White Rose Development Plan Amendment

Production Volume Increase

September 2006

Husky Document No. WR-DVG-RP-0007

Table of Contents

List of Tables

List of Figures

EXECUTIVE SUMMARY

This Development Plan Amendment outlines Husky's request to increase both the Annual Oil Production Rate (AOPR) and Facility Maximum Daily Production Rate (FMDPR) from 15,900 m^3/d (100,000 bbls/d) as stated in the Approved White Rose Development Plan to 22,261 m^3/d (140,000 bbls/d).

The text of the Amendment addresses the following important factors:

- Safety.
- Environmental Protection.
- Proper reservoir management of the White Rose Field.
- Facility integrity
- Process and utilities systems capacities.

The geological, geophysical and petrophysical data acquired to date is in agreement with parameters used in the original Development Plan. Sensitivities conducted via the history-matched ECLIPSE model for varying scenarios show comparable results and indicate that ultimate oil recovery is very similar for the different cases evaluated.

This illustrates that ultimate oil recovery is insensitive to daily oil production rates up to 22,261 m^3/d (140,000 bbls/d). Since field production profiles for the cases evaluated are similar toward the end of the production profile, the effect on field life due to increased production rate is minimal. The drilling and production information acquired since the original Development Application was submitted in 2001 does not support any significant changes to the initial reserves of 200 – 250 million barrels in the South Avalon Pool.

The FPSO topsides have been studied and tested to determine actual versus design capacity. A process model was developed utilizing design data taken from the installed equipment and calibrated by testing the plant at increased rates.

The available oil processing capacity was then predicted using data from both the testing and modeling. The results verify that completion of the operational tuning and minor debottlenecking activities identified enable facility oil throughput to increase to 22,261 m^3/d (140,000 bbls/d).

Vibration analysis was undertaken before and during performance testing in July 2006 and a small number of areas addressed. Vibration monitoring was conducted during testing and no adverse vibration levels were detected.

The Certifying Authority (CA), Det Norske Veritas (DNV), is engaged to ensure that the information requirements of the CA regarding the safety aspects of the increase in production are adequately addressed to facilitate the timely completion of the approval process. The CA is conducting a review of the modifications required to achieve 22,261 m^3/d (140,000 bbls/d). This will include the modifications to the Quantitative Risk Assessment and the supportive Safety Studies and will be completed in November 2006.

1.0 Introduction

This document provides the case for requesting an increase in the Facility Maximum Daily Production Rate and the Average Annual Production Rate for the White Rose field to 22,261 m^3/d oil (140,000 bpd).

Recoverable oil reserves of 200 - 250 million barrels have been identified in the White Rose Significant Discovery Area. The Base Case anticipated field life is 15 years. Subsequent exploration and delineation activities have identified the potential for recovery of additional oil resources from satellite pools. In order to timely and economically recover the additional oil from future satellite developments, and to increase the economic value of the White Rose Development, Husky is proposing to increase production through the FPSO.

In the White Rose Development Plan submitted to the C-NLOPB in 2001, an oil production forecast was presented with a peak production rate of 15,900 m^3/d (100,000 bpd).

In order to determine the potential for increasing oil production through the FPSO, two important factors were considered:

- Proper reservoir management of the White Rose field to ensure optimum resource recovery.
- The capacity of the FPSO topsides processing system and supporting utilities to accommodate increased production.

A detailed review of all the implications of increased production on the South White Rose reservoir was conducted. The results from FPSO performance testing were reviewed, including a study of options for de-bottlenecking the process plant on the topsides and capacity testing of selected process streams and support systems. No material changes are required to the FPSO as a result of the proposed production volume increase.

2.0 FPSO Performance Testing

2.1 Performance Testing Philosophy

As with any new oil and gas offshore production processing facilities, it is established normal practice to carry out performance testing of the major process and utility systems in order to demonstrate that the facilities meet the design intent in accordance with the design basis. Such tests are normally carried out post first production and the data used to understand the actual performance of the facilities. To this end, performance testing has been conducted to confirm the performance of the FPSO topsides facilities and systems against the criteria outlined in the project design specifications and documents.

The performance testing also provided the necessary technical information required to demonstrate that the plant can operate in a safe and responsible manner at higher levels of production than the Base Case and to identify any potential areas which will require additional work to alleviate pinch points in the system. This will, in effect, highlight the de-bottlenecking requirements and allow work to progress so that long term future production and operability of the plant can be enhanced and optimized for oil production.

The systems tested are summarized in Tables 2.1 and 2.2. The produced water test was deferred as no water is currently being produced.

Table 2.1 Production Systems Tested

System	Design	Tested	% Increase
Total Liquids Separation	33,000 m^3/d	19,840 m^3/d	N/A
Crude Separation System			
Oil Separation	15,873 m^3/d	19,840 m^3/d	25%
HP Separator (Gas side)	4.2 $MMsm^3/d$	2.67 $MMsm^3/d$	N/A
MP Separator (Gas side)	N/A. Calculations show this ca. 2.0 $MMsm^3/d$	0.22 $MMsm^3/d$	N/A
LP Separator (Gas side)	N/A. Calculations show this ca. 0.7 $MMsm^3/d$	0.13 $MMsm^3/d$	N/A
Gas Compression and Dehydration Systems			
Single Gas Compression Train	2.52 $MMsm^3/d$	2.9 $MMsm^3/d$	15%
Two Gas Compression Trains	4.2 $MMsm^3/d$	Not Tested	N/A
Gas TEG Dehydration	4.2$MMsm^3/d$	2.9 $MMsm^3/d$	Full capacity not tested
Water Injection System			
Sea Water Deaeration	44,000m^3/d	46,000m^3/d	4.5%
Single Water Injection Pump	14,690 m^3/d	14,200 – 16,000 m3/d (depending on the pump)	N/A

Table 2.2 Support Systems Tested

System	Design	Tested	% Increase
Fuel Gas System	0.67 $MMsm^3/d$	0.6 $MMsm^3/d$, limited by Fuel Gas Super-heater	Only one set tested, standby available
Heating Medium System	50 MW	4 - 5 MW	Only Trim Cooler and partly MP Separator Inlet Cooler were on-line due to abundant heat in the system from well fluids.

System	Design	Tested	% Increase
			No process heating is required due to elevated inlet temperatures.
Cooling Medium System	56 MW	26 MW	Cooling load was just under 50% as per process consumer requirements

Where insufficient stream capacity was available, system tests were carried out pro rata to available production throughput. Performance testing of the nominated streams was not undertaken until stable plant operations were achieved. Where appropriate, records from an unplanned shutdown were utilized to prove this system. Operations records were kept during the performance test periods and were used in lieu of specific capacity tests where appropriate.

In general, the subsea systems were not included in the performance tests as extensive function testing had previously occurred on these systems during field commissioning. However, flowrates, pressures and temperatures were monitored both subsea and topsides to enable a check of the thermal and hydraulic design loading of the flowlines. Similarly, the wax and hydrate management strategies were not intentionally proven during the tests (e.g. flowline depressurization). However, when this event has occurred, the flowline depressurization operation was monitored and evaluated against the operation strategy. Higher flow rate affects the operating arrival temperature to some extent and was monitored during the test. The maximum potential inventory in the pipeline remains the same for depressurization rate purposes since it will be based on the PSHH setting which remains unchanged.

Where possible, the performance tests for gas and water injection demonstrated flowline/manifold/wellhead functionality. Where chemical injection was being carried out, chemical injection flow rates were monitored topsides and subsea.

Firewater and Deluge performance tests were carried out as part of the commissioning program and verification reports from that process were accepted as satisfaction of performance requirements.

2.2 Process Hazards Analysis

Desktop studies have indicated that increased production capacity is available on SeaRose within safe limits. Prior to initiation of performance testing, desktop results and performance test procedures were put through a formal Process Hazards Analysis (PHA) on April 22-24, 2006. A separate PHA was performed on June 9, 2006 on the testing procedure for the electrical power generation system.

The PHA reviewed each performance test procedure to identify potential deviations from normal operating conditions that may occur, the causes and consequences of such potential deviations, and to assign a risk ranking. The Risk Ranking Matrix consisted of three components:

- Consequence - a numerical scale of consequence from 0 to 5 was used to indicate increasing severity. The selection of a consequence for evaluation should represent reasonable circumstances (likely events as opposed to Absolute Worst Case) that could develop from a particular hazard. The Matrix could be applied to potential, initial and actual consequences.

- Likelihood - an alphabetical scale from A to E was used to indicate an increasing likelihood of occurrence. After assessing the consequence, the likelihood of an event occurrence was assessed based on experience and/or historical evidence of such an event occurring within Husky and/or industry.

- Priority Action Setting - the Priority Action Setting provided the maximum period in which corrective action must be implemented. However, corrective action intended to mitigate or eliminative risk must always be implemented in the most reasonable and practical time possible.

Worksheets identifying potential deviations, causes, consequences, risk ranking, existing safeguards, and recommendations were employed for the review of each performance test procedure. Existing safeguards were reviewed and assessed for adequacy to manage the identified issue. Where appropriate, recommendations were made to address identified issues and responsibility and target completion dates were assigned.

Performance test procedures were finalized based upon the results of the PHA. All recommended actions from the PHA were acted upon and resolved prior to initiation of the proving trials.

Considering that no material changes are required for the FPSO to enable the production increase, it is not envisaged that a new Hazard and Operability Study (HAZOP) is required for the higher rate of production. Other quantitative risk assessments are being carried as described in Section 9.0 (Safety Plan Revisions).

Minor modifications to the process and safety systems on the FPSO do normally undergo a PHA prior to implementation, as part of the Management of Change process.

2.3 Performance Test Procedures

2.3.1 Scope

Performance Testing was primarily aimed at finding the maximum oil handling potential of the topside facilities. However since the anticipated safe reservoir short term flow through the five producing wells was limited to 19,876 m^3/d, (125,000 bpd) it was not possible to fully load some of the systems. Any further increase in production will be scaled up based on the test results.

The following procedures were implemented as part of the performance test:

1. Procedure for Oil Separation and Stabilization System.

2. Procedure for Gas Dehydration and Compression System.

3. Procedure for Water Injection System.

4. Procedure for Utilities (Fuel Gas, Cooling Medium & Heating Medium).

5. Procedure for Power Generation & Electrical Tests.

Main tests 1 and 2 were carried out concurrently as the data gathering was mainly through IMS and ICSS. Tests under Procedures 3 and 4 were carried out immediately after completion of the main test, even though data gathering for the utility systems were also part of the main tests at increased process load. Electrical tests under Procedure 5 were conducted later and took approximately a week.

There were very few temporary variations detailed in the procedures and the tests were mostly conducted as per normal operating procedures and operating envelopes as depicted in the operating manuals.

The key parameters assessed during the test include:

- Crude oil rundown to storage flow rate and product qualities like RVP and BS&W

- Gas Flow rates from different separators, compressor flows, load limits, gas composition for different streams, gas dew point at TEG Contactor outlet, liquid carryover to downstream vessels and achieving design operating conditions.

- Sea Water Deaerator capacity, oxygen content, WI Pump(s) flow rate and load.

- Fuel gas at maximum possible flow rate, liquid carryover and super heat limitations.

- Limitations on temperature and flow of Cooling and Heating Medium.

- Opening of control valves above 80%.

- Vibration in piping and equipment.

2.3.2 Summary of Test Procedures

The procedure adapted for the performance tests is summarised as follows:

1. Shut down the Test Separator and divert all production to HP Separator and ensure that all equipment is running as per design.

2. Ramp-up the production from 5 wells as per limits set by reservoir group (Table 2.3).

Table 2.3 Ramping up Choke Settings

RAMP UP GUIDELINES				
Hour	Well	SS Choke Start	SS Choke To	Comments
0	SP1	29	30	
1	CP2	27	28	
2	SP1	30	31	
3	CP2	28	29	
4	SP1	31	32	
5	CP2	29	30	
6	SP3	35	**36**	Recommended
7	CP1	26	**27**	Recommended
8	SP1	32	**33**	Recommended
9	CP2	30	31	
10	CP2	31	**32**	Recommended
11				Stabilise
12				Stabilise

3. Increase the production until 19,876 m^3/d (125,000 bpd) or nearest within approximately 12 hours. Measure vibration and noise levels.

4. Stop all heating to the separator inlet heaters.

5. As production increases during ramp up and when HP Separator flare valve tends to open, reduce LP Compressor discharge pressure gradually to 5500 kPa to increase its throughput.

6. Keep steady production for 24 hours and sample oil and gas.

7. Run all three WI Pumps.

8. Take all local readings and log activities

9. IMS Data will be monitored remotely by Test Process Engineer.

10. Once the 24 hrs steady test is over shut down the FG Compressor for sampling gas composition in LP Compressor.

11. Increase HP and LP Fuel Gas flow to 25,000 sm3/hr and 4,500 sm3/hr respectively by flaring and take all measurements in Fuel Gas System.

12. Increase feed to the Sea Water Deaerator to maximum with all three pumps and sample water for O2 content.

13. Isolate one WI pump from its manifold and test the pump independently under varying flow rates by overboarding the water.

14. Reinstate all changes carried out in process and normalise production.

15. Carryout Power Generation Test separately

2.3.3 Test Schedule and Duration

The performance test schedule and duration is provided in Table 2.4.

Table 2.4 Performance Test Schedule

No.	Description	Duration
Crude Separation System		
1	Ramping up of flow from 15,873 m^3/d (100,000 bpd) to 19,081 m^3/d (120,000 bpd) or more. Identifying limitations, problems etc.	12 hrs of duration during daylight.
2	Steady flow of 19,081 m^3/d (120,000 bpd) or more.	24 hrs (overnight + next daylight)
3	Steady flow of 19,081 m^3/d (120,000 bpd) or more.	6 hrs (oil production to be maintained for Utility System testing without taking any readings for Oil system)
Gas Compression and Dehydration Systems		
1	All readings during Ramp-up of oil production	12 hrs of duration during the day.
2	LP / IP / HP Compressor Train A	12 hrs of duration during the night.
3	LP / IP / HP Compressor Train B	12 hrs of duration during the next day.
4	FG Compressor	24 hrs of duration during the Oil Test.
5	Contactor	24 hrs (overnight and the next full daylight)
6	TEG Regeneration System	24 hrs (overnight and the next full daylight)
7	Extended operation for Utility Systems	6 hrs (no readings are required from Gas system except those for utilities)
Water Injection System		
1	All readings during Ramp-up of oil production 2 WI Pumps at 650 m^3/hr each.	12 hrs of duration during the day (Hourly readings).
2	All readings while steady oil flow 2 WI Pumps running.	18 hrs of duration during the night & following day until noon (2 hourly readings).
3	Pump Flow = 650 + 650 + varying flow from 3rd Pump overboarding 300 to 650 m^3/hr.	4-6 hrs of duration during the day time after carrying out 30 hrs of Oil Test.
4	Raise the flow to 650 + 650 + 650 m^3/hr if possible (O_2 below 10 ppb) OR PSL on any pump suction not less than (-) 20 kPag (PSL is set at 78 kPaA i.e. (-) 22 kPag)	6 hrs of duration after oil test but with high oil production (max. electrical load). This part may be conducted along with other utilities test.

Utility Systems		
1	All readings during Ramp-up of oil production.	12 hrs of duration during the day (Hourly readings for all utilities ICSS & local readings).
2	Steady maximum Oil Flow	24 hrs of duration during the night & following day (hourly readings for all utilities via. ICSS and two-hourly readings locally).
3	Oil & Gas Test completed but extended steady oil flow.	6 hrs of duration after oil test (Hourly readings for all utilities ICSS & local readings). This test will be carried out in parallel with Sea Water Deaeration Tests (WI System)

2.3.4 Data Acquisition

The IMS system was used where ever possible to capture test data. Templates were built to capture all test data and are included in the performance test procedures. For data that had to be recorded manually, these tags are noted as such. For automated data capture, the IMS historian continued to capture data during the test and summarized the test data when the test concluded.

Test data was monitored by the Test Coordinator to ensure that the operational parameters were within the requirements of the test. Where parameters exceeded those required for the test, the Test Coordinator and Test Process Engineer reviewed the data and consulted with the Engineering Manager to determine if the test should be suspended or continued.

2.3.5 Pre-start Checks

Plant systems, equipment, instruments etc. were checked before the test for their functionality and accuracy. Regular meetings with site and St. John's office were conducted to follow up the progress of close-outs of PHA action items. Functional charts with responsibilities were assigned to all participants in the Peformance Testing. Vibration checks were conducted before the test and recommended any potential areas to be rectified. All such action items were completed before the test.

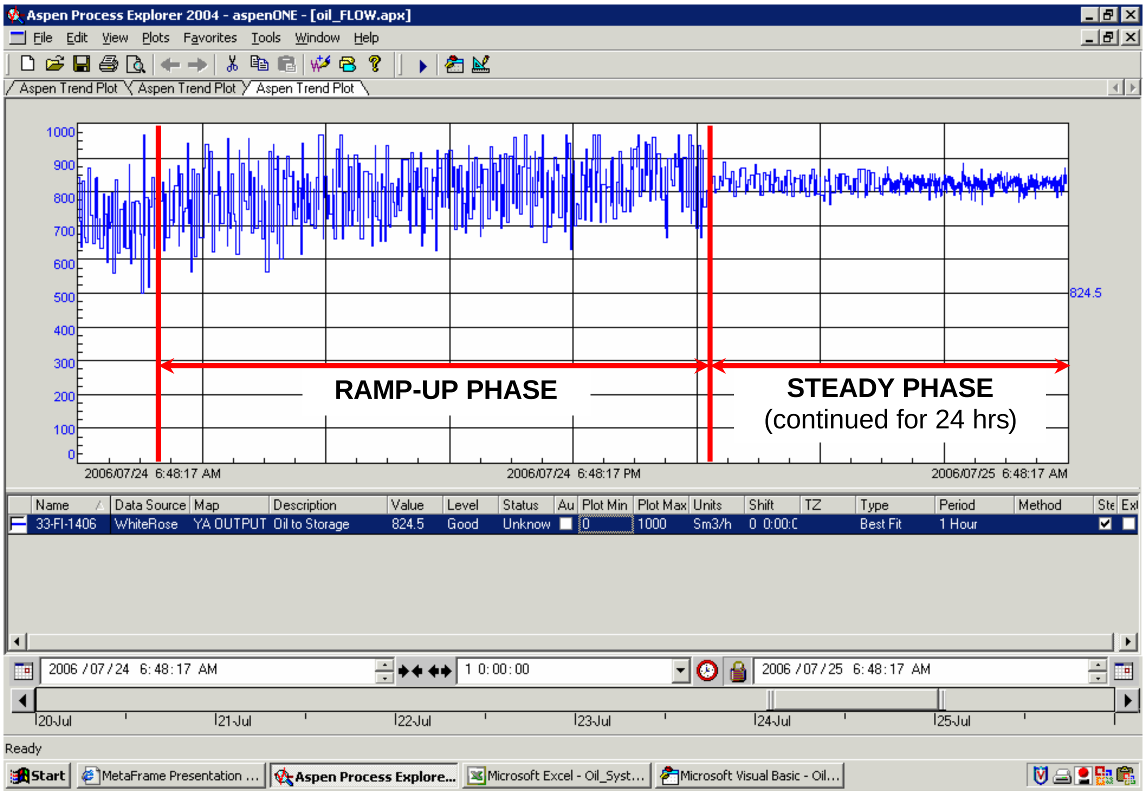
3.0 Performance Test Results

3.1 System Results

3.1.1 Oil Separation System

Just before starting the performance test, the Oil Separation System was flowing at an average of 17,491 m^3/d oil (110,000 bpd). Variation in instantaneous flow rate due to slugging was typically 15,583 m^3/d oil to 19,081 m^3/d oil (98,000 to 120,000 bpd). Ramping up was started at 7:00 AM on July 24, 2006 and took almost 16 hours to stabilise at the desired flow of 19,876 m^3/d oil (125,000 bpd) (Figure 3.1).

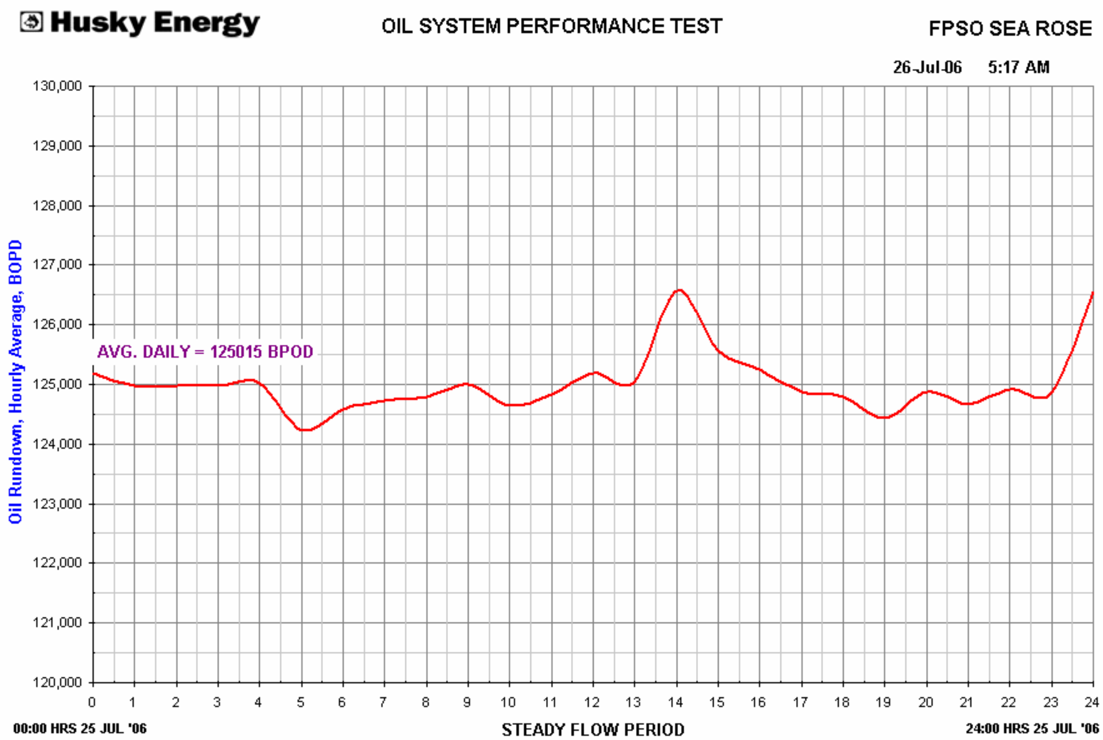
Figure 3.1 Performance Test Period
(Slugging from CP-1 was stopped by choke adjustments at the end of Ramp-up Phase)



The main difficulty that was experienced towards the end of ramp-up was the limitation in opening of the pressure control valve 33-PCV-1107A on the oil separation system that was intentionally restricted at 70%, causing larger pressure losses between the HP Separator and LP Compressor. Such a limit was originally made to prevent overloading of the compressor motor when only one train of compressors is running. Restriction on the PCV caused increased pressure in HP Separator which further resulted in increase in gas flows from MP & LP Separators. Occasional opening of the flare valves was also causing upsets in the Flash Gas Compressor. Increase in MP & LP Compressors were made to prevent flaring but was ultimately limited to avoid an ESD from LP Separator. Since the operating load measured from the LP/IP Compressor motor was within the motor rating, it was decided to investigate the possibility of allowing further opening of the PCV. A PHA was conducted for assessing the risk and the opening limit was raised to 75% without overloading the motor. However it was observed that most of the pressure losses were caused by the HP Separator gas piping, Suction Cooler, Suction Scrubber Demister, orifice flow meter and the suction strainer within the single train that was designed to take up to 2.5 MMsm^3/d while actual flow exceeded ca. 3.0 MMsm^3/d. 19,876 m^3/d (125,000 bpd) ultimately became the limiting capacity without running the 2nd compressor train.

Choke adjustments on E-18 4 (CP-1) well, Line 4 were made to reduce pipeline slugging experienced during ramp up phase (see Figure 3.1). A steady daily average flow of 19,876 m^3/d oil (125,000 bpd) was maintained for 24 hrs during the test. Spot readings showed that the instantaneous flow was generally fluctuating from 19,081 m^3/d to 20,671 m^3/d oil (120,000 to 130,000 bpd) peaking up to 22,261 m^3/d oil (140,000 bpd) occasionally. Highest "hourly average" recorded during the test was 20,114 m^3/d oil (126,500 bpd) (see Figure 3.2). No abnormal vibrations were reported during the ramp up and subsequent steady production phase.

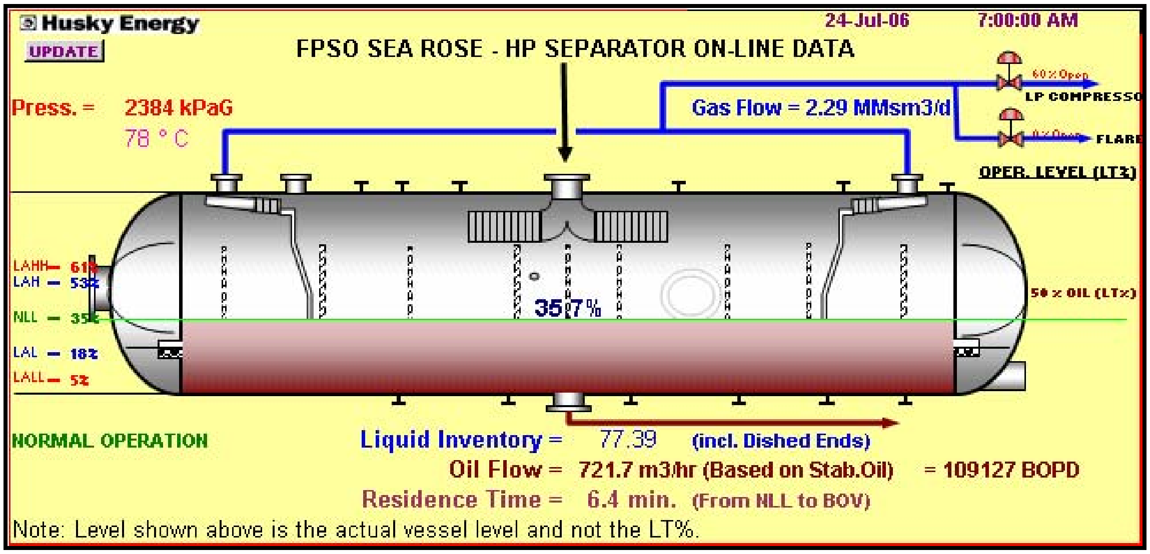
Figure 3.2 Steady Flow Performance Test Period (Data Based on Hourly Average)



3.1.1.1 HP Stage Oil Separation

The HP Separator is a horizontal 2-phase separator designed with a predominantly larger gas section for handling large volumes of associated gas and recycled lift gas. The feed enters from the top, at the centre of the vessel through inlet vane devices directed in both directions (Figure 3.3). The gas velocity in the vessel is split with dual gas outlets provided with proprietary cyclonic devices for coalescing any carried over liquid droplets. The liquid section covers only 35% of the vessel diameter and is a semi-enclosed compartment with restricted entry for liquids through perforated plates on either end of the vessel to minimise sloshing during sea state rolling of the FPSO. Liquid outlet is located at the centre of the vessel taken from the bottom of the semi-enclosed liquid section.

Figure 3.3 Process Conditions before Ramp Up - HP Separator (Green Line shown is the Design Normal Operating Level)



Liquid Section: Design operating level of 35% vessel was maintained throughout the test. Liquid (currently only dry oil) residence time from NLL to the vessel outlet was around 5.3 to 5.8 minutes during the test. Residence time was far above the original design of 3.3 minutes (for identical levels) at a flow rate of 33,000 m^3/d total liquids. Residence time (for identical levels) for 22,261(140,000 bpd) dry oil will be ca. 5 minutes and hence liquid handling by the HP Separator will not be an issue until water production is substantial. When water production begins, the total liquids flow will be maintained at under 33,000 m^3/day.

Gas Section: Gas flow from the separator was steady at around 2.67 MMsm^3/d. The flow corresponds to a vapour velocity (dual outlets) of 0.08 m/sec based on the operating level and 0.159 m/sec based on LSHH setting, as opposed to the calculated maximum allowable vapour velocity of 0.43 m/sec. The above allowable vapour velocity is estimated based on a vessel without any coalescers and hence it is a conservative estimate. As well, the installed proprietary cyclonic device at the gas outlet provides additional capacity. No carryover was observed from the trends of condensed liquid level in the downstream LP Compressor Suction Drum and its LCV opening.

Gas compositions measured at different stages of the test were consistent and the average molecular weight calculated was 20.0 which compares well with the design mol. Wt of 20.1 for Case 1 (Initial Dry Oil case). Average GOR across HP Separator recorded during the test was 136 sm^3 gas per m^3 Stabilised Oil (See Table 3.1).

Table 3.1 Composition of HP Separator Gas during Test (in Mole %)

COMPOSITION (Mol %) FOR HP SEPARATOR GAS DURING PERFORMANCE TEST			
Components	Pre-Ramp up	0 Hour	12 Hour
N2	0.316	1.261	0.365
CO2	1.914	1.879	1.918
C1	85.073	84.645	85.270
C2	6.125	5.959	6.092
C3	3.712	3.482	3.654
IC4	0.521	0.466	0.509
NC4	1.249	1.081	1.214
IC5	0.277	0.228	0.262
NC5	0.353	0.295	0.331
C6	0.242	0.241	0.213
C7+	0.219	0.463	0.173
Mol. Wt.	**19.970**	**20.035**	**19.850**

Notes:
Pre-Ramp up – Just before test start
0 Hour – beginning of Steady flow period
12 Hour – middle of Steady flow period
Gas compositions were identical to the design case.

Pressure in the HP Separator was increased from its normal 2400 kPag to 2500 kPag during ramp-up as the gas flow was handled by a single compressor train. The flare valve setting was raised during this time to 2600 kPag (from normal 2,500 kPag) thus preventing the flare valve from opening. The rise in pressure was caused by the inability to open 33-PCV-1107A in the oil separation system more than 75% (limited by interlock when only a single train compressor was running). Such an interlock was incorporated in the design to safeguard against overloading the motor during start-up. However, actual plant readings showed that the compressor motor was only loaded to 87%. Further, pressure losses in the suction system were self limiting thus reducing any potential for overloading in spite of an increase in the PCV opening. See Figures 3.4 and 3.5 for process trends. See Figures 3.4 and 3.5 for process trends.

Figure 3.4 Process Conditions in HP Separator during Test (Period covers Ramp-up and Steady Phases)

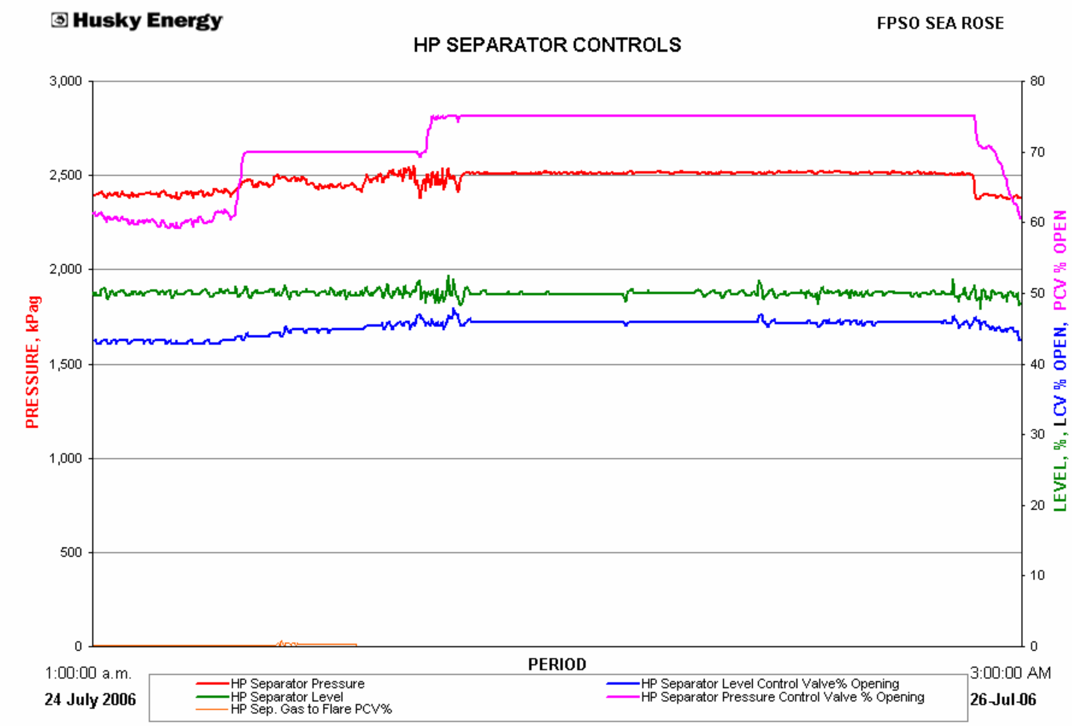
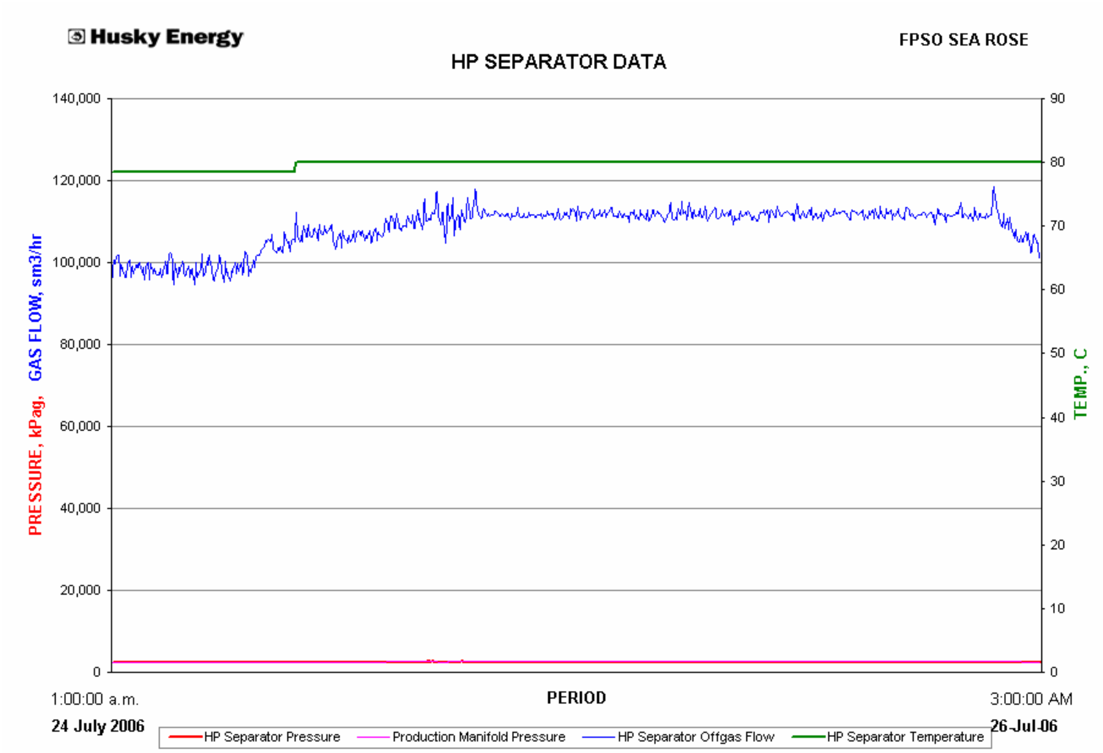
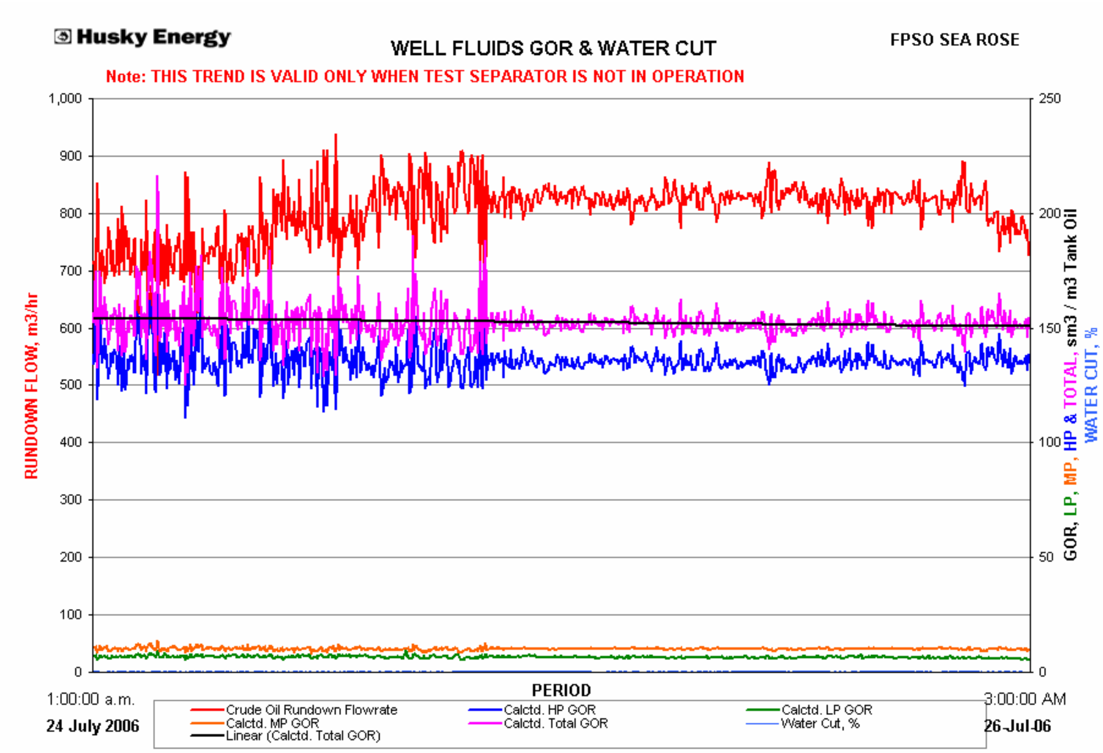


Figure 3.5 Process Conditions in HP Separator during Test (Period covers Ramp-up and Steady Phases)



Even though there were pressure controllability issues in downstream MP and LP Separators during the ramping up phase, the steady high rate operation for 24 hours was very smooth. Pressure control issues downstream could be more attributable to the pipeline slugging during the ramp-up phase. No noticeable increase in gas release is recorded in the downstream MP Separator apart from the proportional increase due to higher oil flow during the ramp-up phase. A steady trend on GOR across MP Separator is shown in Figure 3.6.

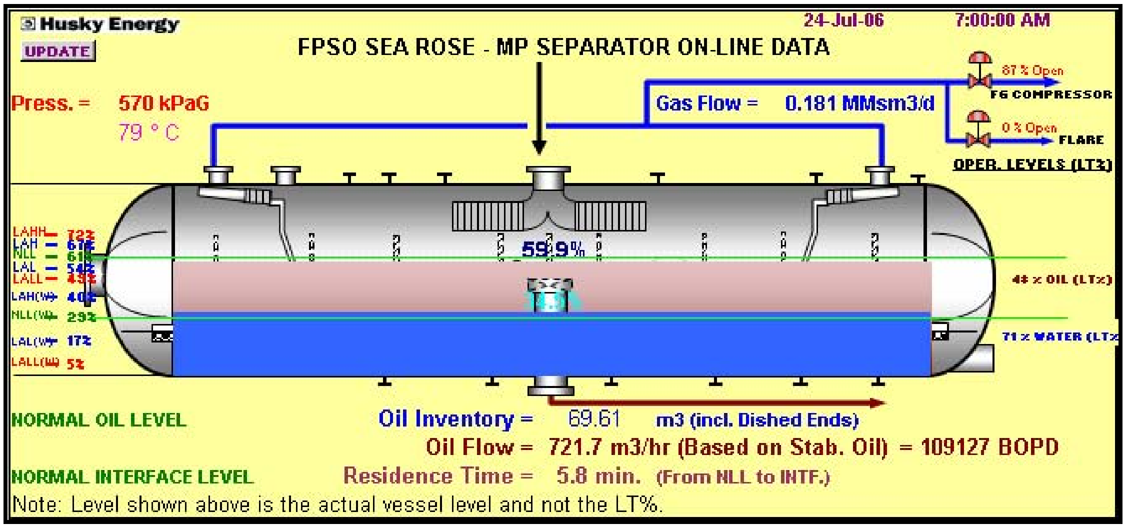
Figure 3.6 Gas Oil Ratio for all three stage of Separation during Test (Period covers Ramp-up and Steady Phases)



3.1.1.2 MP Stage Oil Separation

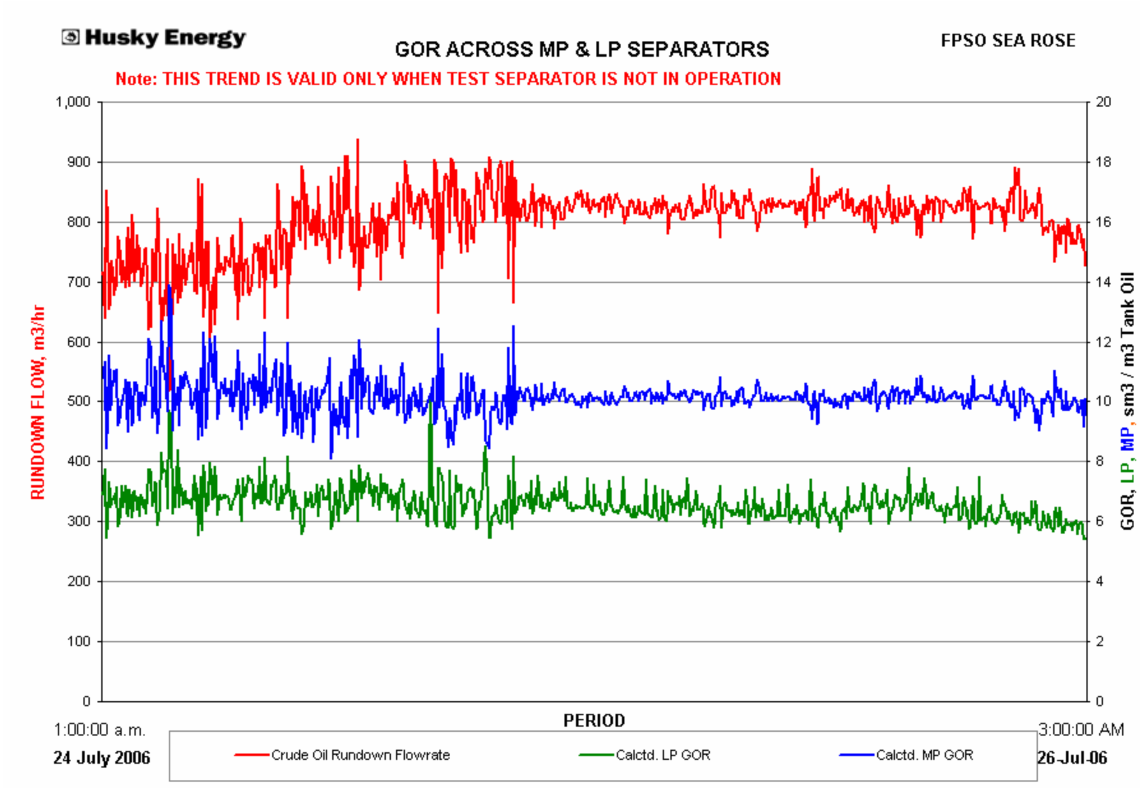
The MP Separator is a horizontal 3-phase separator with a gas section that is smaller than the HP Separator and is designed for handling lesser volumes of associated gas (Figure 3.7). It has a large oil and water sections with coalescers for better settling. The feed enters from the top, at the centre of the vessel through inlet vane devices directed both directions. The gas velocity in the vessel is split with dual gas outlets provided with proprietary cyclonic devises for coalescing any carried over liquid droplets. The liquid section covers 61% of the vessel diameter and is semi-enclosed compartment with restricted entry for liquids through perforated plates on either end of the vessel to minimise sloshing during sea state rolling of the FPSO. Oil is taken out through a riser located at 45% of the vessel level. Produced Water outlet is located at the centre of the vessel taken from the bottom of the semi-enclosed liquid section.

Figure 3.7 Process Conditions before Ramp Up - MP Separator
(Green Lines shown are the Design Normal Operating Levels)



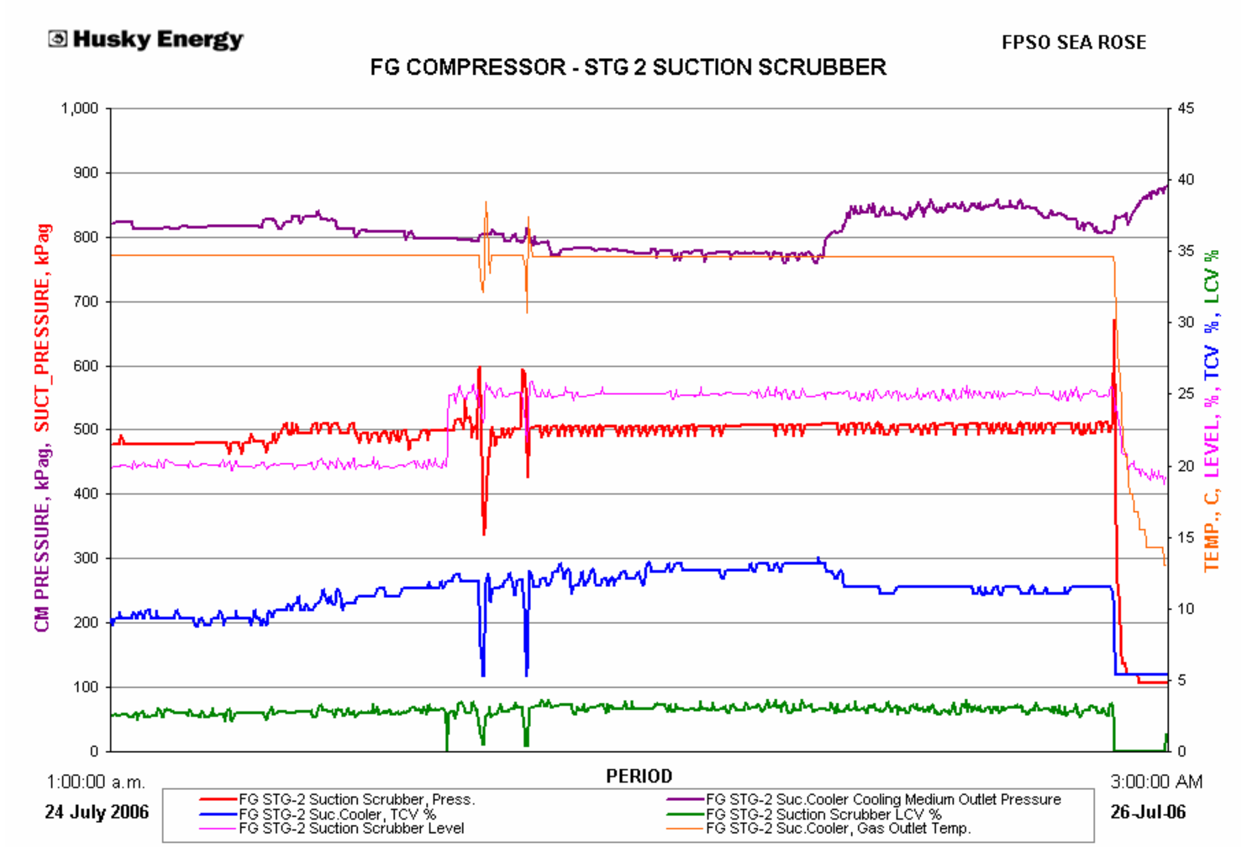
Liquid Section: The design operating oil level of the vessel was maintained throughout the test. Vessel interface level was topped up by filling additional deaerated sea water up to the design NILL. Liquid (now only dry oil) residence time from NLL to the NILL was around 5.5 to 6 minutes during the test. Oil Residence time with the design flow of 15,900 m^3/d (100,000 bpd) for identical levels is 7.2 minutes. No noticeable increase in gas release was recorded from the downstream LP Separator, other than the proportional increase in gas due to increased oil flow during the ramp-up phase (Figure 3.8). Pressure control setting was increased in MP Separator from design 570 kPaG to 620 kPag to prevent the MP gas flare valve opening during pipeline slugging and the PCV operation affected by the sensitive 2nd Stage Flash Gas Compressor operation.

Figure 3.8 Gas Oil Ratio for MP and LP Separation during Test (Period covers Ramp-up and Steady Phases)



Gas Section: Gas flow from the separator was steady at around 0.20 – 0.22 $MMsm^3/d$ and the vapour velocity in the separator (dual outlets) was 0.04 m/sec based on the operating level and it was 0.07 m/sec based on LSHH level as opposed to the calculated maximum allowable vapour velocity of 0.65 m/sec for a vessel without considering any coalescers. Installed internal cyclonic proprietary device at the gas outlet is an added bonus. No carryover was observed from liquid level in the downstream FG Compressor 2nd Stage Suction Drum and its LCV opening trends (see Figure 3.9). A sharp increase in level (purple) seen in the trend was the effect of raising the set point during the ramp up period. LCV opening (green) remained identical showing that the flow of liquid did not change.

Figure 3.9 Flash Gas Compressor Stage 2 Suction Scrubber Levels (Period covers Ramp-up and Steady Phases – See no carry over judged by LCV %)



Gas mol. wt measured at different stages of the test was varying from 27.2 to 29.4 with an average molecular weight at 28.3, compared to the mol. Wt of 25.65 for Design Case 1 (Initial Dry Oil case) – see Table 3.2.

Average GOR across MP Separator is 10.2 sm^3 gas per m^3 Stabilised Oil (see Figure 3.8).

Table 3.2 Composition of MP Separator Gas during Test (in Mole%)

COMPOSITION (Mol %) FOR MP SEPARATOR GAS DURING PERFORMANCE TEST			
Components	**Pre-Ramp up**	**0 Hour**	**12 Hour**
N2	0.153	2.803	0.374
CO2	2.380	2.378	2.312
C1	61.210	62.676	60.608
C2	11.623	11.163	11.071
C3	11.335	9.883	10.523
IC4	2.098	1.700	1.978
NC4	5.563	4.450	5.450
IC5	1.492	1.196	1.652
NC5	1.982	1.602	2.310
C6	1.358	1.211	2.036
C7+	0.806	0.937	1.685
Mol. Wt.	**28.340**	**27.178**	**29.430**

Notes:
Pre-Ramp up – Just before test start
0 Hour – beginning of Steady flow period
12 Hour – middle of Steady flow period

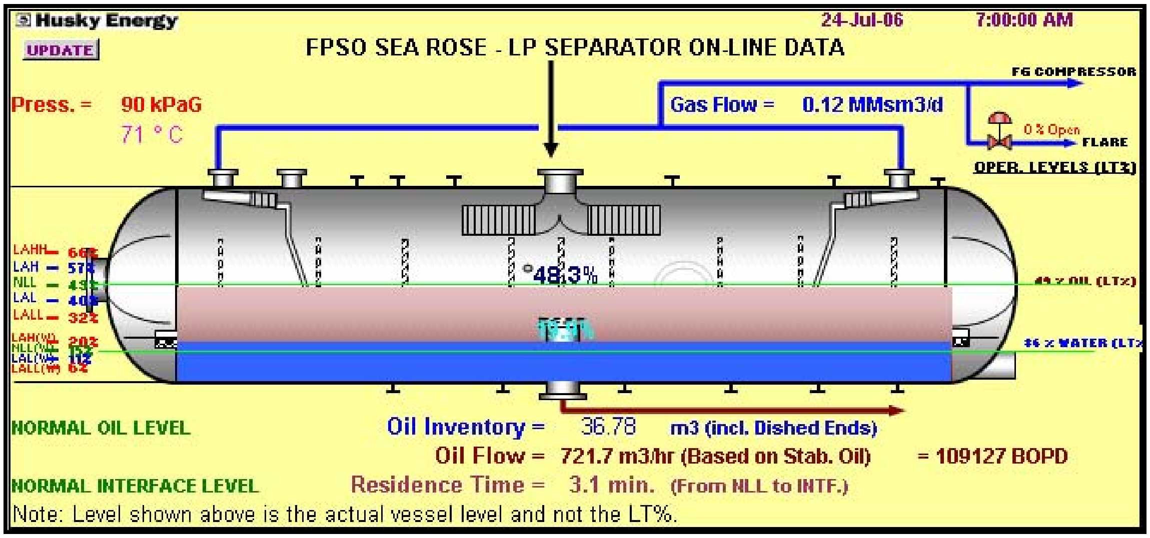
Gas compositions were heavier than the design case. However the molecular weight of gas at the suction of FG Compressor Stage-2 is lighter than design cases due to condensation in the Stage-2 Suction Cooler.

3.1.1.3 LP Stage Oil Separation

The LP Separator is a horizontal 3-phase separator designed with almost equal volumes of gas and liquid sections (Figure 3.10). Out of the liquid section, the Produced Water section is comparatively small as the water is recycled to the MP Separator. The feed enters from the top, at the centre of the vessel through inlet vane devices directed towards both directions. The gas velocity in the vessel is split with dual gas outlets provided with proprietary cyclonic devises for coalescing any carried over liquid droplets. The liquid section covers 49% of the vessel diameter and is a semi-enclosed compartment with restricted entry for liquids through perforated plates on either end of the vessel to minimise sloshing during sea state rolling of the FPSO. Oil is taken out through a riser located at 26% of the vessel level.

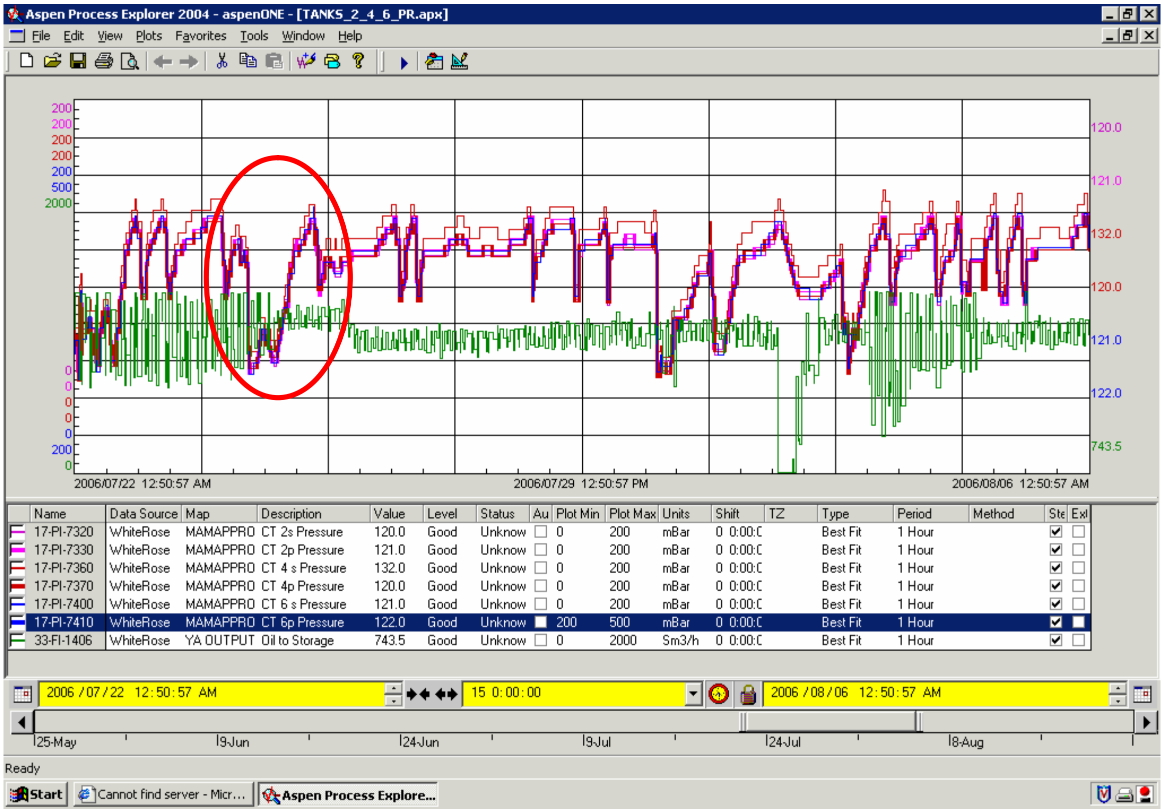
The Produced Water outlet is located at the centre of the vessel taken from the bottom of the semi-enclosed liquid section. The LP Separator will capture any fine water droplets carried over from the MP Separator. Normally, very little water will be carried over. Water from the LP Separator is recycled to the MP Separator and hence the quality of water from the LP Separator is not very critical.

Figure 3.10 Process Conditions before Ramp UP - LP Separator (Green Lines shown are the Design Normal Operating Levels)



Liquid Section: The design operating oil level of 49% within the vessel was maintained throughout the test. Vessel interface level was maintained close to the design NILL. Oil residence time from NLL to the NILL was around 2.8 minutes during the test. Oil Residence time with the design flow of 15,900 m^3/d (100,000 bpd) for identical levels is ca. 3.5 minutes. No noticeable increase in gas release was recorded from the downstream cargo tanks, as seen from the pressurisation trends on cargo tank pressures which were almost identical to periods of design rate (Figure 3.11).

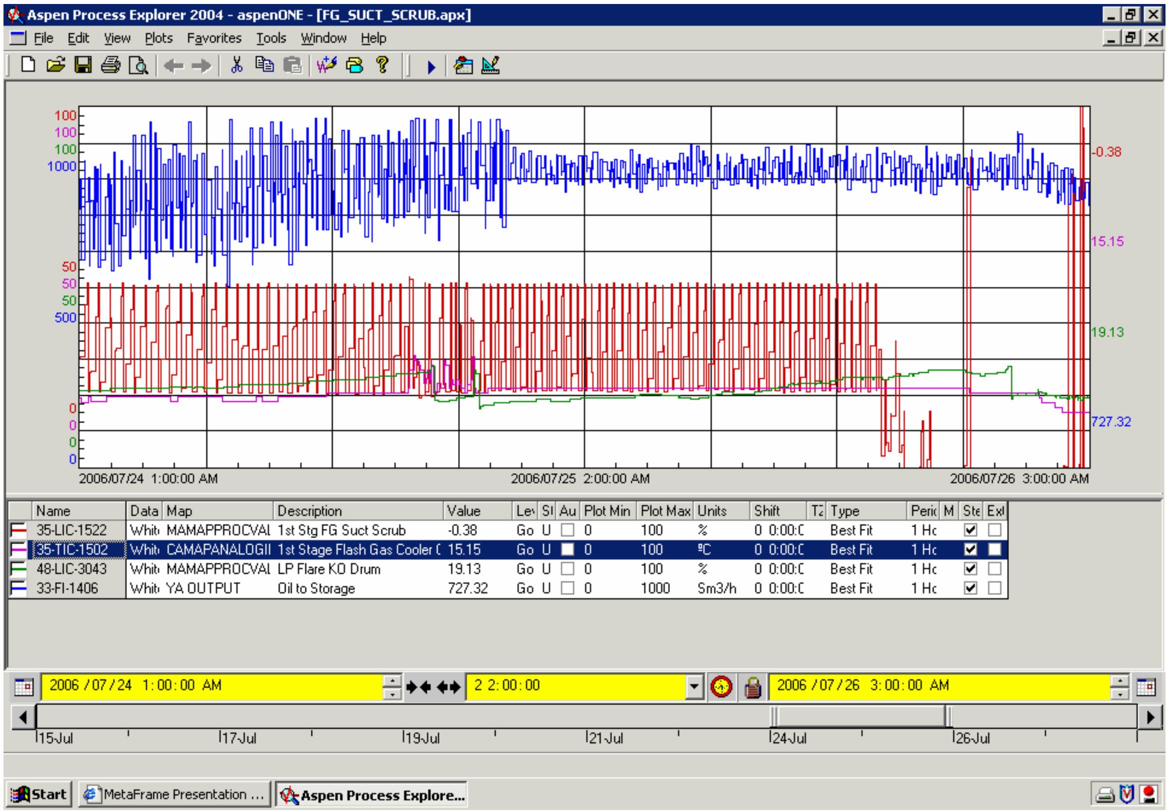
Figure 3.11 Tank Pressurization over a period of 15 days
(Test Period is marked - an offloading was done just before the Steady Flow Test)



Gas Section: Pressure control setting was increased in LP Separator from design 80 kPag to 90 kPag to prevent any carryover observed a day before the test. Flare valve setting was kept at 100 kPag during the test to make the FG Compression operation stable. Further increase was not possible due to its proximity to the existing 33-PAHH-1313 level controller that would have caused an ESD.

Gas flow from the separator was steady at around 0.13 MMsm^3/d and the vapour velocity in the separator (dual outlets) was 0.1 m/sec based on the operating level and 0.2 m/sec based on LSHH level as opposed to the calculated maximum allowable vapour velocity of 1.07 m/sec for a vessel without any coalescers. The installed internal cyclonic proprietary device at the gas outlet also increases capacity. No carryover was observed from condensed liquid level in the downstream FG Compressor 1st Stage Suction Drum and its pump operation trends (see Figure 3.12). The condensate was pumped out from the Suction Drum on a regular basis as seen from the trend in Figure 3.12. Any carryover would have caused an abnormal increase or irregularity in pumping frequency.

Figure 3.12 Flash Gas Compressor Stage 1 Suction Scrubber Level and Pumping (Period covers Ramp-up and Steady Phases – see no carry over judged by pumping frequency)



Gas mol. wt measured at different stages of the test was varying between 40.3 to 41.9 and the average molecular weight calculated was 41.2 compared to the mol. Wt of 40.96 for Design Case 1 (Initial Dry Oil case) – see Table 3.3.

Table 3.3 Composition of LP Separator Gas during Test (in Mole %)

COMPOSITION (Mol %) FOR LP SEPARATOR GAS DURING PERFORMANCE TEST			
Components	Pre-Ramp up	0 Hour	12 Hour
N2	0.049	0.021	0.165
CO2	2.050	1.886	1.910
C1	28.704	26.426	26.554
C2	16.163	15.186	15.369
C3	23.321	23.314	23.724
IC4	4.770	5.092	5.157
NC4	13.006	14.357	14.451
IC5	3.511	4.043	3.947
NC5	4.559	5.267	5.058
C6	2.726	3.009	2.590
C7+	1.142	1.399	1.074
Mol. Wt.	**40.310**	**41.939**	**41.430**

Notes:

Pre-Ramp up – Just before test start
0 Hour – beginning of Steady flow period
12 Hour – middle of Steady flow period

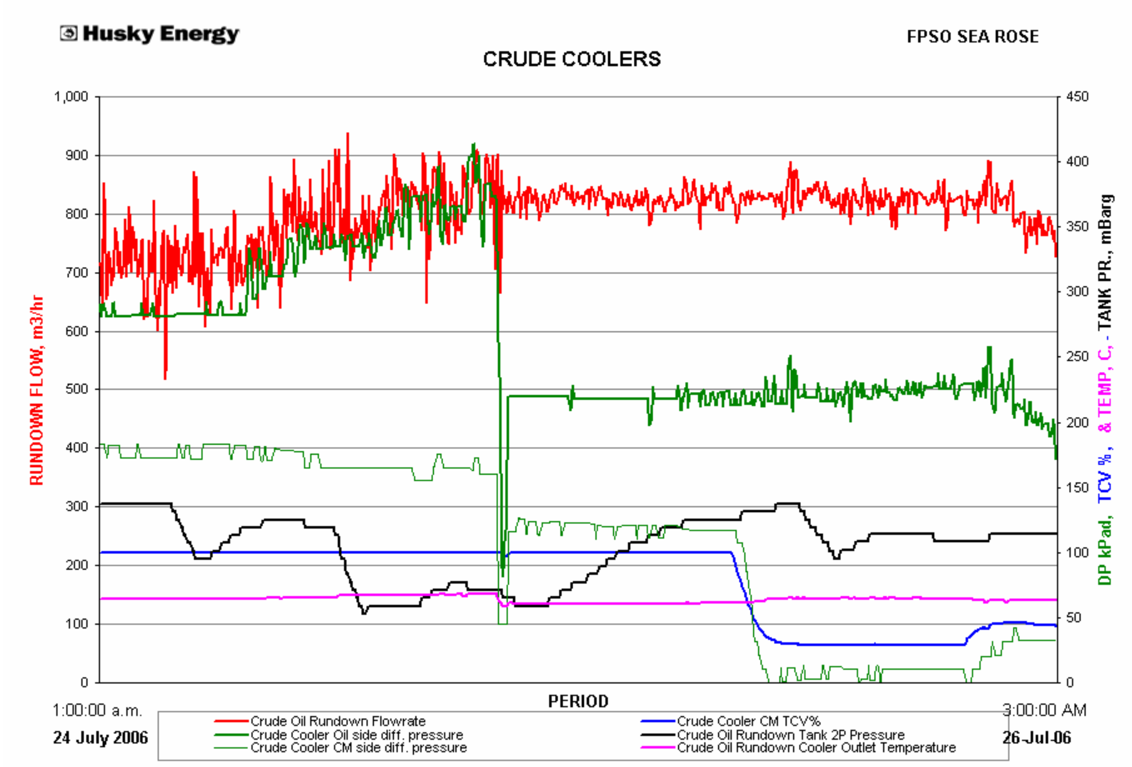
Gas compositions were identical to the design case. However the molecular weight of gas at the suction of FG Compressor Stage-1 is lighter than design cases due to condensation in the Stage-1 Suction Cooler.

Average GOR measured across LP Separator was 6.6 sm^3 of gas per m^3 Stabilised Oil.

3.1.1.4 Oil Rundown

During the ramp-up, Cooler B with original 96 plates was used so that Cooler A with 178 plates was available in clean condition for the steady flow test. Pressure drop in both oil and cooling medium side through the cooler got reduced substantially after the change over of coolers, as expected (see Fig 3.13).

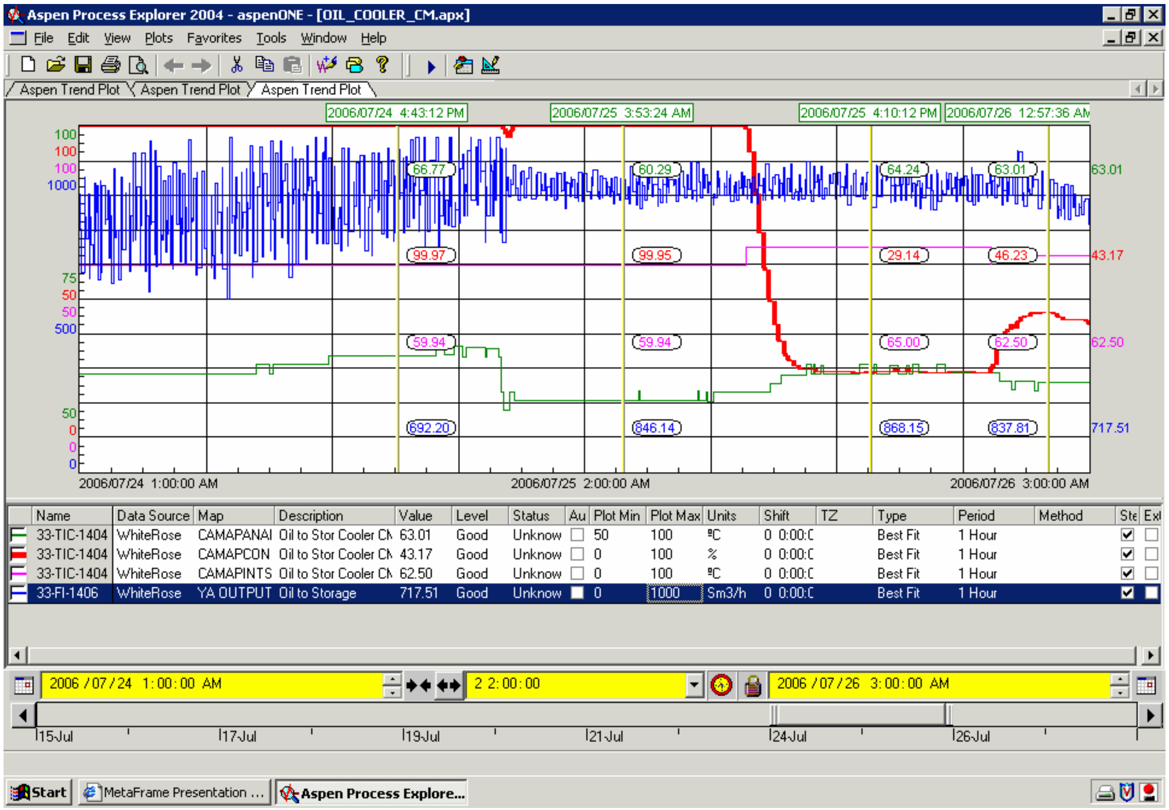
Figure 3.13 Crude Cooler Process Data during Test (Period covers Ramp-up and Steady Phases)



Temperature controls are shown in Figure 3.14 with magnified scales. Before and during ramp up, the set point on the crude cooler temperature control instrument (33-TIC-1404) was 60 C and it was unable to achieve this temperature in spite of its TCV indicated as full open. Oil outlet temperature recorded during this time was around 67 C. It was also observed that even after taking the larger cooler A on line, the TCV opening continued at 100% except for a very short time during the change over when both cooler would have been in service. However the oil temperature dropped to its set point of 60 C. During the steady flow test period, the set temperature was raised to 65 C when the TCV opening decreased to 29% and at a set point of 62.5 C it was controlling at 46% opening.

Note: As per the cooler vendor calculations the larger cooler will have sufficient cooling capacity even at 22,261 m^3/d oil (140,000 bpd) flow. Cv of the TCV is substantially large for the cooling medium flow required (Cv = 907) and is a modified equal% butterfly valve. It is doubtful whether the butterfly valve is actually opening 100%, even though the controller output was indicating 100% opening. Fouling of the butterfly disc with pipe wall/flange lip is possible if the wafer type valve is not centered during installation. Regardless, the Crude Coolers will not be a bottleneck since the standby cooler with 96 plates may also be used, if required during the 22,261 m^3/d oil (140,000 bpd) case

Figure 3.14 Crude Cooler Oil Outlet Temperature Control
(Period covers Ramp-up and Steady Phases)



Two running crude rundown pumps were adequate for the test flow. Pump A was delivering at 65.5 m differential head while Pump B was operating at 62.5 m giving an average flow of 19,876 m^3/d oil (125,000 bpd). The pumps are performing as per their design curve (Figure 3.15). Since the curves are more or less flat, the head requirement for 22,261 m^3/d oil (140,000 bpd) is ca. 60 m. Level control valve in the rundown line was operating at around 45-50% and hence two pumps will be able to deliver the target flow without any problem (see Figure 3.16 for the pump performance curve with marked flow at 463 m3/hr equivalent to 22,261 m^3/d oil (140,000 bpd).

Figure 3.15 Crude Rundown Pump Operation
(Period covers Ramp-up and Steady Phases)

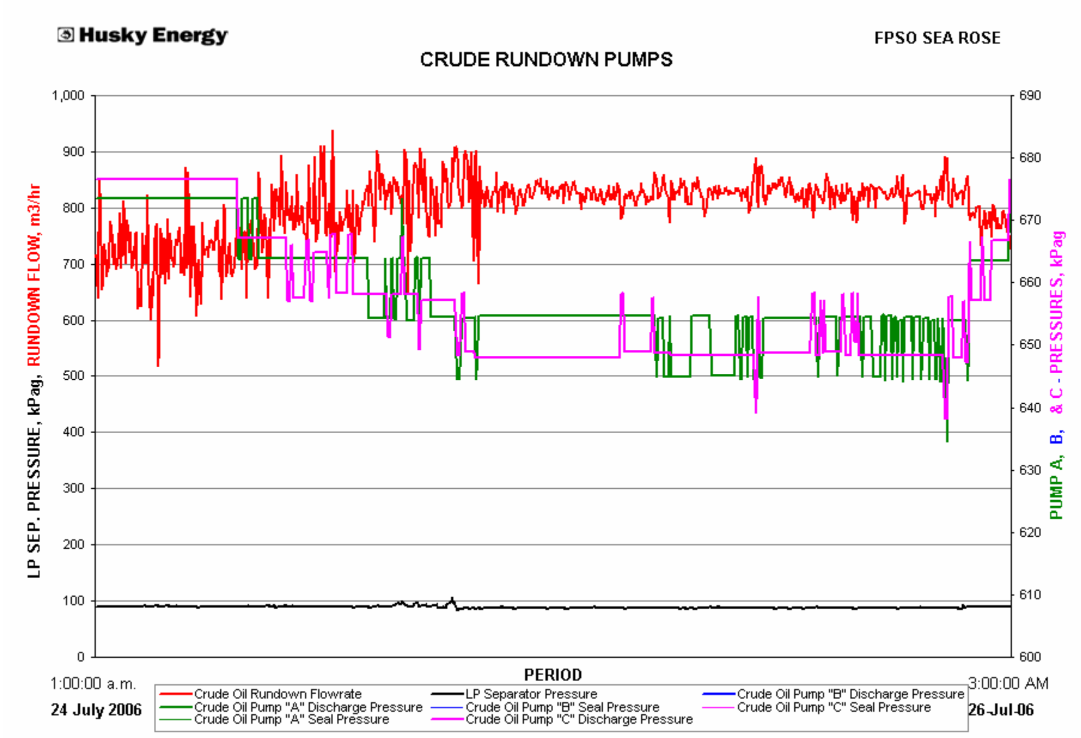
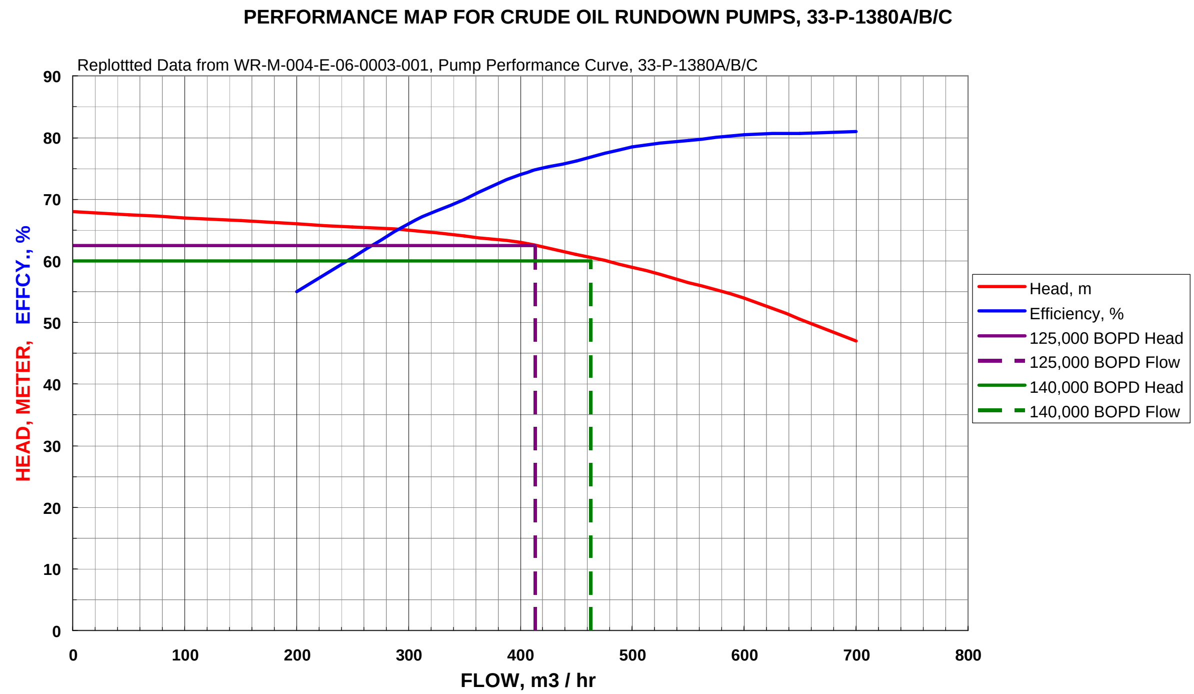


Figure 3.16 Crude Rundown Pump Performance
(Marked Flow of 463 m3/hr is equivalent to 140,000 BOPD using 2 pumps)



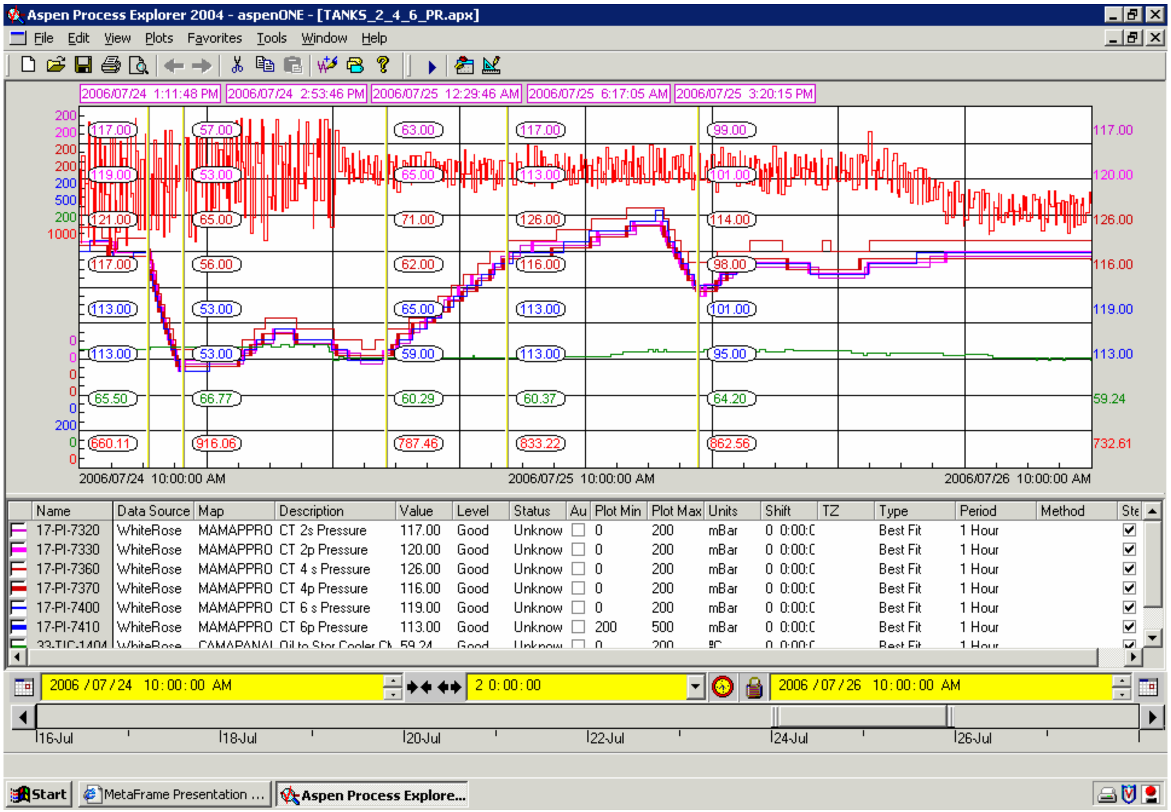
Cargo tanks used for receiving the rundown during the test were as follows:

- Ramp up phase: 4P, 4S, 5P, & 5S
- Steady phase: 2P, 2S, 4P, 4S, 6P & 6S

Offloading was in progress during part of the ramp up phase and the rise in tank pressures are shown in Figure 3.17. It took almost 6 hrs to pressurise the cargo system after the offloading was complete and the IG system stopped when the first level of PV valves set at 120 mBarg was opened. Pressure continued rising to 140 mBarg when the 2nd level of PV valve opened and dropped the pressure to 100 mBarg within short time. Capacity of the PV valves seems to be adequate for their service.

Rundown oil was analysed for RVP and BS&W that did not show any abnormal deviation from their normal values (ca. 25 - 30 kPa and 0.1 - 0.2%).

Figure 3.17 Cargo Tank Breathing during the Test
(Offloading was done just before the Steady Flow Test



3.1.2 Gas Compression System

All compressors operated well during the test. Flash Gas Compressor stages were on continuous part recycle while LP, IP and HP Compressors were operating with their recycle fully shut. Only one train of compressors were run during the test so that its maximum capacity limitation could be assessed. Flow through LP, IP and HP Compressor train was above its design capacity.

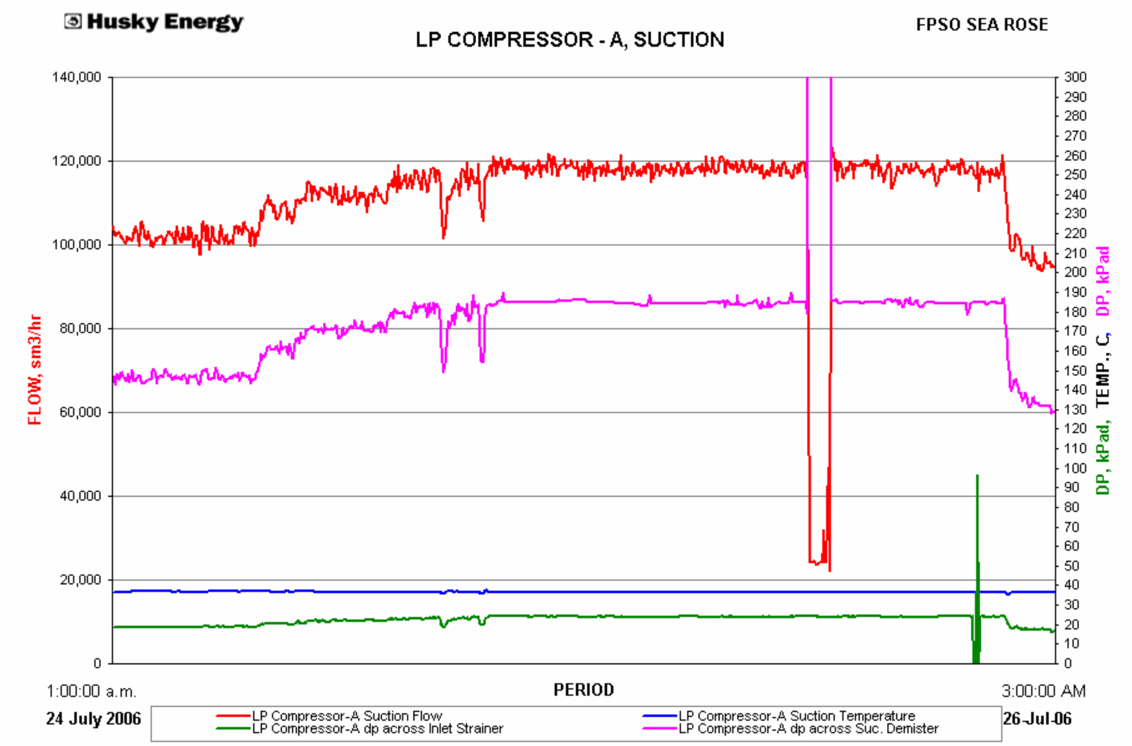
3.1.2.1 LP Compressor

LP Compressor A was run during the test and the maximum flow it handled at 5500 kPag discharge pressure was 2.9 MMsm3/d. Motor load was still below its rating (ca. 87% rated motor load). However increased pressure losses in the suction system prevented raising the flow further (Figure 3.18). Calculations show that the pressure drop is contributed by various elements in the suction system as follows:

- Piping – 50 kPad (calculated)
- Flow Orifice – 37 kPad (measured but there will be some pr. recovery)
- Suction Strainer – 25 kPad (measured by 36-PDI-1685A)
- V-1660A Demister – 68 kPad (by difference)

- Total dp measured by 36-PDI-1663A = 180 kPad

Figure 3.18 LP Compressor Flow and Suction System Pressure Losses (16% Increase in flow raised DP across suction by 28%)



As the compressor is already operating above its design capacity and the second compressor is available for operation, there is no reason to improve the capacity of individual compressor by any changes in suction piping. As the compressor performed satisfactorily no further analysis were carried out.

The gas handling capacity required at the target production rate of 22,261 m^3/d oil (140,000 bpd), is ca. 3.25 $MMsm^3$/d and this will be satisfied by running two compressor trains.

Gas compositions measured during the performance test are given in Table 3.4.

Table 3.4 Composition in LP/IP Compressors during Test (in Mole %)

COMPOSITION (Mol %) FOR LP & IP COMPRESSOR SUCTION GASES DURING PERFORMANCE TEST										
	Pre-Ramp up		0 Hour		12 Hour		Before FG Shutdown		After FG Shutdown	
Components	LP Suct.	IP Suct.	LP Suct.	IP Suct.	LP Suct.	IP Suct.	LP Suct.	IP Suct.	LP Suct.	IP Suct.
N2	5.048	0.327	0.434	0.297	0.548	0.381	0.434	0.000	0.000	0.245
CO2	1.884	1.970	2.002	1.987	1.991	1.978	2.002	2.156	2.055	1.837
C1	78.834	83.045	82.431	82.920	82.033	82.696	82.431	81.813	84.001	85.483
C2	6.508	6.806	6.986	6.832	6.939	6.815	6.986	7.502	6.726	6.084
C3	4.422	4.570	4.770	4.630	4.772	4.587	4.770	5.027	4.049	3.672
IC4	0.643	0.662	0.688	0.669	0.702	0.668	0.688	0.727	0.577	0.520
NC4	1.535	1.577	1.628	1.603	1.706	1.605	1.628	1.732	1.392	1.241
IC5	0.315	0.321	0.321	0.322	0.354	0.344	0.321	0.345	0.319	0.268
NC5	0.386	0.392	0.387	0.390	0.440	0.434	0.387	0.408	0.408	0.332
C6	0.215	0.189	0.207	0.193	0.301	0.286	0.207	0.196	0.269	0.199
C7+	0.210	0.140	0.147	0.156	0.214	0.206	0.147	0.093	0.203	0.120
Mol. Wt.	20.96	20.46	20.61	20.51	20.83	20.65	20.61	20.78	20.29	19.79

Notes:
Pre-Ramp up – Just before test start
0 Hour – beginning of Steady flow period
12 Hour – middle of Steady flow period
Before FG Shutdown – End of Steady flow period
After FG Shutdown – LP & MP gases flared

Gas compositions were identical to the design case and hence the compressor performance was as expected.

3.1.2.2 Gas Dehydration

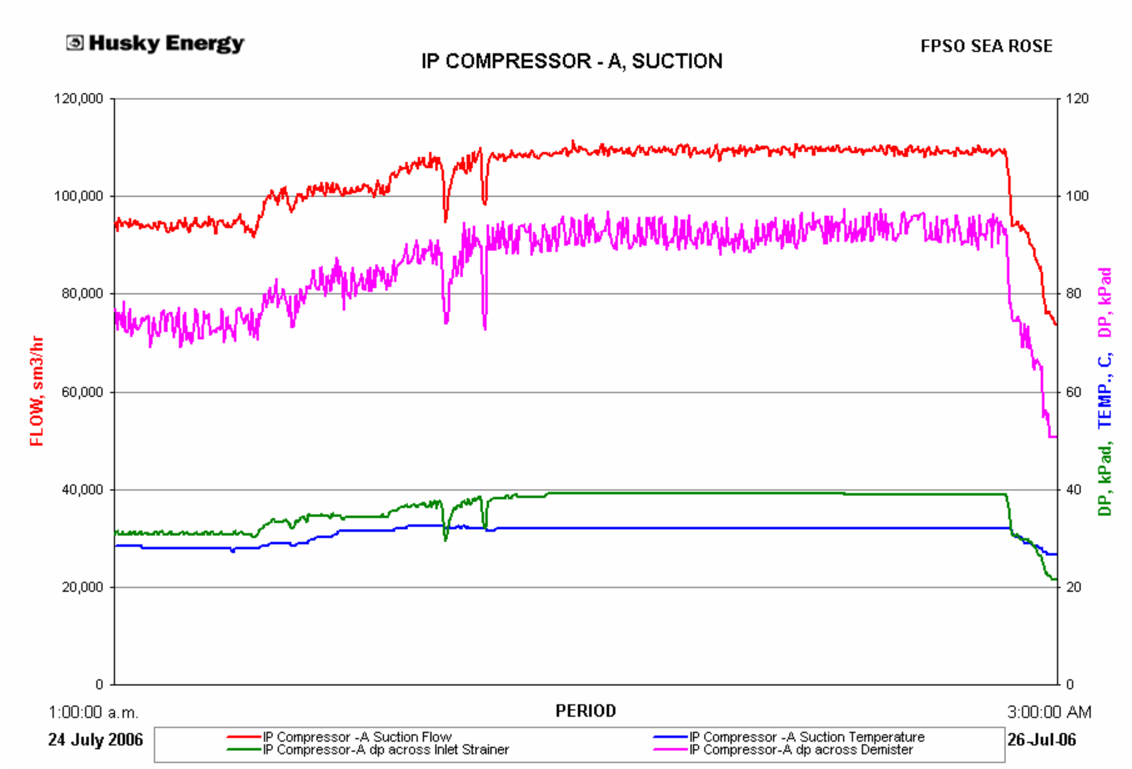
The Gas Dehydration system was run at 2.9 MMsm^3/d capacity and operated on specification. No problems are anticipated for operating at 3.25 MMsm^3/d (flow expected during 22,261 oil m^3/d (140,000 bpd) which is still below its design capacity. A glycol circulating flow of 3.7 m^3/hr was maintained during the test through the Dehydrator and could maintain around (-) 25 deg C dew point.

3.1.2.3 IP Compressors

The IP Compressor handles the net discharge from the LP Compressor after deducting the fuel gas. Fuel gas flow during the flow test was ca. 0.266 MMsm^3/d. The IP Compressor operated well at 2.6 MMsm^3/d capacity without any issues. Since the compressors are required to handle 3.2 MMsm^3/d gas flow, two compressors will be required at the 22,261 m^3/d oil (140,000 bpd) case as it is a tandem compressor with LP casing. The pressure control valve 39-PCV-1733A maintains a back pressure in the TEG Contactor opened to 64% only, even at LP Compressor discharge pressure of 5,500 kPag and IP Compressor Suction Scrubber pressure of 4,800 kPag. When two LP/IP Compressors are running the upstream pressure to this control valve will be in the order of 6,000 kPag and hence handling the increased gas flow will not be a problem. See gas compositions presented in Table 3.4.

The compressor motor common to the LP and IP Compressors was loaded up to 87% of its rated full load amperage. Compressor trains will be on recycle while operating both trains during the target flow. See gas compositions presented in Table 3.4.

Figure 3.19 IP Compressor Flow and Suction System Pressure Losses (16% Increase in flow raised differential pressure across suction by 27%)

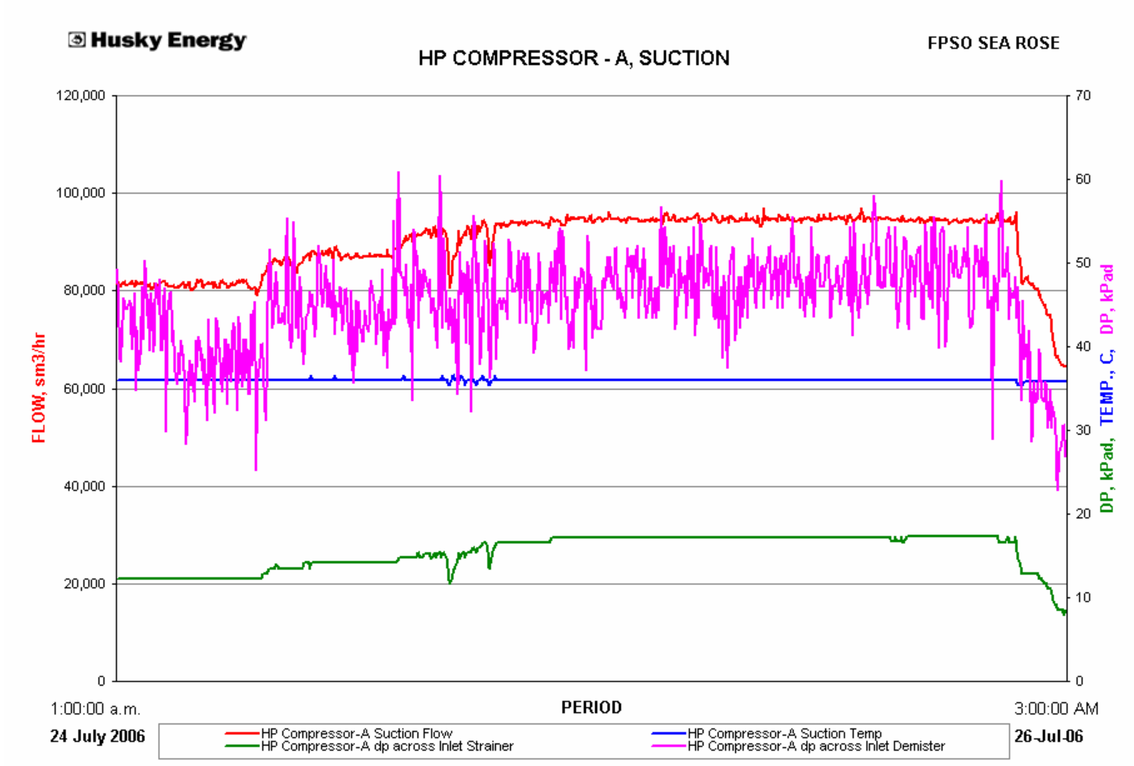


3.1.2.4 HP Compressors

HP Compressor A operated with an average flow at 2.28 MMsm^3/d without any observed problems. Gas was injected throughout at a discharge pressure around 29000 kPag. Injected flow rate more or less corresponds to the HP Compressor internal flow. The compressor motor was loaded only 76% of its rated full load amperage. Expected flow through the compressor during the target flow will be ca. 2.55 MMsm^3/d and even though the flow rate is just above the rated capacity of the compressor it is likely that a single compressor will be able to handle the flow. Operating two compressors will result in running the compressors on recycle.

The HP Compressor gas composition will not vary much from the IP Compressor gas due to negligible condensation in HP Compressor Suction Cooler. See gas compositions presented in Table 3.4.

Figure 3.20 HP Compressor Flow and Suction System Pressure Losses



3.1.2.5 Flash Gas Compressors

The Flash Gas compressor stages handle very low pressure gas and hence are sensitive to variations in suction pressures. Both stages were operating under recycle with the estimated operating flows given in Table 3.5.

Table 3.5 Flow Balance through FG Compressor System (in sm^3/hr)

Description	Stage 1	Stage 2
Raw Gas from Oil Separators (LP & MP, measured)	5,600	14,000 (LP+MP)
Net Gas entering compressor (after condensation, estimated by difference)	3,016	9,146
Flow through Compressor Casing (measured, see Figs 6.21 & 6.22)	13,500[1]	18,000[2]
Recycle Gas (estimated from control valve position)	10,484	8,854

There were upsets during the ramp up phase mainly due to pipeline slugging. However steady operation was observed during the 24 hours of test. The first stage discharge pressure was around 700 kPag while the second stage suction pressure was approximately 490 kPag.

Table 3.6 Gas Composition in FG Compressor during Test (in Mole %)

COMPOSITION (Mol %) FOR FLASH GAS COMPRESSOR SUCTION GASES DURING PERFORMANCE TEST						
	Pre-Ramp up		0 Hour		12 Hour	
Components	Stage-1	Stage-2	Stage-1	Stage-2	Stage-1	Stage-2
N2	0.063	0.092	0.021	0.105	0.113	0.094
CO2	2.178	2.454	2.045	2.481	2.108	2.484
C1	34.150	56.776	30.569	56.836	32.486	57.213
C2	16.088	13.411	15.774	13.721	15.861	13.561
C3	21.833	13.933	23.276	14.623	22.151	14.202
IC4	4.252	2.399	4.738	2.501	4.400	2.426
NC4	11.293	6.049	12.699	6.205	11.836	6.082
IC5	2.842	1.381	3.156	1.208	3.024	1.245
NC5	3.617	1.729	3.964	1.380	3.877	1.466
C6	2.309	1.038	2.374	0.572	2.545	0.724
C7+	1.375	0.737	1.385	0.369	1.598	0.503
Mol. Wt.	**37.98**	**29.18**	**39.52**	**28.60**	**38.92**	**28.67**

Notes:
Pre-Ramp up – Just before test start
0 Hour – beginning of Steady flow period

[1] Flow indicated in Stage-1 is based on orifice calculations carried out using measured molecular weight. Flow in FG Compressor model (spot reading peak flow). ICSS indicated average flow in Figure 3.21 is slightly less.

[2] Flow indicated in Stage-2 is based on orifice calculations carried out using measured molelcular weight. Flow in FG Compressor model (spot reading). Flow indicated in Figure 3.22 has substantial error. The flow recorded by ICSS is only indicative and will not affect the compressor operation in any way.

12 Hour – middle of Steady flow period

The Compressor Performance Map shows that the lowest molecular weights used in the compressor design were based on Design Case-1. The molecular weights are 47.06 for Stage-1 and 35.51 for Stage-2. Measured gas compositions (Table 3.6) were substantially different from the design case and hence a higher suction pressure was required to operate.

During the test, both LP and MP Separators were raised to the maximum level possible within current operating limits. Steady flow test period did not see much slugging in the pipeline and hence the FG Compressor operation was smooth. Any upset would have caused opening of the flare valves on the separators. A stable operation needs flexibility to raise the suction pressure automatically during any upsets. Hence, any increase in flow rate requires an increased set pressure on flaring from MP and LP Separators that will allow automatic operation of the separators at a slightly higher pressure, if necessary.

Figure 3.21 FG Compressor Stage 1 Flow and Suction System Pressure Losses (Flow and suction pressure drop remain steady due to recycling)

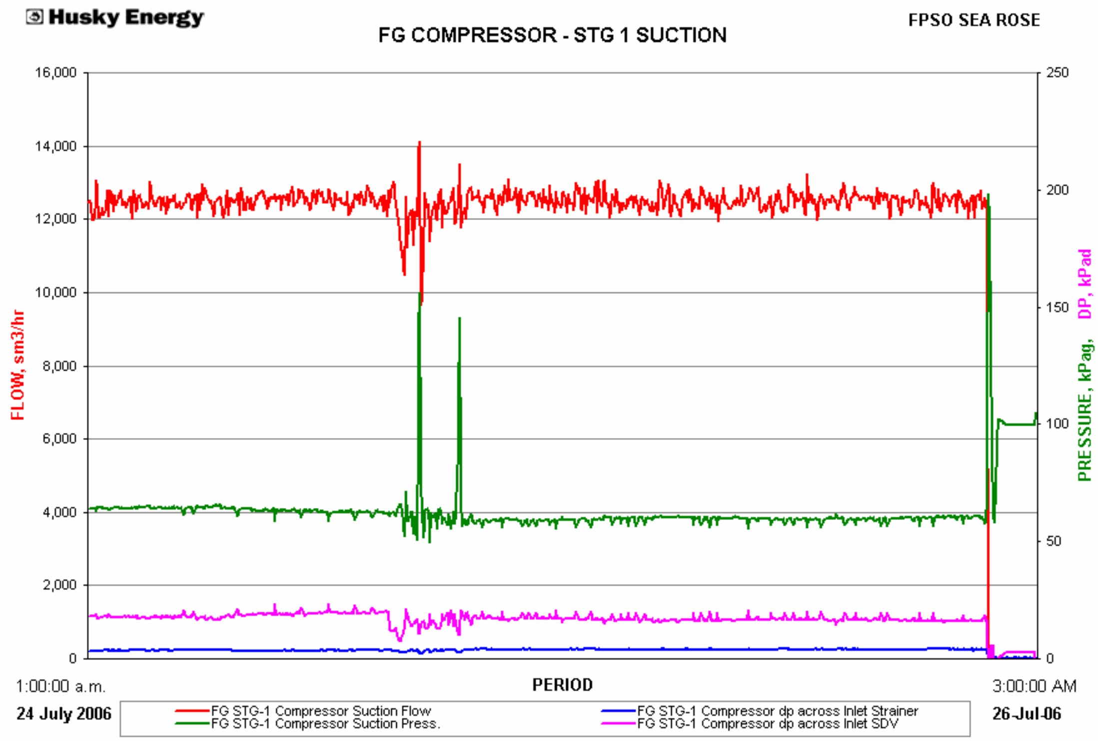
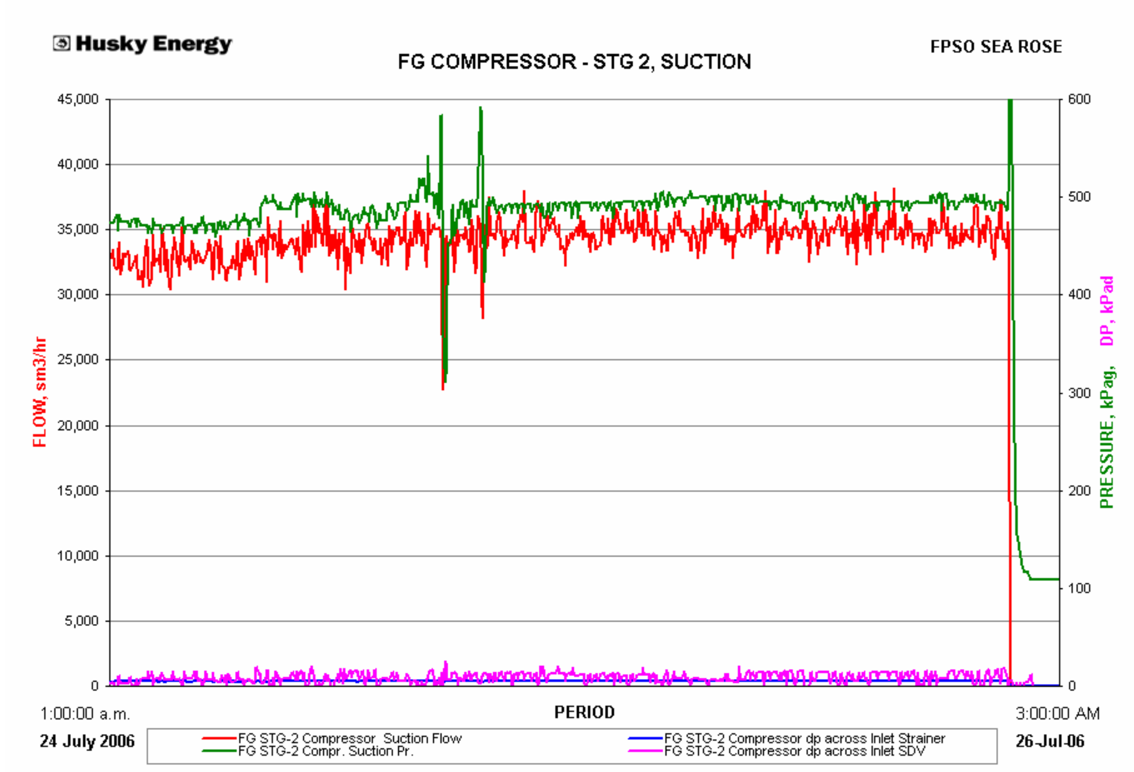


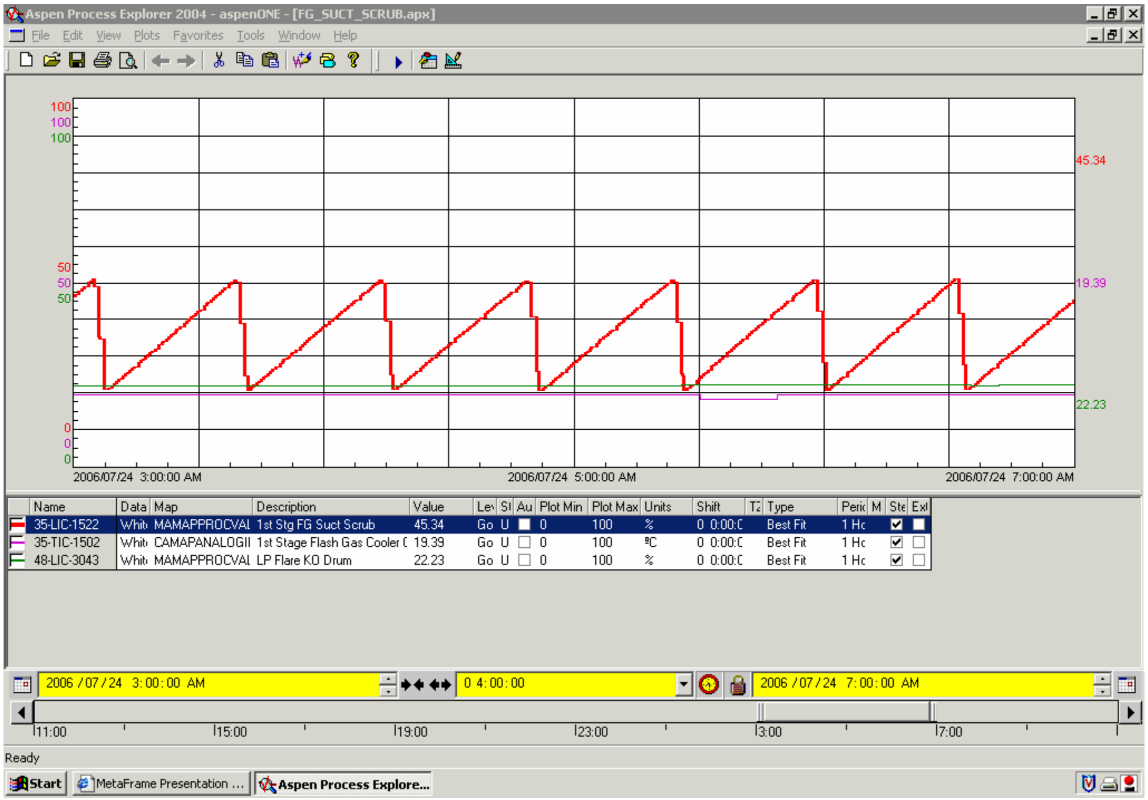
Figure 3.22 FG Compressor Stage 2 Flow and Suction System Pressure Losses (Flow and suction pressure drop remain steady due to recycling. Flow indicated is grossly in error by almost 100%)



The compressor motor was loaded to only 65% of its rated full load amperage. The expected flow through the compressor during the target flow will remain the same as it will continue to be on recycle.

The 1st Stage Flash Gas Suction Scrubber pumps are ON/OFF pumps that maintain level in the FG Compressor 1st Stage Suction Scrubber. No apparent problems or limitations were noted during the test and the pump was cutting-in every 35 minutes (see Figure 3.23).

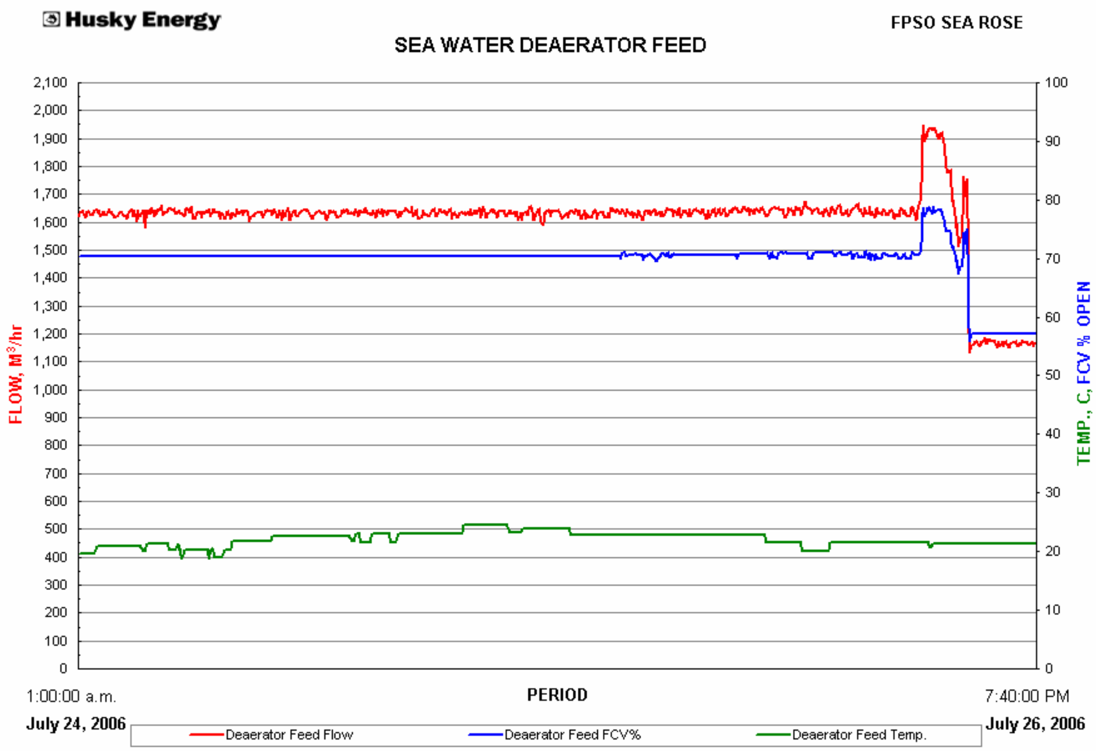
Figure 3.23 First Stage Flash Gas Suction Scrubber Pump Operation



3.1.3 Water Injection System

The deaerator system ran well during the test at 46,000 m^3/d capacity compared to 44,000 m^3/d design capacity. All three water injection pumps were run during the test period without any problems. A maximum flow test on the Water Injection System was carried out independently after the Oil Performance test was completed even though all measurements were also recorded during the oil test period (see Figure 3.24). The deaerator performance was as per design with zero oxygen content. Sulphite injection during the test varied between 2.2 to 3.4 ppm. The feed control valve was opened up to 77% during the peak flow. Vacuum pumps performed as per design during the peak flow.

**Figure 3.24 Sea Water Deaeration System Flow Capacity
(Peak flow of 1,920 m3/hr was maintained for ca. 3 hours after the Oil Test)**

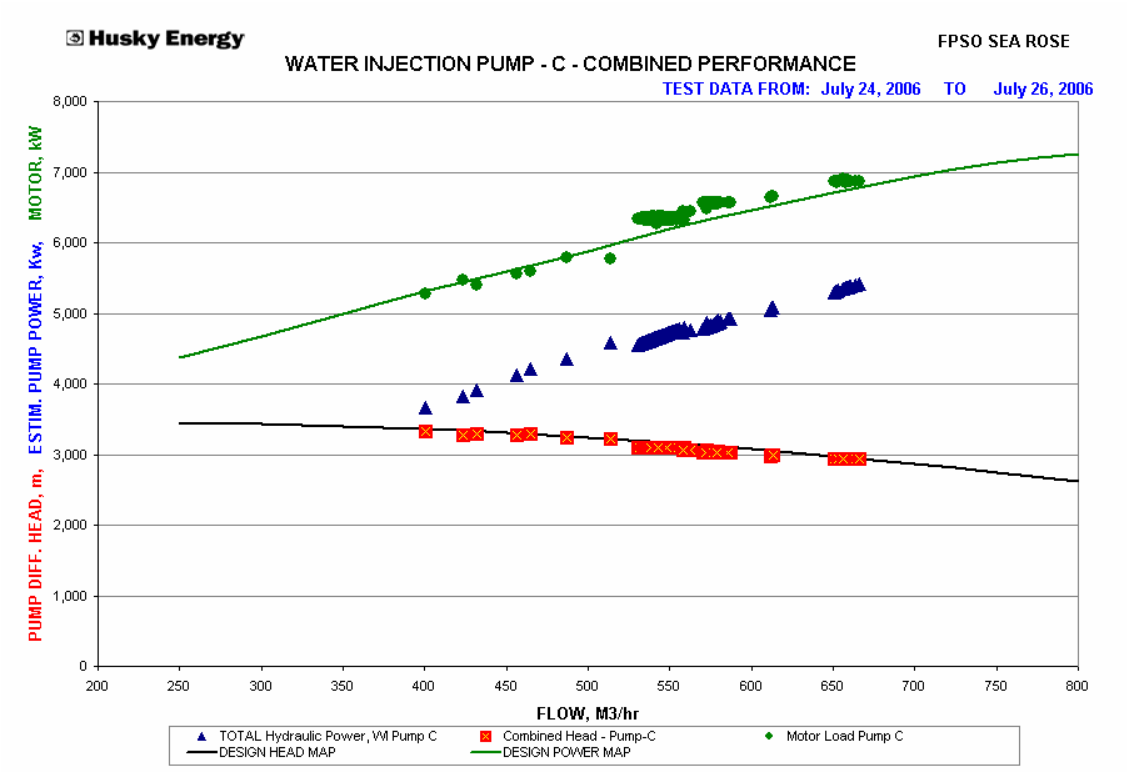


3.1.3.1 Water Injection Pumps

All water injection pumps operated exceptionally well during the performance test. Pump A and B showed greater than design performance while C showed slight under performance (See Figure 3.25) Pump C was specifically tested from lower flow rates to maximum capacity.

The blue coloured trend on Figure 3.25 is the calculated hydraulic pump load in KW without considering pump efficiency while the green trend is the measured motor load. Pump motors were loaded up to 90% of their full load amperage during the peak flow.

Figure 3.25 Performance of Water Injection Pump C
(Combined performance of Booster and Main Pump is shown below)



3.1.4 Fuel Gas System

Fuel gas system measurements were taken during the Oil Performance Test. Flow through one of the fuel gas packages was increased by flaring the gas from downstream piping connections. Testing was conducted to determine the hydraulic and thermal capacity of the system and was carried out after the completion of oil test. No liquid carryover was noticed at high flow through one train of the Fuel Gas system.

The Fuel Gas Super-heater (electrical) “maxed out” during the high flow. Its outlet temperature dropped from 64 to 58 deg C during this time. The lowest HP Fuel Gas supply temperature recorded at the inlet of the power generation system during peak flow (as per IMS) was 49 deg C according to the temperature indicator 43-TI-3302. However, the site log indicated that the gas turbine fuel gas inlet temperature came close to 2 deg C above its trip setting and hence further increase in flow was stopped. Turbine trip is set at 39 deg C within the power generator package. This cannot be treated as a limitation to the superheater as its design temperatures are 25 C (inlet) and 56.6 C (outlet).

3.1.4.1 HP Fuel Gas

A steady flow of HP Fuel gas (ca. 11,000 sm^3/hr) was recorded during the oil performance test (Figure 3.26). HP Fuel gas flow through a single package was increased artificially up to 20,250 sm^3/hr by flaring the gas following the completion of the Oil Performance Test. No abnormal pressure drop or any carryover was visible from the trends except the increased pressure drop through the demister/nozzle in the KOD with increased flow as expected. HP Fuel gas consumption during the target oil flow is approximated as 16 -17,000 sm^3/hr and hence a single package is adequate. HP Fuel gas compositions during the test period (including the Power Generation Tests) are presented in Table 3.7.

Figure 3.26 HP Fuel Gas System during Performance Test
(See the peak flow period at the end of test period)

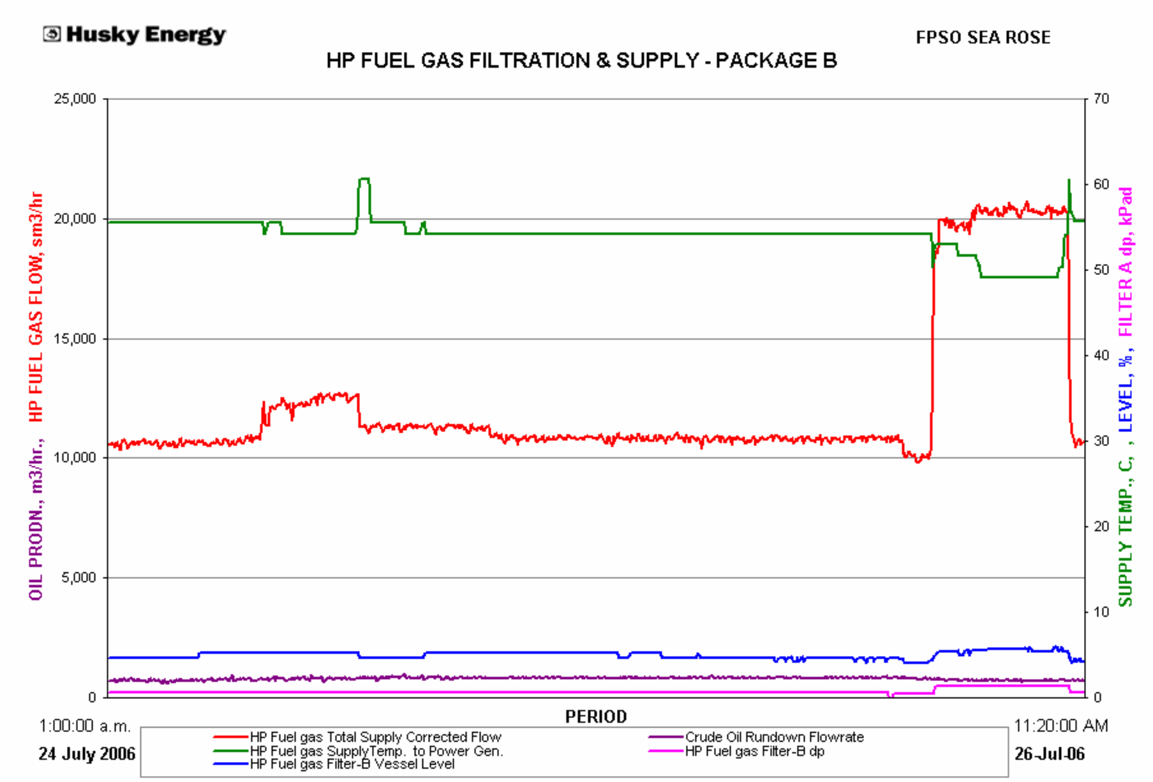


Table 3.7 Gas Composition in HP Fuel Gas during Test (in Mole %)

COMPOSITION (Mol %) FOR HP FUEL GAS DURING PERFORMANCE TEST			
Components	Steady Flow PT 25 Jul '06	During EPT, 2 Aug '06	During EPT, 3 Aug '06
N2	0.241	0.336	0.350
CO2	1.974	1.900	1.976
C1	83.000	85.230	82.466
C2	6.783	6.107	6.871
C3	4.605	3.638	4.720
IC4	0.677	0.510	0.701
NC4	1.629	1.216	1.689
IC5	0.338	0.271	0.355
NC5	0.413	0.353	0.435
C6	0.209	0.263	0.301
C7+	0.131	0.177	0.135
Mol. Wt.	**20.520**	**19.900**	**20.700**

3.1.4.2 LP Fuel Gas

LP Fuel gas is used for boilers, flare purge/pilots and as blanket gas. Normal flow of LP fuel gas is very low at ca. 400 sm^3/hr and remained same during the steady oil test. LP Fuel flow through its supply letdown valves was increased artificially up to 4,700 sm^3/hr by flaring the gas following the completion of the Oil Performance Test. No appreciable pressure drop or any carryover was visible from the trends. Maximum opening of the second pressure control valve was 80% during the peak flow.

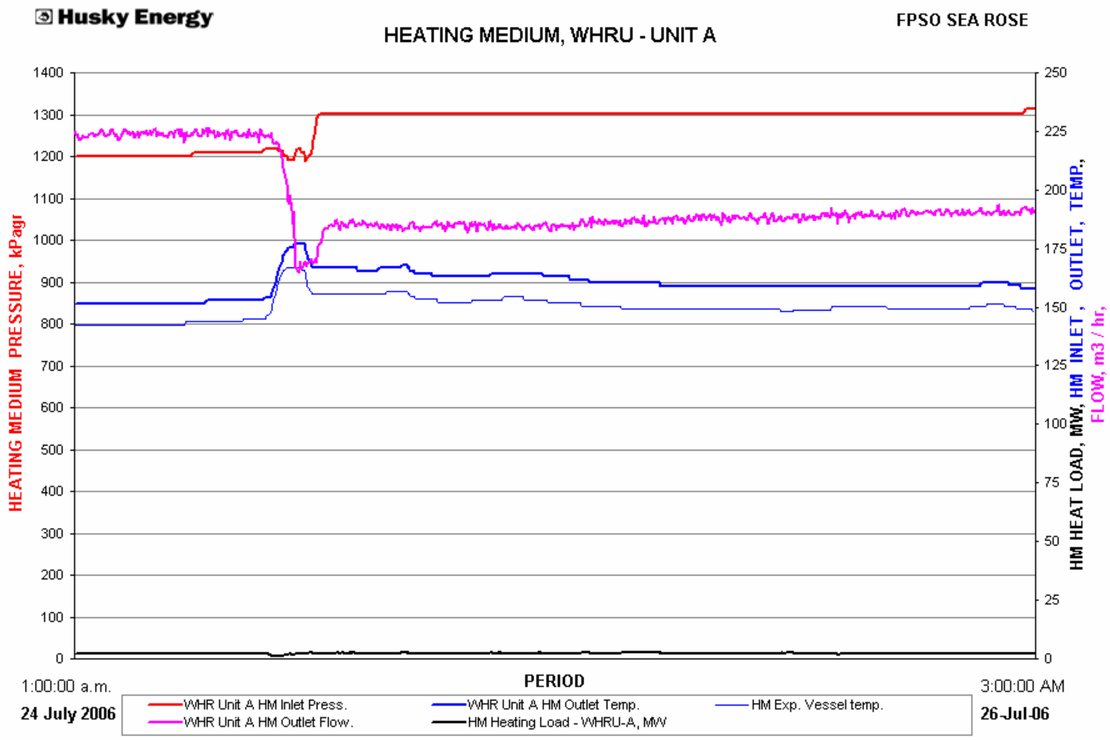
3.1.5 Heating Medium System

The temperature of Heating Medium was approximately 160 deg C throughout the test period since there was no heating requirement for the oil system. For a short while, the temperature rose to 175 deg C when all the three power generators were running during offloading. In order to provide a heat sink, the MP Separator Inlet Heater was placed into service during ramp up and continued throughout the test to control the HM system temperature. The Trim Cooler alone was not sufficient to provide the turn down heat flow. No specific test could be carried out on this system apart from trending the process data.

3.1.5.1 WHRUs

In spite of the complete closure of the exhaust dampers, temperature control was a problem without adequate heat sink. No specific test could be carried out to estimate the possible heat recovery since the heat requirement was below its turndown capacity. Estimated heat recovery from each unit (2 units running) during the test was around 2 – 2.5 MW (Figure 3.27) which was consumed by the Trim Cooler and MP Separator Inlet Cooler.

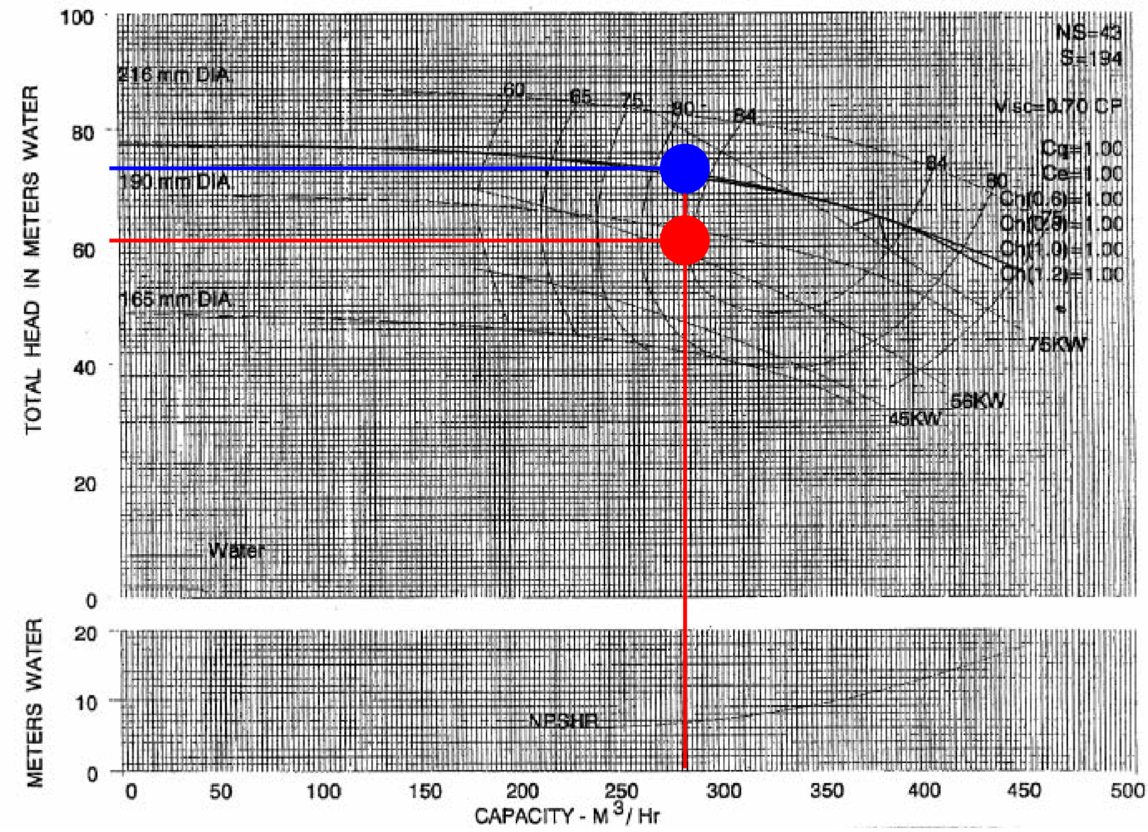
Figure 3.27 Heating Medium System during Performance Test (Only WHRU – A is shown below,)



3.1.5.2 HM Circulation Pumps

Two HM circulation pumps were run with an average total circulating flow rate of 550 m^3/hr. The flow rate measured matched well with the sum of three flow meters in the WHRUs. As per the pump performance curve (Figure 3.28) the pump should have given a head of 75 m at this flow rate although it was actually giving only 60 m. The impeller diameter selected as per the performance curve is 203 mm and it is assumed that the same size is actually installed. It is also assumed that flow through each pump is equal. Even if the flow through the cartridge filter (flow not logged but assumed to be the design value of 32 m^3/hr), the net flow through each pump will be 290 m^3/hr which should have given a head of 70 m. Head calculations were based on HM specific gravity as 1.01 at operating conditions as per the data sheet. It is also possible that actual specific gravity is less than the figure used. However, the issue will not affect operating the plant at increased throughput.

Figure 3.28 Heating Medium Pump Performance
(Flow and Head measured are shown in Red and the design for the same flow is in Blue)



3.1.5.3 HM Consumers

Heating medium consumers during the test were restricted to the Trim Cooler and the MP Separator Inlet Heater. Approximate heat load in these exchangers was estimated from the WHRU thermal balance and is found to be only 4 - 5 MW. The MP Separator Inlet Heater was taken on line only as a heat sink due to turn down limitations on WHRUs especially when three power generators are running. See Section 3.2.6.7 for a discussion of effects on increased production ranges and related recommendations.

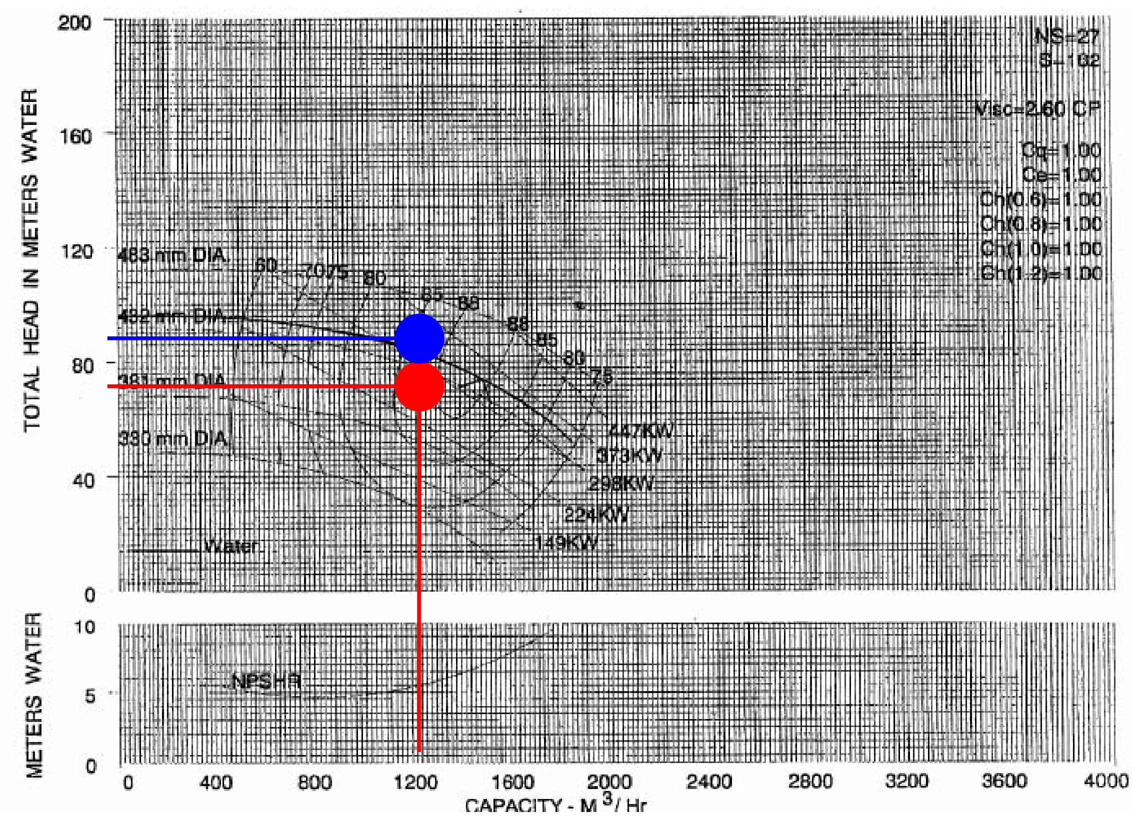
3.1.6 Cooling Medium System

The Cooling Medium (CM) system had ample capacity during the test. A thermal balance across the CM Coolers showed that the system duty during the test was 26 MW. Two CM Coolers were on line. No issues are anticipated at the target production rate of 22,261m^3/d oil even if two compressor trains are run because the CM system has ample capacity.

3.1.6.1 CM Circulation Pumps

Two pumps were run with an average total circulating flow rate of 2500 m3/hr. As per the pump performance curve (Figure 3.29) the pump should have given a head of 90 m at this flow rate although it was actually giving only 76 m. The impeller diameter selected as per the performance curve is 441 mm and it is assumed that the same size is actually installed. It is also assumed that flow through each pump is equal. It may be possible that the flow meter is incorrect or the non-return valve on at the standby pump is passing. However, the issue will not affect operating the plant at increased throughput since the existing installed pump capacity is adequate for the target flow case of 22,261 m^3/d oil (140,000 bpd).

Figure 3.29 Cooling Medium Pump Performance
(Flow and Head measured are shown in Red and the design for the same flow is in Blue



3.1.7 Power Generation System

Power Generation and overall electrical performance tests were carried out separately to avoid unexpected disruption during the process performance test. The Power Generation test involved recording the maximum load achieved by each unit under a range of operating scenarios, and converting those powers to ISO standard conditions. This ensures that the field performance of the power generator can be compared with that which was recorded during the Factory Acceptance Tests. Results are also compared with the supplier-guaranteed performance. Time-averaged data of the maximum loads achieved by each engine under a number of varying operating regimes was recorded, and later those values were converted to ISO standard powers, the results of which are tabulated below in Table 3.8.

Table 3.8 Test Results on Power Generation Output (ISO Corrected, MW)

Fuel Used	Anti-Icing Status	Unit A	Unit B	Unit C
Gas	OFF	25.87	26.22	27.63
Gas	OFF	25.53	27.29	27.63
Gas	ON	22.94	24.11	24.74
Diesel	OFF	24.73	25.12	26.79

When converted to ISO-conditions, the performance of each of the engines at a maximum load condition exceeded the power required in order to satisfy the vendor guarantee guideline. Unit C out-performed the other engines, achieving approximately a 2MW advantage over unit A. For comparison, two max-load trials on fuel gas with the anti-icing protocol disabled were conducted. Unit A achieved similar powers on both these trials, as did Unit C. However, it should be noted that Unit B exhibited approximately a 1 MW discrepancy between its two trials. Enabling the anti-icing system reduced each of the generators output power by approximately 8% to 11% in each case. Switching to liquid (diesel) fuel caused the maximum powers achieved to be 4% to 7% lower than that achieved while running on fuel gas with the anti-icing disabled.

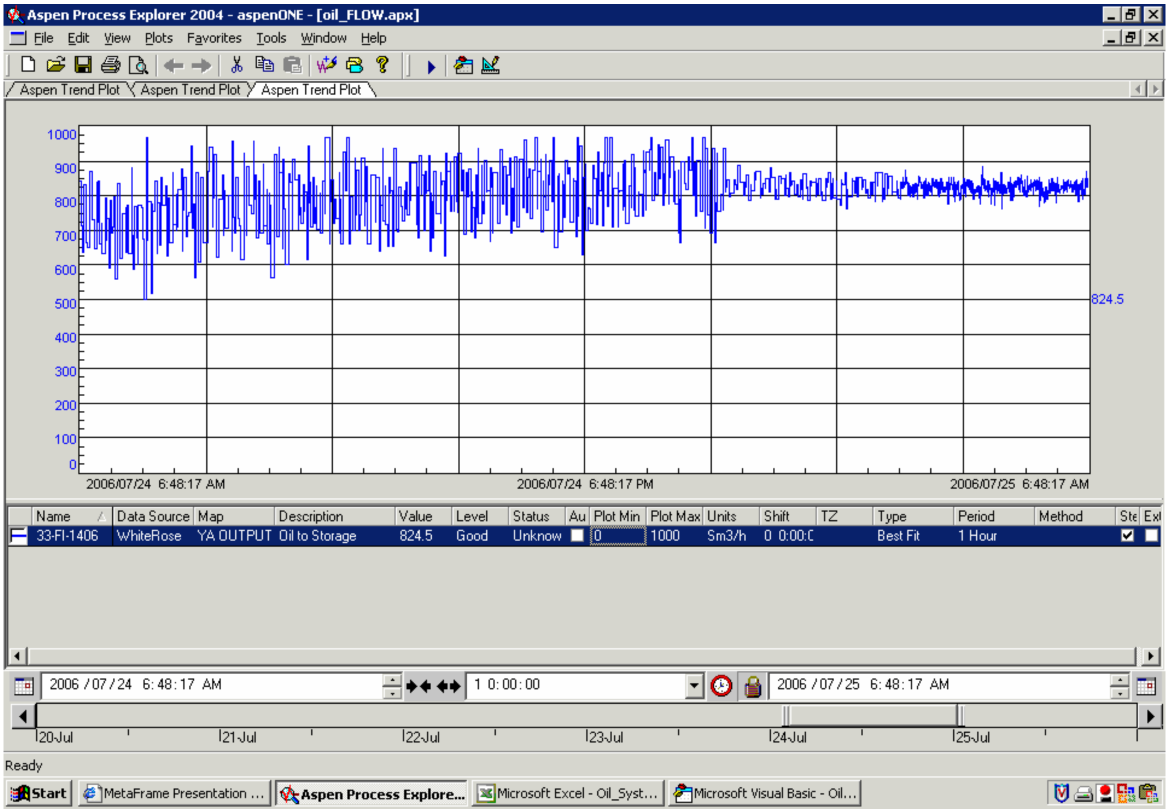
3.2 Analysis of Test Results & Bottlenecks

3.2.1 Overall Process System

Generally the topsides Process system performed exceptionally well during the performance test. Pipeline slugging seen during the ramp up phase almost subsided once the chokes were adjusted, and the steady test period was noted to be the smoothest flow period as indicated in Figure 3.30. No vibrations were reported in the turret, manifold, and the process systems, apart from vibrations in the water injection overboarding valve(s) which are normally experienced when it is open. None of the utility systems showed any limitations during the test.

A daily average figure of 19876 m^3/d (125,000 bpd) was achieved during the 24 hours of steady test period. The topsides process systems would have allowed higher oil flow rates if the 2nd train of compressors was started or the gas was allowed to flare. However this was not attempted to avoid a disruption on the test while starting an additional compressor train. Most of the control valves were adequately sized for the flow and those found to be limiting could be easily made within operable range by varying the process conditions, while still remaining within the safe design envelope.

Figure 3.30 Oil Flow during the Performance Test (Period covers Ramp-up and Steady Phases)



3.2.2 Static Equipment

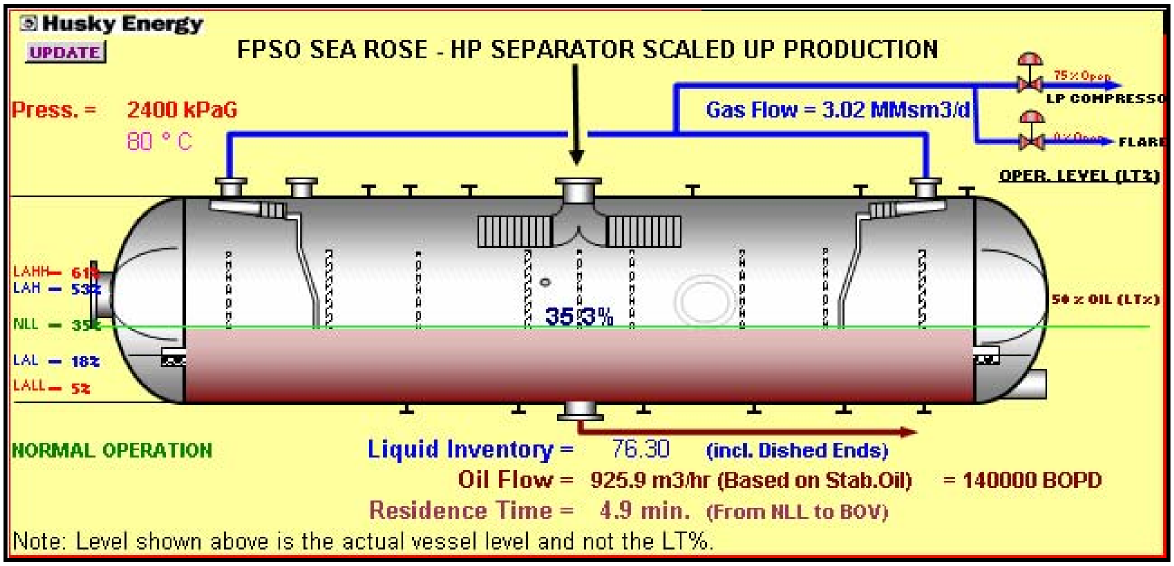
All static equipment like vessels, filters, etc. operated as per design. Many of the vessels have substantially large capacity since produced water is not handled currently. Hence, a production increase while producing dry oil or small water cuts is not anticipated to be a problem.

The following analysis and debottlenecking proposals for major vessels are made in order to achieve the target flow of 22,261 m^3/d oil (140,000 bpd).

3.2.2.1 HP Separator

The HP Separator, being a 2-phase separator with a design liquid capacity of 33,058 m^3/d (207,900 bpd) will easily handle the target dry oil flow. Residence time (from NLL to NILL) for 22,261 m^3/d oil (140,000 bpd) dry oil will be ca. 5 minutes and hence liquid handling by the HP Separator will not be an issue until water production is substantial. No changes are necessary in existing levels or level protection settings. See the modelled residence time with operating levels and flows during the target production in Figure 3.31. The figure is extracted from the process system on-line model by manually entering the target flow.

**Figure 3.31 Proposed Operating Conditions in HP Separator for 140,000 BOPD
(No change in existing settings in the vessel)**



The HP Separator is also designed to handle the total gas volume including the recirculating lift gas. The nominal design capacity of the vessel gas section is 4.2 MMsm^3/d when its level reaches its LAHH (61% of the vessel diameter). Calculated maximum allowable vapour velocity in the vessel is 0.43 m/sec assuming that there are no internal coalescers. Conservative sizing calculations show that this separator with dual gas outlets could handle up to 7 MM sm^3/d even as a simple gravity separator without any coalescers at an extreme case of its operation close to LSHH. Performance will be improved with the installed proprietary cyclonic device at the gas outlet.

The associated gas estimated from a target production of 22,261 m^3/d oil (140,000 bpd) dry oil is ca. 3.0 MMsm^3/d and hence the vapour section will not limit the target production rate.

Existing operating pressure of 2400 kPag with 2500 kPag flare valve setting are adequate for the target flow service as long as two trains of compressors are running.

Currently the HP Separator is protected from over-pressurisation by using three "Q" size orifice relief valves with one kept as a standby. The valves are set with staggered pressures at 4500 and 4725 kPag. The size of the relief valves are based on full flow of liquids (oil and water) and gas in the event that all outlets on the HP separator are blocked-in and the well streams continue to flow. Increased dry oil flow during the targeted production will not affect the size of the relief valves since the total fluids coming into the vessel are still less than the original design. However, calculations show that even a single relief valve has substantial gas capacity when it handles only gas during the initial phase of relieving. Incoming gas for the 22,261 m^3/d oil (140,000 bpd) case will be around 3.2 MMsm^3/d compared to the capacity of single relief valve that will be opened initially (ca. 5.6 MMsm3/d). Since the gas capacity of this relief valve is close to the HP Flare design limit, a dynamic simulation was carried out to see how much time the PSV will continue discharging before it shuts. It was concluded from the simulation that the relief valve will open for very short intervals of 0.3 seconds and hence the flare discharge will be basically limited to the average incoming gas flow which is within the HP Flare capacity limit. The simulation considers the effect of rising liquid level during pressurisation and it was found that the first PSV opens within 63 seconds of rising pressure. The rise in liquid level during this period was only 10% and multi-phase discharge will occur much later once the vessel is filled, and the subsequent relief valves open.

At a production level of 22,261 m^3/d oil (140,000 bpd) and when water cut begins, additional relief valve(s) may be necessary for the multi-phase discharge during a blocked outlet and this may involve reviewing the HP Flare capacity. Apart from an overall increase in mass flow to flare, the HP Flare Drum will fill up quickly since the HP Flare Pump(s) will be able to discharge only 80 m^3/hr of liquids with two pumps running.

3.2.2.2 MP Separator

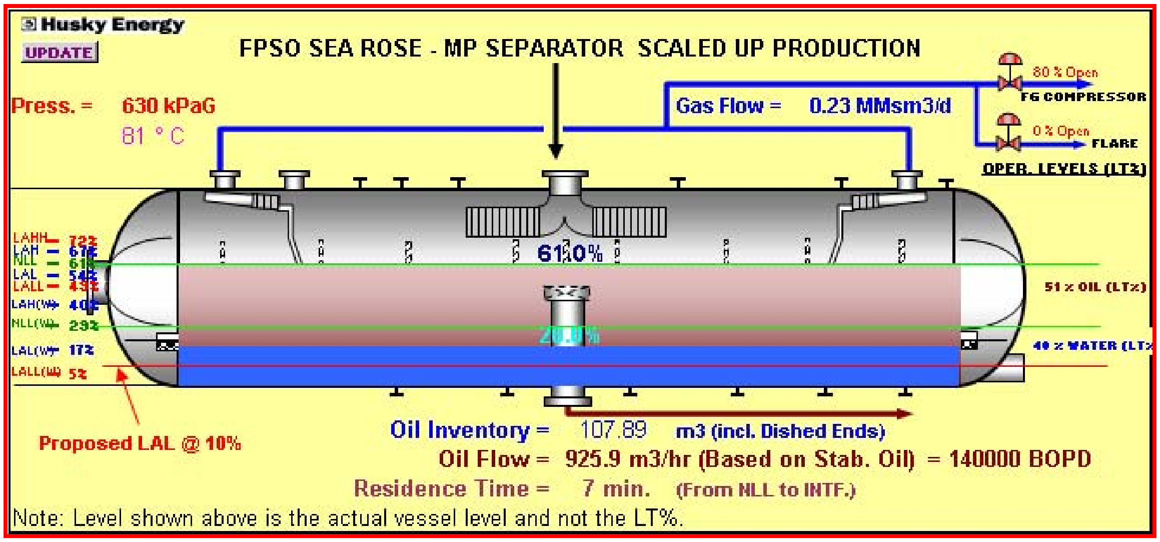
During the test the operating oil and water level in the MP Separator vessel was maintained throughout the test as per design. Liquid (now only dry oil) residence time from NLL to the NILL was around 5.5 to 6 minutes during the test. Oil Residence time for the nominal design flow of 15,900 m^3/d oil (100,000 bpd) for identical levels is 7.2 minutes.

Increase in oil throughput to the target production rate of 22,261 m^3/d oil (140,000 bpd) through the vessel is possible if identical residence time is maintained. In order to achieve this it is necessary to reduce the operating interface level so that residence time similar to the performance test figure (6 minutes) is obtained. Such a recommendation is made only as a precautionary measure so that the proven residence time (without any gas carry-under) is still maintained. Such reduction in level is possible while operating with dry oil and until substantial water production has been reached. [If required, changes in residence time will be reviewed once water cut begins and more information on the quality of the emulsion is available.

As long as water cut is not present in the well fluids, interface level operation (mostly due to a very small amount of condensed water) will be carried out manually.

In order to raise the production capacity it is necessary to maintain the MP Separator pressure at 630 kPag. This will ensure that 33-PCV-1254A to the compressor will be in control at approximately 80% open and Stage – 2 of the FG Compressor will see adequate pressure for operation up to 700 kPag. The MP Separator could also receive reasonable slugs before the flare valve (33-PCV-1254B) opens up. See further discussion on separator pressure requirements under Section 3.2.3.1.

Figure 3.32 Proposed Operating Conditions in MP Separator for 140,000 BOPB (Blue section is the proposed operating water phase with the Red line as proposed Low Interface Alarm Level (LIAL) setting. Green lines are existing operating levels)



Calculated maximum allowable vapour velocity in the MP Separator vessel is 0.65 m/sec assuming that there are no internal coalescers. Conservative sizing calculations show that this separator, with dual gas outlets, could handle up to 2 MMsm^3/d even as a simple gravity separator without any coalescers at an extreme case of its operation close to LSHH. Performance is expected to be better with the installed proprietary cyclonic device at the gas outlet.

Average GOR across the MP Separator is 10.2 sm^3 of gas per m^3 stabilised oil. Hence the associated gas expected from 22,261 m^3/d oil (140,000 bpd) dry oil is ca. 0.23 MM sm^3/d and the MP Separator vapour space will not be a limitation for the target oil production rate. The 2nd stage of the Flash Gas Compressor has adequate surplus capacity to handle the gas, provided that it meets the required pressure.

3.2.2.3 LP Separator

During the test, the operating oil and water level in the LP Separator vessel was maintained close to the design. Liquid (dry oil) residence time from NLL to the NILL was approximately 2.8 minutes during the test. Oil Residence time for the nominal design flow of 15,900 m^3/d (100,000 bpd) for identical levels is a nominal 3.5 minutes. However, no abnormal gas release in the cargo tanks was observed, confirming that even the slightly reduced residence time is adequate for stabilising the oil.

Increase in oil throughput to the target production rate of 22,261 m^3/d oil (140,000 bpd) through the vessel is possible if the same residence time is maintained. In order to achieve this, it is necessary to reduce the operating interface level so that residence time similar to the performance test figure (3 minutes) is obtained. Such a recommendation is made only as a precautionary measure so that the proven residence time (without any gas carry-under) is still maintained. Such reduction in level is possible while operating with dry oil and until substantial water production has been reached. If required, changes in residence time will be reviewed once water cut begins and more information on the quality of the emulsion is available.

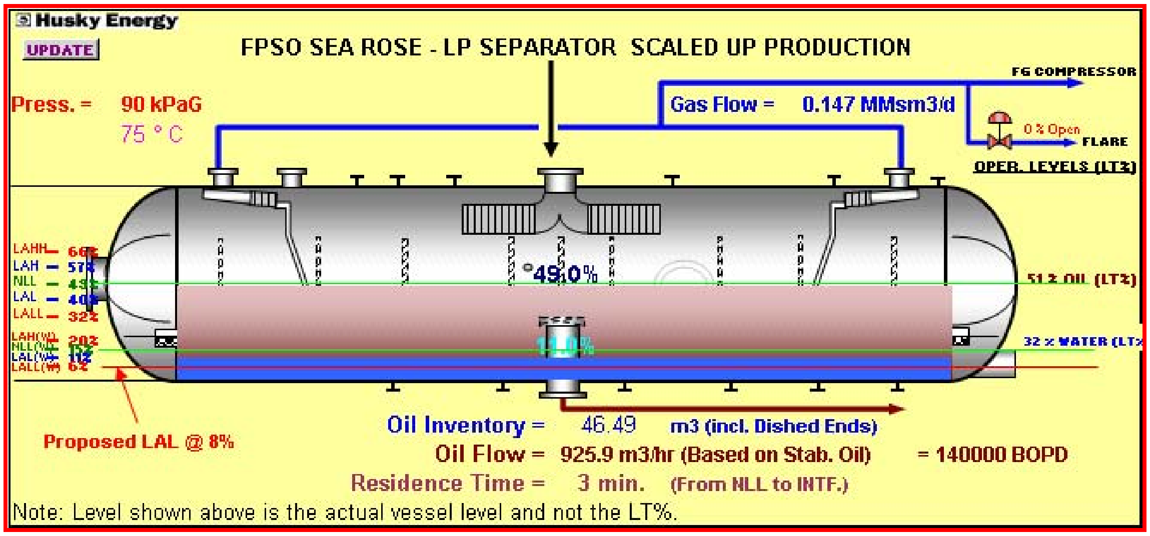
As long as water cut is not present in the well fluids, interface level operation (mostly due to a very small amount of condensed water) will be carried out manually by occasionally running the Produced Water Recycle Pump. The recycled water is further settled in the MP Separator and any carryover of hydrocarbon through this recycle pumps is not a concern. Therefore, a very low operating interface close to the pump trip level is proposed for maximising the volume of the oil phase.

Currently, the separator is operated at 80 kPag and the flare valve is set at 90 kPag. When the FG Compressor stage-1 goes on total recycle without any fresh gas coming in from the LP Separator (as a result of flow fluctuations), the gas molecular weight reduces within the compressor casing due to over-condensation in the suction cooler. A reduction in molecular weight causes the compressor suction pressure to rise and if the LP Separator flare set point is too close to its operating pressure, the flare valve opens up. At this point, the non-return valve in the separator gas to compressor cooler will be closed (due to pressure difference) preventing any fresh gas from entering. Hence in order to have flexibility in the compressor suction pressure depending on pipeline slugging, there should be an adequate gap between the operating and flare set pressures. This will be more prominent at higher flow rates as the pressure drop in the system slightly increases.

An increase in the existing flare set point is not possible at the moment due to the fact that the PSHH is set at 120 kPag and any proximity to this pressure may cause unwanted trips. PSHH setting in the original design was at 220 kPag and the flare valve was at 120 kPag. PSHH set pressure was purposely lowered to 120 kPag before commissioning the plant due to a size limitation on the stage-1 discharge relief valve. Such a reduction in the PSHH set point was necessary since the compressor relieving requirement increases with potential increase in suction pressure. Hence, the set point for the flare valve or PSHH cannot be altered unless the PSVs on the stage-1 discharge are replaced.

A higher set point on the flare valve is necessary to raise the oil flow capacity to 22,261 m^3/d oil (140,000 bpd). It is necessary to maintain the LP Separator pressure at ca. 90 kPag which is slightly above the current operating pressure. However, the most important change proposed in the LP Separator pressure control is that the flare valve (33-PCV-1314B) setting be increased to 120 kPag (but automatically reduced to 90 kPag when the FG Compressor is tripped) and the high pressure trip increased to 220 kPag. This will allow for a gap between the operating pressure and the flare set pressure and will assist the separator pressure to rise/fluctuate a small margin, (i.e., 80 – 100 kPag) for stable operation of the FG Compressor. In order to increase the PSHH on the separator, it is also necessary to replace the relief valves on the FG Compressor Stage-1 discharge from the existing “M” to a proposed “P” orifice. This will allow the separator to receive reasonably sized slugs before the flare valve (33-PCV-1314B) opens up. The effect of the changed operating pressures on oil recovery was verified using Hysys simulations and was found to be insignificant.

Figure 3.33 Proposed Operating Conditions in LP Separator for 140,000 BOPD. (Blue section is the proposed operating water phase with the Red line as proposed Low Interface Level (LIAL) setting. Green lines are existing operating levels

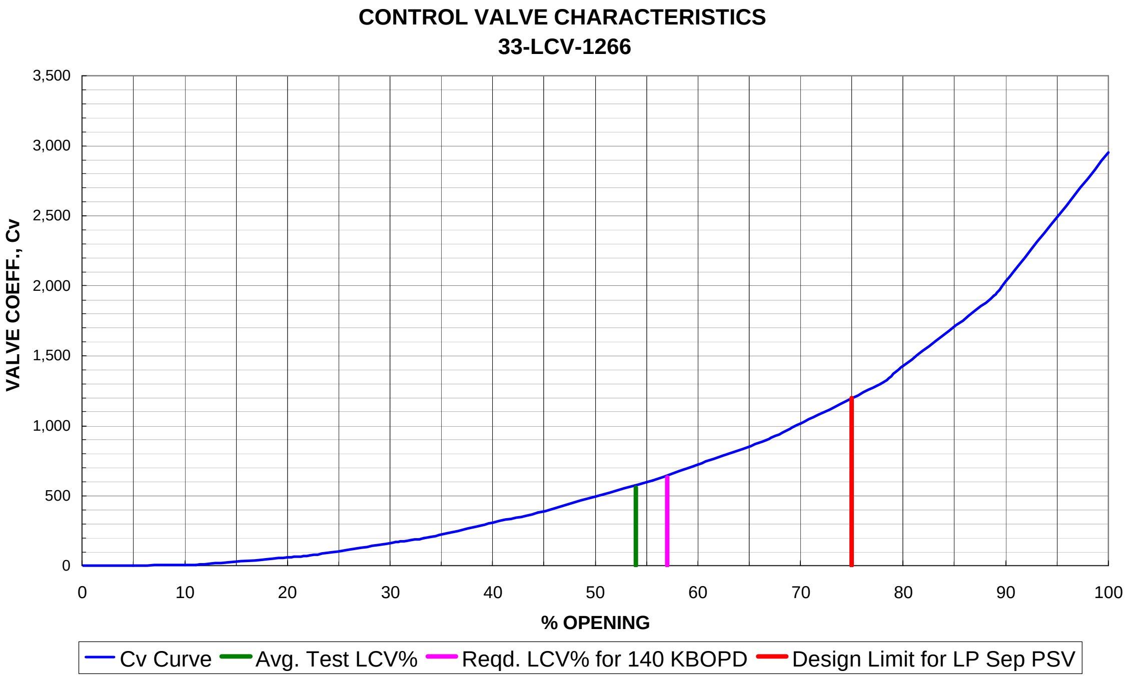


The calculated maximum allowable vapour velocity in the LP Separator vessel is 1.07 m/sec assuming that there are no internal coalescers. Conservative sizing calculations show that this separator, with dual gas outlets, could handle up to 0.7 MM sm^3/d even as a simple gravity separator without any coalescers at an extreme case of its operation close to LSHH. Performance is expected to be better with the installed proprietary cyclonic device at the gas outlet.

Average GOR measured across LP Separator was 6.6 sm^3 of gas per m^3 Stabilised Oil. Hence, the associated gas expected from 22,261 m^3/d oil (140,000 bpd) dry oil is ca. 0.15 MM sm^3/d and the LP Separator vapour space will not be a limitation for the target oil production rate. Flash Gas Compressor Stage 1 has adequate surplus capacity to handle the gas, provided that it meets the required pressure.

Past studies have indicated that there is a limitation on the relief valve on the LP Separator 33-PSV-1312A-D even with the design mechanical limitation on the 33-LCV-1266 valve on the MP Separator. Normal opening of the 33-LCV-1266 valve during the test was approximately 54 to 55%, equivalent to a Cv of 570. For the targeted production, the Cv requirement will be around 640 (12% more flow), equivalent to approximately 57% opening. This LCV, being a V-ball type valve with equal % characteristics, has a large Cv above the current operating region. Existing mechanical limitation is at 75% (as per LCV data sheet) and is almost double the Cv of what is required for the 22,261 m^3/d oil (140,000 bpd). It may be possible to reduce the mechanical restriction limit further down (to be estimated based on PSV capacity on blocked outlet). See Figure 3.34 showing the valve characteristics and operating ranges

Figure 3.34 Characteristics of MP Separator Level 33-LCV-1266
(Note the difference between Restricted Cv and required Cv at 140,000 BOPD is almost 100% and hence it may be possible to reduce the restriction limit to suit 33-PSV-1312A-D size on the LP Separator)



3.2.2.4 Other Vessels

All vessels and filters in Gas Compression, Glycol Dehydration, Fuel Gas, Water Injection, Heating Medium and Cooling Medium Systems functioned as required and no bottlenecks are anticipated from these as a result of an increase in oil production.

3.2.3 Rotating Equipment

All rotating equipment such as compressors and pumps operated as per design. Major equipment like compressors showed capacities above design. Many of the pumps have adequate capacity to meet the extra flow requirement of the increased oil production or they will be able to run as standby units if required.

The following analysis and debottlenecking proposals for major rotating equipment are made in order to achieve the target flow of 22,261 m^3/d oil (140,000 bpd).

3.2.3.1 Flash Gas Compressor

Gas composition measured at the FG Compressor suction during the Performance Test was much lower than what was originally used for the compressor design. Centrifugal compressors are constant head machines (i.e., for any specific suction volume flow, the head is fixed as per its characteristic curve). Lower molecular weight gas requires lesser differential pressure to achieve the same head and thus causes increased suction pressure for any specific discharge pressure to maintain the differential head as per its performance curve. An increased suction pressure will result in opening of the flare valve at the source of the gas – in the case of FG Compressors; it is the LP and MP Separators. If the suction pressure further increases due to recycle, a point will occur when the non-return valve between the source of the gas and the suction cooler will close due to a reversal in differential pressure. Once this happens, the molecular weight of the gas may further reduce due to condensation through the cooler until equilibrium has been reached.

Unless fresh gas is supplied from the separators the situation cannot be recovered which means that additional pressure is required to open the non-return valve and establish a flow. Hence it is important not to have the flare valve opened-up unnecessarily due to any small fluctuations like pipeline slugging.

In the case of the FG Compressor stages, the compressor design capacity is much larger than required and will always be under-recycling even with the gas from the target oil flow of 22,261 m^3/d oil. Therefore, flow through the suction system (Suction Cooler, Scrubber, Strainer and piping) remains almost same and thus there is a pressure drop in the suction system. The only variation in pressure drop will be in the lines from the separator(s) to the compressor suction cooler meeting the recycle line including the pressure control valve (only on MP Separator) and V-cone flow meters. Pressure loss calculations were carried out to estimate the pressure required at the separators.

Flow/pressure upsets are also possible in the separators due to oil slugs and hence varying gas flows. In order to absorb these pressures in the separator by avoiding an opening of the flare valve, it is necessary to keep a suitable gap between the operating and flare set pressures. Raising the operating / flaring pressure settings in the MP Separator is fairly easy. However doing the same in LP Separator requires modifications in the present setting for its PSHH. An increase in PSHH setting will necessitate resizing the relief valve at the stage-1 discharge to make it adequate for the targeted flow of 22,261 m^3/d oil.

3.2.3.2 LP / IP Compressors

The LP/IP Compressors were operated at 115% of their rated capacity. It was possible to operate the compressors even at a slightly higher capacity as their motor was loaded only up to 87% of maximum load amperage. However, limitations appeared from the restricted PCV on the HP Separator gas when a single compressor was operating and pressure losses occurred through the suction system. During the performance test, this limitation caused an increase in HP Separator pressure to 2,500 kPag. Also note that the LP compressor was operated at a lower discharge pressure than the design to facilitate testing at higher flow rates. Such reduction in pressure did not affect the performance of the IP and HP compressors since the pressure control valve, 39-PCV-1733A, located between the LP and IP compressors adjusted the changed pressure drop automatically.

In order to handle the full gas volumes during the target production rate, two trains of compressors will be necessary. As the compressor train performed well, no further analysis was carried out and no changes are required in the system. (See Section 7.6 for discussion regarding the turndown capacity of WHRU / Heating Medium system when two trains of compressors are running.

3.2.3.3 HP Compressor

A single compressor was tested and it performed as per design. No further analysis was done on this compressor. The compressor motor was loaded only up to 76% of its maximum load amperage.

3.2.3.4 Water Injection Pumps

All pumps were tested close to or slightly better than the design curve.

3.2.3.5 Deaerator Vacuum Pumps

A single set of deaerator vacuum pumps operated as per design in spite of the increased sea water flow through the Deaerator during the test. The vacuum pumps performed well throughout the test and no further analysis was done on this machine.

3.2.3.6 Crude Rundown Pumps

Two Crude Rundown pumps were operated during the test and they functioned as per the design performance curve. Two pumps are adequate for the increased flow of 22,261 m^3/d oil since the downstream LCV could be opened more and the pump curve is more or less flat (incremental reduction in discharge pressure is very small for the flow increment required). See performance curve in Figure 3.16. The increase in the number of plates in the Crude Rundown Cooler also helped in reducing pressure losses through the cooler. If pressure losses increase over a period of operation time, the third standby pump is available.

3.2.3.7 1st Stage Flash Gas Suction Scrubber Pumps

The 1st Stage Flash Gas Suction Scrubber Pumps are ON/OFF pumps that maintain the level in the FG Compressor 1st Stage Suction Scrubber. No apparent problems or limitations were observed during the test and the pump was cutting-in every 35 minutes. At target flow, the frequency of pump start will slightly change and it will cut-in every 30 minutes. No further analysis was done on this pump.

3.2.3.8 Lean Glycol Pumps

A single lean glycol pump was run during the test and no problems were observed. Since the Glycol Dehydration System is designed for 4.2 MMsm^3/d gas flow, no problems are anticipated for operating the TEG system at 3 MMsm^3/d during the target oil flow of 22.261 m^3/d. The circulating flow maintained during the test was 3.7 m^3/hr while the pump is designed for 5.08 m^3/hr. Therefore, there is no limitation on its capacity.

3.2.3.9 Heating Medium Circulating Pumps

It is noted that the estimated performance of the Heating Medium Circulating pumps are not matching the design performance curve (see Figure 3.28). The reason for this could be an error in flow measurements, difference in specific gravity of the fluid, the actual installed impeller diameter is different from what is marked in the performance map, passing of the non-return valve on the standby pump (if its discharge block valve was open), or larger flow through the cartridge filter that was not recorded. However, this issue will not affect operating the plant at increased throughput to 22,261 m^3/d oil.

3.2.3.10 Cooling Medium Circulating Pumps

Two Cooling Medium pumps were run with an average total circulating flow rate of 2500 m3/hr. As per the pump performance curve (see Figure 3.29), the pump should have provided a head of 90 m at this flow rate while it actually provided only 76 m. The impeller diameter selected as per the performance curve is 441 mm and it is assumed that the same size is actually installed. It is also assumed that flow through each pump is equal. It may be that the flow meter is incorrect or the non-return valve at the standby pump is passing. However, the issue does not affect operating the plant at increased throughput since the existing installed pump capacity is adequate for the target flow case of 22,261 m^3/d oil.

3.2.4 Piping

In general no piping bottlenecks were observed during the PerformanceTest. However, pipeline velocities during the target production rate may exceed API RP14 limits in some sections of the oil system piping. The affected sections are indicated in Table 3.9.

Table 3.9 Piping Sections with High Velocity at 22,261 m^3/d oil (140,000 bpd)

Service	Size, in.	Line No.	Velocity, m/s (based on 22,261 oil m^3/d)
Crude Rundown Pumps Common Discharge up to Rundown Cooler Inlet Nozzles	10 Std.WT (ID=257.4 mm)	P-10-P-33027-AD1-PG P-10-P-33032-AD1-HT P-10-P-33033-AD1-HT	4.94
Rundown Cooler Outlet Nozzles up to the 12 in Rundown line to Cargo Tanks	10 Std.WT (ID=257.4 mm)	P-10-P-33034-AD1 P-10-P-33035-AD1	4.94

Note: Increased velocity through the 8 in. bypass to the cooler is not considered as the operation through this line will be intermittent and a continuous rundown without cooling at high oil production is not a genuine case.

The API 14 maximum recommended velocity is 4.2 m/s for the oil density. This is believed to be highly conservative when compared with NORSOK Standards which recommend up to 6 m/s for carbon steel piping. As long as there are no pressure loss problems, these lines may be used with regular wall thickness monitoring at critical areas. Monitoring will be included as part of the IMS. No vibration issues in the piping were reported as a result of the Performance Testing.

3.2.5 Control Valves

Most of the control valves operated well within their operating ranges. Control valves that showed limitation are detailed in Table 3.10.

Table 3. 10 Control Valve Limitations

Service	Tag No.	Observations	Remedy (based on 22,261 m^3/d oil (140,000 bpd))
HP Separator Gas to LP Compressor	33-PCV-1107A	Currently limited intentionally at 70% when a single compressor is running. HP Pressure was increased to 2500 kPag during the test and limit temporarily raised to 75%	Not a limit when two compressors are running. Also the pressure drop through suction system will reduce with 2 parallel compressors.
HP Separator Gas to Flare	33-PCV-1107B	Calculations show that the PCV could discharge more gas into the flare (if opened fully) than what the HP Flare could handle.	Mechanically Limit the opening to 70%. There is a Technical Query (TQ) existing on this subject. The limited opening is adequate for the 22,261 m^3/d oil (140,000 bpd) service.
MP Separator Gas to FG Compressor Stage-2	33-PCV-1254A	Control valve opens fully resulting in opening of flare valve. MP Separator pressure and flare setting were raised. This was caused by lower mol. gas from MP Separator than design.	MP Separator pressure to be increased to 630 kPag and flare valve setting at 700 kPag.
Level Control on MP Separator	33-LCV-1404	Normal opening of the control valve is around 54-55% and is normally very steady. Currently its opening is mechanically limited to 75% due to LP Separator PSV limit. Target flow rate will involve revision of PSV sizing.	Target flow needs a normal opening of 56-57% and it is possible to reduce the mechanical limit (to be estimated) to suit the PSV-1312A - D.(see section 7.2.3 and Fig 6.34)
Crude Rundown Cooler Cooling Medium Return	33-TCV-1404	Control valve opened fully during the test when temperature control set point was 60 deg C. Installed Valve Cv seems to be substantially large for its service. It is doubted whether the butterfly disc is touching the pipe wall and may not be actually opening.	MP Separator pressure to be increased to 630. Physically inspect the TCV and do more analysis and flow tests around the cooler. TCV size is adequate for the target flow service.
Cargo Tank Gas Venting	100 mm PV Valve set at 12 kPag	PV Valve set at 12 kPag is inadequate for the maximum gas venting. However the larger 14 kPag set PV valve(s) is more than adequate for the service. Both are located at the far end of the vent/IG header. However	Reduce set pressure on the 14 kPag valves and if necessary the 12 kPag valve so that there is adequate difference in set points between Tank PV breakers and

Service	Tag No.	Observations	Remedy (based on 22,261 m^3/d oil (140,000 bpd))
		the 16 kPag set Tank PV breakers located on the tanks are likely to release early due to the pressure losses in the header.	normal operating breather valves.

None of the control valves require trim upgrading for the targeted flow rate of 22,261 m^3/d oil.

3.2.6 Heat Transfer Equipment

All heat exchangers showed adequate capacity for the test service.

3.2.6.1 Crude Rundown Coolers

One of the Crude Rundown Coolers had additional plates (total of 178 plates) installed just before the test. The capacity requirement for the Rundown Cooler is directly proportional to the oil production rate. As per its revised specifications (with additional plates), the rundown cooler appears to be adequate for the target flow rate of 22,261 m^3/d oil. The standby unit with the original number of plates (total of 96 plates) is also available, if required.

3.2.6.2 Oil Separators Inlet Heaters

Heaters in the Oil Separation System were not required for the current oil production due to adequate well fluids temperature. The MP Separator Inlet Heater was on line partially during the test as a heat sink for keeping the Heating Medium System at its turn down condition. All the heaters are provided with a full sized bypass and do not cause any bottleneck for increased production.

3.2.6.3 Gas Compressor Coolers

Two compressor trains will be run during the target flow of 22,261 m^3/d oil, and thus additional coolers are available for the new service from the second train. FG Compressor cooling requirements will be almost identical since the flow through the coolers will remain the same for the new service due to recycling.

3.2.6.4 Fuel Gas Cooler

The Fuel Gas Cooler was tested at 20,000 sm3/hr rate and the flow expected during the target flow case of 22,261 m^3/d oil will be much less. The Fuel Gas cooler outlet was approximately 24 deg C and is adequate for the target flow.

3.2.6.5 Fuel Gas Heater

The Fuel Gas Super-heater (electrical) “maxed out” during the high flow. Its outlet temperature dropped from 64 to 58 C during this time. The lowest HP Fuel Gas supply temperature recorded at the inlet of the power generation system during peak flow (as per IMS) was 49 C (at temperature indicator 43-TI-3302). However the site log indicated that the gas turbine fuel gas inlet temperature came close to 2 deg C above its trip setting and therefore further increase in flow was stopped. The turbine trip is set at 39 C within the power generator package. This is not considered a limitation to the superheater since its design temperatures are 25 C (inlet) and 56.6 C (outlet).

However, since the target flow rate of 22,261 m^3/d oil does not require such a high flow of fuel gas, the system is not considered a bottleneck for increasing the oil flow rate.

3.2.6.6 Glycol System Coolers & Exchangers

The Glycol Contactor Inlet Cooler will not have any limitations during the target flow of 22,261 m^3/d oil since the gas flow at that rate will be much less than the cooler's design flow. It is also the same case for the exchangers/reboiler in the Glycol Regeneration System.

3.2.6.7 Waste Heat Recovery Units

Since the well fluids have adequate integral heat, there are no additional heat requirements for oil stabilisation. The only heating medium consumers during the test were the Trim Cooler and the MP Separator Inlet Heater which was later taken on line as a heat sink. The approximate heat load in these exchangers was estimated from the WHRU thermal balance and was found to be 4 to 5 MW only when two power generators were running.

It is necessary to provide an adequate heat sink to the Heating Medium System when three power generators are required to operate while running two trains of compressors (22,261 m^3/d oil (140,000 bpd case).

3.2.6.8 Cooling Medium Sea Water Coolers

Two cooling medium sea water coolers were operated during the test with one on standby. The overall heat duty during the test was less than 50% of the installed capacity. No issues are expected at the target production rate of 22,261 m^3/d oil even if two compressor trains are run.

3.2.7 Power Generation

Electrical testing showed that all power generating machines are working as per the design capacity and no issues are anticipated in running two trains of gas compressors for the target flow case of 22,261 m^3/d oil..

3.3 Performance Test Summary and Conclusions

3.3.1 Summary

The performance test for FPSO Sea Rose topsides facilities were carried out 24 to 26 July 2006. The purpose of the test was to assess the plant performance with the maximum flow available from the five oil-producing wells. The systems included in the test were limited to oil separation, gas processing and compression, sea water deaeration and water injection, fuel gas, and cooling and heating medium systems. The power generation system was tested separately between August 3 and 9, 2006. The produced water system could not be tested since no water is currently being produced. Most of the data were captured remotely through the IMS system along with some local plant data that were manually recorded.

The maximum steady production achieved during the 24 hour test was 19,840 m^3/d oil (125,000 bpd). The above daily production rate included a peak hourly rate of up to 20,114 m^3/d oil (126,500 bpd). No abnormal vibration or control valve limitations were observed during the test. Even though a further increase in production was possible, it was not attempted since it involved starting the second train of compression or flaring gas that may have disrupted the steady oil flow during such a step change. The potential to increase production capacity is estimated theoretically by analysing the performance test results. With a few operational adjustments and minor modifications, it will be possible to increase the production to 22,261 m^3/d oil (140,000 bpd) as long as the oil received is dry.

The Gas Compression and Sea Water Deaeration / Water Injection Systems performed higher than their rated capacities. A summary of design and tested capacities are presented in Table 2.2.

3.3.2 Conclusions

The Performance Test achieved production of 19,876 m^3/d oil (125,000 bpd) without any observed issues. Information on how to achieve the production target of 22,261 m^3/d oil (140,000 bpd) is provided in Table 3.11.

Table 3.91 Target Production and Required Changes

Equipment	Target	Changes	Remarks
Total Liquids Separation	22,220 m^3/d	Nil	Liquid Flow is only 2/3rd of design
Oil Separation	22,220 m^3/d	See below	Liquid Flow is only 2/3rd of design
Inlet Manifold / chokes	22,220 m3/d oil + 3.0 MMsm3/d associated gas	Nil	Liquid Flow is only 2/3rd of design
HP Separator	22,220 m3/d oil + 3.0 MMsm3/d associated gas	1) Nil on vessel 2) Introduce HIPPS protection and size the PSV for fire case only.	1) Necessary to run 2 x LP Compressors to maintain the operating pressure of 2400 kPag. 2) Additional relief capacity may be necessary for blocked outlet case at 140,000 bpd flow rate and water cut with total liquids exceeding 33,074 m^3/d (208,000 bpd). Any additional relief valve(s) added may overload existing HP Flare system and hence suggested to introduce HIPPS system if total liquids flow is exceeded.
MP Separator	22,220 m3/d oil + 0.23 MMsm3/d associated MP gas	1) Reduce interface operating level to 20% vessel (40%	1) Interface level is reduced to get an operating residence time of 7 minutes.

Equipment	Target	Changes	Remarks
		on 33-LIC-1258) 2)Increase operating set pressure to 630 kPag 3)Increase flare set pressure to 700 kPag 4) Revise mechanical limit to 33-LCV-1266 to suit relief valve size on LP Separator	2) Pressure increase for stable operation of 2nd stage FG Compressor with PCV-1254A within 80% open. 3) Calculations show that the vessel could handle gas flows up to 2.0 MMsm3/d 4) Existing 75% Limit could be reduced since the LCV capacity is more than adequate.
LP Separator	22,220 m3/d oil + 0.15 MMsm3/d associated LP gas	1) Reduce interface operating level to 11% vessel (32% on 33-LIC-1318) 2) Increase operating set pressure to 90 kPag 2) Increase flare set pressure to 120 kPag (and reduce automatically to 90 kPag when FG Compressor is not running) 3) Increase PSHH set pressure to 220 kPag	1) Interface level reduced to get an operating residence time of 3 minutes. 2) Pressure increase for stable operation of 1st stage FG Compressor with PCV-1314A within 80% open. 3) Increase in pressure will be made in such a way that the oil RVP which is currently very low (< 30 kPa) will not exceed the spec. 3) Calculations show that the vessel could handle gas flows up to 0.7 MMsm3/d. However process upsets caused by slugging/pressure swings results fast opening of the flare PCV and carryover was experienced in the past outside the performance test.
Rundown Coolers	22,220 m^3/d	Inspect 33-TCV-1404 to verify whether it is sticking.	Cooler A is already upgraded and is adequate for 140,000 BOPD. Standby cooler is also available, if required.
Rundown Pumps	22,220 m^3/d	Nil	Two pumps are adequate for the target service.
Cargo Tanks	22,220 m^3/d	Reduce set pressures on PV valves	Keep sufficient difference in pressure set point to avoid opening of Tank PV breakers.

Equipment	Target	Changes	Remarks
Oil System Piping	22,220 m^3/d	Nil	1) The piping that will have increased velocity at 140,000 BOPD that exceeds API 14 recommendation are the 10 in. inlet and outlet of Rundown Pumps and Coolers including the Rundown line to cargo tanks. The above recommended velocity is a guideline for a new design. It is possible to operate these lines at 140,000 BOPD at velocity ca. 4.9 m/s provided regular wall thickness monitoring is carried out at critical locations (elbows etc.)
Oil System Control valves	22,220 m3/d	LCVs and PCVs have adequate capacity (see MP Separator section on mechanical limit on LCV)	1) See section on MP Separator & LP Separator pressure increase that will ensure capacity of the PCV to FG compressor.
Oil System Heaters	22,220 m3/d	Nil	1) Heating is not required due to high feed temperature and low crude RVP. However MP Separator Inlet Heater could be used as a heat sink when 3 power generators are running
Two Gas Compression Trains	3.2 MMsm^3/d	Nil	N/A
FG Compression Train	0.36 MMsm^3/d (uncondensed)	Replace 33-PSV-1554A/B with “P” orifice (same body size)	This will allow raising PSHH setting on LP Separator to 220 kPag and make compressor operation stable.
Gas TEG Dehydration	3.2MMsm^3/d	Nil	N/A
Sea Water Deaeration	44,000m^3/d	Nil	Nil
Single Water Injection Pump	16,800m^3/d	1) Nil on pumps	1) Nil
Fuel Gas System	0.4 MMsm^3/d	1) Nil on unit 2) Inspect insulation/heat tracing for heat loss near power generator fuel system.	1) Nil 2) Low temperature noted at 20,000 sm3/hr flow in the power generator fuel gas inlet during the test.
Heating Medium System	N/A	If MP Separator	It is difficult to control HM

Equipment	Target	Changes	Remarks
		Inlet cannot be used as a heat sink, provision to use cargo tank heating using HM may be required.	temperature when 3 generators are running.
Cooling Medium System	40 MW (approx)	Nil	2 Trains of compressor running

Operating the plant at 19,876 m^3/d oil (125,000 bpd) is possible without any major changes or modifications. However for operating the plant at 22,261 m^3/d oil (140,000 bpd), a number of operational adjustments and hardware modifications will be required. No major changes are necessary in support utilities.

4.0 SeaRose Piping Vibration Risk Assessment

A three stage risk based assessment has been undertaken by an independent specialist contractor to investigate and minimize the potential of pipework fatigue failures on all major process and utility piping systems on the SeaRose FPSO.

4.1 Assessment Procedure

This risk assessment comprised:

- An initial paper based screening to highlight main lines with the potential for excessive process induced vibration
- A visual inspection of the lines at risk and their associated small bore connections
- A base line vibration survey at 13,834 m^3/d (87,000 bbls/d) production rate
- A vibration survey during the performance test at 19,876 m^3/d (125,000 bbls/d) production rate.

The objective of this study was to determine the risk of a vibration induced fatigue failure of small-bore connection fittings (SBCs) and associated parent pipework, so that appropriate remedial vibration control measures could be instigated as necessary. Additionally, the vibration data gathered during the two surveys was used to assess the maximum safe production rates that could be achieved from a vibration point of view.

The screening highlighted a total of 408 small bore connections that were considered to be at a medium or high risk of having a fatigue failure. These connections were included in vibration surveys at an initial baseline production rate of 13,834 m^3/d (87,000 bbls/d), and then during the performance test at 19,876 m^3/d (125,000 bbls/d).

4.2 Assessment Results

The SeaRose FPSO has well supported piping and small bore connections, and no main lines were considered at risk of fatigue failures. A summary of the results of the piping vibration risk assessment are provided in Table 3.1..

Table 4.1 Piping Vibration Risk Assessment Results

System Tested	Proven Test Rate	Safe Operating Limit by Calculation	Comment
Oil Process with 4 flowlines	19,876 m^3/d (125,000 bbls/d)	23,851 m^3/d (150,000 bbls/d)	See qualifications
Oil Process with 5 flowlines	N/A	27,031 m^3/d (170,000 bbls/d)	See qualifications
Gas Compression	79.4 mscfd	160 mscfd	50% in each train
Water Injection	29,703 m^3/d (186,800 bbls/d)		Not limited by flow induced vibration

As committed to by Husky's Intergrity Management program, all significant changes to process parameters such will require a confirmatory offshore survey to negate risk of small bore piping fatigue failure. The following qualifications were made with respect to the piping vibration risk assessment:

- No gas lift.
- No significant water cut (less that 5% of liquid flow).
- Flow between four flowlines is relatively even.
- GOR is below 135 m^3/m^3.
- No major changes in pressure drops (i.e. flow is controlled by topside chokes).

5.0 Flow Metering

A report was commissioned to determine whether the existing Tier 1 flow metering systems were adequate for the increased throughput and that compliance would be maintained with all relevant regulations related to such systems. Tier 1 meters are defined to be those that are used for reservoir material balance and were included in the White Rose Flow Systems Application. The fiscal metering package will be unaffected by any increase in production as the flow rates are determined by the export pump capacity.

The SGS review of the existing SeaRose FPSO metering systems concluded that the majority of measurement points can operate satisfactorily within the required measurement and allocation uncertainty at a 140,000 bbls/day facility mean daily production rate (FMDPR) capacity. A summary of the findings are provided in Table 5.1. No modifications are required to the existing Tier 1 metering systems therefore, no changes are considered necessary to the currently approved planned maintenance system schedule.

Table 5.1 Measurement Point Summary

Station	ü / û	Comment	Status
Fiscal	ü	No change	Sample loop flow too low
Storage	ü	No change	Good
Test Oil	ü	No change to individual well rates	Good
Test Gas	ü	No change to individual well rates	Good
Test Water	ü	No change to individual well rates	Not tested (no water breakthrough)
Water O/B	ü	No change to individual well rates	Not tested (no water breakthrough)
HP Fuel	ü	No change	Good
LP Fuel	ü	No change	Plate oversized
HP Flare	ü	No change	Good
LP Flare	ü	No change	
Production Wells (IDUN)	ü	No change to individual well rates	Good
Water Injection Wells	ü	No change to individual well rates	Tuning vs topsides ongoing
Gas injection	ü	No change	Good
Gas injection wells	ü	No change	Tuning vs topsides ongoing action
Water injection	ü	No change	Good, but FSA requires update to reflect use of drill centre meters
LP Flare	ü	No change	Good
Seawater to process	ü	No change	Good
Lift gas	ü	No change	No increase above design proposed. Still to be commissioned.

6.0 Resource Management

The characteristics of the South Avalon Pool have not changed significantly since the Development Application was submitted in 2001. Significant drilling has been completed since that time and the field has been on production since November 2005 with no deviations from the original development plan. In summary, drilling and production to date have not indicated any significant change in the premises upon which the original development plan was based.

The original Development Plan envisaged the potential for 15 wells as part of the base case development. Currently the number of wells planned for the South Avalon pool is 18 with 7 horizontal producers, 4 horizontal water injectors, 5 deviated water injectors and 2 deviated gas injection wells. The current development region includes only the core South Avalon pool (Figure 6.1). Other regions under consideration for future development based on delineation drilling since the original development application include the South White Rose Extension (delineated with F-04 and F-04Z wells), Blocks 2 and 5 (region penetrated by B-19z and H-20) as well as the West White Rose pool drilled in 2006 with the O-28x and O-28 y wells (Figure 6.2). Any future development amendments relating to additional developments or satellites would be submitted separately to the C-NLOPB.

6.1 Geology

The geological interpretation of the South Avalon Pool has changed very little since the original development plan was submitted in 2001. The information gained from the drilling of 14 additional wells into the South Avalon pool has reinforced the structural, stratigraphic and reservoir quality information included in the original development plan (Figure 6.1). The discussion on regional setting and general geological aspects of the White Rose region as presented in the original Development Application (DA) remain the same and therefore will not be addressed in this application.

The current geologic interpretation used for geological modeling is an updated version of that presented in the Development Application for the White Rose oilfield submitted January 15th, 2001. At the time of submission there were seven delineation wells in the greater White Rose region that included the South, West, and North White Rose sub-regions. The updated model currently includes all wells within the core White Rose development region, as well as the F-04 and F-04z wells drilled in the SWRX region in 2003 (Figure 6.2). This brings the total number of wells in the region to 23. The F-04 and F-04z penetrations of the reservoir section in the SWRX region confirmed the presence and quality of the Ben Nevis reservoir to the south of the core development, further delineating the shoreface trend. Development drilling has provided six vertical/deviated (J-22 1, E-18 1, B-07 1, B-07 4, B-07 6, and B-07 8) and six horizontal (E-18 2, E-18 3, E-18 4, B-07 2, B-07 3, and B-07 5) penetrations of the Ben Nevis reservoir. Although information from these wells has provided a concentrated data set for modeling purposes, no unexpected results were encountered. The same is true for the delineation wells B-19 and B-19z. As a result, no material changes have been made to the depositional framework (or petrophysical maps) for the Ben Nevis Formation as proposed in 2001. Furthermore, no material changes have been made to the static geological model as provided in the DA.

The results of the F-04 and F-04z wells have been tied to the seismic data, and F-04 was used in developing the velocity model for depth conversion. Aside from these shifts, the geophysical interpretation has not materially changed since the original DA submission.

A note of clarification is required regarding the naming convention used in the development application. The reservoir section was termed the ‘Avalon’ in the 2001 submission. 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 thus likely to be the Ben Nevis Formation. Reasons for this are two-fold. Firstly, biostratigraphic evidence suggests that the reservoir package at White Rose rests unconformably upon Barremian to early Aptian-aged strata. Secondly, seismic defines Jurassic through lower Cretaceous subcrop edges, indicating that the mid-Aptian unconformity at the base of the reservoir is an *angular* unconformity. When this is taken in a regional context, the reservoir section at White Rose correlates favorably to the back-stepping transgressive Ben Nevis Formation. Note that with the two naming conventions spanning the work done in this compilation, Ben Nevis (BN) and Ben Nevis-Avalon (BNA), are used interchangeably throughout this report.

Current geological understanding places the South Avalon Pool in a region of shallow marine lower shoreface deposition trending southwest-northeast. Points **A** and **B** on Figure 6.3 illustrate the tectonic relationships to the deposition of the Ben Nevis formation in the White Rose Development region.

A – Early Nter fault movement resulting in increased accommodation space and thicker Ben Nevis Fm relative to the southern field extents.

B – Increased region of accommodation east of the H-20 well. No evidence of syntectonic growth is interpreted over the South White Rose Extension (SWRX) region. This has been confirmed by the additional 16 well penetrations drilled since the DA submission.

Figure 6.4 illustrates the general stratigraphy and hydrocarbon contacts in the Ben Nevis Avalon formation across the South Avalon Pool. As illustrated on this cross-section, the stratigraphy in the wells drilled after the Development Plan submission (B-19, B-19Z, B-074 and F-04) have essentially the same character as the wells drilled pre Development Plan submission (N-30, L-08 and A-17).

Internal divisions of the Ben Nevis formation represent seven parasequence sets; the BN_ramp, BN_Shell_Cmt, BN_1, BN_2, BN_3, BN_4, and BN_5 from base to top respectively (Figure 6.5). These units correspond with coarsening upwards cycles evident in distal wells (such as H20), but lose resolution where the net to gross is high, and sand-on-sand intra-formational contacts exist. In these regions the internal divisions are highly interpretational, but correlated through the area nonetheless.

Figure 6.1 Illustrating the current Development Region and Wells in the South Avalon Pool

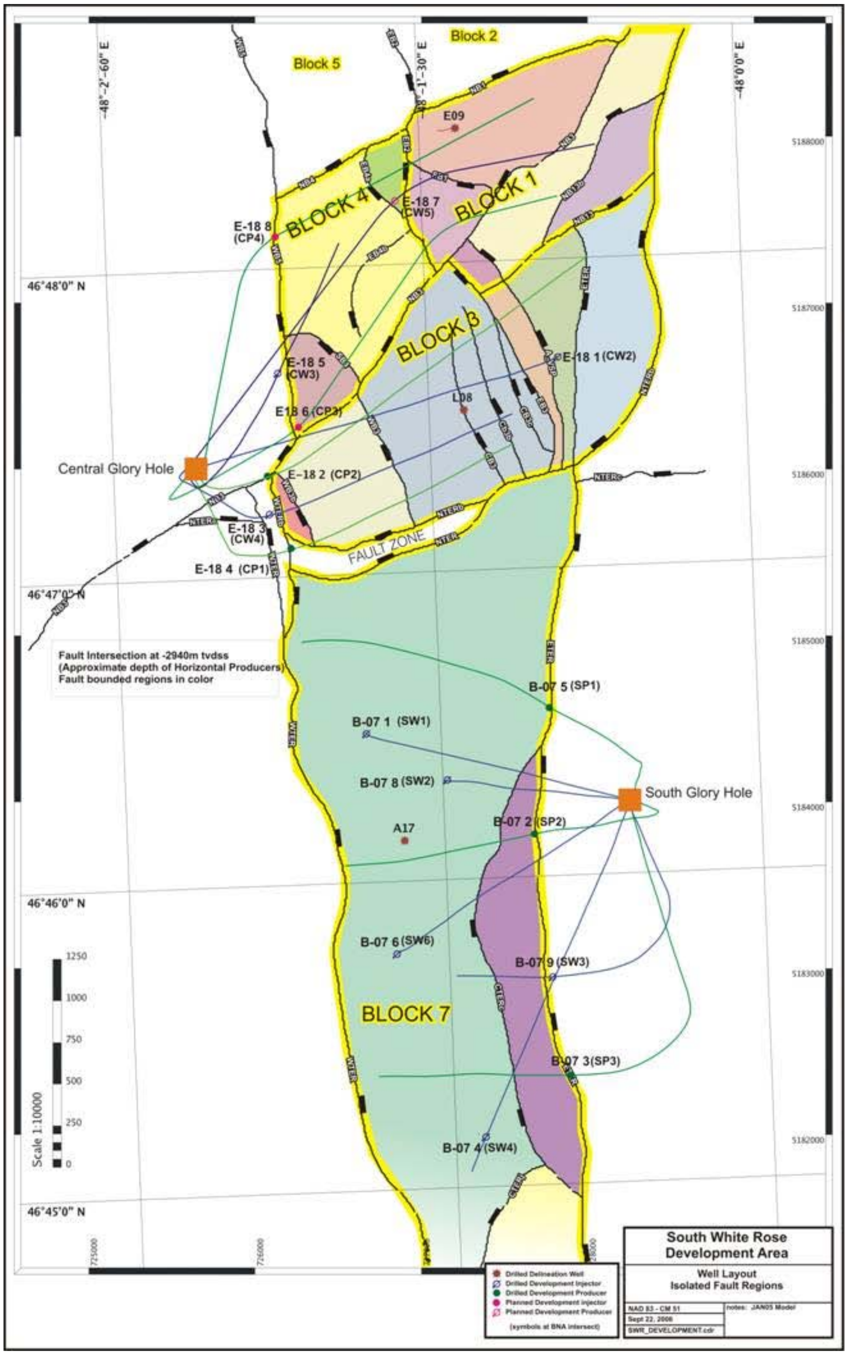


Figure 6.2 Map illustrating the location of the South Avalon Pool in relation to other delineated pools in the White Rose Region

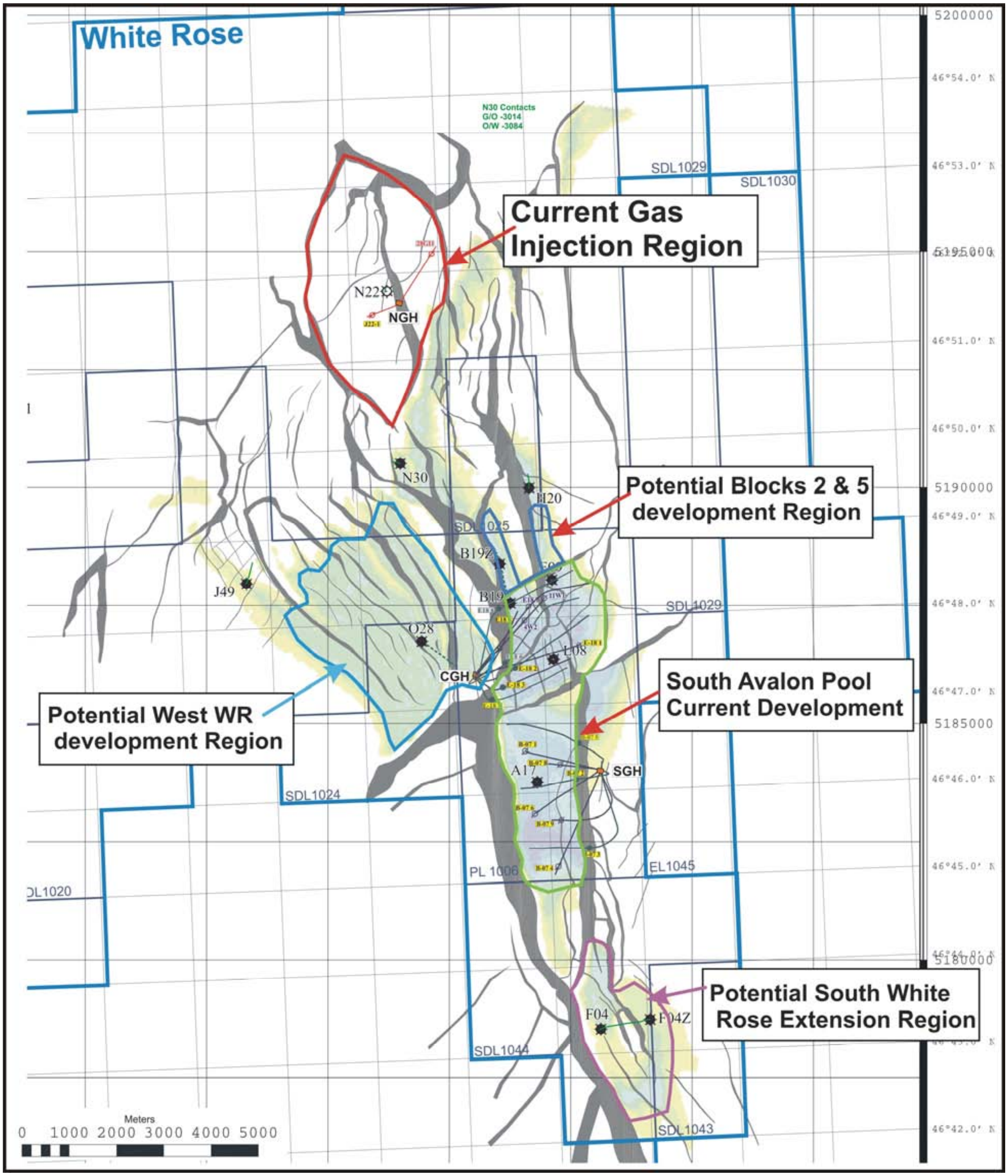


Figure 6.3 Schematic of Aerial Distributing of Shoreface Sandstone and Early moving Faults related to the initial phases of Ben Nevis Fm Deposition
(Note development wells are not displayed)

Figure 6.4 Schematic Cross Section across the South Avalon Pool

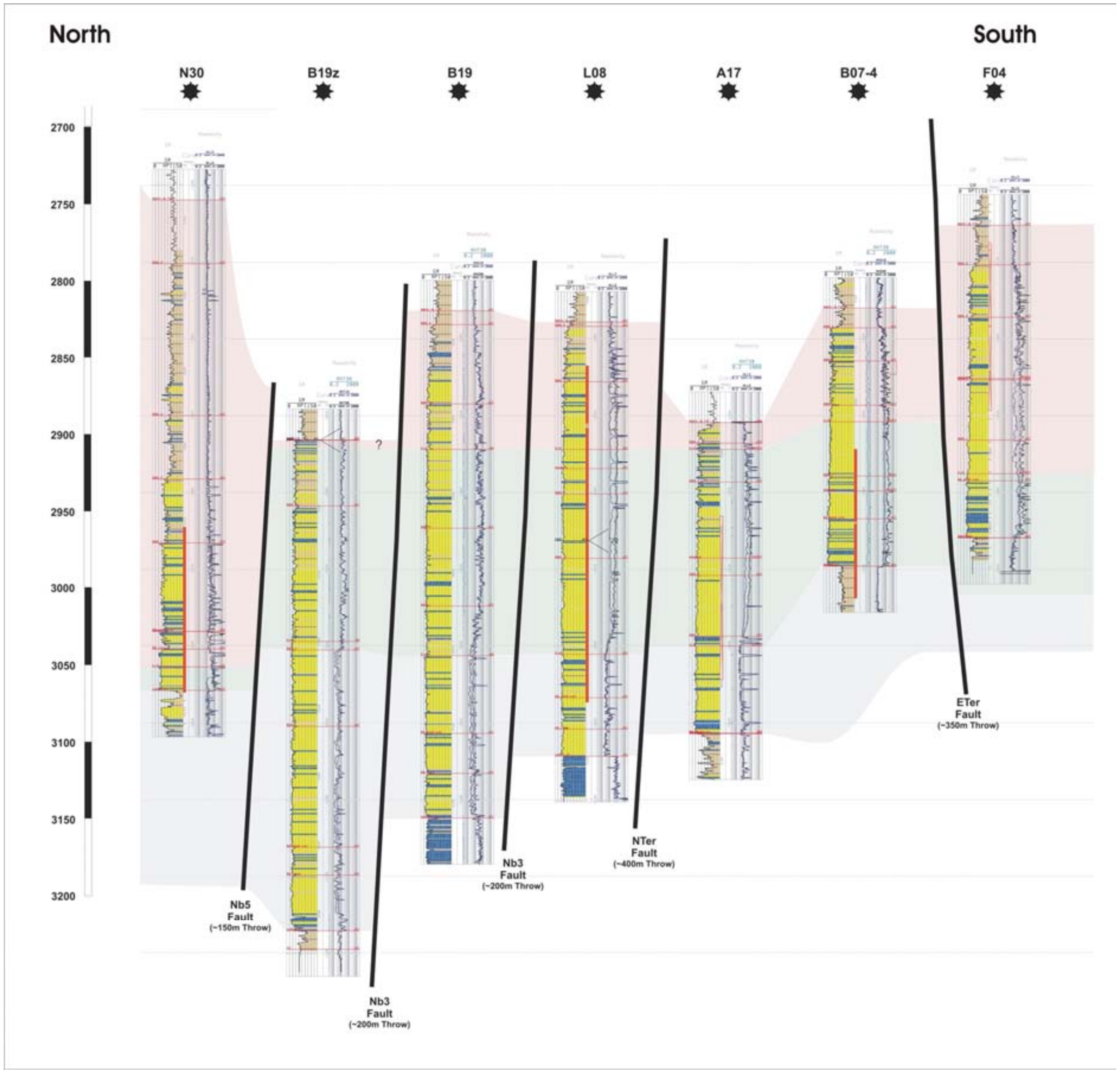
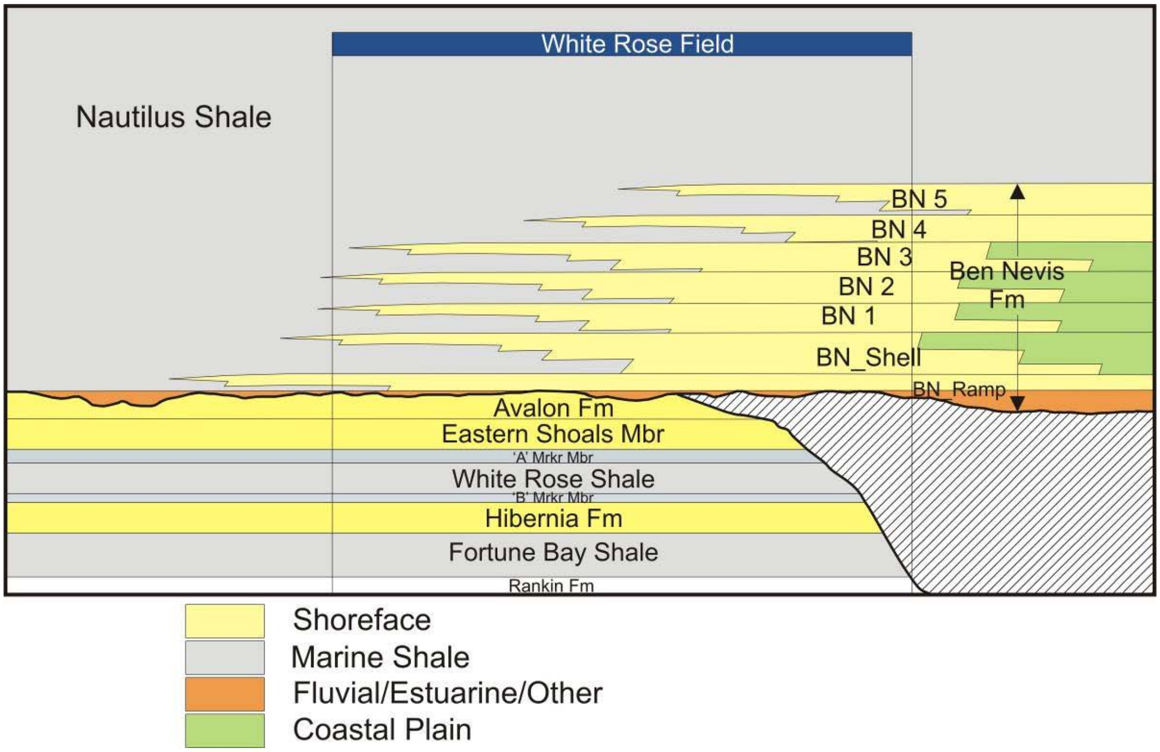


Figure 6.5 White Rose Field Stratigraphy Illustrating the Internal Divisions of the Ben Nevis Formation



As presented in the original Development Application, three main facies associations (FA) and some diagenetic components are identified at White Rose.

1. FA1: Lower Shoreface Storm Deposits. Consisting of well sorted very fine grained sandstone, this FA is the main reservoir rock type in the region. Facies encountered within this grouping are low-angle (hummocky to swaley), laminated sandstone, massive sandstone, and parallel laminated sandstone. Varying amounts of shell bioclastic and sideritised shale ripup clasts are present as lags along basal scour contacts.

2. FA2: Lower Shoreface Fairweather Deposits. These intervals consist of heavily bioturbated siltsone to silty-sandstone to sandstone. Primary sedimentary structures are rarely preserved.

3. FA3: Marine Deposits. Representing the distal component of White Rose region deposition, the facies types for this group are laminated and massive silty-shale to shale, with some minor bioturbated intervals.

4. Diagenetic Components. Although not representative of a primary depositional feature, due to the abundance of secondary components in the reservoir rock, these have been separated into three groups. Calcite cement is dominant within the Ben Nevis Fm and consists of two types of nodules. Calcite nodules are defined by their round edges as seen in both core and on image logs and likely have poor lateral continuity. Calcite nodules can also be concentrated along shell lag intervals, appearing more lenticular and usually exhibiting convolute edges. Although more continuous than singular nodules, these occurrences are not

likely to form intra-reservoir barriers. A third type, siderite nodules, are not significant in terms of reservoir proportion but are locally present, commonly within mud-lined trace fossils.

These facies associations have been incorporated within the static reservoir model and the resultant dynamic model used in simulation.

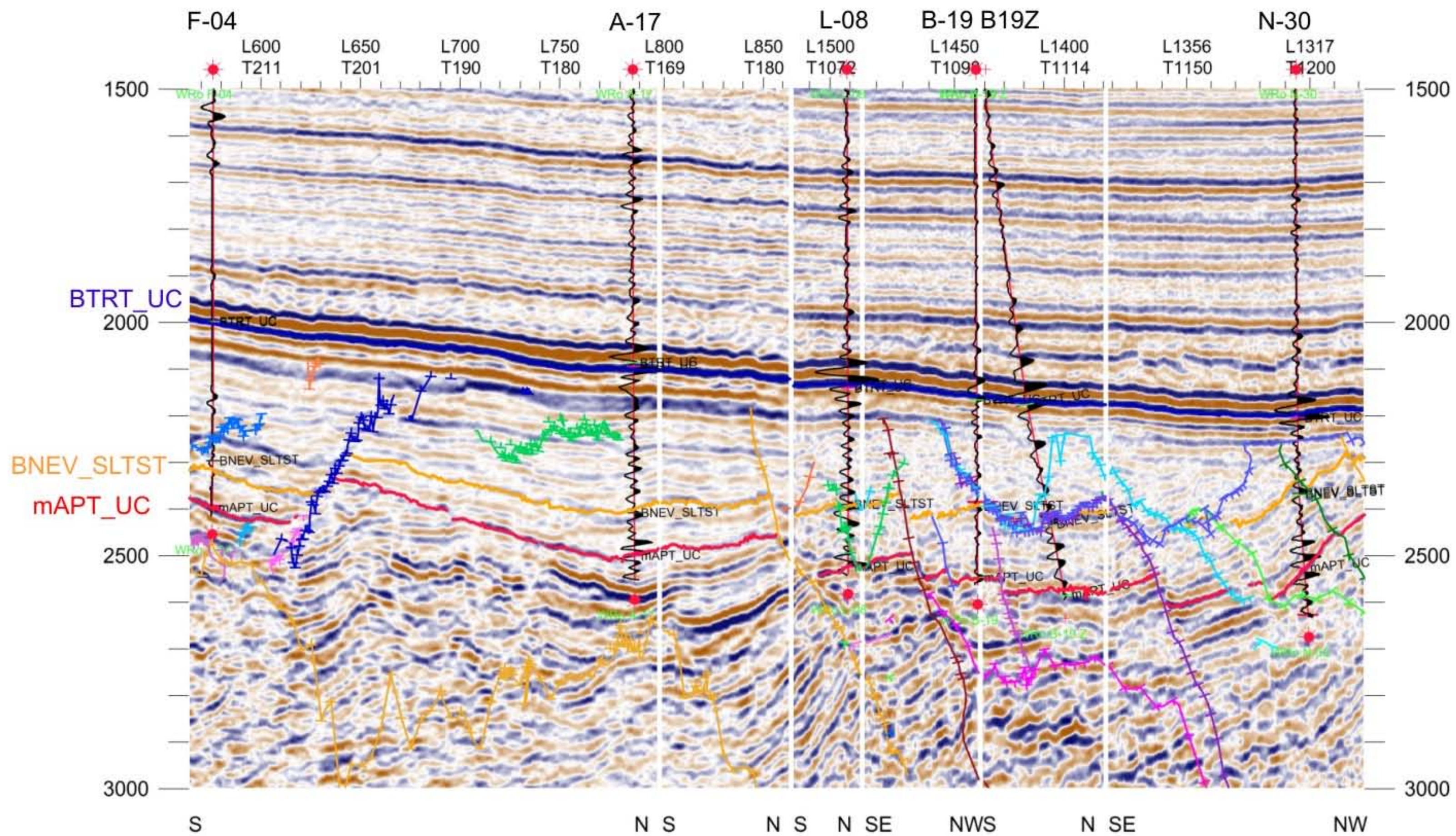
6.1 Geophysics

In general development wells drilled in the South Avalon Pool have substantiated both the geophysical interpretation and depth conversion generated for the pool. Most well penetrations into the reservoir have been very close to that predicted prior to drilling.

Results of the F-04 and F-04z wells led to a downward shift in the top reservoir surface in the southern region of the pool. The primary difference was related to the pre-drill interpretation being a cycle higher than where the actual post-drill top was encountered in both wells. This is the main difference in the current seismic interpretation relative to that presented in the DA. Although several interpreters have made slight adjustments to the pre-existing interpretation, no further material changes have resulted. The results of the B-19 and B-19z wells confirmed both the structural interpretation and velocity model for the South Avalon Pool.

The current velocity model being used for the White Rose field is a two layer seismic velocity (VoK) model with Tertiary (sea level to base tertiary) and Upper Cretaceous (base tertiary to mAPT_UC) velocity intervals, and includes data from the F-04 well. Current uncertainty between prognosed and actual results in the main development region place the velocity model uncertainty at between +/- 35 m for the top reservoir and +/-15 m for the base reservoir.

Figure 6.6 South to North Seiemic Section from the SWRX region through the South Avalon pool to the North Avalon Pool



6.2 Petrophysics

The petrophysical parameters encountered in the wells drilled since the DA was submitted in 2001 have shown no significant deviations from that expected from the original delineation wells. Overall, the porosity and permeability are slightly better than that envisaged in the original application, however are still within the margin of error.

Petrophysical summaries for all wells within the White Rose development region and SWRX are listed in Tables 6.1, 6.2, 6.3, and 6.4. For this Development Plan Amendment, the F-04 and F-04z wells are the relevant sources of information for the southeastern extents of the Ben Nevis reservoir while the B-19 and B-19z wells provide relevant information for the northern extent of the South Avalon Pool. In all of these wells, thick, porous hydrocarbon-bearing sandstone was encountered, with reservoir properties being similar to the development/delineation wells in the South Avalon Pool.

White Rose F-04 was drilled in 2003 to delineate the SWRX region. A thick sand interval with a large gas zone (118 m) and thin oil zone (19 m) at its base was encountered. Porosity and permeability were in the same range as the Ben Nevis reservoir in the White Rose development region, but did trend towards the higher side of the ranges.

The sidetrack to F-04, White Rose F-04z, was then drilled into a structurally lower block in order to confirm the oil-water contact expected in the region. This well encountered no significant gas leg, and 27m of oil pay before reaching the OWC at a depth of 2991m TVD. Again porosity and permeability where found to be in the same ranges sampled in the development region. This well encountered 183.3 metres of gross interval, with 114m being of reservoir quality.

White Rose B-19 and B-19z were drilled in 2005 and helped to define the northern edge of the South Avalon Pool. The B-19 well was almost identical to the original discovery well, E-09. The more advanced formation evaluation tools used in the B-19 well confirmed the presence of high quality reservoir at the northern edge of the current development region. The B-19z well as expected had lesser amounts of reservoir quality Ben Nevis Avalon. The region of the B-19z well is not included in the current development region, however the area is subject to further studies to determine the merit of developing the region.

Table 6.1 Petrophysical Summary for the Gas Leg Intervals

	Gas Leg						
	Well	Type	Top Depth (m TVD ss)	Gross Thickness (m)	Net:Gross	Porosity (%)	Permeability (mD)
White Rose Development Region	H20	Delineation					
	B19z	Delineation	2857.2	43.6	0.14	12.8	34.7
	B19	Delineation	2779.5	94	0.27	14	68.2
	E09	Delineation	2784	82	0.22	13	41
	L08	Delineation	2771.2	102	0.46	15.6	92.6
	E18 1	Injector	N/A	N/A	N/A	N/A	N/A
	E18 2	Producer	N/A	N/A	N/A	N/A	N/A
	E18 3	Injector	N/A	N/A	N/A	N/A	N/A
	E18 4	Producer	N/A	N/A	N/A	N/A	N/A
	A17	Delineation	2854.5	19.5	0.20	15	91.3
	B07 1	Injector	2758.53	113	0.42	16.3	139.5
	B07 2	Producer	N/A	N/A	N/A	N/A	N/A
	B07 3	Producer	N/A	N/A	N/A	N/A	N/A
	B07 4	Injector	2752.46	157.5	0.48	16	125.5
	B07 5	Producer	N/A	N/A	N/A	N/A	N/A
	B07 6	Injector	2819.03	66	0.01	12.5	33.7
	B07 8	Injector	2851.88	20.52	0.23	11.5	25
	B07 9	Injector	N/A	N/A	N/A	N/A	N/A
SWRX	F04	Delineation	2700.06	191.3	0.62	17.2	140.5
	F04z	Delineation	2881.98	6	0.21	15.8	95.4

Table 6.2 Petrophysical Summary for the Oil Leg Intervals

	Oil Leg						
	Well	Type	Top Depth (m TVD ss)	Gross Thickness (m)	Net:Gross	Porosity (%)	Permeability (mD)
White Rose Development Region	H20	Delineation					
	B19z	Delineation	2893.56	128	0.38	15.4	86.9
	B19	Delineation	2871.9	129.4	0.74	16	114.63
	E09	Delineation	2869.4	138.2	0.73	16	72.6
	L08	Delineation	2872	137.7	0.83	17	133
	E18 1	Injector	N/A	N/A	N/A	N/A	N/A
	E18 2	Producer	N/A	2071.6	0.86	17	140
	E18 3	Injector	N/A	N/A	N/A	N/A	N/A
	E18 4	Producer	N/A	1247	0.88	17	130
	A17	Delineation	2874.4	125.3	0.74	16.4	99
	B07 1	Injector	2871.52	113.75	0.80	16.5	140.5
	B07 2	Producer	N/A	1102	0.80	16	140.5
	B07 3	Producer	N/A	1075	0.91	17	170
	B07 4	Injector	2858.94	131.5	0.76	17	156
	B07 5	Producer	N/A	1447	0.85	17.8	146
	B07 6	Injector	2871.99	106.8	0.78	17	172
	B07 8	Injector	2871.54	122	0.81	15.2	103
	B07 9	Injector	N/A	N/A	N/A	N/A	N/A
SWRX	F04	Delineation	2888.26	42	0.46	16.6	126.05
	F04z	Delineation	2887.94	79.5	0.34	17	142.2

Table 6.3 Petrophysical Summary for the Water Leg Intervals

	Water Leg						
	Well	Type	Top Depth (m TVD ss)	Gross Thickness (m)	Net Sand :Gross	Porosity (%)	Permeability (mD)
White Rose Development Region	H20	Delineation					
	B19z	Delineation	3004.81	191.6	0.77	16	110.7
	B19	Delineation	2999.9	110.5	0.74	15.6	91.36
	E09	Delineation	3008.3	111.5	0.75	15	69
	L08	Delineation	3009	63	0.67	14.6	68.1
	E18 1	Injector	N/A	N/A	N/A	N/A	N/A
	E18 2	Producer	N/A	N/A	N/A	N/A	N/A
	E18 3	Injector	N/A	1352	0.73	15	75.7
	E18 4	Producer	N/A	N/A	N/A	N/A	N/A
	A17	Delineation	3000	58	0.71	16	85
	B07 1	Injector	N/A	N/A	N/A	N/A	N/A
	B07 2	Producer	N/A	N/A	N/A	N/A	N/A
	B07 3	Producer	N/A	N/A	N/A	N/A	N/A
	B07 4	Injector	N/A	N/A	N/A	N/A	N/A
	B07 5	Producer	N/A	N/A	N/A	N/A	N/A
	B07 6	Injector	2998.45	66.5	0.65	16.7	157
	B07 8	Injector	2992.62	42.28	0.70	14.7	87
	B07 9	Injector	N/A	454.9	0.75	16.5	144.8
SWRX	F04	Delineation	N/A	N/A	N/A	N/A	N/A
	F04z	Delineation	2968.23	97.4	0.77	17.6	156.2

Table 6.4 Petrophysical Summary for the entire Ben Nevis Interval

	Total Ben Nevis Interval						
	Well	Type	Top Depth (m TVD ss)	Gross Thickness (m)	Net Sand :Gross	Porosity (%)	Permeability (mD)
White Rose Development Region	H20	Delineation					
	B19z	Delineation	2857.2	362.4	0.63	15.5	95
	B19	Delineation	2779.5	330	0.64	15.7	96.5
	E09	Delineation	2784	335.9	0.63	14.6	66.3
	L08	Delineation	2771.2	300.9	0.71	16.3	109.8
	E18 1	Injector	2840.42	242	0.78	16	91.6
	E18 2	Producer	N/A	N/A	N/A	N/A	N/A
	E18 3	Injector	N/A	N/A	N/A	N/A	N/A
	E18 4	Producer	N/A	N/A	N/A	N/A	N/A
	A17	Delineation	2854.5	203.1	0.70	16.1	92.4
	B07 1	Injector	2758.53	226.3	0.62	16.3	140.5
	B07 2	Producer	N/A	N/A	N/A	N/A	N/A
	B07 3	Producer	N/A	N/A	N/A	N/A	N/A
	B07 4	Injector	2752.46	285.5	0.62	16.5	142.5
	B07 5	Producer	N/A	N/A	N/A	N/A	N/A
	B07 6	Injector	2819.03	234.7	0.56	16.9	162
	B07 8	Injector	2851.88	183.3	0.72	15	96.8
	B07 9	Injector	N/A	N/A	N/A	N/A	N/A
SWRX	F04	Delineation	2700	232.25	0.60	17.1	138
	F04z	Delineation	2881.98	183.3	0.62	17.3	149.5

6.3 History Match Process

Data for the history match process included the first seven months of production, with a cutoff date of June 13, 2006. As expected the first seven months of production has not shown a rate decline in any of the producers or injectors from the initial advised rates. Accordingly, it was decided to use the prorated oil production and water injection rates as input data to the model. The matching parameters were:

- Well Bottom Hole Pressure (WBHP)
- Well Tubing Head Pressure (WHP)
- Well Producing Gas-Oil Ratio (WGOR)
- Well Producing Water Cut (WWCT)
- P* (extrapolated pressure) at datum 2,930 m-TVDss from Build-Up Test Analysis

All producers (with the exception of B-07 2) have been producing at solution GOR and zero water-cut. As a result, WBHP, WHP and build-up extrapolated pressure were the major matching parameters.

Generally, the prorated production and injection data were found to best match the recorded bottom-hole pressures of individual producers. The actual production performance of the wells B-07 3, E-18 2 and E-18 4 were found to be in a good agreement with the model predictions. Also, the initial multi-rate test in well B-07 5 (June26 to July04, 2006) was well matched by the model. Figures 6.7 to 6.10 illustrate the quality of the history match for these wells.

Figure 6.7 B-07 3 History Match

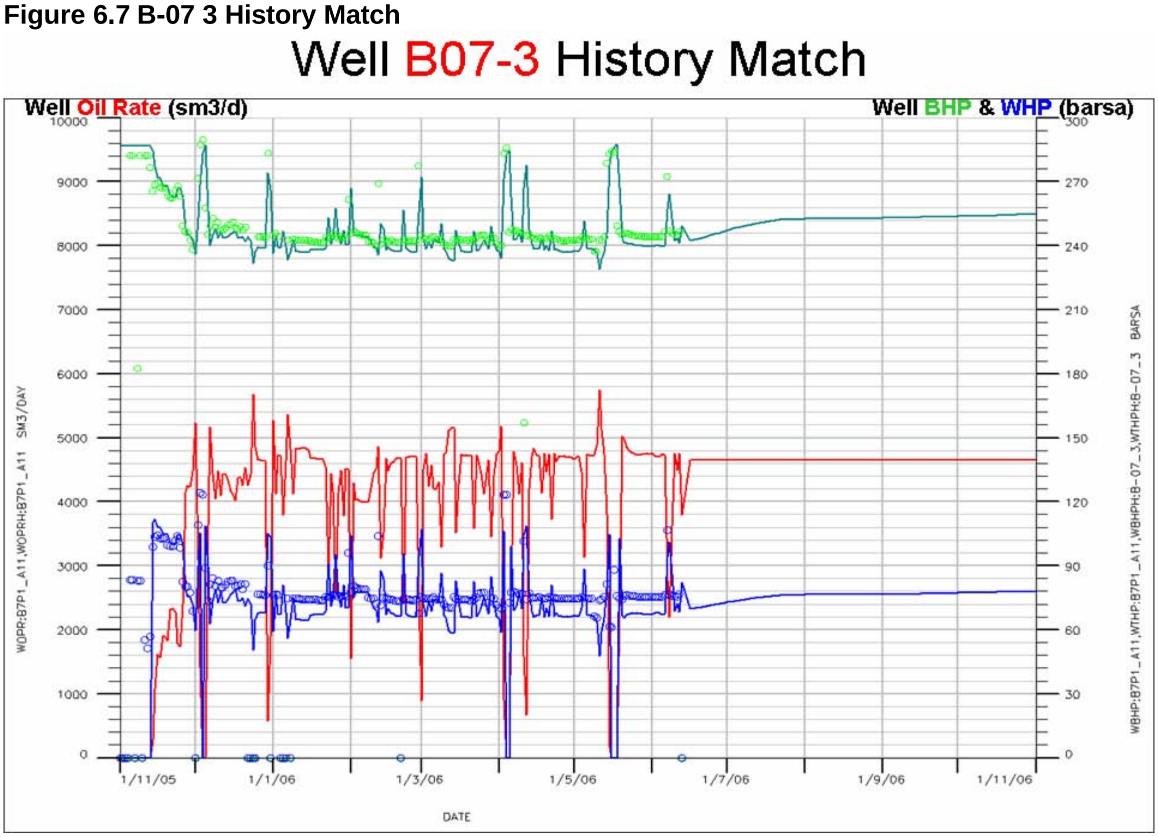


Figure 6.8 B-07 5 Multi-rate Test (post history match process) showing the Eclipse model prediction versus actual data)

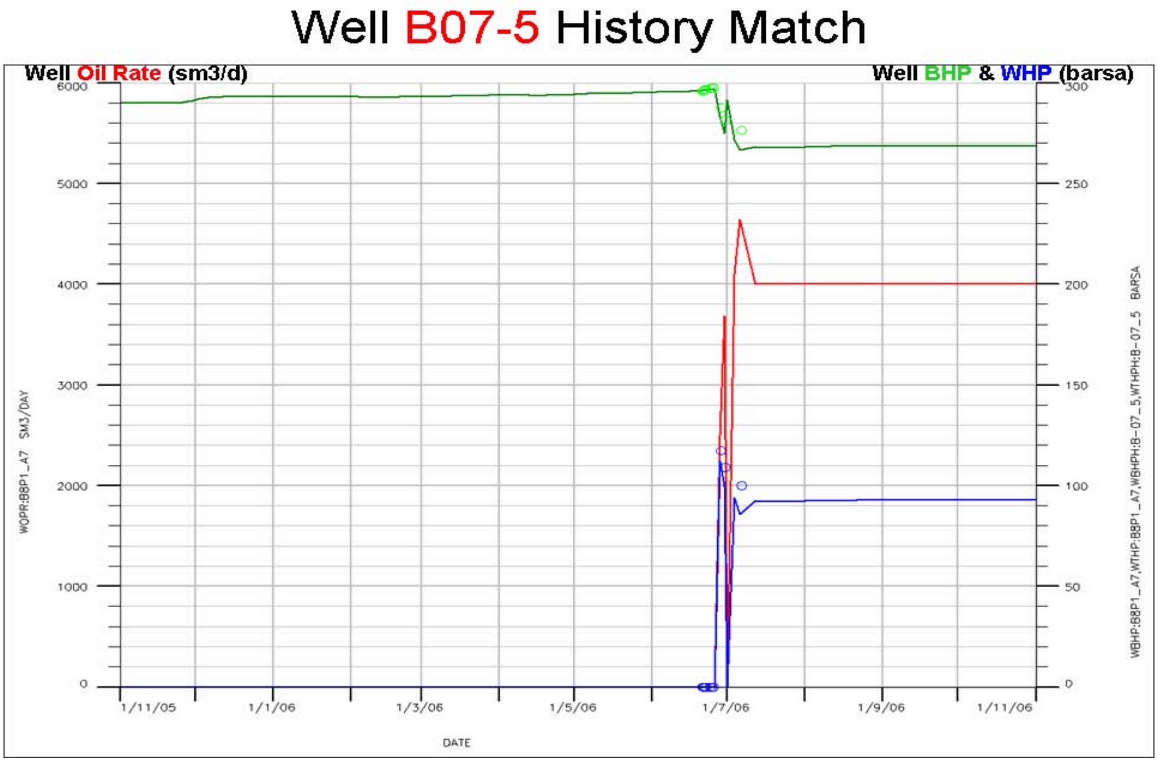


Figure 6.9 History Match of E-18 2

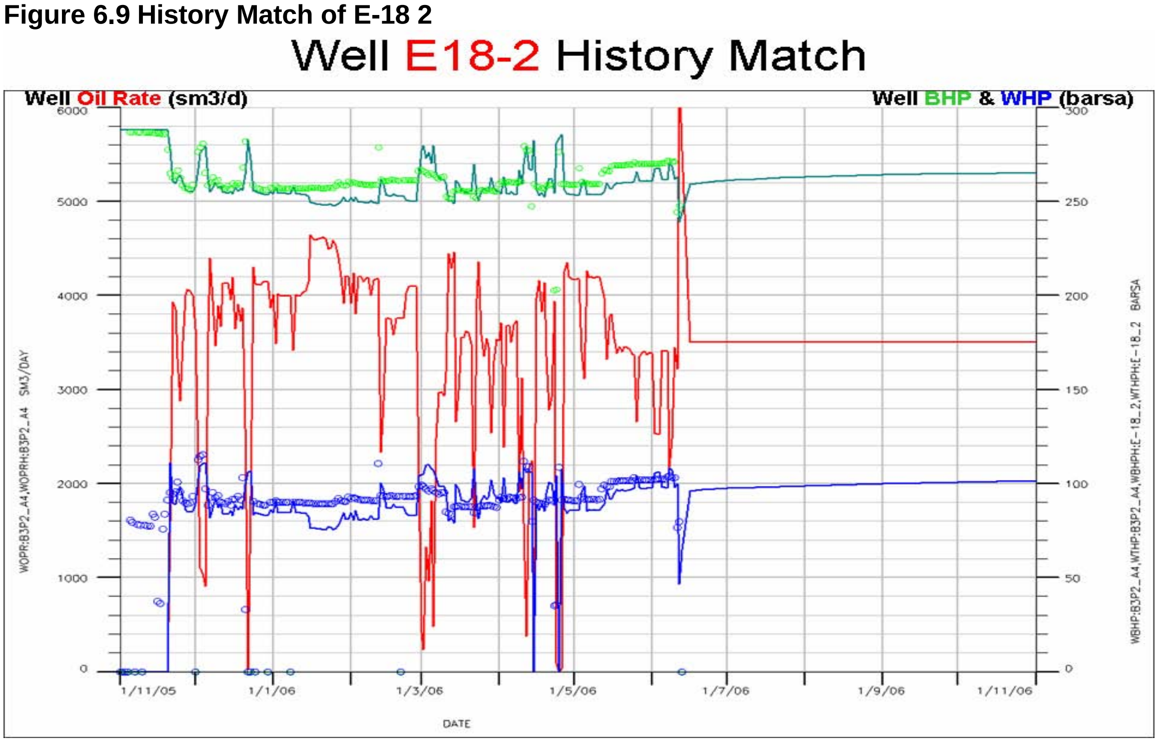
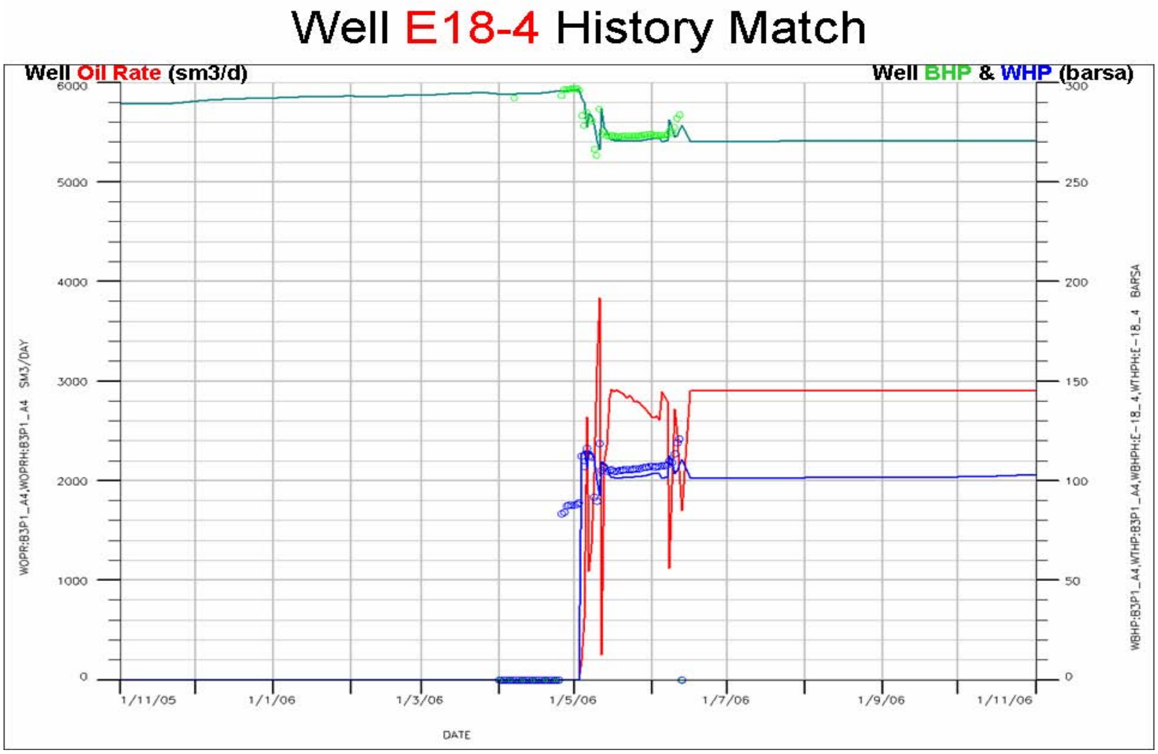


Figure 6.10 History Match of E-18 4



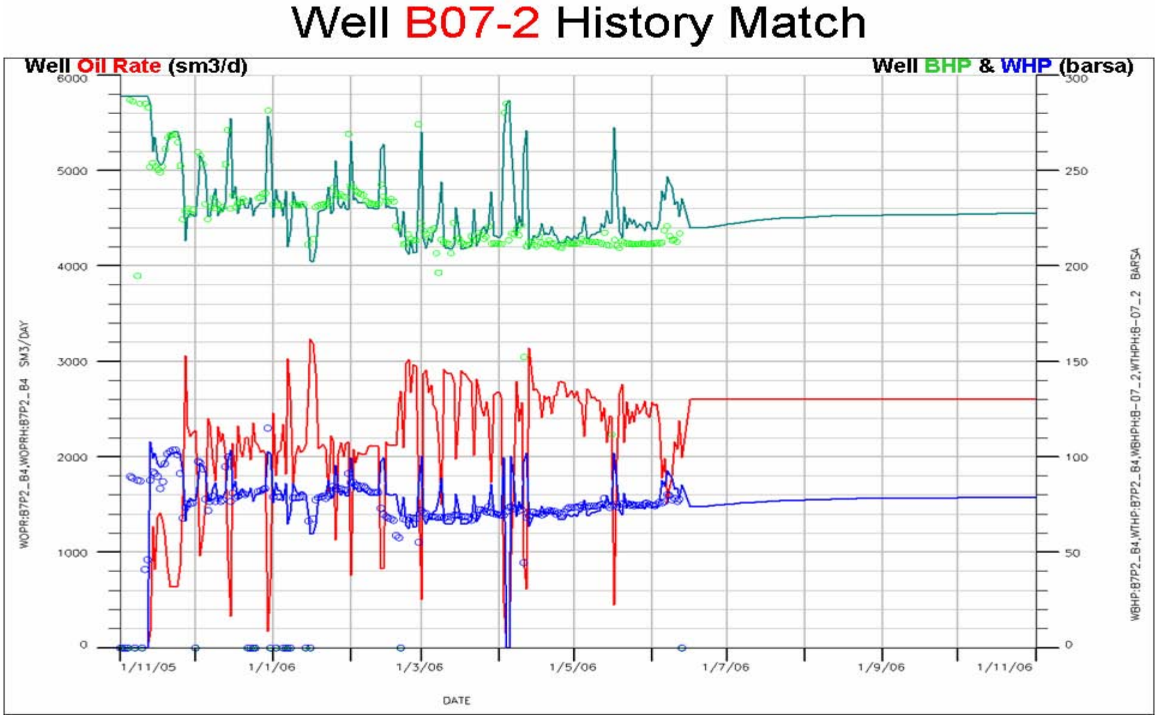
6.3.1 History match process for B-07 2

The actual production performance (rates and bottom-hole pressures) of B-07 2 well was found to be poorer than predicted. In an attempt to verify the reasons the Pressure-Transient data of the well were analyzed both analytically and numerically. The analysis concluded the main reasons to be:

1) the well location near the bottom of a NO-FLOW Bioturbated Bed at the top of the Ben Nevis sandstone (BN-SS) reservoir,
2) zero contribution from the Intersected Bioturbated intervals along the wellbore resulting in about 50% reduction in the well-contributing-length to production.

Figure 6.11 illustrates the quality of the match once these parameters were incorporated into the model.

Figure 6.11 History Match for B07-2 Well

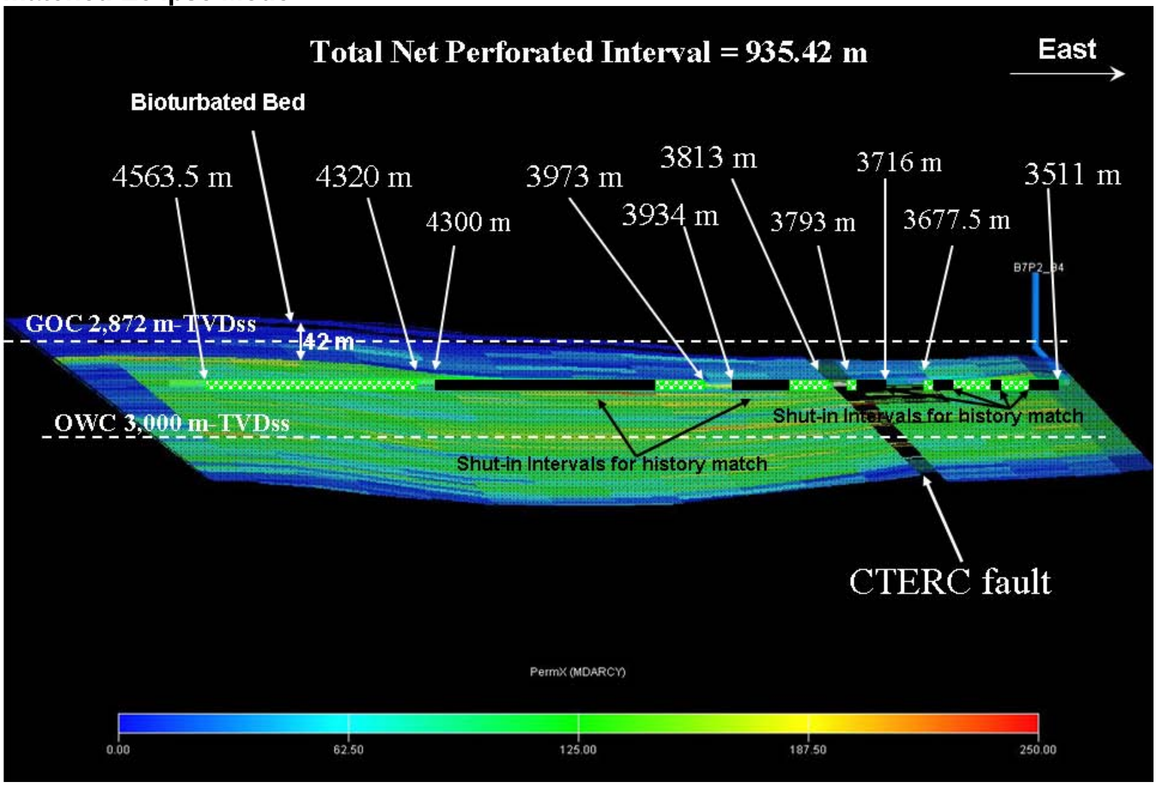


In the pre-history-match Eclipse Model, due to the coarse cell dimensions (100x100x • 4 m) at the B-07 2 location the reduced flow-capability of the Bioturbated facies were not accurately modeled. A Local-Grid-Refinement (LGR) Exercise at the B-07 2 well location has predicted about 30% reduction in the well initial productivity index compared to the Coarse-Grid case. Due to inconvenient slow run times (15 years prediction) with LGR, the results of Pressure Transient Analysis (PTA) and LGR exercises were implemented in the full-field coarse model by shutting the following perforated intervals in the well B-07 2:

3533 - 3567 m-MD (34 m)
3601 - 3617 m-MD (16 m)
3645 - 3670 m-MD (25 m)
3716 - 3740 m-MD (24 m)
3871 - 3934 m-MD (63 m)
4050 - 4300 m-MD (250 m)

The total net perforated interval in the well was 935 m. The contributing length in the coarse model for best matching the well history was 523 m (935 – 34 – 16 – 25 – 24 – 63 – 250). Figure 6.12 shows an East-West cross-section along the wellbore highlighting the actual perforated intervals and simulated shut-in intervals in the history-matched model.

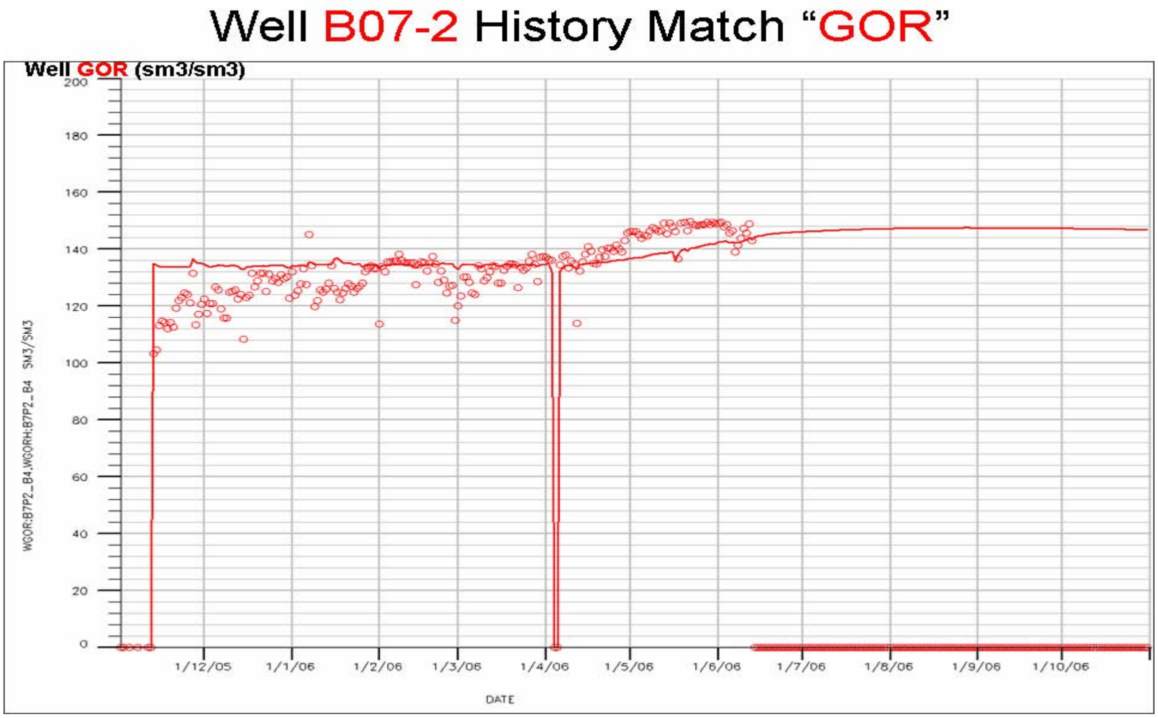
Figure 6.12 Image of Simulated Shut-in (non contributing) Intervals for B-07 2 Well in the History-matched Eclipse Model



A 44% reduction in the contributing length (523 m comparing to 935 m) in the B-07 2 well was required to match the actual well production performance (rates and bottom-hole-pressures) during the first seven months of production. It is thought that the Eclipse coarse model may still overestimate the flow capability of the Bioturbated facies within the entire full-field. However, this is expected to NOT have a significant impact on the performance of wells located/completed away from the Bioturbated facies.

The B-07 2 well also exhibited a gradual increase in GOR (from 137 to 165 sm^3/sm^3) from April through July 2006. This increase in GOR is believed to be liberated gases out of solution due to low pressures in the vicinity of the well bore. The GOR has declined /stabilized back to around 150 sm3/sm3 following water injection rate increase in wells B-07 6 and B-07 9. The model provides a reasonable match to both the gradual increase and gradual decline /stabilization in GOR as shown in Figure 6.13

Figure 6.13 History Match of B-07 2 GOR Profile



6.3.2 Additional parameters incorporated in the History-Match process

6.3.2.1 PVT Properties

Since year 2000, all Eclipse models have been using the same PVT properties. The source of PVT properties was the analysis results of DST-samples from wells A-17, L-08 and E-09. The analysis results were averaged to an initial gas-oil-ratio (Rsi) of 122 sm3/sm3, saturation pressure (Ps) of 294 barsa and an initial oil-formation-volume-factor (Boi) of 1.346 rm3/sm3.

Following a review of recorded production data during the first seven months of production (Nov-2005 to June-2006), new PVT property tables were found to best match the confirmed producing gas-oil-ratio (GOR) in wells B-07 2, B-07 3, E-18 2 and E-18 4. The new PVT tables were generated from the differential-liberation experimental data of the sample "A17 03-15 SEP43-02" from well A-17 after correcting saturation pressure (Ps) to 294.05 bars. The revised PVT properties are shown in Table 6.5.

Table 6.5 Revised PVT Parameters used in Current Eclipse Model

A17 03-15 SEP43-02 Oil Properties				A17 03-15 SEP43-02 Gas Properties		
Rs	Pressure	Bo	Oil Visc.	Pressure	Bg	Gas Visc.
(sm3/sm3)	(barsa)	(m3/Sm3)	(cp)	(bara)	(m3/Sm3)	(cp)
@ T = 106 deg.C. & Pb = 292.54 barsa corrected to 294.05 (MDT)						
0.0000	0.8946	1.0550	2.9130	0.8946	1.5187	0.0107
13.8000	9.5591	1.0960	2.0260	9.5592	0.1372	0.0135
18.0000	18.2236	1.1120	1.8970	18.2238	0.0713	0.0141
24.4000	35.5425	1.1300	1.6850	35.5430	0.0360	0.0147
39.1000	70.2005	1.1650	1.4370	70.2015	0.0178	0.0156
53.8000	104.8484	1.1990	1.2420	104.8498	0.0118	0.0168
68.4000	139.5064	1.2330	1.0940	139.5083	0.0088	0.0182
82.4000	174.1543	1.2670	0.9800	174.1567	0.0071	0.0199
97.7000	208.8022	1.3030	0.8710	208.8051	0.0060	0.0218
113.7000	243.4602	1.3410	0.7850	243.4635	0.0052	0.0241
137.5000	294.0500	1.4050	0.7076	294.0500	0.0045	0.0280
137.5000	312.0625	1.4010	0.6959	312.0625	0.0043	0.0298
137.5000	350.0000	1.3926	0.6863	350.0000	0.0040	0.0346

Surface (101.4 Kpa & 15.56 °C) Densities (Kg/m3):

Oil 849.93 Water 1030.7 Gas 0.935

Bw = 1.0359 rm3/sm3 & Cw = 2.89E-5 1/bar @ 276 barsa

Cf = 5.80E-5 1/bar @ 300 barsa

6.3.3 GOC Depth at the Southern region of the Terrace Block

History match sensitivities were run with different GOC depths 2872 m-TVDss and 2853 m-TVDss within the Southern Region of the Terrace Block. The goal was to achieve a good match to the production/injection and pressure performance of the Wells B-07 3 and B-07 4. The sensitivities have not indicated a significant impact on the model predictions (within the 7 months of actual production) when using the two different GOC depths. It is believed that it is still too early to see an impact from different GOC depths on the well B-07 3 and B-07 4 performances.

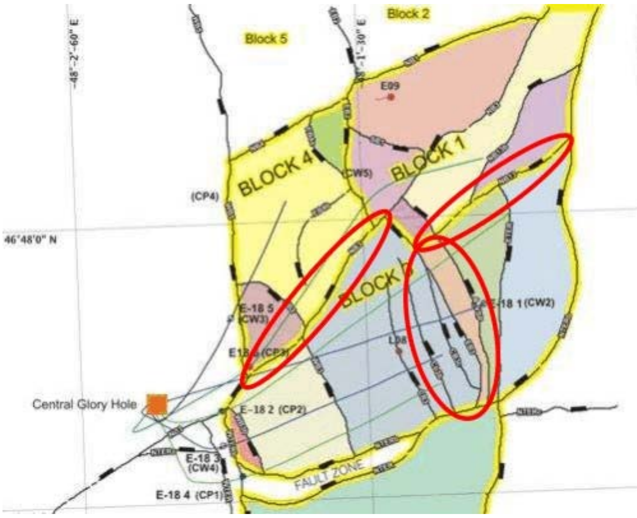
6.3.4 Internal and Boundary Faults

The production/pressure performance of wells E-18 2 and E-18 4 has indicated a possibility of partially non-sealing efficiency for:

- the internal faults at the Eastern flank of Block3 (CB3b, CB3c, EB3 and VSP) and
- northern boundary faults between Block3 and Block1&4 (NB3 and NB13). The recent results while drilling E-18 5 (water injector in Block4) and E-18 6 (producer in Block1&4) have also indicated a partially non-sealing NB3 fault.

The non-sealing faults are shown in Figure 6.14.

Figure 6.14 White Rose Non-Sealing Faults



However, a seven-month production history is believed to be too short to judge the sealing efficiency of internal or boundary faults. Therefore, it is still preferred for a model Base-Case Prediction to consider all internal and boundary faults sealing. The non-sealing (or partially sealing) scenario has been used for sensitivity purposes. In this regard, the History matched ECLIPSE simulation model that was provided to the C-NLOPB on July 26, 2006 (Husky Ref. No.: HUS-CPB-WR-LTR-00279) contained files for both the sealing and non-sealing scenarios. Furthermore, the simulation sensitivities presented in Section 6.4 illustrate comparisons for both the sealing and non-sealing scenarios

6.4 Field Peak Rate Sensitivities

Sensitivities conducted via the history-matched ECLIPSE model for the sealing and non-sealing scenarios show comparable results, with the non-sealing fault model giving slightly higher oil recovery as shown in Figures 6.15 through 6.18. Figure 6.14 shows the oil production profile, and cumulative oil production for each of the production rate sensitivities that were evaluated, and serves to illustrate the similarities for all cases investigated. However, for greater clarity, Figures 6.15 – 6.17 show the oil production rate and cumulative oil production for the 15,900 Sm^3/d, 19,875 Sm^3/d and 22,261 Sm^3/d cases respectively. Furthermore, 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 22,261 Sm^3/d.

Figures 6.19 – 6.21 show the gas production rates and cumulative gas production for each of the rate sensitivity cases investigated. For each case, the Eclipse simulation honors the FPSO maximum (pre-performance test) gas handling capacity constraint of 4.2 million Sm^3/d.

Figures 6.22 – 6.24 show the GOR profiles for each of the rate sensitivity cases. As expected, each of the non-sealing fault scenarios predict slightly higher GOR profiles, which can be explained by the ability of free gas to move more easily across faults in the non-sealing model. However, despite the minor differences in GOR, the model does honor the FPSO gas-handling constraints as discussed in the previous paragraph.
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6.4.1 Impact on Field Life

As shown in Figures 6.15 through 6.18, toward the end of the production curve, there is no significant difference in the field production rate for each of the rate sensitivity cases. 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.

6.4.2 Impact on Produced Water Discharge Volumes

Figures 6.25 and 6.26 show the predicted produced water volumes are within the design requirements of the FPSO (28,600 Sm3/d), and in keeping with the volumes originally predicted during the Development Plan process.

6.5 Reserves

The drilling and production information acquired since the original DA was submitted in 2001 does not support any significant changes to the reserves in the South Avalon Pool. Husky has publicly stated a range of between 200 to 250 million barrels of recoverable oil from the South Avalon Pool. Additional reserves were discovered in the South White Rose Extension in 2003 which adds between 20 and 25 million barrels of oil to the south of the main pool. The potential development of the South White Rose extension will be the subject of another submission to the C-NLOPB.

Figure 6.15 Comparison of Oil Production Rate and Cumulative Oil Production for Sealing and Non Sealing Scenarios

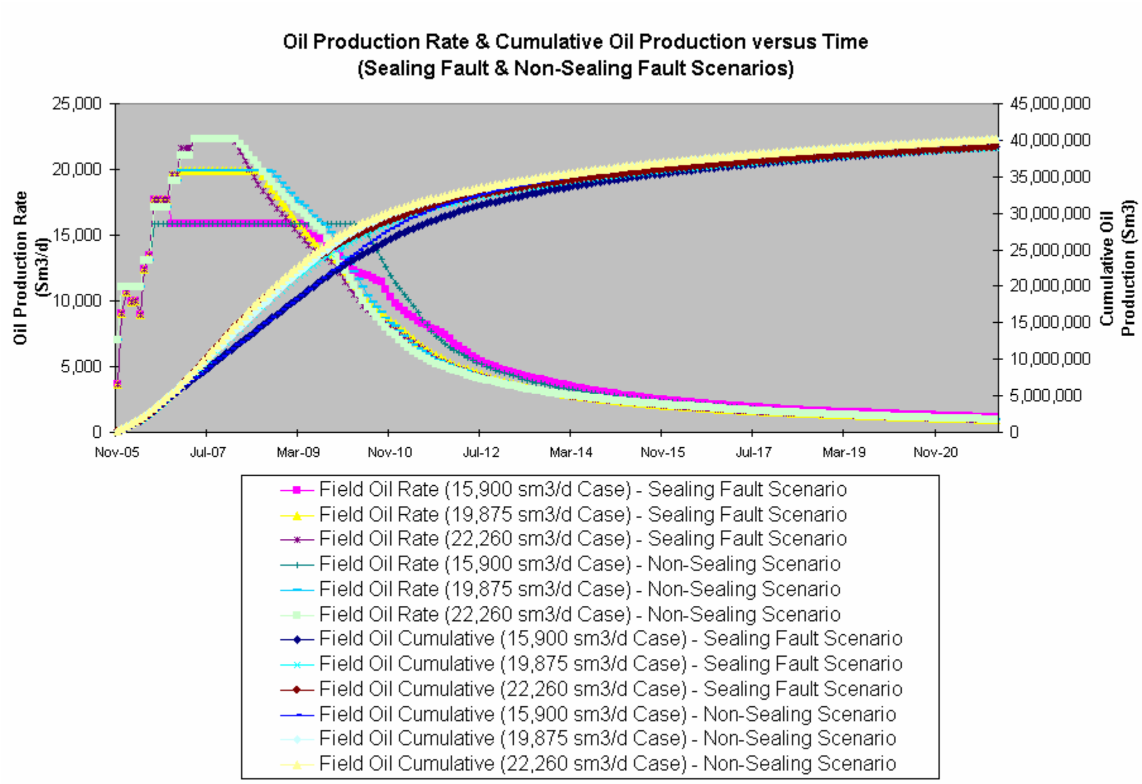


Figure 6.16 Oil Production Rate and Cumulative Oil Production (15,900 Sm3/d case)

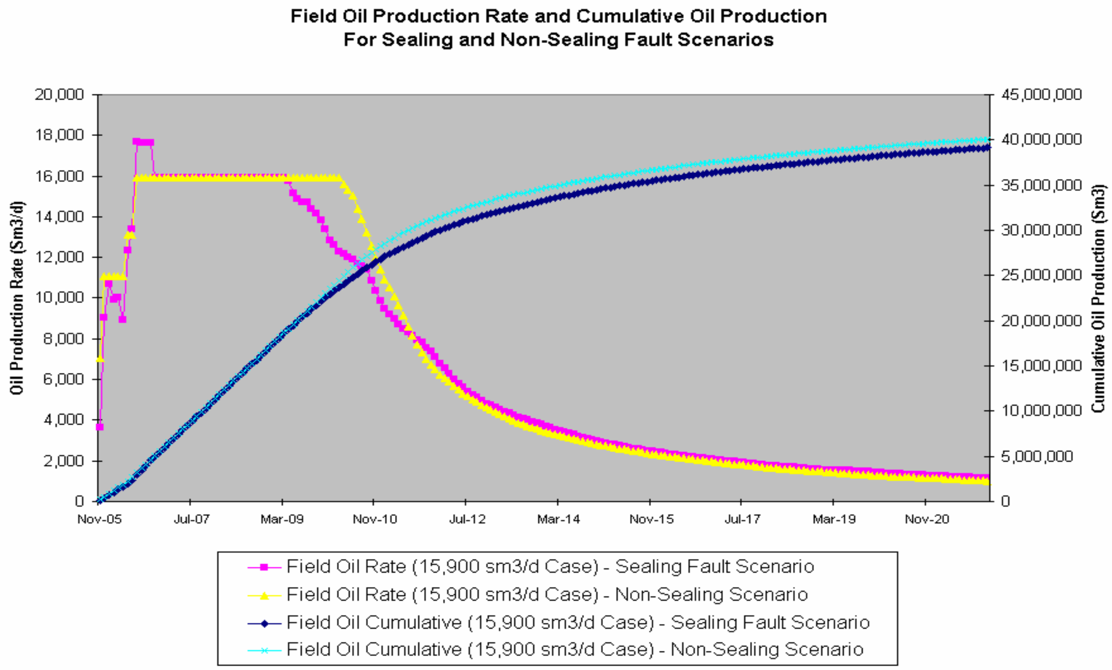


Figure 6.17 Oil Production Rate and Cumulative Oil Production (19,875 Sm3/d case)

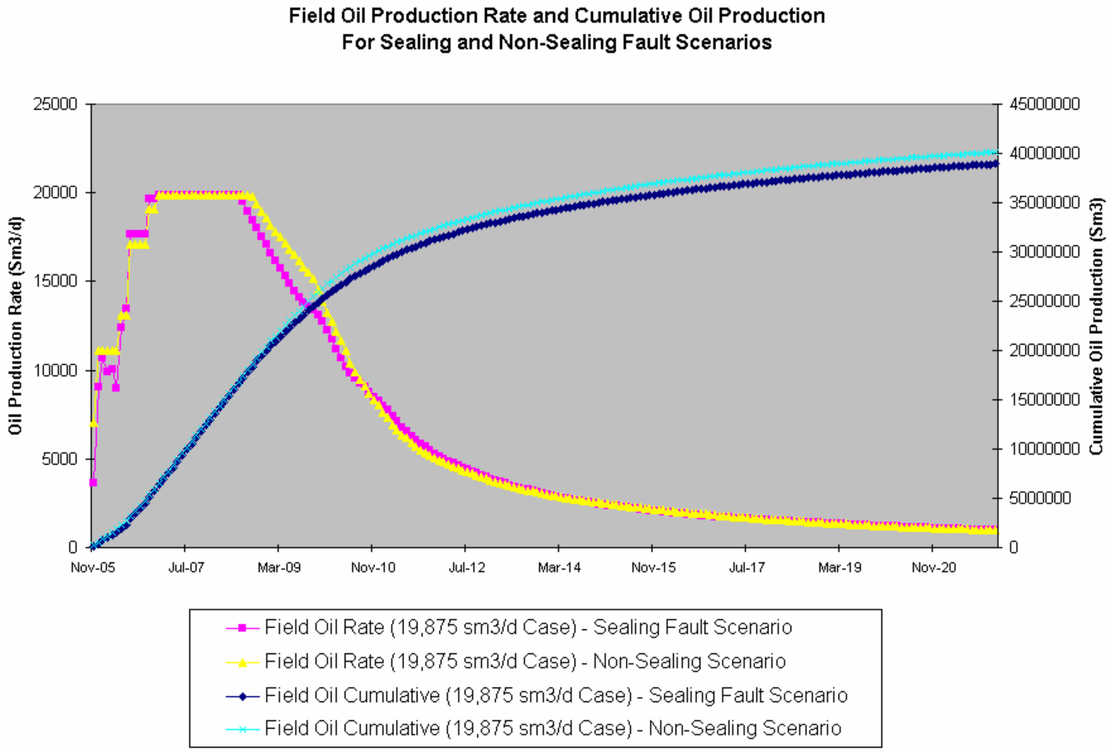


Figure 6.18 Oil Production Rate and Cumulative Oil Production (22,260 Sm3/d case)

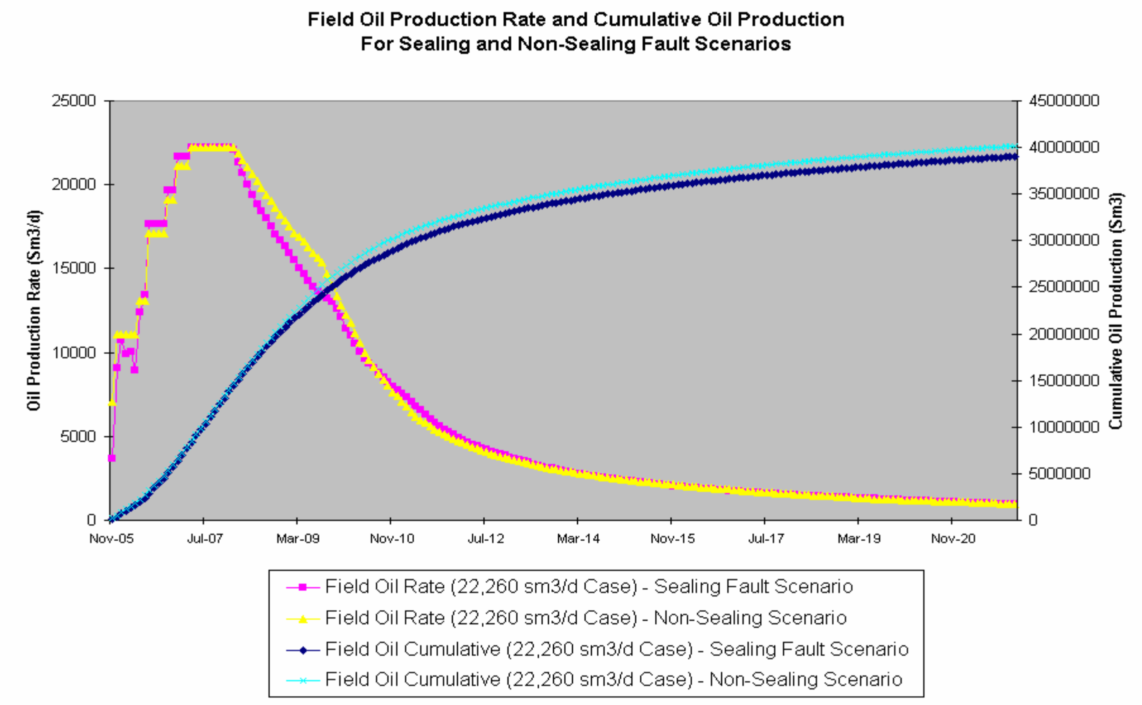


Figure 6.19 Gas Production Rate and Cumulative Gas Production (15,900 Sm3/d case)

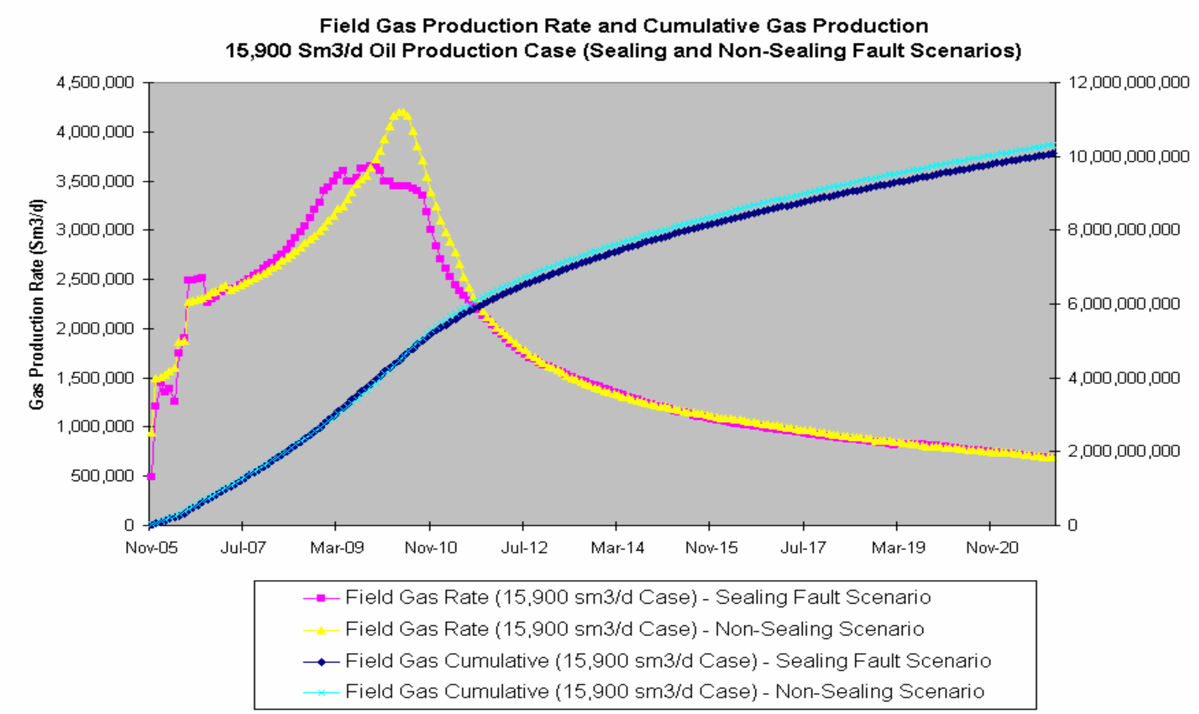


Figure 6.20 Gas Production Rate and Cumulative Gas Production (19,875 Sm3/d case)

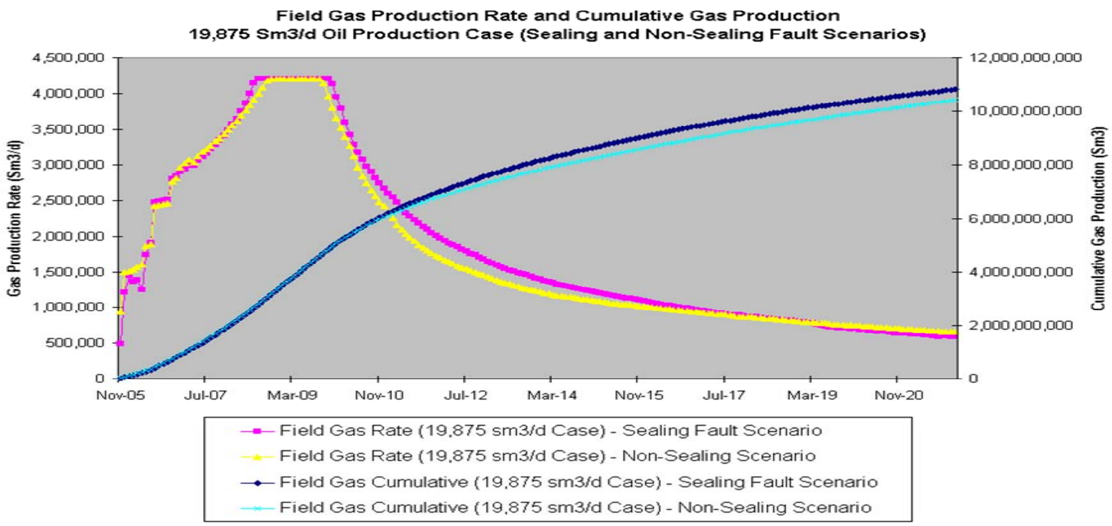


Figure 6.21 Gas Production Rate and Cumulative Gas Production (22,260 Sm3/d case)

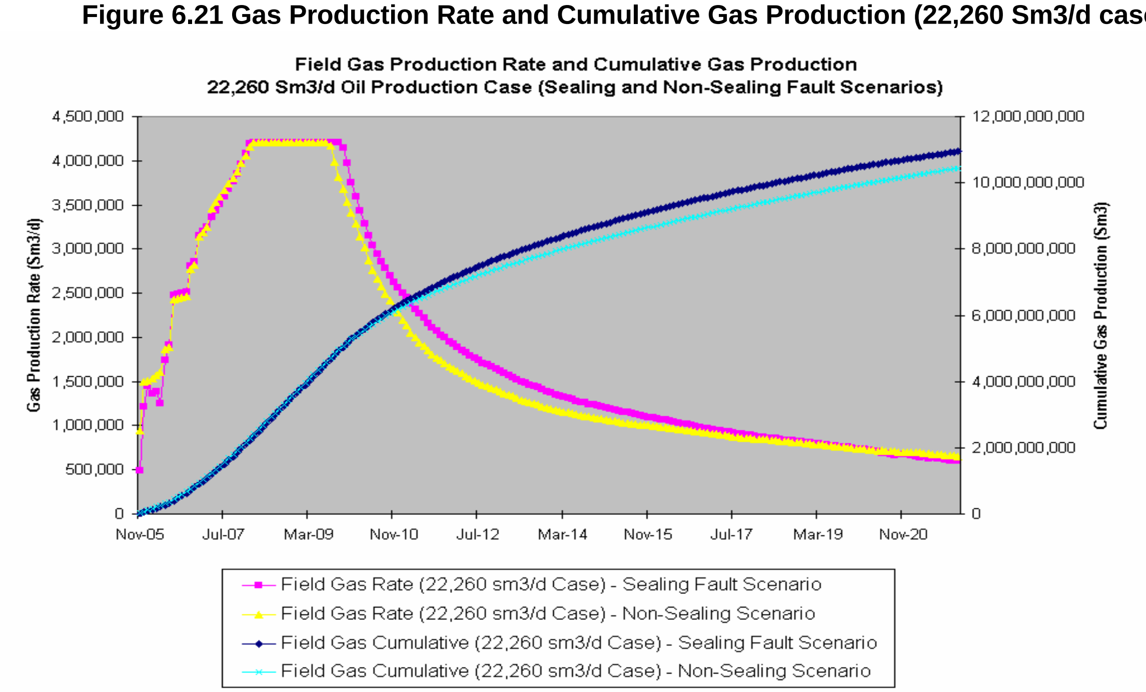


Figure 6.22 Oil Production Rate and GOR (15,900 Sm3/d case)

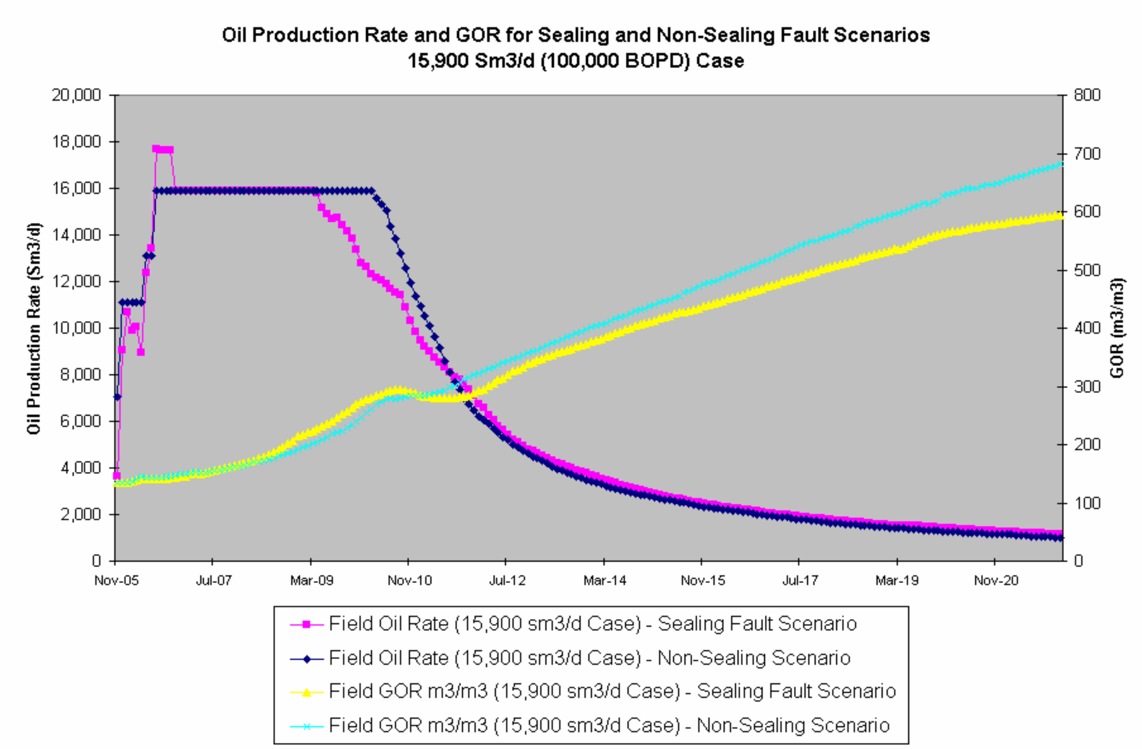


Figure 6.23 Oil Production Rate and GOR (19,875 Sm3/d case)

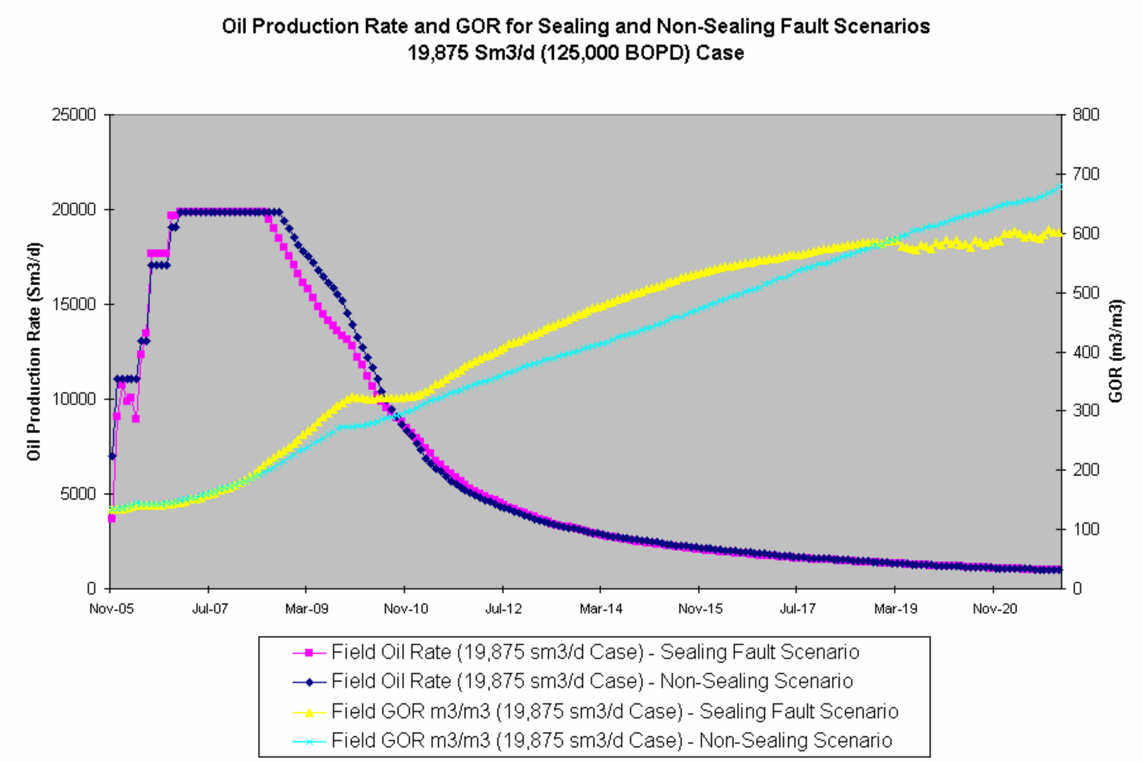


Figure 6.24 Oil Production Rate and GOR (22,260 Sm3/d case)

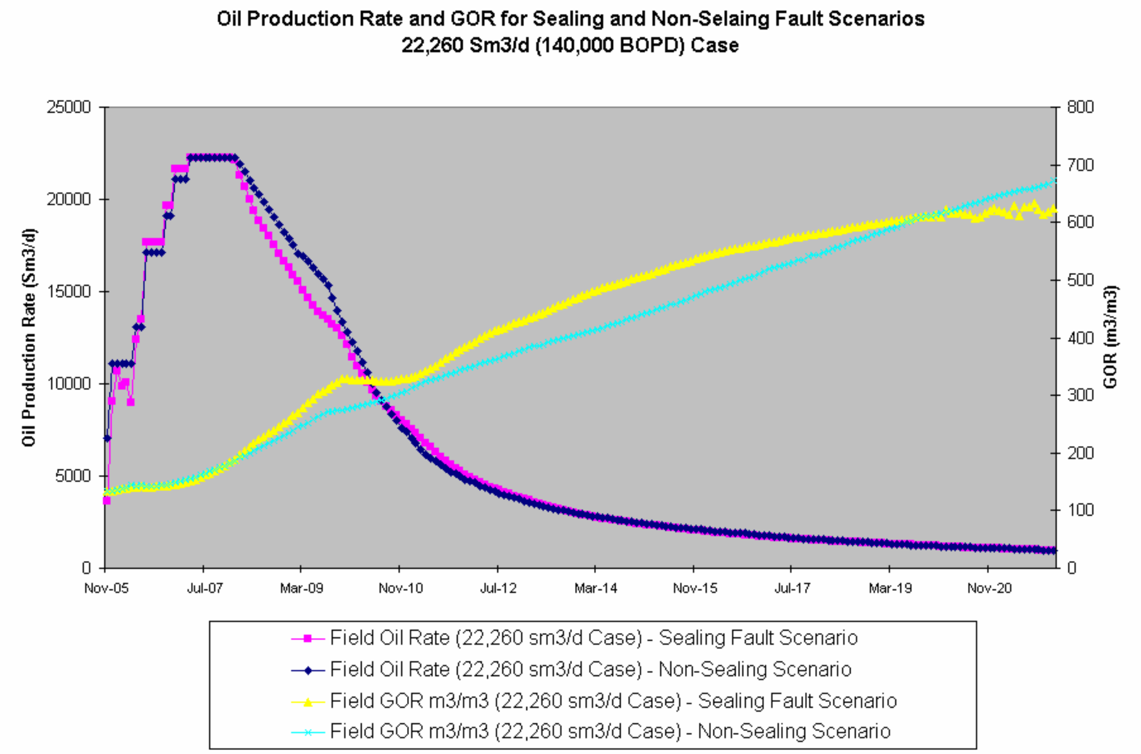


Figure 6.25 Water Production Profiles (Sealing Fault Scenario)

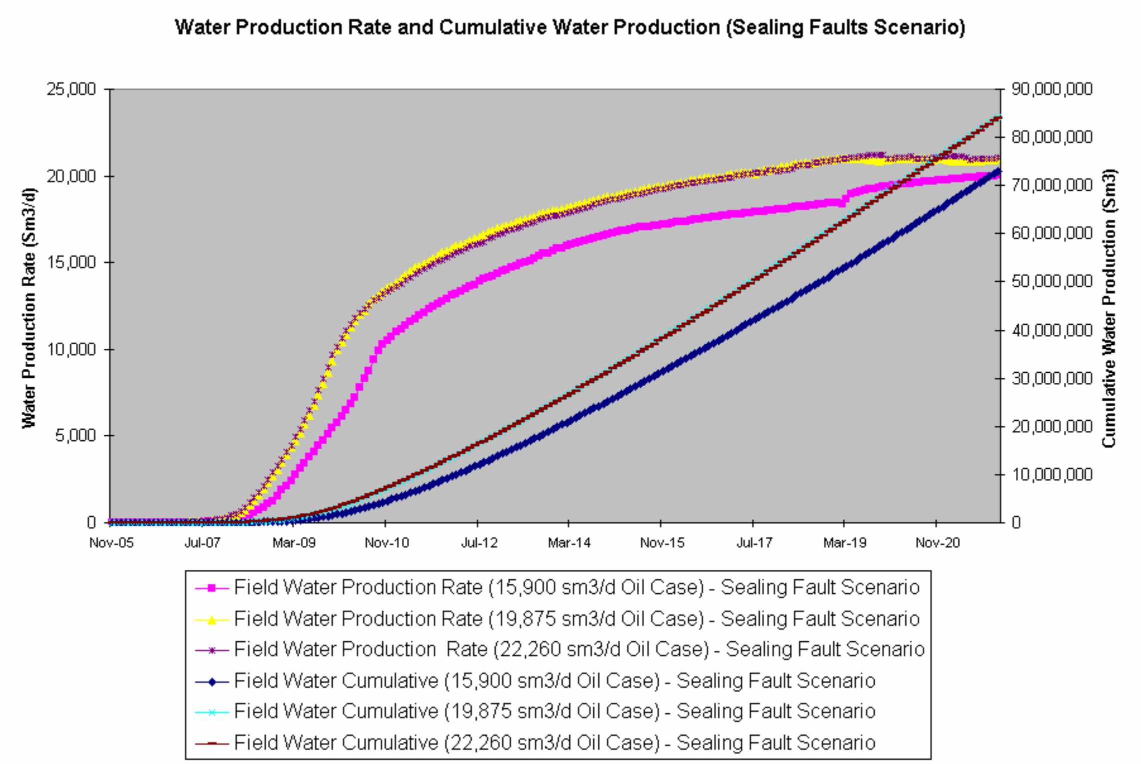
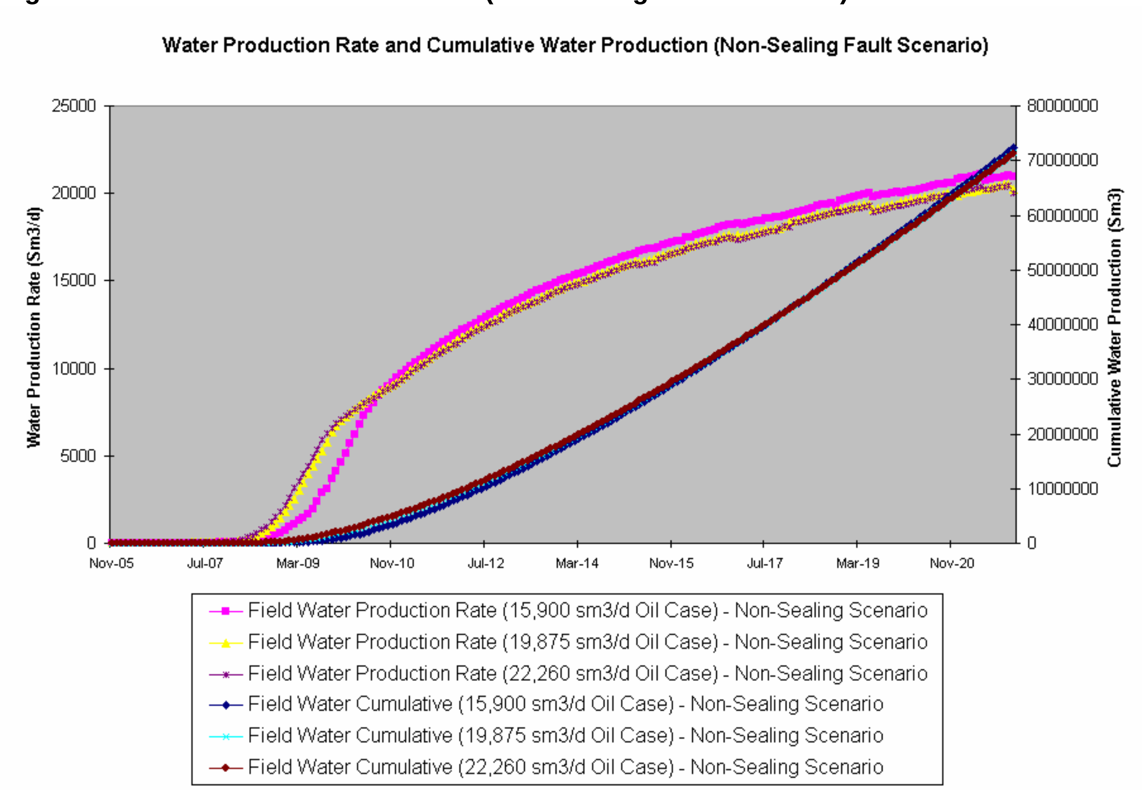


Figure 6.26 Water Production Profiles (Non-Sealing Fault Scenario)



7.0 Certifying Authority Review

The Certifying Authority (CA), Det Norske Veritas (DNV), is engaged to ensure that the information requirements of the CA regarding the safety aspects of the increase in production are adequately addressed to facilitate the timely completion of the approval process. The CA is conducting a review of the modifications required to achieve 22,261 m^3/d (140,000 bbls/d). This will include the modifications to the Quantitative Risk Assessment and the supportive Safety Studies and will be completed in November 2006.

8.0 Safety Plan Revisions

It is recognized that the higher production rate will necessitate an assessment of the FPSO Quantitative Risk Assessment (QRA) model and associated reports. Table 7.1 identifies the study areas that are currently being assessed.

Table 8.1 Study Area Being Assessed

Study Area	Driver for Reassessment
Cargo Pump Room Fire & Explosion Reports	Risks associated with increase in offloading frequency
Vessel Collision Risk Analysis	Increased tanker traffic frequency due to shorter time duration between offloads
Contaminated Inert Gas Vent Dispersion	Higher IG flowrate during production due to increased volumetric displacement rate in storage tanks
FPSO Fire Risk Analysis	Potential increase in spill and pool fire sizes (with existing shutdown valve closure times) and determination of need to evaluate adjustment of ESD system response times.
QRA and Temporary Refuge (TR) Impairment Analysis	These reports are highly dependent on the results of the major hazard design risks (fire, explosion, collision) in the risk model

Husky intends to take this opportunity to undertake a general update of the QRA risk model to reflect more current data sources than were used when the QRA was first developed starting in 2002. Specifically, newer North Sea industry data sources for hydrocarbon release and ignition frequency will be employed.

The White Rose Quantitative Risk Assessment (QRA) and Fire Risk Analysis (FRA) reports were prepared using the results of a risk model developed and refined during the course of the White Rose project. Release modeling aspects of the hydrocarbon risk model were based upon process conditions for isolatable sections of the process plant. These conditions were used to determine initial and decaying release rates and accumulated release volumes, based on successful and unsuccessful isolations (with appropriate frequencies based on historical databases) and other factors.

The most recent issue of the QRA report shows the following selected results, as compared with the Target Levels of Safety established by Husky at the outset of the White Rose project.

	Result	Target	Fraction of Target
Individual Risk per Annum (IRPA) for Process Operator	3.65E-04	1.0E-03	36.5%
Individual Risk per Annum (IRPA) for Marine/Deck Crew	3.20E-04	1.0E-03	32.0%
TR Impairment Frequency	3.20E-04	1.0E-03	32.0%
Impairment of Escape Routes	1.93E-04	1.0E-03	19.3%
Impairment of Evacuation Systems	2.16E-04	1.0E-03	21.6%

It is evident in the above results that there is considerable remaining safety margin within the established Target Levels of Safety (TLS), in the case that values increase due to the reassessment of the QRA and FRA as required for the higher production throughput.

The risk assessments (based on increasing throughput to 22,261 m^3/d (140,000 bbls/d) are currently ongoing and are expected to be completed by the end of October 2006. The FPSO Safety Plan will be updated based on the revised risk assessment, which primarily affects Section 4: Basis of Safe Operations. The Safety Plan update will be carried out in parallel with the Certifying Authority review in November 2006.

9.0 Environmental Effects

The environmental/cumulative effects for the White Rose project documented in the White Rose Environmental Impact Statement (EIS) will not be impacted by the increase in production. All potential effluent streams, i.e. cooling water, bilge water, deck drainage, ballast, produced water would remain as described in the White Rose EIS.

Air emissions are the only effluent stream that has the potential to increase with increased production. The cumulative effects of air emissions will remain as described in the EIS, however, there may be a slight increase quantitatively with increased generator use. This will be reflected in the annual reporting of greenhouse gas emissions to the C-NLOPB required under the Offshore Waste Treatment Guidelines

10.0 Canada-Newfoundland and Labrador Benefits

The proposed Amendment to the White Rose Development 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.

11.0 Acronyms

Term	Description
API RP14	American Petroleum Institute Recommended Procedure 14
barsa	pressure (bars absolute)
barsg	pressure (bars gauge)
bpd	barrels per day
BN	Ben Nevis Formation
BNA	Ben Nevis-Avalon Formation
BOPD	barrels of oil per day
ca	circa (approximately)
Boi	initial oil formation volume factor
BS&W	base sediment and water
CM	cooling medium
Cv	choke coefficient
DA	Development Application
DST	drill stem test
EIS	Environmental Impact Statement
ESD	emergency shutdown
FG	flash gas (a mixture of low pressure gases released from MP & LP Separators
FMDPR	Facility Mean Daily Production Rate
FPSO	Floating Production, Storage and Offloading Facility
GOC	gas oil contact
GOR	gas oil ratio
HAZOP	Hazard and Operability Study
HIPPS	High Integrity Pressure Protection System

Term	Description
HM	heating medium
HP	high pressure
ICSS	Integrated Control and Safety System
IG	inert gas
IMS	Integrity Management System
ISO	International Standards Organization
KOD	Knock out drum
kPa	kilopascal
kPaa	kilopascal absolute
kPad	kilopascal differential
kPag	kilopascal gauge
LAHH	level alarm high high (Trip)
LAL	level alarm low
LALL	level alarm low low (Trip)
LCV	level control valve
LGR	Local-Grid-Refinement
LIAL	low interface alarm level
LP	low pressure
LSHH	level switch high high
mD	millidarcy
M^3/d	cubic metres per day
MMsm3/d	million standard cubic metres per day
MMscf/d	million standard cubic feet per day
MP	medium pressure
MW	megawatts

Term	Description
NILL	normal interface liquid level
NLL	normal liquid level
OWC	oil water contact
PAH	pressure alarm high
PAHH	pressure alarm high high (Trip)
PAL	pressure alarm low
PCV	pressure control valve
PALL	pressure alarm low low (Trip)
PHA	Process Hazard Analysis
PPM	parts per million
Ps	saturation pressure
PSHH	pressure switch high high
PSV	pressure safety valve
PTA	pressure transient analysis
PV	pressure valve
PVT	pressure, nolume, temperature
QRA	Quantitative Risk Assessment
RVP	Reid vapour pressure
Rsi	gas oil ratio
SBC	small bore connection
SIL	Safety Integrity Level
Std. WT	standard wall thickness
SWRX	South White Rose Extension
TCV	temperature control valve
TEG	tri-ethylene glycol

Term	Description
TQ	Technical Query
TVD	true vertical depth
TVDss	true vertical depth subsea
WBHP	well bottom-hole pressure
WHP	well tubing-head pressure
WHRU	waste heat recovery unit
WGOR	well producing gas-oil ratio
WI	water injection
WWCT	well producing water cut