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Paul A. Sacuta, President

April 7, 2010

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

Hibernia Development Project
Development Amendment – January 2010
Request for Additional Information
File 353.2.5
HSCNOPB-2474

Dear Mr. Ruelokke,

On March 10, 2010, the C-NLOPB sent a letter to HMDC requesting clarification or further information on the "Hibernia Development Amendment, Part I and Part II January 2010" that was received by the C-NLOPB on February 1, 2010. In response, the requested information is provided in the document attached (see Attachment 1). Also included with this document are electronic files contained in a CD. A workshop on "Well Management Logic", as requested in the letter of March 10, 2010, will be scheduled in April.

If you have any questions or concerns, please feel free to contact me at 778-7302 or Jamie Long at 778-7567.

Yours truly,

Paul Sacuta
HMDC President

Attachments

cc: E.F. O'Keefe
J.M. Long
Document Control

Attachment 1
Hibernia Development Project
Development Amendment – January 2010
Request for Additional Information

Part II for Public Review

With regards to the Board's opinion that Part II should be made available for public review, we offer the following. We are willing to allow the Petrophysical reports to be made available for the public review, but we would ask that the other reports in Part II be kept confidential. Specifically the reports listed below should be kept confidential:

Hibernia North Sector Compositional Simulation
Hibernia North Sector Gas Flood Model
Hibernia R Block Recovery by Double Displacement
Hibernia Service Life Extension Report
Hibernia Debottlenecking and Expansion Report
GSA Project - Technical Feasibility Expansion Report
Ben Nevis-Avalon Deterministic Volumetric Spreadsheets 2008
Ben Nevis-Avalon Volumetric Maps 2008

These reports contain confidential information and use proprietary software. Thus we respectfully ask that these be kept out of public review, consistent with the intent of Part 2 of the Development Plan Guidelines. If questions arise regarding these reports during the public review, we will address them in an appropriate manner.

The reports that are available for public review are as follows:
Hibernia Field Petrophysical Analysis 2008 BNA
Hibernia Field Petrophysical Analysis 2008 Cape Island
Hibernia Field Petrophysical Analysis 2008 Catalina
Hibernia Field Petrophysical Analysis 2008 Hibernia

Additional Information

Resource Management

1. Please provide in graphical and tabular format (Excel) a forecast of production and injection of oil, water and gas on an annual basis for the life of the field for each well, pool and field, as described in section 3.6 of the Development Plan Guidelines.

This is provided in the CD as an electronic file. The data has been updated to include actual production data through January 2010. The file on the CD is called "Excel_Data_Hibernia_Flowstreams.xls". There are minor differences between this production table and the one submitted with the Hibernia Development Plan Amendment February 1, 2010. This is because when the actual production period volumes are changed, this will change the production volumes available in the prediction period.

2. Please provide in graphical and tabular format (Excel) a forecast of the total gas to be flared, used as fuel and injected on an annual basis for the life of the field, as described in section 3.6 of the Development Plan Guidelines.

This data is also in the CD, in the same file as item 1 under Resource Management ("Excel_Data_Hibernia_Flowstreams.xls"). The data will be in the tab labeled "Gas Injection_English" and "Gas Injection_Metric".

3. Please provide a prediction of the average pressure over each pool that is producing for the life of field, as described in section 3.6 of the Development Plan Guidelines.

This is provided in the CD as an electronic file. The file on the CD is called "Excel_Data_Pressure_Prediction_20100325.xls".

4. Cumulative production statistics for the Hibernia Field is provided up to the end of 2008 throughout this document. Please provide a more up to date review of oil, water and gas production for the Hibernia field (to end of January 2010).

This data is also in the CD, in the same file as item 1 under Resource Management ("Excel_Data_Hibernia_Flowstreams.xls"). The data will be in the tab labeled "Cumulative Production Volumes".

5. Please provide an up to date B Pool Reservoir Structure Map showing existing wells up to the drilling of B-16 37Z.

This map is provided in the CD, in a file titled “Geoscience Maps.ppt”. The specific map is on a page labeled “Resource Management, Item 5”, (page 1).

6. In table 1.3-2 the downside recoverable estimate for the Ben Nevis – Avalon metric and field units are inconsistent. Please clarify which estimate is correct.

In this table the metric units are correct. Here is the corrected table.

	Upside Recoverable		Most Likely Recoverable		Downside Recoverable	
Reservoir	**(Mm3)**	**(MB)**	**(Mm3)**	**(MB)**	**(Mm3)**	**(MB)**
Hibernia B Pool (Non HSE Unit)	152.0	956.3	145.0	911.8	132.7	834.4
Hibernia AA Blocks	11.1	69.8	7.7	48.4	5.9	37.0
Hibernia (HSE Unit)	26.9	169.3	17.1	107.6	10.9	68.3
Ben-Nevis Avalon (Non HSE Unit)	34.6	217.4	17.3	108.5	14.7	92.5
BNA (HSE Unit)	5.1	32.0	4.2	26.7	3.6	22.8
Hibernia A Pool	2.2	14.0	1.3	8.4	0.7	4.1
Catalina	1.1	6.9	0.0	0.0	0.0	0.0
Cape Island	0.1	0.4	0.0	0.0	0.0	0.0
Total	233	1466	193	1211	168	1059

7. In section 2.2.1 the Hibernia Field total oil in place is listed as 600.0 Mm3 (3775 MB) while in other sections of this document it is listed as 576.3 Mm3 (3625 MB). Please clarify which is the correct best estimate.

The 600.0 Mm3 (3775 MB) was a rounded number. The correct number is 576.36 Mm3 (3625 MB).

8. In tables 1.3-1a/1b, 2.2-1a/1b the STOOIP and GIIPsoln / GIPtot for the BNA and BNA HSE are different from those presented in tables 3.4-2c/2d and 3.5-2a/2b and 3.5-4a/4b. Please clarify which estimates are correct.

Tables 1.3-1a/1b and 2.2-1a/1b have an incorrect split of the total BNA between the HSE Unit and the Non HSE Unit. Tables 3.4-2c/2d and 3.5-2a/2b and 3.5-4a/4b have the correct split between HSE Unit and Non HSE Unit STOOIP / GIIP. Corrected Tables 1.3-1a/1b, 2.2-1a/1b are attached (Tables 1.3-1a/1b are identical to Tables 2.2-1a/1b).

Hibernia In-Place Hydrocarbons – Field Units

C-NLOPB Pool	STOOIP (MB)	GIP Gas Cap (GCF)	GIP Solution (GCF)	GIP Total (GCF)
Hibernia B Pool (Non HSE Unit)	1464	466	1970	2436
Hibernia AA Blocks (B Pool)	117	0	119	119
Hibernia (HSE Unit)	261	0	139	139
Ben-Nevis Avalon (Non HSE Unit)	1362	0	728	728
BNA (HSE Unit)	177	0	53	53
Hibernia A Pool	135	111	179	290
Catalina	103	89	65	154
Cape Island	8	0	5	5
Total	**3625**	**666**	**3258**	**3924**

Hibernia In-Place Hydrocarbons – Metric Units

C-NLOPB Pool	STOOIP (Mm3)	GIP Free Gas (Gm3)	GIP Solution (Gm3)	Total GIP (Gm3)
Hibernia B Pool (Non HSE Unit)	232.7	13.2	55.8	69.0
Hibernia AA Blocks (B Pool)	18.6	0.0	3.4	3.4
Hibernia (HSE Unit)	41.5	0.0	3.9	3.9
Ben-Nevis Avalon (Non HSE Unit)	216.5	0.0	20.6	20.6
BNA (HSE Unit)	28.1	0.0	1.5	1.5
Hibernia A Pool	21.4	3.1	5.1	8.2
Catalina	16.3	2.5	1.8	4.3
Cape Island	1.2	0.0	0.1	0.1
Total	**576.3**	**18.8**	**92.2**	**111.0**

9. In section 2.2.1.1.1.2 Hibernia B Pool, Hibernia AA Blocks it is stated that reservoir quality in the AA Blocks is anticipated to be poorer then that observed in the

developed field. Please comment on any lessons learned as a result of drilling the first well pair in the AA Block that supports that statement.

The deeper well (WIAA1-1) exhibited slightly poorer reservoir quality than the OPAA1-1, which in turn, was comparable in reservoir quality to wells drilled at a similar depth. The AA2 Producer injector pair will be drilled this year and we would expect a decrease in porosity as they are slightly deeper. Petrophysics for these wells are included with this document (please see Resource Management, item 20).

10. Section 2.2.1.2 refers to the Hibernia 2006 DPA as being the most recent DPA submission and indicates that wells drilled since that time have been incorporated into pressure plots of the field. In fact, the most recent Hibernia DPA was submitted June 2009 and was subsequently approved. Have wells drilled since the submission of the June 2009 DPA been incorporated into the pressure plots of the field?

Wells drilled since the submission of the June 2009 DPA have been incorporated into the pressure plots of the field.

11. In section 2.1.2.2, the infill drilling opportunities listed in the text on page 25-46 differ from those opportunities highlighted on the map in figure 2.2-1. Also, the areas highlighted on figure 2.2-1 do not correspond with opportunities presented in table 3.2-1a. Please clarify which opportunities are currently being considered and provide an up to date map.

Map Updated. Note there are "Upside Opportunities Not in Schedule" of which there is currently no volumes assigned. "Infill Opportunities" referred to on page 25 were listed as "such as" and was not meant to be all inclusive. For clarity that listing could be removed. This map is provided in the CD, in a file titled "Geoscience Maps.ppt". The specific map is on a page labeled "Resource Management, Item 11", page 2.

12. Please provide details on the flexibility of the planned sub-sea development as described in section 3.9.3 of the Development Plan Guidelines for the HSE Unit particularly addressing potential expansion should drilling and production data indicate possible infill opportunities in the HSE Unit.

There is currently the ability to add one well to the currently planned five subsea water injection wells. Provisions have been made for future expansion that would incorporate other drill centers.

13. Please provide a preliminary drawing of the sub-sea manifold planned for the HSE unit sub-sea development.

Preliminary drawings are provided on the CD, in a file titled “Subsea Manifold.ppt”.

14. The Capital Cost Estimate for the HSE Unit provided in section 2.2.1.9.3 indicates an estimate of $20 million for Well Tie In / Workovers. Does this estimate include possible workovers on sub-sea wells? Is the 'Bottoms-Up' strategy employed in the developed field planned for the HSE Unit including the planned sub-sea water injection wells?

This Capital Cost Estimate does not include any funds for Workovers for subsea wells and none are anticipated over the life of the project. The $20 million for Well Tie In / Workovers is for the platform producing wells. The current strategy for the planned subsea water injection wells currently assumes perforating all of Zone 1 with Zone 2. The strategy for the oil producers is to initially complete in Zone 2, with Zone 1 production added after that.

15. The potential rig schedule presented in figure 3.1-8 appears to be incomplete. Please provide a complete, long-term drilling schedule complete with a legend.

Figure 3.1-8 appears to be incomplete, but in the Most Likely Case there is no forecast drilling after January 2018. However, in the Upside Case there are a number of wells that are on the Drilling Schedule after 2020. These wells are put in this time frame because of slot availability and they have significantly higher uncertainty and / or fewer reserves. The rig Schedule in Figure 3.1-8 is illustrated in Appendix 5, showing the rig shut down period and wells scheduled for drilling after the shut down (but the volumes are not included in the Most Likely production forecast). A legend is also included. An augmented rig schedule is provided on the CD, in an Excel file titled "HiberniaRigSchedule_20100402.xls". This rig schedule is very dynamic and is subject to change as field performance and other factors (such as slot availability) change.

16. In section 3.1.6.4, it is indicated that some slots are anticipated to become available for reclamation in 2009. Please provide details of which slots are now available for reclamation and which slots are anticipated to become available prior to the beginning of the HSE Unit drilling program.

Seven slots 33 (B-16 5), 36, 41 (B-16 60), 45 (B-16 38), 60 (B-16 62), 61 (B-16 56), and 64 (B-16 37), were available for reclamation. There are four wells that are (or will) use some of these slots (WIAA1, OPA2, OPAA2, WIAA2). Slot 64 was used for the WIAA1well (B-16 37z). Slot 61 is currently being used for the OPA2 well (B-16 56). Slot 33 will be used for the OPAA2 well, and WIAA2 will be coming from B-16 42 (slot 26, currently being used by a marginal A pool producer). This leaves four slots (36, 41, 45, and 60) that may be available for reclamation at the start of HSE drilling. Also available for drilling the HSE wells will be slot 62, currently the location of B-16 54w, a suspended NFW. Another slot currently predicted to be available for reclamation is slot 29 (B-16 47), currently a shut in water injection well that was ineffectual in the A pool.

17. Tables 3.1-6a, 3.1-6b, 3.1-8a and 3.1-8b provide Hibernia production data up to the end of 2008 and a forecast thereafter. Please resubmit these tables providing actual data up to the end of January 2010.

This data is also in the CD, in the same file as item 1 under Resource Management ("Excel_Data_Hibernia_Flowstreams.xls"). The data will be in the tab labeled "Tables".

18. In section 3.1.7.5, it indicates that gas lift is being evaluated for installation on the Hibernia platform. Please clarify the status of this project indicating if the implementation of gas lift is still being considered, or if the decision to install gas lift has been confirmed. Please provide an estimated timeline for the implementation of gas lift on the Hibernia platform. Please provide a list of wells currently being considered for retro-fit of gas lift completions.

We have evaluated and confirmed the requirement for the Gas Lift Project and are progressing the project towards funding in order to have the system operational in 2012. Candidate wells will be evaluated and proposed on a case by case basis. A formal presentation is being prepared on the overall functional design basis of the Gas Lift project for review with the C-NLOPB, date in April to be finalized.

19. Table 3.3-1 lists development options being considered for the Hibernia AA Blocks. Given that the recommended option has been accepted, are subsea wells still being considered for the development of the AA Blocks as indicated in this section of the DPA?

Subsea wells were considered as a development option for the Hibernia AA Blocks. However, this is no longer being considered for the AA Blocks.

20. The application refers to the Hibernia Field Petrophysical Analysis 2008, which is a Part II document of this DPA. Please provide a petrophysical analysis of wells drilled since 2008, particularly a petrophysical analysis of the AA Block wells B-16 37Z and B-16 57X as this analysis is of particular relevance.

This data is on the CD, in an Excel spreadsheet called Geoscience.xls. This data is in the tab labeled "20_Hibernia_petrophysics".

21. Although some details were included for various intervals, more information needs to be provided on how the petrophysical summaries were calculated The methodology, assumptions and criteria used in interpreting the data should be documented and provided for each reservoir interval. The following petrophysical data should be submitted for each Hibernia well as supplemental information to the petrophysical summaries: Porosity / Permeability Relationship, water saturation method, cutoffs used for net pay values, cementation exponent, saturation exponent, water salinity and temperature gradient.

A detailed Petrophysical procedures document is attached for Hibernia Fm. This is in the file called 21_Hibernia Field Petrophysical Analysis 2009 Part1.pdf on the CD. Catalina and Cape Island both require additional work as indicated in our plans to hold a

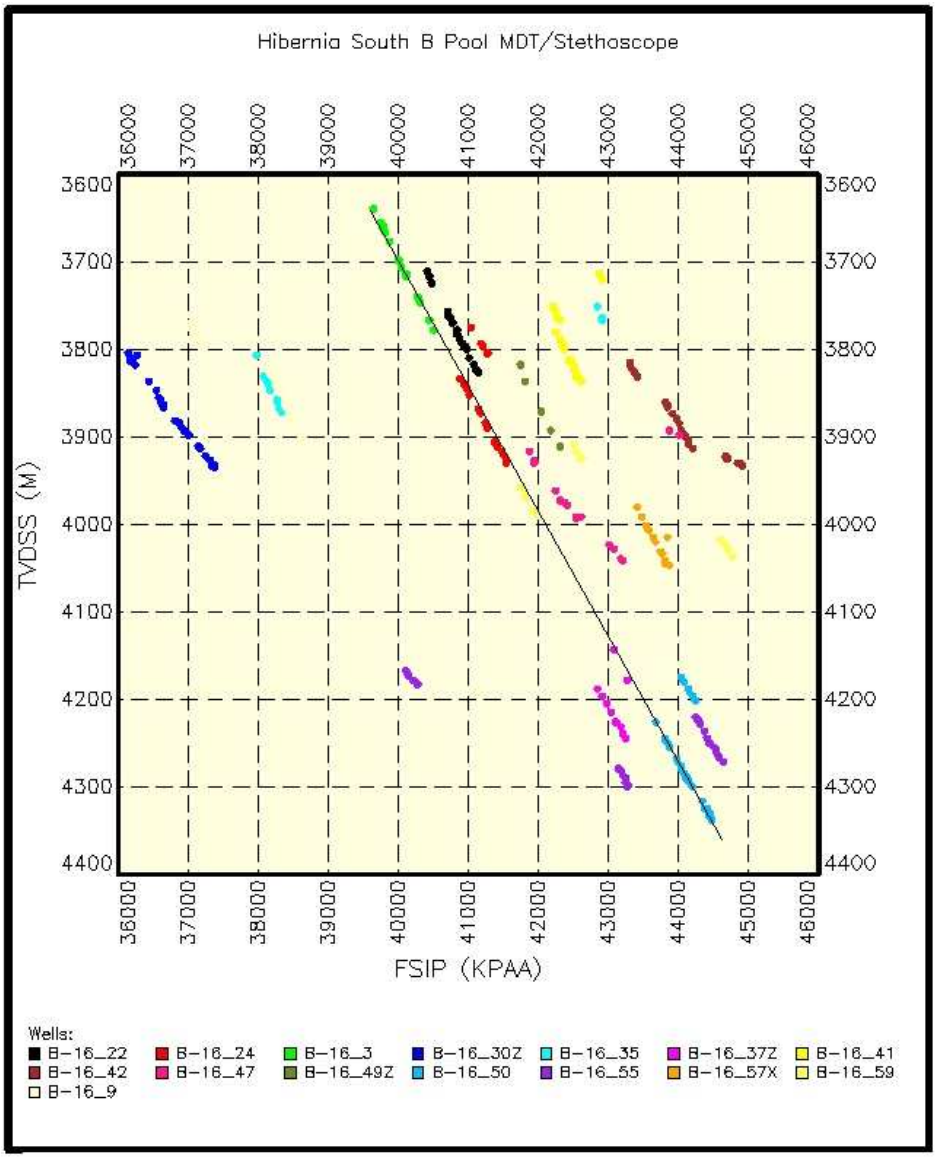
Catalina workshop which will include the issue of thin bed petrophysics. This workshop has been scheduled for April 27.

22. In section 3.1.7.1 B-16 57 is described as being plugged and abandoned while redrill options are being considered. This information is out of date as B-16 57X is now the AA Block producer. Please provide a revised statement with up do date well information.

The statement, "B-16 57 has been temporarily abandoned. Redrill options are being evaluated for this B-16 57" should be revised to, "B-16 57 has been redrilled to the AA1 blocks as oil producer, B-16 57x."

23. Please provide a revised MDT Plot (figure 3.2-12) to include MDT data from the B-16 37Z and B-16 57X wells.

Figure 3.2-12 is revised and included here.



24. A cost estimate for the development of the AA Blocks has been provided. Is there any update to this cost estimate considering that 2 of the 4 development wells in the AA Blocks have been drilled to date?

Table 3.3-4 gives a cost estimate for AA1 and AA2 of $ 196 M CDN. A total of $105.0 M CDN has been spent for the AA1 block development.

25. Please provide a representative set of interpreted seismic sections for the HSE Unit, tied to wells as described in section 3.2 of the Development Plan Guidelines.

The 2009 HSE GeoModel has been reviewed with C-NLOPB and will be provided as a Part 2 Digital file. It includes the complete seismic cube covering HSE.

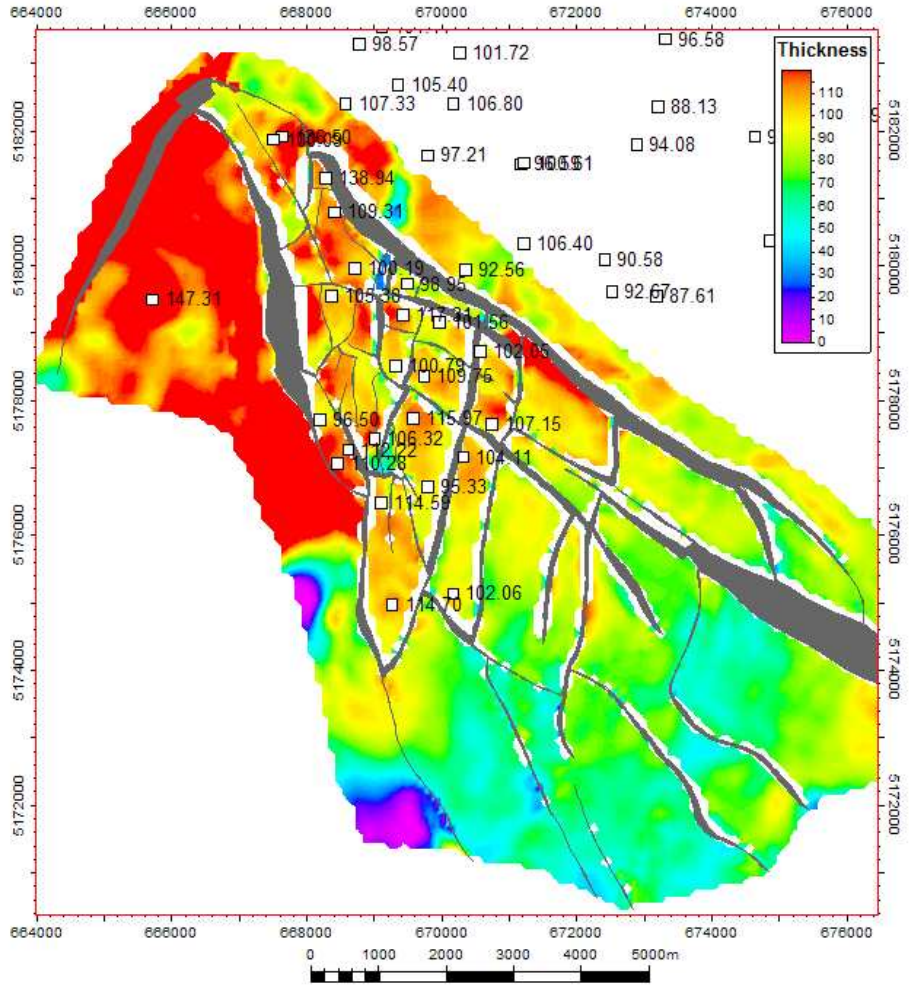
26. Please provide a clear explanation for the current reduction in estimated STOOIP compared to the June 2009 DPA submission. At a meeting with Board staff on February 19, 2010, there was discussion about the impact of possible facies boundaries

and associated reservoir degradation to the southeast. It was also suggested that the reservoir may thin towards the HSE Unit. Please explain and illustrate these two contributing factors and their impact on volume estimates.

The 2009 HSE GeoModel has been reviewed with C-NLOPB and an additional section explaining the change in STOOIP due to layer thinning and revised environments of depositions was reviewed. As discussed in this workshop, in preparation for a Development Plan Amendment for Hibernia, an updated Geological model was constructed for the Hibernia South area including the Hibernia Southern Extension. Modeling techniques were similar to that used in previous models with two notable exceptions for 2009.

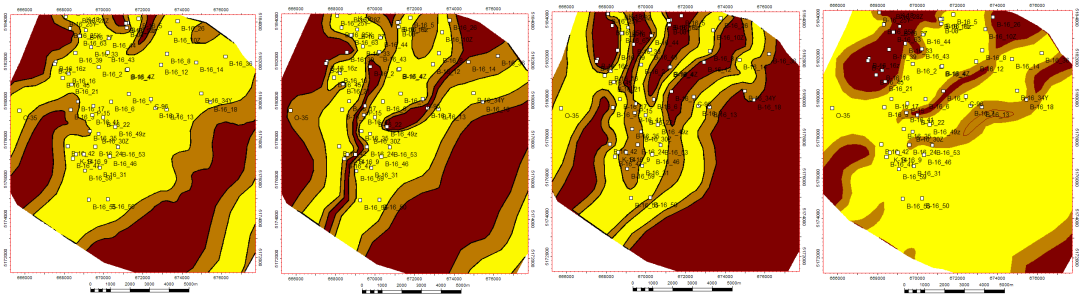
The first revision was an updated thickness map for Hibernia B Pool Zone 2 (Layer 3), Figure 1. The revision results in a thinning of this interval in a southeasterly direction.

Figure 1 - Thickness between Top of Medial Shale and Base Layer 3 Reservoir from 2009 Geological Model

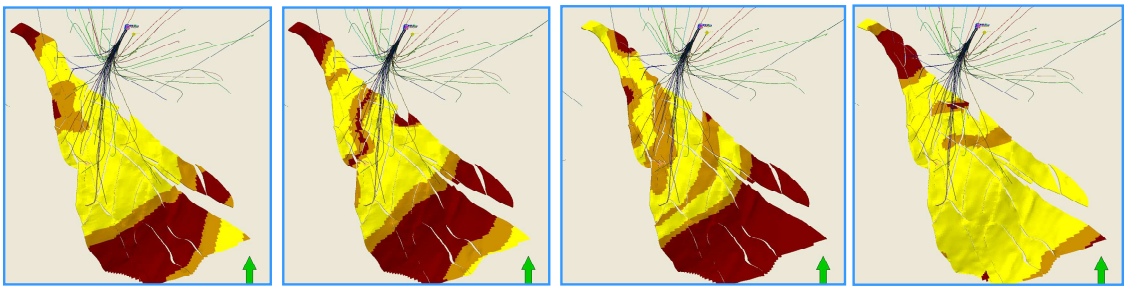


The second revision was a re-interpretation of the extent of the environments of deposition. Based on an implied link between layer thickness and position of channel belt axis, a limit of the good quality channel belt axis facies was shifted northwest to coincide with the thinning trend, Figure 2. The combination of thinner reservoir with poorer quality facies in the southeast resulted in a lower oil volume in the Hibernia Southern Extension Unit area.

Figure 2 - Model EOD for Hibernia South Sector 2009



Layer 3 Lower | Layer 3 Middle | Layer 3 Upper | Layer 2



Yellow = Channel Belt Axis
Lt. Brown = Proximal Channel Belt Axis
Brown = Distal Channel Belt Axis

27. Please provide a discussion of the sensitivity analysis reflecting uncertainty in the data and assumptions on reserve/STOOIP estimates for the HSE Unit. This discussion should include detail on the range of STOOIPS/reserves associated with upside/downside OWC and varying reservoir quality.

A probabilistic assessment is provided with ranges of all inputs for each block. The inputs are in the Geoscience.xls spreadsheet on the CD, in a tab called 27_HSE_GEOX_Inputs. A summary of this assessment is in a document on the CD titled "27_HSE_Prob_Assessment.pdf".

28. Pooling boundaries currently in place (as shown in section 3.2) do not cover the HSE (i.e. PL1005 and EL1093 not covered). Please provide a map with revised pooling boundaries.

This map is provided in the CD, in a file titled "Geoscience Maps.ppt". The specific map is on a page labeled "Pooling Boundaries, Item 28", (page 3).

29. In section 3.5.5.2 information provided on the K Block is inconsistent with information presented when applying to abandon B-16 37 (AWO 8962-H29-100-00 September 2009). Please clarify which development scheme for the BNA K Block is correct.

The reference to the BNA K block is incorrect in paragraph 3 of Section 3.5.5.2. The statement should read "Fault blocks with good reservoir quality and only one recovery factor challenge, such as moderate compartmentalization, thin pay, or high predicted fluid viscosity, are assigned a recovery factor of 18%.

With respect to the BNA K block, the development plans have not changed from the information provided in the B-16 37 abandonment request (AWO 8962-H29-100-00). The remaining reserves will be produced thru the penetration in the B-16 59 wellbore, either concurrently with the CC3 or following abandonment of the CC3. The WIAA2 injection well is being planned as a dual injector with a penetration in the BNA K block. The timing assumed in the flowstreams is a concurrent production scheme beginning in 2012. Technical work to support a concurrent production scheme is ongoing and will be submitted to the C-NLOPB upon completion. Slight differences in ultimate recovery between the DPA and the B-16 37 abandonment request are due to water percent cut off assumptions.

30. Please provide production to date from the A Pool and comment on any lessons learned since the approval of the A Pool depletion plan in January of 2009, given that the A Pool has been perforated in the EE, V and CC blocks.

Production for the A Pool is included in Appendix 1. The A Pool has been perforated in the EE, V, and BB blocks. The production performance to date has been varied. In general, the reservoir continuity is limited and reservoir quality is poor, relative to the Hibernia B Pool.

31. In section 3.6.4.2, it indicates that fluid analysis is not available for B-16 17, yet this analysis is presented on the previous page. Please update table 3.6-2 to include this analysis.

Table 3.2-12 is revised and included here.

	B-27	C-96	P-15	B-16 16	B-16 17
Date	27-Nov-83	8-Jul-84	9-Sep-80	16-Oct-04	10-Mar-08
DST#	7	5	10	n/a	n/a
Sample Type	Bottomhole	Bottomhole	Surface	Surface	Surface
Pool	A1	A4	A3	A1	A3
Depth (TVDss)	3757	3759	3729	3718	3840
Reservoir Temperature (deg C)	95	100.6	97.8	96.5	92
Reservoir Pressure (kPag)	39800	40200	40310	39159	37363
Bubble Point (kPag)	38528	32371	36039	39114	34812
FVF (rm3/sm3)	1.68	1.68	1.65	1.68	1.61
GOR (m3/m3)	247.7	218.2	219.4	242.6	227.5
API Gravity	35.3	33.7	32.3	35.9	35.0
Density at Pb (kg/m3)	623.6	648.2	648.8	640.4	654.8
Viscosity at Pb (mPa s)	0.299	0.396	0.412	0.354	0.327

32. Please provide a discussion of the sensitivity analysis reflecting uncertainty in the data and assumptions on reserve/STOOIP estimates for the Catalina member.

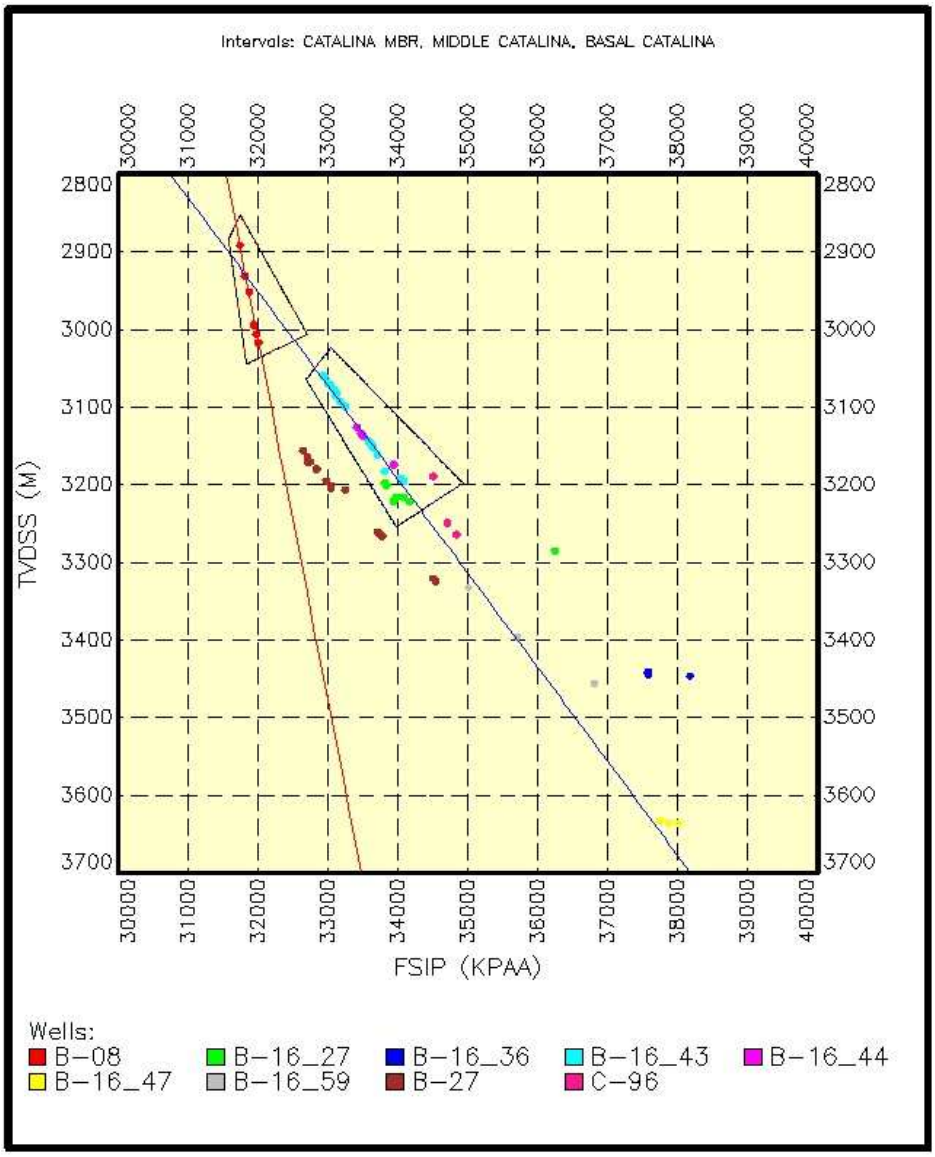
Analysis of the Catalina is challenging with limited well data in a number of wells. Petrophysical cutoffs for the thin bedded reservoir are a major uncertainty given the impact of the thin beds. Also there is limited production data. Thin bed analysis of the Catalina and Cape Island member is part of ongoing work at HMDC. A workshop with the C-NLOPB on the Catalina and Cape Island members is scheduled for April 27.

33. In section 3.7, it is indicated that the Catalina is not anticipated to be commercially productive due to water saturation in the HSE Unit. Please provide the basis for this conclusion.

The petrophysical analysis of the Catalina in the HSE suggests it is water-bearing in the HSE Unit. The Unit agreement however allows inclusion should hydrocarbons be encountered.

34. In section, 3.7.4.2 MDT data from K-18 and B-27 is discussed but not presented in figure 3.7-9. Please provide a revised version of figure 3.7-9 that includes the MDT data from B-27 and K-18.

Figure 3.7-9 is revised and attached. K-18 is not MDT data (as written in section 3.7.4.2, but rather data from a DST). It is therefore not included in the plot.



35. A complete petrophysical summary for all wells with either complete or partial Catalina and Cape Island intervals should be provided. This would include wells with what is referred to in the document as “sporadic” data. Currently, summary data is provided for only 5 wells in the Catalina Member and 27 wells in the Cape Island Member.

Analysis of the Catalina and Cape Island members is challenging with limited well data in a number of wells. Petrophysical cutoffs for the thin bedded reservoir are a major uncertainty given the impact of the thin beds. Also there is limited production data. Thin bed analysis of the Catalina and Cape Island member is part of ongoing work at HMDC. A workshop with the C-NLOPB on the Catalina and Cape Island members is scheduled for April 27.

36. In section 3.8.5.1, STOOIP is presented for the Cape Island Member by well penetration. Please provide a STOOIP analysis for the Cape Island Member for all prospective fault blocks/areas. Also, please clarify whether the 200,000 m3 drainage area allotted to each well penetration results in any overlapping in the reserve calculation.

As indicated in the discussion of petrophysics (question 35), the uncertainty with cutoff etc. for such thin beds is challenging. We have only assigned STOOIP to those blocks with well penetrations, as interpolating a zone this thin across large areas would be very speculative.

37. Section 3.8.5.1 references use of the A Pool simulation model to evaluate the Cape Island member, however, section 3.6.4 states that no simulation models have been constructed specifically for the Hibernia A Pool. Please clarify if an A Pool simulation model exists and is being used to evaluate the A Pool.

A field wide simulation model for the A pool does not exist. In certain sector models, namely the North and the South-West Models, the A Pool was included as part of the initial model builds. However it was recognized at the time that property modeling within the A Pool was highly uncertain. There has been limited use to date of the A Pool sector models in evaluation of the A Pool, with the exception of the V Block. A Pool simulation work that was conducted to justify the sidetrack of the B-16 21 wellbore.

38. Please provide hydrocarbon pore volume maps or isoporosity maps for the B Pool, A Pool, Cape Island and Catalina units, and net pay maps for the Cape Island and Catalina units.

Details for the B Pool included in Petrel GeoModel will be forwarded to C-NLOPB. This submission will be under a separate cover letter in April. A Pool, Cape Island, and Catalina still remain outstanding to be discussed at the workshop on April 27.

39. In 2008, HMDC submitted a full field Petrel project to the Board that contains petrophysical log analysis and structural information but is limited over the Cape Island and Catalina members. Please provide an updated project including all geological/petrophysical analysis for the Cape Island and Catalina members.

Analysis of the Catalina and Cape Island members is challenging with limited well data in a number of wells. Petrophysical cutoffs for the thin bedded reservoir are a major uncertainty. Issues of modeling and petrophysical analysis will be discussed at the workshop on April 27.

40. The application indicates that there is no STOOIP for the Cape Island member with the HSE Unit area. Please provide an explanation of the basis for this assessment.

With no well penetrations to date we do not predict any STOOIP in the Cape Island in the HSE Unit. To date the uncertainty due to the thin Cape Island reservoir has resulted in only assigning net pay to blocks that have a well penetration that has possible pay.

41. This application indicates that more evaluation of the Cape Island member is necessary. How does HMDC plan on carrying out this evaluation?

Thin bed analysis of the Catalina and Cape Island member is part of ongoing work at HMDC.

42. Please provide a discussion of the sensitivity analysis reflecting uncertainty in the data and assumptions on reserve/STOOIP estimates for the Cape Island member.

Analysis of the Cape Island member is challenging with limited well data in a number of wells. Petrophysical cutoffs for the thin bedded reservoir are a major uncertainty. There is limited production data. Thin bed analysis of the Cape Island member is part of ongoing work at HMDC.

Safety

1. Section 3.1.8.2 references the repealed Production and Conservation Regulations and the repealed Drilling Regulations. The Drilling and Production regulations, which came into force on December 31, 2009, should be referenced.

Noted. HMDC will ensure that new Drilling and Production Regulations are referenced, where appropriate, in project documentation

2. With regards to the proposal for water injection wells in the subsea templates, rules, codes, standards and specifications to be used for the design, construction, installation, operation and maintenance of these wells, above what is required for surface wells, has not been identified in the submission. In addition, any implications from the application of standards that are different from those specified in the regulations should be considered at this point.

The Project will be designed to be in compliance with the regulations. The HMDC Projects group has produced a document that specifies the regulatory compliance for the project. We can supply a copy to the C-NLOPB, if required. No exceptions to regulations are anticipated at this time. However, if exceptions do occur they will be subject to the RQF process that will demonstrate adherence to an equivalent level of safety.

3. There is mention of the potential to have production wells in the subsea templates, however, the effects of this impact has not been described in the application. In order for the Board to assess the impact of subsea production wells the following information should be provided:

- The functional design basis as per Section 3.9.2 of the Development Plan Guidelines.

The DPA indicates the potential to have subsea production wells in other future subsea tie backs. The subsea component of the HSE project will be for water injection wells only. A functional design specification will be developed for any future development that may include production as well as injection wells.

- Rules, codes, standards and specifications to be used for the design, construction, installation, operation and maintenance of production wells from the subsea templates and associated other equipment changes to the platform.

A project design basis will be developed for any future development that may include production as well as injection wells.

- The impacts of this change on the Concept Safety Analysis, Safety Plan, as well as impacts on procedures and training.

The CSA for the first of the subsea tie back projects, the Hibernia Southern Extension, will be completed during FEED (mid 2010). A copy of this CSA can be made available to the C-NLOPB at that time. The results of the CSA will be used to update the QRA which will in turn be used to update the Operational Plan and associated Safety Case. While the CSA is intended to cover other future subsea tie backs that may include production wells, it is not possible to revise the CSA without a design concept for such an installation. Each future subsea project will undergo separate reviews to determine the effect of any new equipment on the Hibernia risk profile and impact on the Operational Plan and include any recommendations to reduce risk to As Low As Reasonably Practicable (ALARP).

4. There is mention of the potential installation of a gas lift system on the installation, however, the effects of this impact has not been described in the application. In order for the Board to assess the impact of a gas lift system on the installation the following information should be provided:

- The functional design basis for gas lift systems as per Section 3.9.2 of the Development Plan Guidelines.

Gas Lift is a Hibernia project that has recently completed the define stage. A formal presentation is being prepared on the overall functional design basis of the Gas Lift project for review with the C-NLOPB, date in April to be finalized. The facilities scope of work will dehydrate a portion of the gas from the 3rd stage compressor discharge using tri ethylene glycol and will be distribute through new manifolds. Candidate wells will be evaluated on a case by case basis.

- Rules, codes, standards and specifications to be used for the design, construction, installation, operation and maintenance of gas lift and associated other equipment changes to the platform.

References to applicable codes, standards and specifications are documented in the "Gas Lift Project Design Basis" and project specifications, including gas dehydration. Copies can be provided, if required. An overview of project scope has been reviewed with the CA.

- The impacts of this change on the Concept Safety Analysis, Safety Plan, as well as impacts on procedures and training.

An independent "Hibernia Gas Lift Project Concept Safety Evaluation (CSE)" report is being prepared to consider the overall effect of the new equipment on the Hibernia Risk profile and impact on section 4 of the Operational Plan. When completed, this will be reviewed with the CA and C-NLOPB, currently targeting before the end of May. Any procedural changes/updates and training requirements are project deliverables prior to start-up and hand-over to operations.

5. Although the current application discusses the construction and installation of subsea templates and the impacts on equipment, procedures and training on the Hibernia Platform, there is very little information provided on the impact of the addition of a MODU for subsea drilling activities and future workover and intervention activities on the subsea wells. The following information has not been provided:

- A functional description of the planned MODU for development drilling and its expected capabilities, including a description of well control and safety systems for drilling.

The process of securing a MODU for HSE is currently under review. A harsh weather semi-submersible drilling unit, suitably designed and rated for operation in the Grand Banks region, is envisioned as the vessel of choice.

Station Keeping

Station-keeping is expected to be accomplished via mooring lines, with type and quantity to be confirmed upon final vessel selection. A Mooring analysis will be completed with appropriate metocean criteria to ensure the Drilling Unit has adequate station-keeping capabilities for the proposed environment.

Well Control Systems

The Drilling Unit shall be equipped with a subsea BOP stack mounted on the subsea wellhead, a Lower Marine Riser Package (LMRP), Marine Riser, a diverter system, and auxiliary equipment.

The BOP stack shall include ram and annular style closing mechanisms. Subsea BOP stacks typically contain four to six ram blowout preventers and two annular blowout preventers. There is no single acceptable BOP stack arrangement, but there are operating characteristics to consider in the stack arrangement for the particular drilling program. Final selection of the BOP configuration will be a function of well design and operating characteristics of the selected drilling unit. Working pressure, required kick tolerances, gas hydrates, trapped gas, testing requirements, stripping and hangoff requirements, pipe shear requirements, elastomer service conditions and temperature limits all have input on the final selection of the BOP configuration.

It is anticipated the upper hole sections will be drilled riserless with water based drilling fluids. A Marine Drilling Riser shall be employed during the drilling of the lower hole sections. The Riser serves as the conduit to attach the rig vessel to the BOP stack and wellhead on the seabed, and is used to convey drilling fluid and cuttings from the wellhead to the rig. The riser is also used to transport the BOP to and from the wellhead and serves as an attachment point for auxiliary piping and umbilicals. A riser analysis shall be used in the selection of the riser arrangement (i.e., buoyant joints/slick joints) and in developing the tensioning plan as a function of mud weight and water depth. The analysis work is interfaced with the mooring analysis to establish vessel offset conditions.

A diverter system shall be installed whenever the Marine Riser assembly is in operation. The diverter system serves to direct well flow safely away from the drill floor and drilling unit. The diverter can be used as a primary well control system or as a secondary system. When used as the primary well control system, the objective of a diverter system is to control the path of the flow safely while minimizing the backpressure build up so shallow formations are not fractured. When used as a secondary well control system, the diverter is used to redirect any fluids that might have inadvertently worked its way into the riser when the subsea BOPs were used to shut in a well.

Several auxiliary systems shall be employed to support the main systems. A choke and kill manifold shall serve to direct well fluids to/from the wellbore as needed to maintain an appropriate hydrostatic column. A trip tank system shall be employed to assist in monitoring hole volumes into/out of the wellbore. An atmospheric ("poor-boy") mud gas separator (degasser) system will be employed in the well control system to separate entrained gas returning in the well fluids. Mud Control monitoring systems shall be utilized to measure fluid volumes stored in the drilling units storage tanks (pits).

- A description of the additional training and procedures that will be applied for subsea development drilling activities, especially as it relates to additional training and/or resources for onshore drilling/marine personnel and offshore supervisory personnel onboard the Hibernia Platform.

All ExxonMobil and contract supervisory personnel associated with subsea Drilling operations will have received appropriate training in subsea operations, specifically Subsea Well Control. Suitably trained and experienced personnel will be specifically assigned to the drilling unit. Supervision of the subsea drilling unit will be performed directly from the drilling unit, separate from Platform Drilling operations.

Contractor personnel employed on the subsea drilling unit will be reviewed and approved for subsea operations prior to deployment to the drilling unit. Transfer of personnel from the Hibernia Platform to the subsea drilling unit will only occur after verification of training suitable for floating drilling environments.

- A description of plans for future workover and intervention activities on the subsea wells and procedures, training and equipment that will be applied.

It is currently envisioned the subsea wells will be initially drilled and completed to minimize future well intervention activity. Should well intervention become necessary during the life of the well (equipment repair, reservoir monitoring) a suitably rated vessel will be employed to execute the well intervention program depending upon the magnitude and extent of the scope of work. Vessels may range from a fully fitted semi-submersible drilling unit (large scopes) to a Light Well Intervention Vessel (minimum scopes). Training and equipment will be applied based on the services to be executed at the time of execution. As a minimum, all supervisory personnel will be suitably trained in subsea Well Control activities, specifically Intervention activities, should a Light Well Intervention Vessel be required.

- Functional design basis for drilling systems for subsea wells, as per Section 3.9.2 of the Development Plan Guidelines.

Section 3.9.2 of the Development Plan Guidelines is associated with Topsides mounted Drilling Units. For the subsea portion of the Hibernia Southern Extension Project, a harsh weather semi-submersible drilling unit, suitably designed and rated for operation in the Grand Banks region, is envisioned as the vessel of choice (as described above).

- Functional design basis for workover/intervention systems for subsea wells, as per Section 3.9.2 of the Development Plan Guidelines.

Section 3.9.2 of the Development Plan Guidelines is associated with Topsides mounted Drilling/Intervention Units. For the subsea portion of the Hibernia Southern Extension Project, a harsh weather semi-submersible drilling unit or Light Well Intervention Vessel, suitably designed and rated for operation in the Grand Banks region, is envisioned as the vessel of choice (as described above).

6. Section 3.10 of the Development Plan Guidelines requires confirmation that a Safety Plan be submitted with each application for any project construction, or any installation activity or group of activities, as appropriate, which takes place within the jurisdiction of the Board. The application does not specify if the current Safety Plan (i.e., the Hibernia Operational Plan), will be expanded to incorporate all construction and drilling, workover and intervention activities with a MODU or if a separate Safety Plan, or plans, will be submitted.

In general, a project-specific Safety Plan and appropriate Bridging documents will be developed for each construction and installation program associated with the installation of subsea facilities in the Hibernia field. At this point, HMDC foresees the development of separate safety plans for the Excavated Drill Centre program and the subsea facilities

installation program. HMDC intends to revise the Hibernia Operational Plan to include MODU drilling and intervention operations and subsea producing operations in addition to current platform drilling and producing operations.

7. The submission does not provide sufficient commitment and information on the planned review and update of the Ice Management Plan, Emergency Response Plan, Collision Avoidance Plans, and the configuration of standby vessels especially in the context that a MODU will be on the field from the period of 2013 – 2015. The submission reflects that these documents will be reviewed and updated from the perspective of the addition of subsea templates and subsea wells, but does not describe the plans for updating these documents to reflect that two installations will be on the field at the same time. In reviewing this, consideration also needs to be given to future workover and intervention activities.

HMDC will undertake a complete review of all contingency plans as well as its support vessel configuration as part of its review of the Hibernia Operations Plan. This updated Hibernia Operations Plan will address future installation activities, drilling activities, and possible intervention activities. An updated Plan reflecting the results of this review will be submitted to the C-NLOPB as part of HMDC's application for the requisite Operations Authorization covering all Hibernia drilling and operations activities post expiry of the existing Hibernia Operations Authorization in 2012.

8. Section 3.11 of the Development Plan Guidelines requires an overview of the operations and maintenance procedures, including system descriptions, operating procedures, inspection and maintenance procedures, safety procedures and equipment, etc. The application states that operating and maintenance procedures will be revised, however, there is no commitment provided of revisions or development of “system descriptions” for the new subsea systems which should describe the equipment, diagrams, drawings, equipment limitations for the particular equipment that is installed. The plans in this regard has not been provided.

Section 2.2.1.8 of the DPA indicates that accurate, up-to-date, risk classified Operating and Maintenance (O&M) procedures are required for the Competency Assurance Standard. All O&M procedures will be revised to incorporate the requirements to operate and maintain new subsea facilities.

Operating System Manuals (OSM's – system descriptions) will be developed for any new systems required for the HSE project, such as subsea systems and Methanol. OSM’s will be revised for any current systems that are impacted by modifications performed by the project.

9. As per Section 4.1 of the Development Plan Guidelines, please provide an updated Concept Safety Analysis for review.

HMDC intends to update the existing Hibernia Concept Safety Analysis (CSA) during FEED. When completed, the updated CSA will be submitted to the C-NLOPB. This is scheduled to be the middle of 2010.

10. As per Section 3.14 of the Development Plan Guidelines, a description of all studies, analysis and evaluations that will be reviewed and/or conducted as part of this amendment has not been described. Please provide a list of any safety or production system studies that will be reviewed, such as fire and explosion studies.

A review was conducted of all existing Hibernia safety studies to determine which would be impacted by the HSE project.
The Quantitative Risk Assessment will be updated to include:
- Methanol Hazards
- Increased probability of events from addition of wells
- Dropped objects

A fire and blast study will be performed to examine any effect on explosion vent paths due to the addition of topsides equipment. The results of these studies and the updated QRA will be presented in the revised Hibernia Operations Plan.

11. As per Section 4.1 of the Development Plan Guidelines, the Development Plan Application does not discuss the risk assessments that will be conducted for development drilling and future workover and intervention activities and how the results of these assessments will be incorporated into plans for equipment, personnel and procedures.

Risk Assessments shall be executed prior to start-up of subsea drilling operations according to ExxonMobil's Operations Integrity Management Systems (OIMS).

A general Drilling Risk Assessment shall be executed based on the marine and well operations anticipated for the life of the drilling program. Generic Risk Assessment Templates have been generated and common risk scenarios evaluated for the various drilling environments. Drilling Program assessments for individual wells or regional combination of wells use these generic templates as a starting point with additional scenarios being added/upgraded or scenarios being removed where not applicable. The outcome of this is a Risk Assessment Report that captures identified scenarios, anticipated Risk Levels, and all necessary mitigations and follow-up actions required to be closed before the start of the Drilling Program.

During the life of the Drilling Program, unforeseen procedures or circumstances not originally covered in the initial General Drilling Risk Assessment may arise. These situations shall be reviewed with an Incremental Risk Assessment. All changes during the well planning process subsequent to completion of a risk assessment are evaluated. A revised Risk Assessment Report may be issued to reflect those changes and mitigation or additional action plans.

Mitigations deemed necessary to manage the Risk associated with specific operations shall be incorporated into necessary operational procedures, equipment specifications,

and personnel requirements. Operations identified as requiring mitigations shall not be initiated until all follow-up actions have been closed or mitigations established.

A specific Risk Assessment shall be executed prior to commencing subsea workovers / interventions. The outcome of this is a Risk Assessment Report that captures identified scenarios, anticipated Risk Levels, and all necessary mitigations and follow-up actions required to be closed before the start of the workover / intervention program.

If during the intervention, unforeseen procedures or circumstances not originally covered in the initial Risk Assessment arise, these situations shall be reviewed with an Incremental Risk Assessment. All changes during the intervention process subsequent to completion of a risk assessment are evaluated. A revised Risk Assessment Report may be issued to reflect those changes and mitigation or additional action plans.

Mitigations deemed necessary to manage the Risk associated with specific wellwork operations shall be incorporated into necessary operational procedures, equipment specifications, and personnel requirements. Operations identified as requiring mitigations shall not be initiated until all follow-up actions have been closed or mitigations established.

12. The Development Plan Application does not discuss the involvement the Certifying Authority will have in installation and development drilling activities, as per Section 4.3 of the Development Plan Guidelines.

Section 3.1.8.7 indicates that the Certifying Authority (CA) will provide certification for all subsea and topsides tie-back project activities (design, fabrication, and commissioning) to support the Hibernia Platform Certificate of Fitness requirements. All activities include installation and drilling.

The CA, Lloyds Register, has already been engaged for the project.

Environment

1. Information should be provided to show the maximum forecast produced water production and marine discharge falls within the limits described in the produced water environmental assessment performed in satisfaction of Condition 2003.01.03(i).

The produced water environmental assessment performed by HMDC in response to Condition 2003.01.03(i) concluded that the impact predictions described in the original Hibernia EIS did not change with increased produced water discharge rates up to 40,000 cubic meters per day. Going forward, Hibernia may request Approval from the C-NLOPB for an increase in the allowable daily discharge volume to better optimize oil production. HMDC's current forecast of produced water discharge rates is up to 26,000 cubic meters per day (Appendix 1).