequency of release from the hose must be reduced in accordance with its usage.

The offloading tanker has a greater storage capacity than the FPSO and it is preferred that the tanker leaves the field with a full load. Staying moored together for the extended period while the FPSO completes the differential production volume is considered unsafe and therefore the crude oil offload is conducted in two stages. Since this means that the offloading hose will be attached / detached from the tanker more frequently than for a single transfer, it could be argued that there is a higher chance of damage occurring to the hose, increasing the potential for a release of crude during transfers. To account for this, and for the purposes of this note, the PARLOC release frequency has been increased by 10%. This gives an increased total crude oil release frequency from the offloading hose of 6.27E-03 per annum, or once in every 160 years.

For the current, 100k bopd operating case, one full parcel (840,000 bbls) is offloaded to the shuttle tanker approximately every 8 days. For the 140k bopd case, there will be a full parcel offloaded every 6 days. The duration of one full offload is conservatively estimated at 24 hours. The release frequency can therefore be factored by 1/8 for the 100k bopd case and by 1/6 for the 140k bopd case to take account of the actual period of time that the hose will be in use. On this basis, the increase in production throughput from 100k bopd to 140k bopd could therefore result in a potential increase in a crude oil release from the hose during transfers from 7.43E-04 per annum (once in every 1276 years) to 1.05E-03 per annum (once in every 957 years), on a statistical basis.

The PARLOC data splits the release frequency according to the size of the breach in the riser; 68% are assumed to be small (0 - 20mm) breaches, 11% are assumed to be medium (20 - 80mm) sized and the remaining 21% are assumed to be full bore ruptures of the riser. If releases from small to medium sized breaches were detected relatively quickly then the spill would likely be contained using response measures and is not considered to result in a major release of crude, particularly since the export pumps would be shut down upon detection of release. However, a large or full bore rupture of the hose could result in the loss of containment of a large volume of oil. The frequency of a large rupture of the offloading hose is calculated to be 1.68E-04 per annum (once in every 5961 years) for the 100k bopd case and 2.24E-04 per annum (once in every 4471 years) for the 140k bopd case, on a statistical basis.

It can therefore be seen that whilst the increased frequency of offloading operations may increase the potential for a spill from the offloading operations, the likelihood of such an event occurring is considered to be very low indeed.

If you have any questions, please contact me at 724-4760 or Ms. Kathy Knox at 724-3994.

Yours sincerely,

HUSKY OIL OPERATIONS LIMITED

Kathy Knox

pp Chris Laing
Development Manager

KK/jp

cc: Kathy Knox
Jeff Jenkins
Francine Wight

Appendix C: Glossary

AOPR
Annual Oil Production Rate

bbls (Barrels)
1 bbl = 0.15898 m^3

BOARD
The Canada-Newfoundland and Labrador Offshore Petroleum Board

C-NLOPB
Canada-Newfoundland and Labrador Offshore Petroleum Board

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

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

FMDPR
Facility Maximum Daily Production Rate

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

FPSO
Floating Production, Storage and Offloading facility

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.

MSRC
Maximum Safety Related Capacity

M
Millions

m^3
1 m^3 = 6.2898 bbls

Petrophysics
Study of reservoir properties from various logging methods.

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

Porosity Unit
A measure of formation porosity used on the scale of neutron porosity or other porosity sensing log. The porosity unit is calibrated to 1% porosity.

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

Production platform
An offshore structure equipped to produce and process oil and gas.

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

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.

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. Hibernia, Terra Nova, and White Rose are classified as reserves.

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

Reservoir pressure
The pressure of fluids in a reservoir.

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

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.

Staff
The staff of the C-NLOPB.

TCF
Trillion Cubic Feet