Husky Energy

White Rose Extension Project

Environmental Assessment

December 2012

Husky Energy SUNCOR ENERGY nalcor energy

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1.0 INTRODUCTION

Husky Oil Operations Limited (Husky), on behalf of the White Rose Extension Project (WREP) proponents, Husky, Suncor Energy Inc. (Suncor) and Nalcor Energy – Oil and Gas Inc. (Nalcor), is leading the development of the WREP. The current focus of the WREP is on the development of West White Rose pool, delineated in 2006. Husky and its co-venturers are considering two development options for the WREP: a wellhead platform (WHP) development option (Figure 1-1) or a subsea drill centre development option. Both development options will be tied back to the existing *SeaRose* floating production, storage and offloading (*FPSO*) vessel. Future development opportunities for the WREP will be evaluated by Husky and its co-venturers.

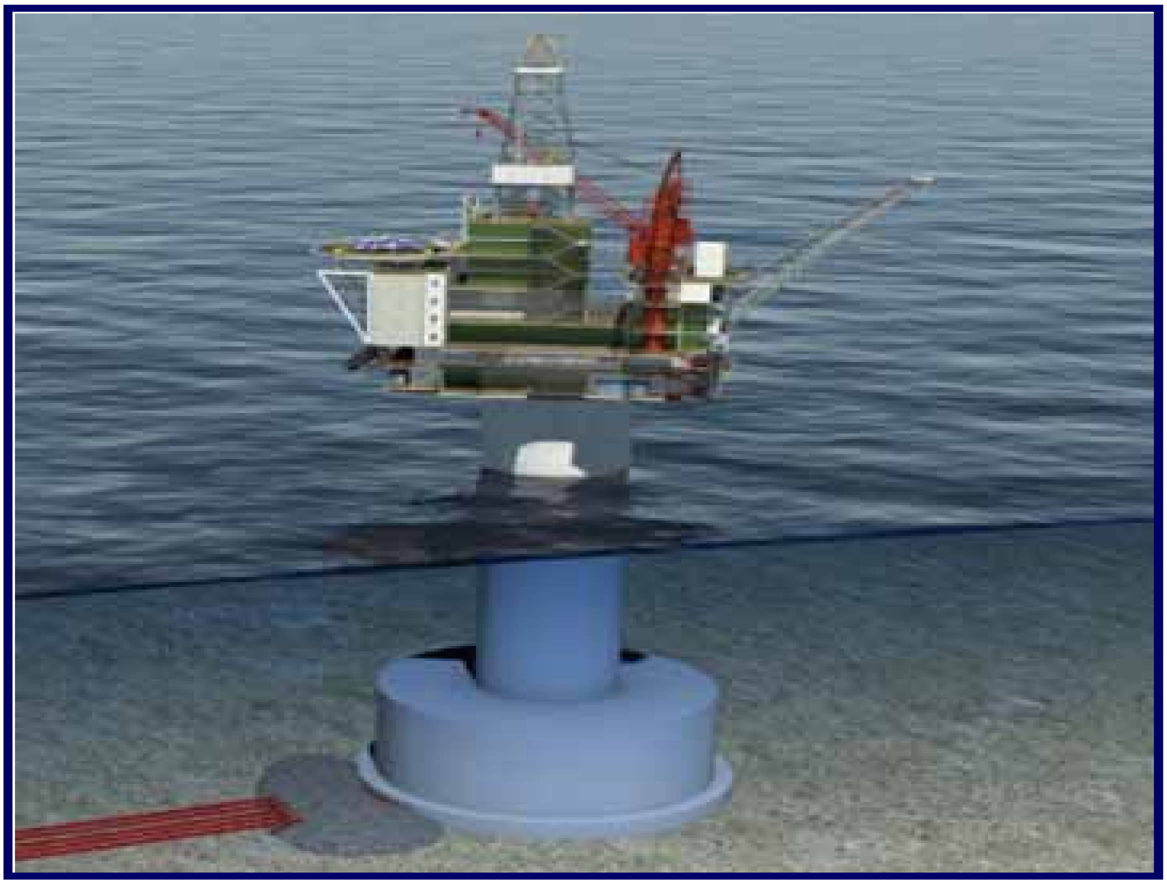

Figure 1-1 Typical Wellhead Platform

The White Rose field and satellite extensions are located in the Jeanne d'Arc Basin, 350 km east of Newfoundland and Labrador in approximately 120 m of water (Figure 1-2). Initial development was through excavated subsea drill centres, with flexible flowlines bringing product to a centralized floating platform, the *SeaRose FPSO*. The White Rose field was originally developed using subsea wells in two subsea drill centres; the Central Drill Centre (CDC) and the Southern Drill Centre (SDC). A third drill centre, the Northern Drill Centre (NDC), was subsequently used as an injection site for gas stored for future use.

Figure 1-1 Location of the White Rose Field

First oil from the White Rose field was produced in November 2005. In 2006, delineation and exploration drilling identified additional resources at North Amethyst and West White Rose. The WREP is wholly contained within the White Rose field.

In May 2010, production commenced from North Amethyst, the first of a number of potential subsea tie-ins to the main White Rose field (Figure 1-3). The Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) approved the Development Application with the release of Decision Report 2008.03. Similar to White Rose, North Amethyst was developed using subsea wells in an excavated subsea drill centre, the North Amethyst Drill Centre (NADC), tied back to the *SeaRose FPSO* for production, storage and export to tanker.

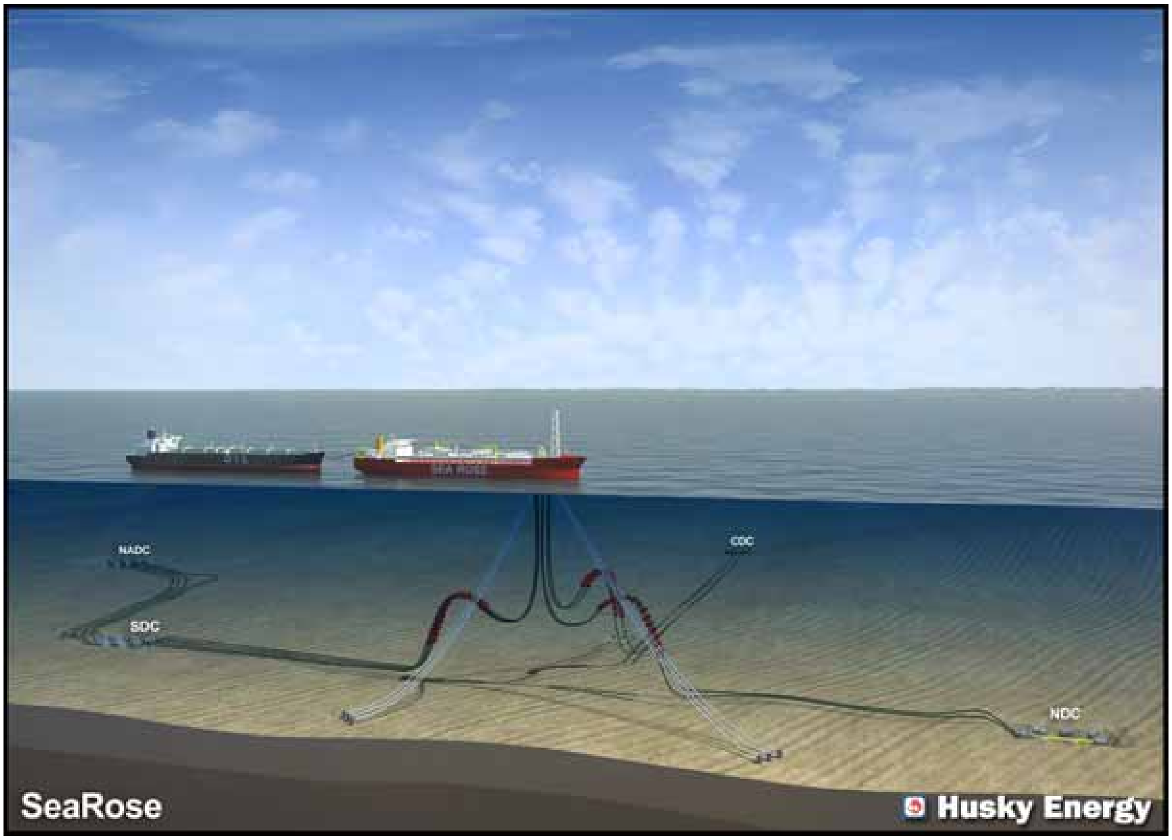

Figure 1-2 Existing White Rose Field Layout

The original White Rose field underwent an environmental assessment in 2000 pursuant to the *Canadian Environmental Assessment Act* (the CEAA) (S.C. 1992, c. 37) as a comprehensive study (Husky Oil 2000). In 2007, a further environmental assessment was undertaken on activities associated with construction of up to five additional subsea drill centres and associated flowlines under *Husky White Rose Development Project: New Drill Centre Construction and Operations Program Environmental Assessment Addendum* (LGL 2007a). The environmental assessment (including the addendum and supporting documents) was released from the CEAA process with the Environmental Assessment Determination issued on May 25, 2007. These previous environmental assessments encompassed the location of the subsea tiebacks proposed herein, as well as the way in which the construction and operation activities would be performed. Therefore, the description of the WREP (Chapter 2) focuses mainly on the WHP development option, which has not been previously assessed. The environmental effects analysis considers both development options.

The WHP development option is the only option with an onshore/nearshore component, located on the Argentia Peninsula in Placentia Bay. There have been numerous environmental assessments for various projects at Argentia, including a proposed hydromet facility on the Argentia Peninsula (Voisey's Bay Nickel Company (VBNC) 2002). Other assessments for projects within Placentia Bay include Newfoundland Transshipment Limited (NTL) (1996), Jacques Whitford Environment Limited (JWEL) (1997, 1998), Newfoundland and Labrador Refining Corporation (2007), Newfoundland LNG Ltd. (2008) and Vale Inco (2008).

1.1 White Rose Extension Project Areas

The WREP will be located offshore in the White Rose field, in the extension known as the West White Rose pool. If the WHP development option is selected, there will also be a nearshore component to the WREP.

1.1.1 Nearshore Project Area

Construction of the WHP will occur on the Argentia Peninsula, which is located in Placentia Bay, on the southern Avalon Peninsula, 130 km south west of St. John's, NL (Figure 1-4). The activities include excavation and construction of a graving dock, construction of a concrete gravity structure (CGS) and mating of a topsides component to the CGS at a deep-water mating site in Placentia Bay. The Nearshore Project Area is illustrated in Figure 1-5.

1.1.2 Offshore Project Area

Both the WHP and subsea drill centre development options will be installed within the previously assessed White Rose Field (Figure 1-6).

1.2 White Rose Extension Project Proponents

Ownership interests in the White Rose field are held by Husky (72.5 percent) and Suncor (27.5 percent). In 2007, Husky entered into an agreement with the Province of Newfoundland and Labrador, in which the province, through Nalcor, acquired a 5 percent equity interest in West White Rose extension; of the remaining equity, Husky owns 68.875 percent and Suncor 26.125 percent.

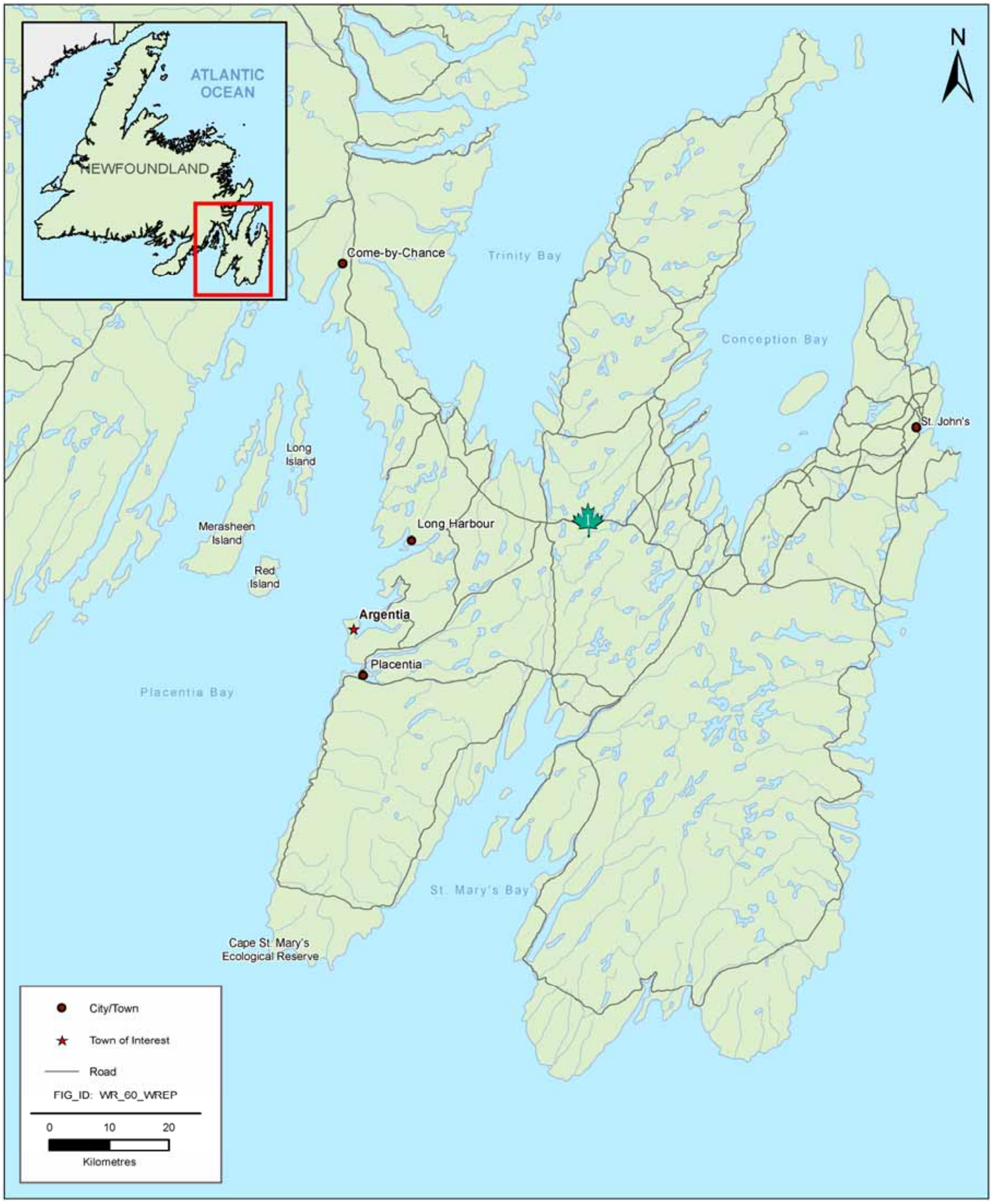

Figure 1-3 Location of Argentia, Newfoundland and Labrador

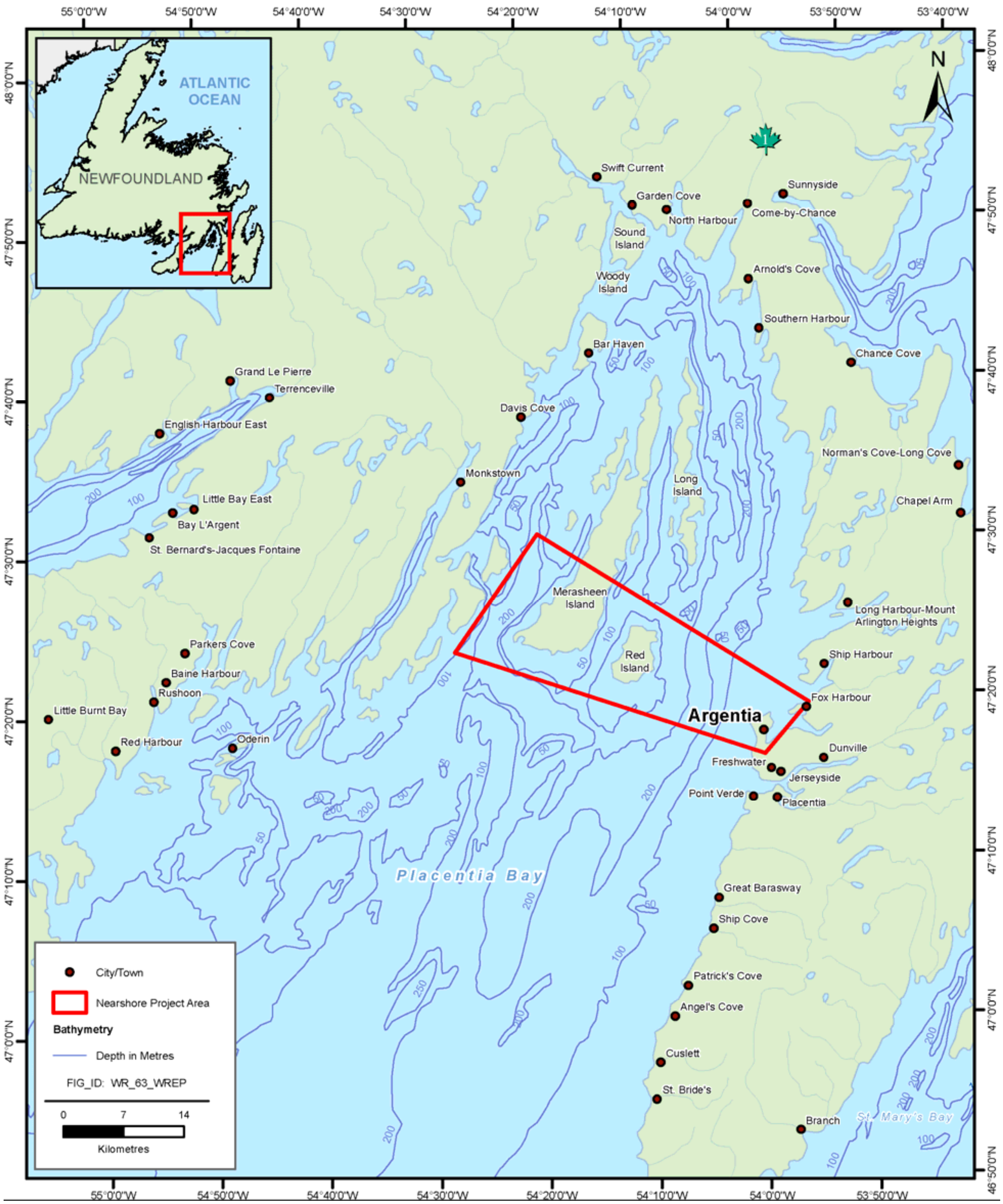

Figure 1-4 Nearshore Project Area

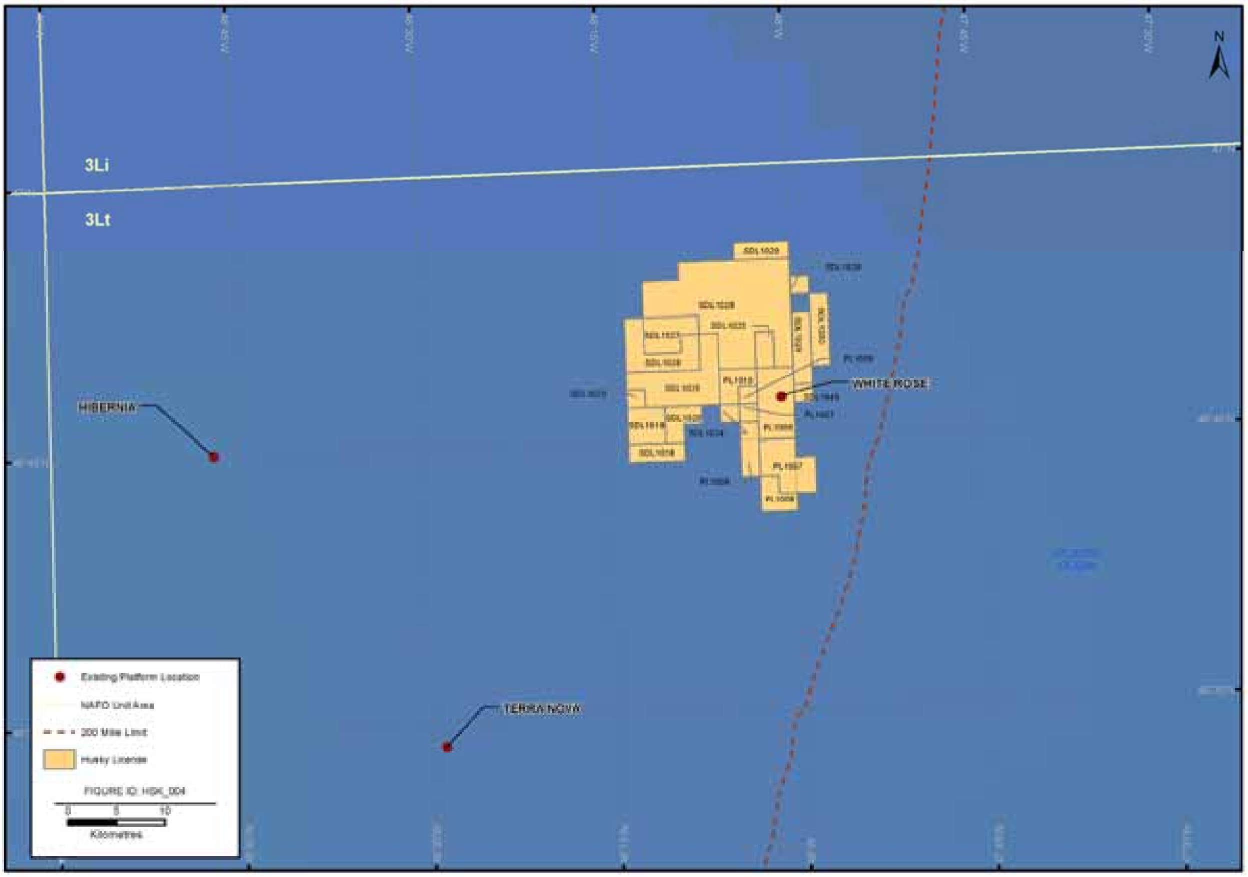

Figure 1-5 Offshore Project Area

1.3 Regulatory Context

Environmental assessment is a regulatory review process that is often applied to proposed developments to proactively identify and address potential environmental effects through project planning and decision-making. Through environmental assessment review, environmental issues are identified (often through consultation), likely environmental effects are assessed and evaluated, and measures to avoid or reduce adverse effects and to optimize benefits are identified and proposed. The results of an environmental assessment are considered in project design, and ultimately, in eventual government (regulatory) decisions regarding whether and how the project can proceed.

In Newfoundland and Labrador, proposed development projects may be subject to provincial and/or federal environmental assessment requirements.

Oil and gas exploration and development activities in the Newfoundland and Labrador offshore area are regulated by the *Canada-Newfoundland Atlantic Accord Implementation Act* (S.C. 1987, c. 3) and the *Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act* (R.S.N.L. 1990, c. C-2) (collectively, the Accord Acts).

The C-NLOPB, established by the joint operation of the Accord Acts, is a prescribed federal authority to which CEAA applies. In accordance with CEAA, the C-NLOPB and other federal authorities are required to conduct an environmental assessment of proposed oil and gas projects, such as the WREP, before they may issue authorizations, licenses and permits for the purpose of enabling such projects to be developed. The environmental assessment process is intended to ensure that projects are considered in a careful and precautionary manner before federal authorities take action in connection with them, in order to ensure that such projects do not cause significant adverse environmental effects.

Regardless of the development option selected, the offshore component of the WREP will be wholly contained within the study area of the original White Rose field, which was previously assessed by a CEAA comprehensive study (Husky Oil 2000). The proposed offshore infrastructure will be connected to existing infrastructure within the previous study area and no portion of the proposed offshore infrastructure will be located outside the boundaries of that area. The eventual decommissioning of the proposed offshore WHP will not include disposal or abandonment offshore, nor will it include conversion of the WHP on site to another role. Because of the factors stated above, the WREP is not a project described in CEAA's *Comprehensive Study List Regulations* and therefore, the CEAA process applicable to the WREP is an environmental assessment by screening.

Newfoundland and Labrador's *Environmental Protection Act* (the EPA) (SNL 2002, c. E-14.2) requires anyone who plans a project that could have a significant effect on the natural, social or economic environment (an undertaking) to present it for examination through the provincial environmental assessment process. Under the EPA, the WREP's WHP option is considered an undertaking subject to Part X, and pursuant to Section 44(3)(a) of the associated *Environmental Assessment Regulations*:

> 44. (3) An undertaking that will be engaged in
>
> (a) operating a dry-dock or shipyard, manufacturing, constructing, repairing, altering, or converting ships or boats of more than 4.54 tonnes displacement including marine production platforms for petroleum, natural gas or mineral resource extraction; […]
>
> shall be registered.

On May 28, 2012, Husky submitted the *WREP Project Description (*Husky 2012a) to the C-NLOPB, to formally initiate the environmental assessment processes required for the WREP. The C-NLOPB reviewed the Project Description and determined that the WREP requires a CEAA screening-level assessment (Reference number 68249).

CEAA was repealed when the *Canadian Environmental Assessment Act, 2012* (CEAA 2012) came into force on July 6, 2012. However, pursuant to subsection 124(1) of CEAA 2012, a screening of a project commenced under CEAA must, if the project is a designated project, be continued and completed as if CEAA had not been repealed. On July 12, 2012, the C-NLOPB informed Husky that pursuant to CEAA 2012 (subsections 124(2) and 14(2)), the Minister of the Environment determined that the WREP was a designated project, so the environmental assessment (a screening) for the WREP was to be continued and completed under CEAA.

On June 7, 2012, the C-NLOPB notified federal and provincial governmental agencies of the filed *WREP Project Description* and forwarded copies of the document, as well as copies of a draft Scoping Document, for their review and comment.

On June 19, 2012, the Newfoundland and Labrador Department of Environment and Conservation (NLDEC) advised Husky of its determination that the WREP is an undertaking requiring environmental review pursuant to the EPA and that registration was therefore required. Husky formally submitted the Registration to the Province of Newfoundland and Labrador on August 3, 2012.

Following governmental and public review of the Registration, on October 30, 2012, the provincial Minister of Environment and Conservation advised Husky that an environmental preview report was required for the WREP. This environmental assessment is to satisfy the requirements of both the EPA and CEAA. In that regard, a harmonized and coordinated review process will be implemented between the C-NLOPB and provincial and federal authorities. The C-NLOPB will act as federal environmental assessment coordinator for the CEAA screening. As such, the C-NLOPB will coordinate the participation of federal and provincial authorities in the assessment process and will facilitate communication and cooperation among them.

The C-NLOPB, provincial and federal authorities have set out the required scope of this environmental assessment in a Scoping Document released on December 18, 2012 (C-NLOPB 2012a). This environmental assessment meets these requirements, as well as the requirements of the C-NLOPB *Development Plan Guidelines* (C-NLOPB 2006).

In addition to the CEAA and the EPA processes, the Atlantic Accord Acts require that an environmental impact statement (EIS) and a socio-economic impact statement (SEIS) be submitted as part of the development approval process. The environmental assessment of the WREP will therefore include submissions addressing the requirements of the CEAA, the EPA and the Accord Acts.

As previously stated, should the subsea development option be selected, the subsea drill centre and flowlines and the activities associated with that development option have already been assessed under the *Husky White Rose Development Project: New Drill Centre Construction and Operations Program Environmental Assessment Addendum* (CEAR No. 06-01-17410) (LGL 2007a). A fish habitat compensation agreement (Authorization No. 07-01-002) has been in place with DFO since 2007 to compensate for the excavation of up to five subsea drill centre sites, of which only two have been excavated to date (the NADC and South White Rose extension (SWRX)). The construction of a subsea drill centre for the West White Rose pool was one of the potential subsea drill centres assessed and compensated for in 2007.

1.4 Purpose of the Environmental Assessment Report

This environmental assessment was prepared in the context of the WREP CEAA Scoping Document (dated December 2012), and in fulfillment of regulatory requirements to assess the significance of potential environmental effects and reduce adverse environmental effects resulting from the WREP under CEAA, the EPA and the Accord Acts. This report addresses the requirements for a screening level of assessment pursuant to CEAA, the environmental preview report required by the EPA and the EIS pursuant to the Accord Acts. While the offshore area has been previously assessed and subsea drill centres have been previously assessed (and therefore the focus of the Project Description is on the WHP), the effect analysis considers both development options.

1.5 Scope of the Project

The scope of the WREP includes a nearshore component (if the WHP development option is selected), an offshore component and potential future expansion activities within the White Rose field.

1.5.1 White Rose Extension Project Components - Nearshore Project Area

On-land and nearshore WREP components are related solely to the WHP development option. There will be no nearshore components associated with the subsea drill centre development option. Husky has identified the following key WREP-related activities in the Nearshore Project Area:

- Graving dock excavation. Associated activities may include graving dock side stability/reinforcement (e.g., sheet piles, bund wall, etc.) and site grading and levelling
- Site dewatering and disposal
- Use of The Pond for disposal of excavated soil material and dredged material
- CGS construction at the graving dock
- shoreline dredging
- Tow-out channel dredging
- Tow-out to the deep-water mating site
- Topsides mating and commissioning at the deep-water mating site
- Tow-out of the WHP to the White Rose field
- Operation of support craft associated with the above activities, including but not limited to heavy lift vessels, construction vessels, supply vessels, helicopters, tow vessels and barges

- Associated surveys for all above activities, including: remotely-operated vehicle (ROV) surveys, diving programs, geotechnical programs, geophysical programs, geological programs, environmental surveys.

1.5.2 White Rose Extension Project Components - Offshore Project Area

Husky has identified the following key WREP-related activities in the Offshore Project Area:

- Offshore site and clearance surveys
- Installation of the WHP/subsea drill centre at its offshore location (may include site preparation activities such as dredging, seafloor levelling, offshore solid ballasting, piles and mooring points,
- Subsea equipment and flowline installation to tieback to the *SeaRose FPSO*
- Flowline berm protection (i.e., rock piles and/or concrete mats)
- WHP/subsea drill centre commissioning
- Operation, production, maintenance, modifications, decommissioning and abandonment of the WHP/subsea drill centre
- Drilling operations (exploration and development drilling), from the WHP of up to 40 wells, or 16 wells from a mobile offshore drilling unit (MODU) through a subsea drill centre, including well testing, well completions and workovers and data logging
- Supporting activities, including diving programs, and operation of support craft associated with the above activities, including but not limited to dredging vessels, light intervention vessels, construction vessels, MODUs, WHP supply and standby vessels and helicopters
- Associated surveys for all above activities, including: ROV surveys, diving programs, geotechnical programs, geophysical programs (e.g., vertical seismic profiles (VSPs), geohazard/wellsite surveys), geological programs, environmental surveys (including iceberg surveys)
- Potential future activities, including excavation of up to two additional subsea drill centres and installation of infrastructure, including any associated surveys (e.g., VSP, geohazard/wellsite).

1.6 Document Organization

This environmental assessment is organized into the following chapters.

- Chapter 1 - Introduction: Provides a description of the Nearshore and Offshore Project Areas, identifies the WREP proponents, indicates the regulatory context and the purpose of this environmental assessment, details the scope of the WREP and the nearshore and offshore WREP components and describes the organization of this environmental assessment.

- Chapter 2 - Project Description: Provides the justification and need for the WREP, discusses the alternatives to the WREP, discusses and evaluates the alternatives within the WREP and discusses in detail the preferred concept for the WREP in terms of construction in the Nearshore and Offshore Project Areas and operation and maintenance and decommissioning and abandonment in the Offshore Project Area and potential future development in the Offshore Project Area.

- Chapter 3 - Summary of WREP-specific Modelling: Summarizes the results of the modelling conducted specifically for the WREP, including air quality, noise, dredging, drill cuttings discharge, synthetic-based mud (SBM) whole mud spills, hydrocarbon spill probabilities and hydrocarbon spill trajectories.

- Chapter 4 - Physical Environment Setting: Describes the terrestrial, socio-economic and nearshore and offshore physical environment setting (including the atmospheric environment, oceanic environment, wind and wave extremes, sea ice and icebergs, geotechnical and geological conditions and climate change).

- Chapter 5 - Environmental Assessment Methods: Details the scope of the environmental assessment and the scope of the factors to be considered in the environmental assessment; provides the nine-step method used in conducting the environmental effects assessment of the WREP on identified Valued Ecosystem Components (VECs).

- Chapter 6 – Issues Scoping: Provides details on the consultations conducted in support of the environmental assessment, including consultation with the public, meetings with government departments and agencies and other consultations methods used.

- Chapter 7 - Air Quality: Describes the existing environment, potential interactions, proposed mitigation measures and assesses the potential environmental effects of the WREP (including cumulative environmental effects and accidents and malfunctions) on Air Quality.

- Chapter 8 - Marine Fish, Shellfish and Fish Habitat: Describes the existing environment, potential interactions, proposed mitigation measures and assesses the potential environmental effects of the WREP (including cumulative environmental effects and accidents and malfunctions) on Fish and Fish Habitat.

- Chapter 9 - Fisheries: Describes the existing environment, potential interactions, proposed mitigation measures and assesses the potential environmental effects of the WREP (including cumulative environmental effects and accidents and malfunctions) on Fisheries.

- Chapter 10 - Marine Birds: Describes the existing environment, potential interactions, proposed mitigation measures and assesses the potential environmental effects of the WREP (including cumulative environmental effects and accidents and malfunctions) on Marine Birds.

- Chapter 11 - Marine Mammals and Sea Turtles: Describes the existing environment, potential interactions, proposed mitigation measures and assesses the potential environmental effects of the WREP (including cumulative environmental effects and accidents and malfunctions) on Marine Mammals and Sea Turtles.

- Chapter 12 - Species at Risk: Describes the existing environment, potential interactions, proposed mitigation measures and assesses the potential environmental effects of the WREP (including cumulative environmental effects and accidents and malfunctions) on Species at Risk.

- Chapter 13 - Sensitive Areas: Describes the existing environment, potential interactions, proposed mitigation measures and assesses the potential environmental effects of the WREP (including cumulative environmental effects and accidents and malfunctions) on Sensitive Areas.

- Chapter 14 - Effects of the Environment on the Project: Describes the potential effects of the environment on the WREP in both the nearshore and offshore, including bathymetry, wind, waves and currents, tsunamis, tides, water levels and storm surge, sea temperature, geohazards, and climate change and the mitigation measures that will be applied.

- Chapter 15 - Follow-up and Monitoring: Provides the framework for the follow-up programs (including environmental effects monitoring) and environmental compliance that will be conducted for the WREP, as well as environmental assessment validation.

- Chapter 16 - Environmental Management: Details the environmental management procedures that Husky will apply to the WREP, as well as contingency plans in the event of an oil spill (or other accidental event).

- Chapter 17 – Summary and Conclusions: Provides the conclusions of the effect of the WREP resulting from the environmental effects assessment.

- Chapter 18 - References: Provides the personal communications and literature cited to prepare the environmental assessment.

Note that a list of acronyms and abbreviations and glossary is provided at the end of the Executive Summary.

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2.0 PROJECT DESCRIPTION

This chapter describes the attributes of the two WREP development options from construction through operations to decommissioning and abandonment. The WREP schedule for each option is also provided.

2.1 White Rose Extension Project Need and Justification

The WREP is the next step in further development of White Rose area resources. The West White Rose pool was identified for potential development in the original White Rose development plan and is the primary focus of the WREP. Development of WREP resources will provide oil production to assist in offsetting the natural decline in production from the main White Rose pool and the North Amethyst field. Oil production from the WREP will also result in additional royalties to the provincial government and a share of profits through Nalcor's equity interest in the WREP. With the White Rose project, Husky has demonstrated a strong commitment to ensuring that maximum project benefits accrue to Newfoundland and Labrador. Husky has in place policies and procedures to ensure that Newfoundland and Labrador companies have full and fair opportunity to supply goods and services in support of WREP development.

2.2 Alternatives to the Proposed White Rose Extension Project

Based on Husky's experience as an operator within the Jeanne d'Arc Basin, there are no economically and technically viable alternatives to development of WREP, besides the two options being considered as alternative means of carrying out the WREP (Section 2.3).

2.3 Alternative Means of Carrying out the White Rose Extension Project

2.3.1 Offshore Options

Husky and its co-venturers are currently evaluating options for development of the WREP resources, including subsea tiebacks, a WHP, or a combination of both. The selection of concepts for development of the WREP included consideration of environmental effects, safety, capital and operating cost, reliability, energy efficiency, constructability and schedule for construction. Two potential concepts were considered in detail for developing the initial stage of the WREP, West White Rose:

- WHP, which is a fixed drilling platform tied back to the *SeaRose FPSO*
- Subsea drill centre tied back to the *SeaRose FPSO*, which would require a mobile drilling platform.

The WREP would continue to use the existing infrastructure in the White Rose field, including the *SeaRose FPSO* and existing drill centres. The *SeaRose FPSO* process facilities will continue to supply injection water and gas to existing subsea drill centres and the WHP or any new subsea drill centres. The *SeaRose FPSO* will also continue to process all incoming production well fluids from subsea drill centres and/or the WHP, and store and offload crude oil for export.

Both concepts are carried through in this environmental assessment. There is no onshore/nearshore construction associated with the subsea drill centre concept.

2.3.2 Nearshore Options

Should the WHP option be selected as the offshore development concept, there are options during the construction process to consider. The CGS would be constructed in a dry, on-land facility, called a graving dock. The graving dock may be constructed as a permanent facility, or as a single use facility. A permanent facility would have gates installed at the shoreline during excavation of the graving dock. If the graving dock is a single-use facility, then the graving dock area will be left flooded once the CGS is towed out.

Husky engaged SNC-Lavalin Inc. (SLI) to evaluate the options for disposal of the soil and rock excavated from the graving dock and the tow-out corridor. The following text is from their report (SLI 2012).

2.3.2.1 Disposal Alternatives

The options for disposal of the soil, sediment and rock excavated from the graving dock and the tow-out corridor have been evaluated to determine the best option for disposal and a thorough review of the possible locations for material disposal was undertaken by SLI. The possible disposal options included five options, including three from the Husky's 2012 Environmental Assessment Registration document (Husky 2012b). The following disposal options have been considered and evaluated:

1. Disposal at sea
2. On-land disposal
3. Hillside disposal
4. Out of area disposal
5. The Pond

2.3.2.2 Evaluation of Material Disposal Options

A detailed evaluation of the above alternatives was carried out. The options assessment included both short-term and long-term effects of each alternative, from the construction and operation phase, through to eventual abandonment/closure of the site. The options were evaluated using a semi-qualitative comparative matrix, which included:

- Environmental considerations
- Technical considerations
- Socio-economic considerations.

The results of the evaluation are presented in Tables 2-1 to 2-3 and a detailed discussion of each alternative is presented in the following sections. It should be noted that soil and sediment samples taken from the proposed graving site, as well as the proposed dredging sites have, to date, indicated little risk to the environment or human health as a result of the planned activities (Husky 2012b). Even so, Husky is committed to the development and implementation of a soil and sediment sampling plan as part of their Environmental Protection Plan (EPP) for the construction phase of the WREP. If contamination is detected above applicable guidelines, the material will be moved to a quarantined area and treated, as necessary. Depending on the nature of the constituent of concern the site could be used as a treatment site (e.g., land farming). Further details will be presented in Husky's EPP: Project Construction Phase and the program will be developed in consultation with the Newfoundland and Labrador Department of Environment and Conservation (NLDEC).

Based on the caveat that any contaminated material will be handled and treated as necessary, separately from the bulk of the excavated and dredged material, which is assumed to be uncontaminated, the following disposal options have been evaluated with this qualification in mind.

Disposal at Sea

Disposal at sea was evaluated and is not considered to be an environmentally valid option due to the negative effects that ocean dumping would likely have on fish habitat, as well as the perception or possibility for marine pollution (i.e., potential for suspended sediment plume in the marine environment). Husky has already discussed this option with Environment Canada and at that time it was determined that an active ocean disposal site could not be identified within Placentia Bay (Husky 2012b). The topic of disposal at sea was also discussed during stakeholder meetings held by the Husky with local fish harvesters and at that time, the invested parties objected to material from Argentia being disposed of in the marine environment (Husky 2012b).

On-Land Disposal

This option involves the dry stacking/stockpiling of material on the Argentia Peninsula itself. Portions of the Argentia Peninsula can be considered a contaminated/remediated brownfield site and therefore, stockpiling uncontaminated material is a potentially environmentally valid option. It is estimated that approximately 1.2 million m^3 of excavated soil and sediment will need to be stored and due to the lack of available topography, which may otherwise be used to help contain the material, this would mean that an area of approximately 13.2 hectares would be required. The required area is based on a slope angle of the stockpiled material of 30°, which is the estimated angle of repose of the material to be stored, and also assumes that the maximum height of the stockpile will be limited to 10 m. Potential concerns related to this option are: the possibility for atmospheric issues related to dust and airborne particles; collection ditching required in order to control runoff; aesthetic concerns associated with such a large stockpile of material; and continual maintenance and monitoring. The stockpile could also be of benefit (i.e., the stockpile would provide a central location where a large quantity of material could be stored and then used as necessary for both local and regional construction projects).

Table 2-1 Material Disposal Alternatives Evaluation – Environmental Considerations

No.	Criteria	Disposal Alternatives				
		Disposal at Sea	**On-land Disposal**	**Hillside Disposal**	**Out of Area Disposal**	**The Pond**
1	Physical and geochemical characterization of wastes (e.g., % fines)	3	3	3	1	1
2	Topographical factors (e.g., relief and complexity of topography)	5	4	3	1	1
3	Geotechnical and seismic stability (e.g., depth of permafrost, geology of bedrock)	1	4	3	2	2
4	Hydrology issues	1	3	3	2	2
5	Hydrogeological issues (e.g., migration of contaminated groundwater)	1	2	3	2	1
6	Atmospheric issues (e.g., particulates, heavy metals)	1	5	4	2	2
7	Overall affected land footprint size of impoundment related infrastructure and access roads	5	4	5	1	1
8	Size of affected water body area (e.g., lake, stream) and watershed catchment boundaries	4	1	1	1	3
9	Water quality issues	4	2	3	1	2
10	Impacts to fish and their habitats related to each alternative	5	1	2	1	1
11	Impacts to aquatic plant and animal species and their habitats related to each alternative	5	1	1	1	2
12	Impacts to terrestrial plant and animal species related to each alternative	1	3	5	1	1
13	Impacts to birds related to each alternative	1	2	2	2	3
14	Impacts to species at risk and their habitats related to each alternative	3	1	1	1	1
15	Impacts on humans (including air quality, noise, drinking water and contamination of country foods issues, as applicable)	3	3	3	1	2
16	Potential for post-closure/decommissioning recovery and rehabilitation related to environmental vectors related to each alternative	5	3	4	1	2
17	Distance from removal area to disposal area (e.g., carbon footprint)	5	2	4	5	1
18	Failure consequences	1	3	4	2	3
	Sub-Total Score	**54**	**47**	**54**	**28**	**31**

SCORE
1 Most favourable (no or negligible impact)
2 Favourable (minor or insignificant impact)
3 Average (Low to moderate impact)
4 Slightly unfavourable (Moderate impact)
5 Unfavourable (High or major impact)

Table 2-2 Material Disposal Alternatives Evaluation – Technical Considerations

No.	Criteria	Disposal Alternatives				
		Disposal at Sea	**On-Land Disposal**	**Hillside Disposal**	**Out of Area Disposal**	**The Pond**
1	Containment structure designs (e.g., size, hydraulic capacity, construction materials, substrate, etc.)	1	3	4	1	1
2	Availability of construction materials and volume requirements (e.g., quarry material for containment structures, access road and site drainage)	1	2	4	2	1
3	Diversion and other water control structures that may be required	1	3	3	1	1
4	Potential for future use of materials	5	1	4	5	2
5	Transportation of materials (e.g., from removal site to disposal option)	5	2	4	5	1
6	Chemical and physical characterization of disposal material	1	3	3	4	2
7	Design and construction of impermeable covers over wastes	n/a	n/a	n/a	n/a	n/a
8	Flexibility with regard to technical, operational and environmental uncertainties	2	3	3	5	2
9	Proposed technologies and advantages/disadvantages of the technologies considered, (e.g., proven technology used elsewhere or new)	4	3	4	2	2
10	Technical feasibility and risks (e.g., unforeseen conditions that may not allow all the material to be disposed of)	1	3	3	5	2
11	Unforeseen technical difficulties (e.g., in terms of foundation complexities for dams, etc.)	1	2	3	1	1
12	Risks associated with requirements for perpetual treatment or maintenance	1	3	4	2	2
13	Post-closure risks and uncertainties	1	3	4	1	2
14	Rehabilitation of aquatic and/or land ecosystems including timeframes	4	3	4	1	1
15	Risks associated with construction	1	3	4	4	2
	Sub-Total Score	**29**	**34**	**51**	**39**	**20**

SCORE
1 Most favourable (no or negligible impact)
2 Favourable (minor or insignificant impact)
3 Average (Low to moderate impact)
4 Slightly unfavourable (Moderate impact)
5 Unfavourable (High or major impact)

Table 2-3 Material Disposal Alternatives Evaluation – Socio-Economic Considerations

No.	Criteria	Disposal Alternatives				
		Disposal at Sea	**On-Land Disposal**	**Hillside Disposal**	**Out of Area Disposal**	**The Pond**
1	Capital costs	5	3	5	4	2
2	Operational costs	1	4	3	1	2
3	Closure costs	1	3	4	1	2
4	Post-closure costs, including the costs of perpetual treatment/maintenance should it be required	1	3	4	1	2
5	Fish habitat compensation and monitoring costs	5	1	1	1	1
6	Economic risks and benefits	5	3	4	5	2
7	Closure, post-closure plan risks where some form of perpetual treatment or maintenance is required	1	4	4	2	2
8	Regulatory review and construction timeline costs	5	3	4	5	2
9	Preservation of archeological/cultural sites	n/a	n/a	n/a	n/a	n/a
10	Aboriginal land rights	n/a	n/a	n/a	n/a	n/a
11	Maintenance of traditional lifestyle	4	2	3	1	1
12	Spiritual well being	3	3	4	1	1
13	Perceived community response	5	3	4	1	2
14	Ecological/cultural values (in the sense of natural capital value)	5	3	4	1	2
15	Use of fisheries resources	4	1	1	1	1
16	Aesthetics	1	4	4	1	1
17	Other uses such as recreation/tourism, industrial, etc.	5	2	3	1	2
18	Contracting opportunities, building community capacity	5	1	3	5	2
19	Safety considerations	4	3	3	3	2
20	Landowner opinion including governments	5	5	4	1	2
21	Overall perceived socio-economic consequences, benefits and relative preferences; and other factors considered significant by the WREP proponent and reviewers	5	3	5	1	2
	Sub-Total Score	**70**	**54**	**67**	**37**	**33**
	TOTAL	**153**	**135**	**172**	**104**	**84**

SCORE
1 Most favourable (no or negligible impact)
2 Favourable (minor or insignificant impact)
3 Average (Low to moderate impact)
4 Slightly unfavourable (Moderate impact)
5 Unfavourable (High or major impact)

However, before a site could be selected the Argentia Management Authority (AMA) would have to approve the plans (i.e., AMA owns/operates the site). AMA would also have to take ownership of the material post-excavation, as material handling is not part of Husky's business. Additionally, the cost of Husky acquiring additional land in order to facilitate disposal, combined with the required approvals and ownership issues, makes this option unfavourable.

Hillside Disposal

This option requires trucking the disposal material off of the Argentia Peninsula to a hillside location, within the immediate area and with sufficient topographic relief, whereby the amount of material to be disposed can be adequately contained. This may also require the construction of a large rock fill containment dam(s). From an environmental standpoint, this option would likely require a large area of currently undisturbed land in the immediate vicinity in order to keep transportation costs to a minimum and may result in the infilling of or disturbance of natural waterbodies/watercourses.

Husky has already heard concerns from residents and authorities in the Placentia area about the increased traffic as a result of the proposed WREP and given the volume of material that will require disposal, further concerns about vehicular traffic are warranted. Also, due to the criticisms already associated with the use of Sandy Pond as a tailings disposal site for the Long Harbour nickel processing plant operated by Vale Newfoundland & Labrador Limited, the further disturbance of natural landscapes in this area is not recommended.

Out of Area Disposal

This option would require moving the disposal material large distances in order to facilitate disposal. Possibilities include loading the material onto barges for disposal at sea at an approved disposal site or to a transfer station where the material could be off-loaded and then trucked to a disposal site/local landfill. The material could also be trucked directly from the Argentia Peninsula to a landfill site where the material could be used a cover. The disadvantage of this is the potential for high transportation costs, unless a cost share agreement could be made between Husky and a waste handling contractor, as well as the increased vehicle or vessel traffic associated with transporting the material off the Argentia Peninsula. In addition, this option would also require that the rate of offsite removal is matched by the rate of excavation, as there is no material storage area available with this option.

There are some advantages to this option, including recycling the disposal material and the social perception surrounding its reuse for landfill closure/remediation. The reuse of the disposal material as landfill cover is considered to be the best case scenario with respect to out of area disposal and has been further evaluated herein within this context. It should also be noted that this option requires or is dependent on an organization outside of Husky's control and therefore, Husky is unable to take full responsibility for the implementation of this option. Therefore, while this option appears to be viable, particularly from an environmental perspective, Husky cannot ensure that the total amount of material to be disposed of would actually be reused, if in fact the material is deemed acceptable for use as a landfill cover.

The Pond

This option would result in the complete infilling of The Pond. A recent survey by C-CORE (C-CORE 2012a) has shown that the material volume of both the excavated soil and dredge material would exceed the water volume presently in the Pond; however, the material volume would not exceed the natural topography of The Pond. Sediments within The Pond are contaminated (Husky 2012b) and capping the contaminated sediments with cleaner sediments is a method of remediation that has been previously proposed (ARG 1998).

DFO has established that The Pond does not constitute productive fish habitat (DFO letter to Husky October 2, 2012) and that from a fish and fish habitat perspective, considering this location for the disposal of dredged materials is acceptable to DFO.

Provided that there are no geotechnical concerns with using The Pond to store the excavated material, it appears that the use of The Pond is beneficial from an environmental remediation perspective and there are no negative effects associated with fish and fish habitat due to infilling. Husky has also presented the case for use of The Pond to Environment Canada, DFO and local stakeholders and no objection has been raised to date (Husky 2012b).

The use of The Pond also has benefits over each of the previously discussed options, which include: negligible effects on fish and fish habitat; minimizing the sub-aerial footprint of the disposal site by allowing the disposed material to infill the existing pond and as a result, minimize the amount of material that will be exposed to atmospheric effects); minimizing the use of greenfield areas; minimizing the amount of vehicle and vessel traffic associated with transporting material off the Peninsula; minimization of transportation costs needed to transport the material off the Peninsula; and full control by Husky to ensure proper compliance and decommissioning.

A semi-qualitative comparative matrix, which combines all of the environmental, technical and socio-economic issues affecting each of the potential disposal options, is provided in Tables 2-1 to 2-3. Each of the criteria is weighted equally on a scale of 1 to 5, with a score of 1 being most favourable. The subtotal score for each section is given at the bottom of table section and the grand total is shown at the bottom of the table.

Based on the information available to date; the results from the comparative matrix show that The Pond is the preferred site for materials disposal.

2.3.2.3 Materials Disposal Option – Preferred Option

The results of the detailed evaluation presented in the previous sections show that The Pond is the preferred option with the best score in two of the three evaluation categories (i.e., The Pond is both technically and socio-economically the most viable option) and it also had the best overall score. With regards to the environmental category, the out of area disposal option scored the best, while The Pond was a close second. However, it must be stressed that the out of area option was evaluated within the context that all of the material for disposal could be reused as landfill cover. Therefore, if a portion of this material were found to be not acceptable for use as land fill cover, than a secondary disposal option is required, this realistically would be either The Pond or on-land disposal on the Argentia Peninsula. Moreover, recent informal correspondence with

Eastern Waste Management has revealed that the closest landfills to Husky's construction site that would have a requirement for cover material are too far away to make this option viable due to transportation costs.

In an effort to minimize the environmental footprint and disturbance to all stakeholders as much as possible, Husky has committed to ensuring proper disposal and use of the excavated and dredged material within the Argentia Peninsula. Husky has assumed environmental responsibility for the material from the AMA, and will test and treat the material as required, for the designated use.

2.4 White Rose Extension Project Concept and Design

The original White Rose field underwent an environmental assessment in 2000 pursuant to CEAA as a Comprehensive Study. In 2007, a further environmental assessment was undertaken in regards to activities associated with construction of up to five additional subsea drill centres and associated flowlines under the *Husky White Rose Development Project: New Drill Centre Construction and Operations Program Environmental Assessment Addendum* (LGL 2007a). These previous environmental assessments encompass the location, construction and operation of the proposed subsea drill centres within the WREP. Therefore, much of this Project Description focuses on the WHP development option, which has not been previously assessed, although information is also provided on the subsea development option. The effects analysis considers both development options.

2.4.1 White Rose Extension Project Design Criteria

An overview of the design basis for the WREP is provided in Table 2-4. These design rates may change as the reservoir depletion strategy and initial development phase are finalized. The design basis values listed are representative of peak production. The environmental assessment will, therefore, use the upper limit of these ranges in its effects assessment.

Table 2-4 White Rose Extension Project Attributes

Project Component	Attribute
Platform/Subsea Drill Centre Location	Centred on 724 080.00 E 5 187 208.00 N (NAD 83, Zone 22) within the West White Rose pool
Life of Field	Up to 25 years
Measured Well Depth (m)	7,700 m
Potential Field Expansion	Future options may include up to 32 subsea wells through two drill centres
WHP Concept	
Crude Oil Production (m^3/d)	7,800
Water Production (m^3/d)	10,500
Water Injection (m^3/d)	25,000
Gas Handling (km^3/d) (includes associated gas and gas-lift gas)	2,500

Project Component	Attribute
Well Slots	20 well slots drilling up to 40 wells
Preliminary Topsides Weight (CGS only)	14,000 Tonnes Dry, 23,000 Tonnes Operational
Overall Height (seabed to top of central shaft) (CGS only)	144 m [Range 145 to 155 m]
Foundation Diameter (CGS only)	105 m^2 [Range 105 to 110 m^2]
Caisson Diameter (CGS only)	75 m^2
Shaft internal diameter (CGS only)	18 to 29 m taper
CGS Dry Weight (CGS only)	172,000 Tonnes [Range 170,000 to 195,000 T]
Solid Ballasting (CGS only)	92,000 Tonnes [Range 90,000 to 125,000 T]
Concrete Volume (CGS only)	64,000 m^3 [Range 64,000 to 68,000 m^3]
Reinforcing Steel (CGS only)	25,000 Tonnes [Range 25,000 to 27,000T]
Post-Tensioning Steel (CGS only)	311 Tonnes [Range 300 to 400 T]
Life Expectancy of WHP	Approximately 25 years
Subsea Drill Centre	
Well Slots	Up to 16
Productive life of the subsea infrastructure	20 years
Water Quality	
Produced Water Handling (*Offshore Waste Treatment Guidelines*) (OWTG) (National Energy Board (NEB) et al*.* 2010)	OIW ≤30 mg/L 30-day average OIW ≤44 mg/L 24-hour average
Ballast / Bilge Water (oil content – OWTG)	≤15 mg/L
Deck (open) Drainage (oil content – OWTG)	≤15 mg/L
Well Treatment Fluids	≤30 mg/L; strongly acidic fluids should be treated with neutralizing agent to a pH of at least 5.0 prior to discharge
Cooling Water	1.0 mg/l residual chlorine
Desalination Brine	No discharge limit
Fire Control Systems Test Water	No discharge limit
Sewage and Food Waste	Macerated to ≤6 mm
Water-based Drill Solids	No discharge limit
SBM-based Drill Solids	CGS: Re-injected Subsea Drill Centre: ≤6.9 g/100 g oil on wet solids
Note: OIW = oil in water concentration	

2.4.2 Wellhead Platform Systems

The WHP will be designed to have temporary and permanent mechanical systems installed as follows:

- 20 well slots drilling up to 40 wells
- Shale chute
- Seawater systems including cooling water and firewater
- Corrosion protection system (the discharge from any hypochlorite system will be treated in accordance with the Offshore Waste Treatment Guidelines (OWTG) (National Energy Board (NEB) et al. 2010))
- Sewage disposal line routing water from the sewage treatment unit to the marine environment and discharged according to the OWTG
- Systems to minimize the occurrence of flammable gases and flammable or combustible liquids entering the shaft
- Fire and gas detection system
- Control and monitoring systems
- Cooling system.

Drilling facilities on the WHP will consist of the following systems:

- Mechanical drilling systems
- Well-control system (including a blowout preventer (BOP) stack)
- Bulk material and storage system
- Mud storage, mixing and high pressure system
- Mud return and reconditioning system
- Onboard gravel pack equipment
- Cementing system
- Driller's cabin
- Cuttings re-injection system for SBM-based muds and cuttings.

Water-based mud (WBM) cuttings are currently planned to be used on the conductor and surface hole sections of the WREP wellbores, (see Table 2-5 for estimate of volume of drill cuttings).

Table 2-5 Estimate of Drill Cuttings Volumes from a Wellhead Platform

Well Hole Section	Volume (m^3)	Release Location
Conductor	107	shale chute [(A)]
Surface	188	shale chute [(A)]
Intermediate	--	treat and inject
Main	--	treat and inject
(A) Elevation of chute exit from CGS estimated at 20 m above seafloor: to be confirmed during CGS design		

Other primary main systems used on the WHP include:

- Water injection system
- Test separation system
- Vent and flare system
- Oily water treatment
- Chemical injection
- Seawater lift
- Power generation
- Fuel gas
- Potable and service water
- Fire suppression systems
- Escape, evacuation, and rescue facilities
- Jet fuel storage
- Diesel fuel storage
- Hydraulic power
- Heating, ventilating and air conditioning.

2.4.3 Subsea Drill Centre

For any subsea development component of the WREP, drilling will be conducted from a MODU as per previous subsea drill centres in the White Rose field. Subsea drill centres will include all infrastructure/equipment necessary for the safe and efficient operation and control of the subsea wells and transportation of production and injection fluids.

Procedures for installation of subsea facilities and subsequent operation are anticipated to be the same as those currently used in the White Rose field. The following equipment will be installed in any new subsea drill centres:

- Wellhead and xmas trees (production and water injection)
- Production and water injection manifolds;
- Subsea distribution units
- Subsea umbilical termination unit
- Flowlines (gas lift, production, water injection)
- Jumpers (control, gas lift)
- Rigid spools (to production and water injection xmas trees).

WBM and SBMs cuttings will be released from the MODU as per the OWTG (Table 2-6).

Table 2-6 Estimate of Drill Cuttings Volumes from a Mobile Offshore Drilling Unit

Well Hole Section	Volume (m^3)	Release Location
Conductor	79	seafloor
Surface	188	seafloor
Intermediate	192	sea surface [A]
Main	77	sea surface [A]
(A) SBM cuttings treated prior to release. Estimated release at 20 m below sea surface		

2.5 Project Schedule

The WREP development schedule (Figure 2-1) reflects the current preliminary timeline projected to achieve first oil within the fourth quarter of 2016, under the WHP option. Developing the WREP using a subsea drill centre, subsea construction could begin in 2014, with installation of equipment and first oil potentially in 2015 (Figure 2-2). Additional subsea drill centres could be developed in a similar timeframe or later in the WREP life. In either development option, the WREP is designed to support production by the *SeaRose FPSO* for the life of the White Rose field.

2.5.1 Pre-Front-end Engineering and Design

The major focus within pre-front-end engineering and design (FEED) is to identify, screen and select the preferred option for the development of the identified resources and to provide information to support regulatory submissions. Pre-FEED started in the second quarter and was completed in the third quarter of 2012.

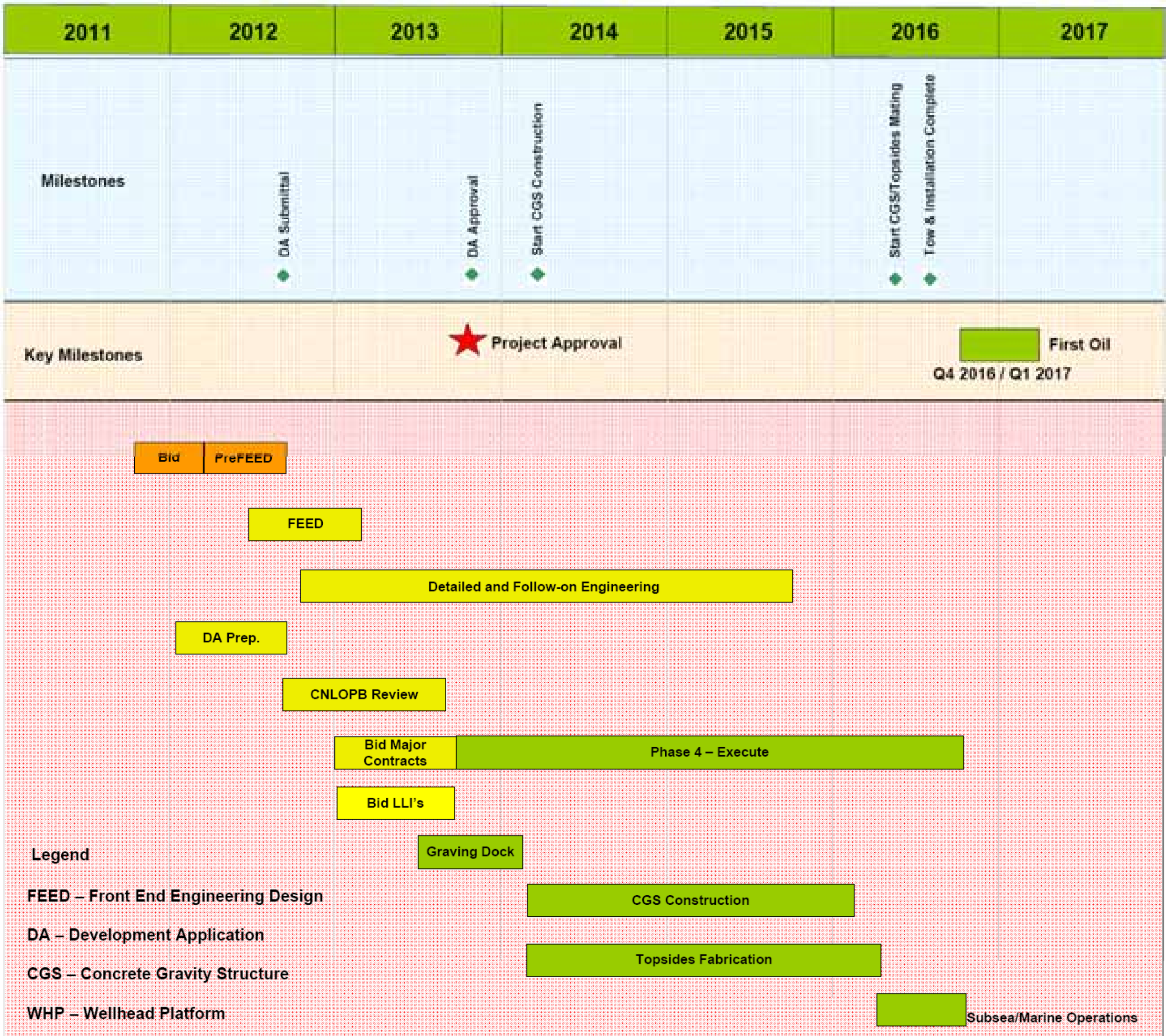


Figure 2-1 Proposed Schedule for Wellhead Platform Development Option

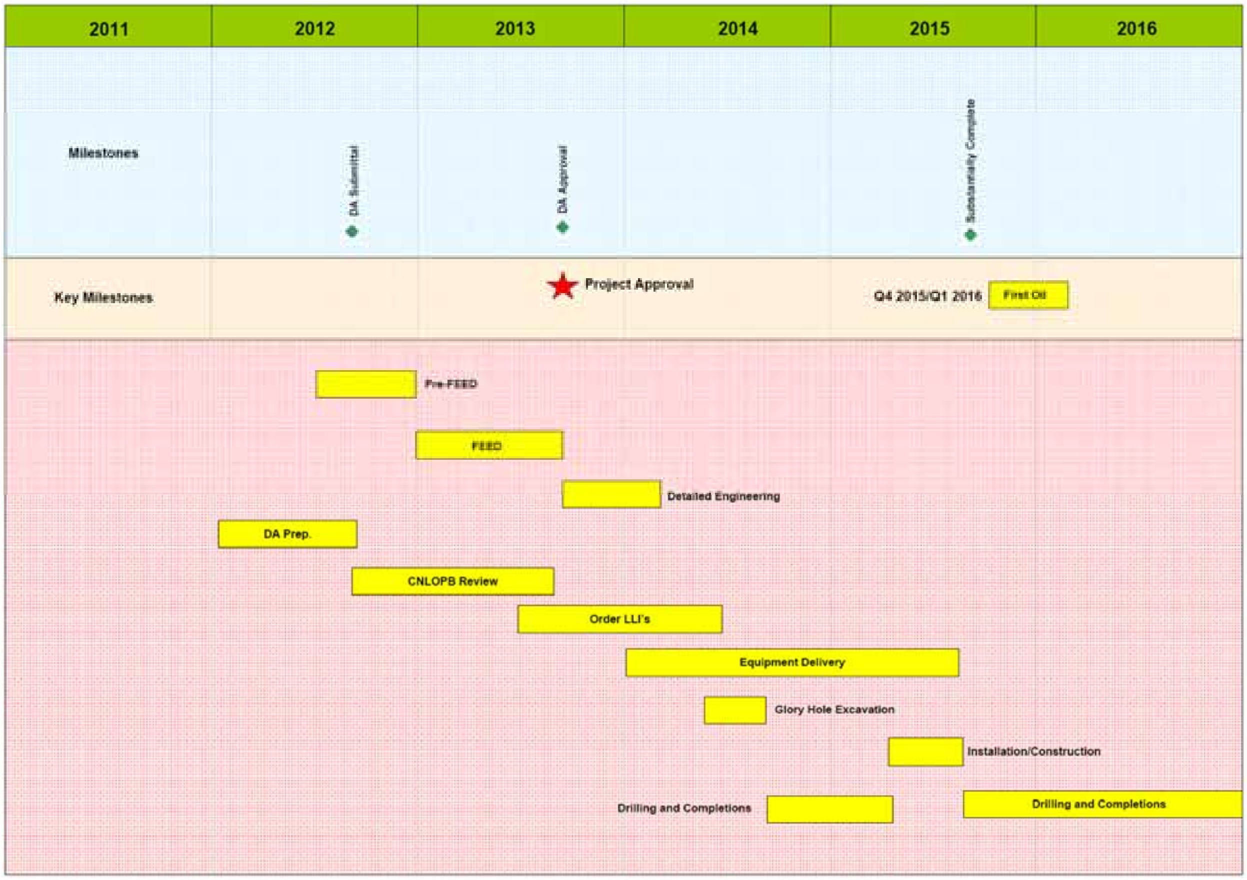


Figure 2-2 Proposed Schedule for Subsea Drill Centre Development Option

2.5.2 Front-end Engineering and Design

The major focus within FEED will be to fully define the scope of the WREP, complete detailed execution plans and refine engineering, cost estimates and schedules for the selected development option. FEED commenced in the third quarter of 2012 and anticipated to conclude by the end of first quarter of 2013.

2.5.3 Detailed Design and Follow-on Engineering

It is currently estimated that detailed design for the WHP and engineering work will commence in the fourth quarter of 2012, culminating in award of the various contracts during 2013. The detailed design and engineering will be replaced by follow-on engineering, which will be managed by the respective contractors responsible for the construction of the WREP components. For the subsea drill centre option, detailed design and engineering work would commence during the third quarter of 2013.

2.6 White Rose Extension Project: On-Land Activities

This section describes the construction activities associated with the WHP option only, since there will not be any onshore/nearshore activities associated with the subsea drill centre option.

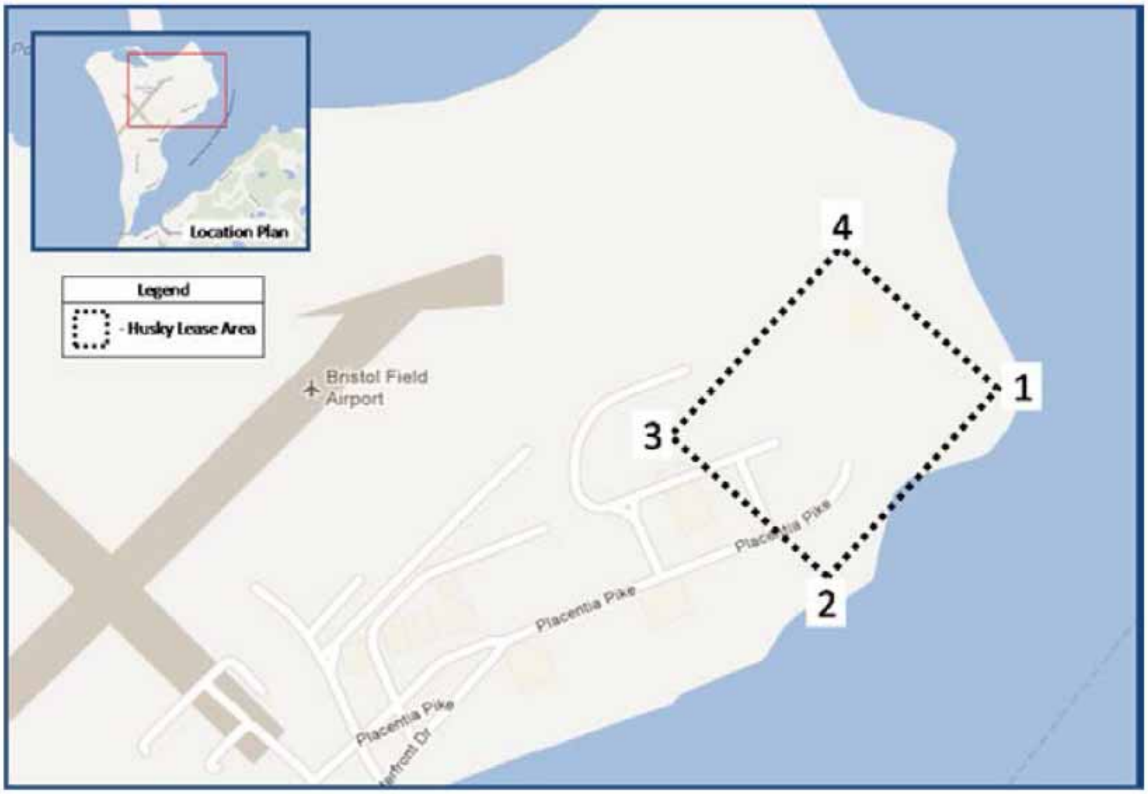
2.6.1 Construction Location

Under the WHP development option, the CGS will be constructed in a purpose built graving dock at Argentia, NL (refer to Figure 1-4). Argentia is managed by the AMA and there are multiple industrial companies occupying the surrounding area. The site is approximately 50 km away from the Trans-Canada Highway, via Route NL S 100, which is an industrial-sized road.

Argentia has been the location of more than 70 years of military and industrial activities. It is a brownfield location and has undergone several geophysical and environmental evaluations. The graving dock will be constructed in the northeast portion of the Northside Peninsula, bordering Argentia Harbour (Figures 2-3 and 2-4).

The overall construction site area will be approximately 20 hectares. Land clearing or watercourse diversion will not be required for the CGS graving dock construction. General excavating and grading activities will be required. Additional onshore surveys to support site preparation and necessary repairs or upgrades to existing infrastructure may be required.

Geotechnical bore holes, drilled to a maximum depth of 40 m below sea level, indicate that the graving dock can be excavated with routine earth-moving equipment. Environmental samples from the construction site indicate little risk to the environment or human health. Additional chemical analysis will be conducted during excavation to ensure compliance with applicable guidelines.



Husky Lease Area - Corner Pin Coordinates		
Point	Easting	Northing
1	275,562	5,243,954
2	275,208	5,243,618
3	274,927	5,243,917
4	275,280	5,244,256

Notes:
1. Lease area contains 20 Hectares.
2. Map Projection: UTM NAD83, Zone 22N.

Figure 2-3 Husky's Lease Area on the Argentia Peninsula

Source: Google Earth 2012

Figure 2-4 Aerial Photo of Potential Graving Dock Construction Site

2.6.2 On-Land Construction

The CGS construction site will maximize the use of existing access roads (Figure 2-5). The road system that currently exists is within 500 m of the graving dock site. Such infrastructure will be extended into the site in a manner compatible with the final site layout. Any required repairs and construction will also be made to the existing roads to prepare them for industrial use.

The CGS construction site will maximize the use of the existing water supply. An existing source of potable, fire and industrial water is located near the construction site. If necessary, additional water supply infrastructure will be extended into the area in a manner compatible with the final site layout. Sewage will be treated on-site prior to ocean disposal.

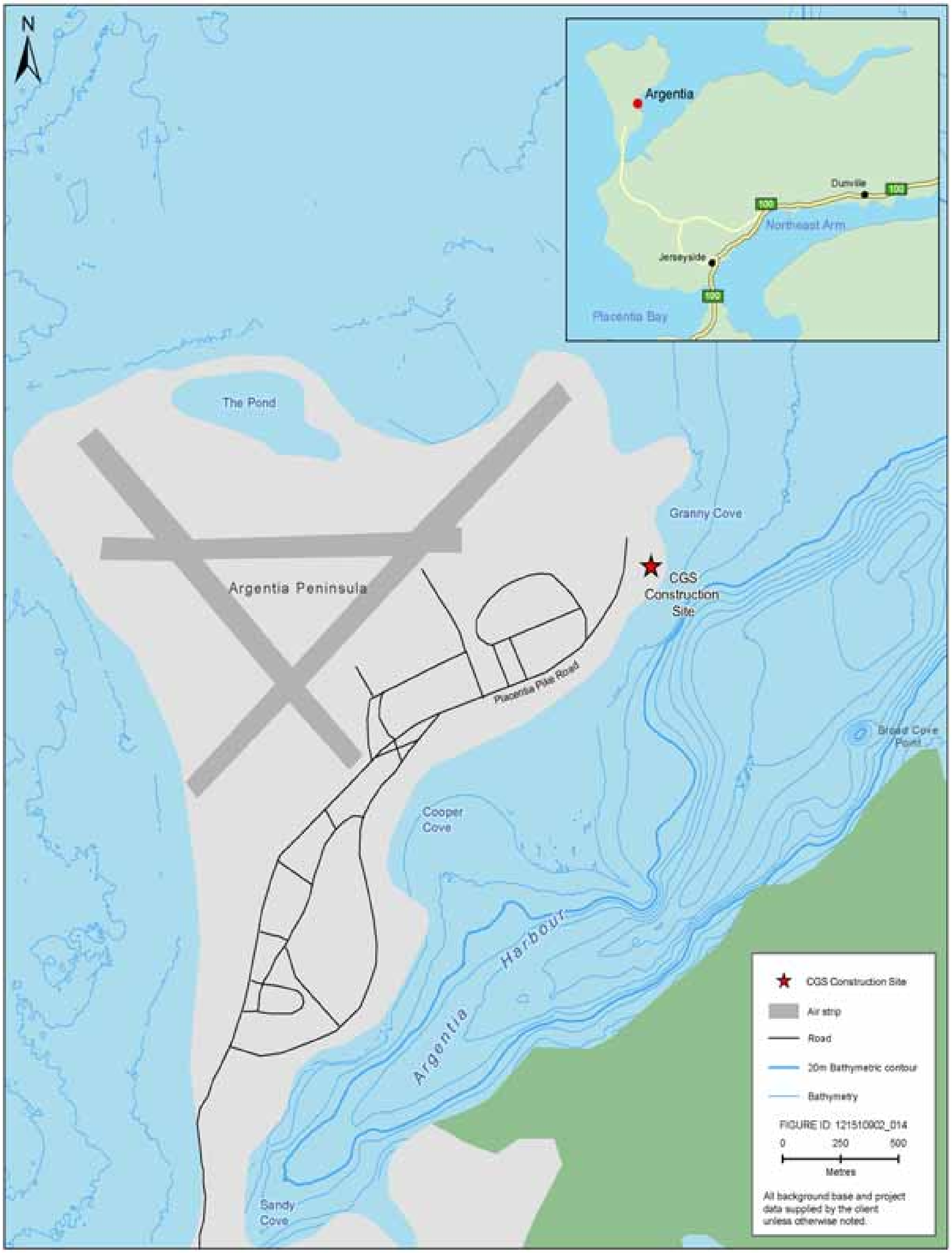


Figure 2-5 Existing Road Access to the Graving Dock Location on the Northside, Argentia

The CGS construction site will maximize the use of the existing grid power. Although grid power will be the primary source of electricity, there will be an emergency generator on site with a capacity of approximately 750 kilowatts. This will be used in the case of a grid black-out to provide on-site power for services such as the concrete batching plant and emergency lighting around the site. Generators may be required to power the site during excavation for lighting and water pumps, for example.

The CGS construction site location is within 500 m of existing overhead power lines. These lines will be extended into the site and then fed to a site distribution system. The same will be done for telephone lines.

Potential temporary support facilities include a concrete batching plant, offices, a dining hall, a medical clinic, sheds, lay down areas and storage areas. The construction site will be fully fenced with a security-controlled entrance. Facilities will be placed and constructed on environmentally and geotechnically suitable locations with soils, groundwater and air quality tested as required. At this time, Husky does not anticipate the need for a labour camp (see Section 4.1.1.1).

2.6.3 Graving Dock

2.6.3.1 Excavation

The graving dock will be excavated using traditional earth-moving equipment, blasting is not expected to be required. The floor area of the dock at the toe of the bund will be approximately 140 m x 140 m (Figure 2-6). Approximately 1,100,000 m^3 of material will be removed, with approximately 250,000 m^3 of this material used to level and grade the area surrounding the graving dock site above existing grade to approximately 8 m above chart datum.

The proposed graving dock will be excavated behind the natural coastal berm to a depth of approximately 18 m below chart datum. A cut-off wall, approximately 900 mm thick, will be constructed to minimize the ingress of water into the graving dock. The wall has been designed with a permeability of 10 to 8 m/s to a depth of -28 m chart datum at the sea bund side, continued 180 m along the sides and to a depth of -10 m chart datum along the remainder of the perimeter. The cut-off wall can be locally removed by a cutter suction dredger during the flooding of the graving dock prior to the float out of the CGS.

Environmental samples from the construction site indicate little risk to the environment or human health as a result of planned activities (see Section 2.6.3.2). However, confirmatory soil sampling will be conducted during excavation of the graving dock. If contamination is detected above applicable guidelines, the material will be moved to a quarantined area and treated, as necessary. Excavation and aeration was considered the preferred remediation method by Public Works and Government Services Canada (PWGSC) for the Northside Fuel Storage Area (NFSA) at Argentia. In fact, the act of excavation, transport and stockpiling of soil essentially resulted in the reduction of contaminant levels to meet the objectives of the remediation (Dillon 2011).

The excavation of the graving dock is anticipated to take approximately six to eight months.

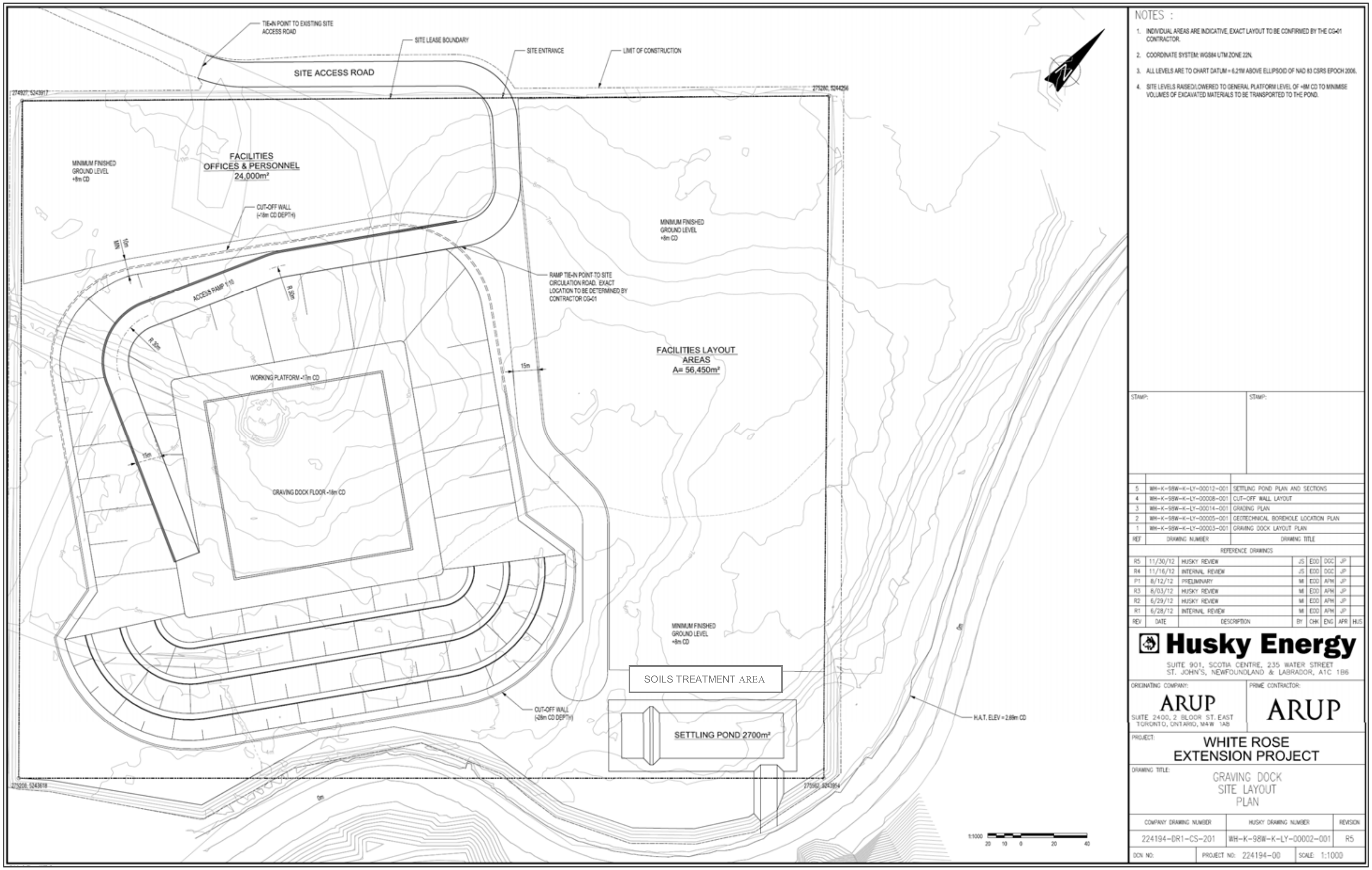


Figure 2-6 Conceptual Site Layout for Graving Dock

During the design of the graving dock and its associated construction site, consideration will be given to designing the facility as a permanent graving dock, which could be used for the construction of future CGSs or for other industrial applications. Design of the graving dock for future use could include provision for a gated system allowing the graving dock to be flooded and drained as required.

The final design of the graving dock will be completed once the groundwater modelling study is able to determine the method and degree of drainage required to maintain a dry facility during the construction of the CGS. Site surface water and groundwater from any dewatering of the graving dock will be collected, assessed and, if necessary, held in an engineered lined settling pond onsite to satisfy all regulatory requirements before being discharged into the marine environment.

A list of potential marine activities and potential emissions and discharges, associated with the pre-construction and installation is provided in Table 2-7.

Table 2-7 Potential Discharges and Emissions Associated with Pre-Construction and Graving Dock Excavation Activities

Potential Activities	Potential Discharges/Emissions/Wastes from All Activities
Additional onshore surveys (e.g., topographic, geotechnical, environmental) Grading of site Construction of temporary buildings and structures Upgrading/installation of infrastructure (e.g., site roads, buildings, cranes) Water supply requirements (potable water, fire water and industrial water) Watering discharge from The Pond Waste (domestic, construction, hazardous and sanitary) Excavation material use and disposal Chemical and fuel storage Welding and x-ray inspections Bulk material handling (sand, cement, crushed rock, aggregate) Construction of graving dock (include sheet pile/ driving, potential grouting)	Air emissions from vehicles Noise Site run-off and water from the graving dock disposal. Disposal of water from The Pond Disposal of excavation material from the Graving dock Solid, construction, hazardous, domestic and sanitary waste disposal

2.6.3.2 History of Environmental Sampling and Remediation near the Graving Dock

The CGS graving dock site is partially located within the southwest portion of the former NFSA, in the northeast portion of the Peninsula. The southwest portion of NFSA contained barracks and recreational buildings for enlisted personnel, as well as numerous warehouses, aircraft maintenance hangars and general support and administration buildings. There were also storehouses, transformer vaults, two truck loading stands and a batching plant. Most of the barracks and warehouses were demolished prior to initiation of site-wide environmental assessment by the federal PWGSC in 1993/1994, and the majority of remaining buildings and foundations were removed by 1999.

As part of PWGSC’s site-wide environmental site assessments (ESAs) completed in 1993/1994 and 1995, 64 test pits, 62 monitor wells, and 15 boreholes with related soil and groundwater sampling were completed at the NFSA site, with the primary emphasis on petroleum hydrocarbon contamination in the area of petroleum hydrocarbon product tank storage, located immediately east of the current site (Figure 2-7).

Results of the 1995 Phase III/IV ESA within the NFSA indicated no unacceptable risks to human receptors based on a limited future land use scenario (i.e., humans could live or work outdoors safely provided they did not exceed the exposure frequency of 140 days/year, and that they did not consume the groundwater). However, in 1997, high concentrations (combustible levels) of petroleum hydrocarbons encountered in soil during removal of sub-surface infrastructure in the NFSA area prompted PWGSC to reassess the risk potential. This review, along with the planned development of the Voisey's Bay Nickel Company (VBNC) refinery/smelter facility, resulted in the recommendation for remediation of the area and site-specific remedial objectives were developed for soil and groundwater. Another 22 monitor wells were installed between 2000 and 2003 in an effort to further delineate the extent of petroleum hydrocarbon impacts in this area. Full-scale remediation, applying excavation/aeration (land farming) techniques, was initiated by PWGSC in 2005 and completed in 2007, with the primary objective to remove/capture free product and remove vapours through volatilization. Various contaminant sources, including leaking tanks and pipelines were removed and approximately 175,000 m^3 of impacted soil was treated to reduce petroleum hydrocarbon levels to below the risk-based remedial objectives (ROs) established for the site (i.e., 2,800 mg/kg in soil for total petroleum hydrocarbons and 4.4 mg/kg in soil for benzene).

Based on information provided in the 2010 NFSA Closure Report by Dillon Consulting Ltd., petroleum hydrocarbon impacted soil at the NFSA has been remediated. Ongoing post-remediation monitoring involving free product measurement and petroleum hydrocarbon groundwater sampling in several sentry monitor and recovery wells in the remediated area has not identified any issues of concern.

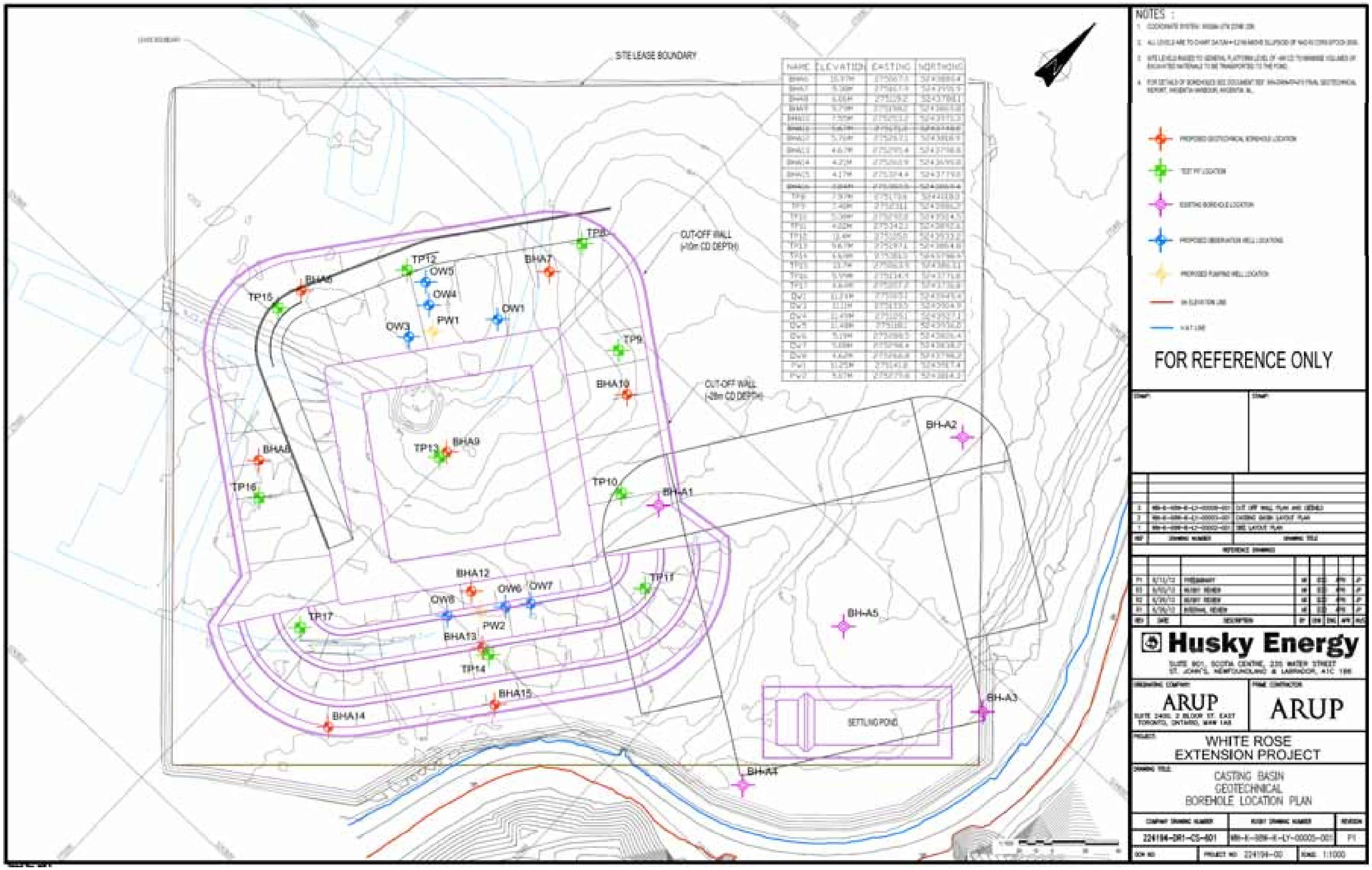


Figure 2-7 Environmental Site Assessment Site Plan

In addition, the southwest portion of the graving dock site is immediately adjacent to the former net dipping area. During United States Naval (USN) occupation, this area was used to manufacture submarine nets reportedly used to protect the harbour entrance. Historically, there were three concrete structures: a net weaving slab; a net dipping tank; and an unidentified concrete slab. The 1993/1994 Phase I/II ESA report indicates the net dipping tank contained a mixture of creosote, tar and other products to coat the metal buoys and nets. In addition, it is reported that one wall of the net dipping tank was destroyed in the 1970s, resulting in the release of the creosote mixture to the surrounding soil. A subsurface investigation was completed in this area as part of PWGSC's 1995 Phase III/IV ESA and included excavation of two test pits and drilling and installation of four monitor wells, with related soil and groundwater sampling for petroleum hydrocarbons, polycyclic aromatic hydrocarbons (PAHs), radionucliides and metals. Results indicated no significant issues of concern and no further assessment or remediation work was completed at the site.

Soil and groundwater analysis in 1995 of monitoring well NFSA-515-MW indicated no detectable concentrations of petroleum hydrocarbons. Similarly, no detectable concentrations of petroleum hydrocarbons were detected at monitor wells NFSA-514-MW and N-MW1B-35. No analytical data have been found for test pits N-TP1B-139 and 140, but no field evidence of impacts were noted in the logs for these test pits. The NFSA remediation was completed from 2005 to 2007, so soil conditions would have improved since the historical data were collected.

The closure report indicates that based on the depth of impacts, the relatively low hydraulic gradient and the distance from any receptor (i.e., Argentia Harbour), it is unlikely that remaining contamination in these areas will cause adverse environmental affect. Husky's own environmental sampling at the graving dock (Section 2.6.3.3) has confirmed the conclusions of the closure report.

NFSA soil has not been influenced by the thermal remediation project at Argentia (K. Knight, PWGSC, pers. comm.). Soil from the NFSA was not thermally treated, only land-farmed. Polychlorinated biphenyls (PCBs) were never an issue at the NFSA (which have been confirmed by recent sampling) and dioxins and furans may therefore only occur as a result of airborne emissions in surface soil.

2.6.3.3 Husky's Environmental Sampling at Graving Dock

Husky and its consultants have reviewed the history of the environmental sampling and remediation near graving dock and have completed a recent investigation of soils testing to confirm the suitability of the site for the purpose of graving dock construction.

The initial environmental investigation involved the excavation of ten test pits with related soil sampling from within the footprint of the graving dock site. The program was initiated to determine if any environmental impacts exist at the site. A copy of the report (Stantec 2012a) was sent to the NLDEC for review. A summary of that report is provided in the following text.

Total petroleum hydrocarbons (TPH) were detected in seven of the ten soil samples, with concentrations ranging from 20 to 64 ppm. However, the concentrations of TPH in the soil samples did not exceed the Atlantic PIRI Tier I RBSL for lube oil on an industrial/ commercial site with non-potable groundwater use and coarse-grained soil (i.e., 10,000 mg/kg). The analytical results indicated that the product impacting the soil sample TP13-BS2 resembled lube oil; while the concentrations of TPH detected in the other soil samples were identified as having no resemblance to petroleum hydrocarbon products, and therefore possibly related to organic interference.

One of the ten samples reported benzene and toluene at 0.029 and 0.072 ppm, respectively; which is well below their Atlantic PIRI Tier 1 RBSL guidelines of 2.5 and 10,000 ppm. Other BETX compounds (ethylbenzene and xylene) were not detected.

Low level PAHs were detected in 8 of 10 soil samples analyzed, ranging from 0.011 to 0.179 ppm. However none of the detected concentrations of PAHs exceeded industrial/ commercial human health or environmental guidelines.

PCBs were detected at low-levels in two of the ten samples reporting concentrations of 0.082 and 0.068 ppm, compared to the CCME industrial/commercial land use guideline of 33 ppm.

The available metals analysis from the ten soil samples reported all metal concentrations were either not detectable or well below the CCME guideline for industrial/commercial land use (Table 2-8).

The analysis of volatile organic compounds in soil from the ten test pits reported only one single above the reportable detection limit of 0.025 ppm, which was toluene at a concentration of 0.026 ppm in one sample, versus a guideline of 10,000 ppm.

Two test pit samples were analyzed for dioxins and furans and reported a total toxic equivalency of 1.34 and 0.374 pg/g (parts per trillion), well below a CCME industrial/commercial guideline of 4 pg/g.

The results and conclusions of the test pit report (Stantec 2012a) are:

- The stratigraphy observed on the site was generally similar at all test pit locations and comprised loose to dense brown silty sand (SM) with varying percentages of gravel, cobbles and boulders. With the exception of minor wood debris identified at 1.0 m depth in test pits TP9 and TP10, as well as a zone of various concrete and metal debris identified from 1.0 to 2.0 mbgs in test pit TP13, no other debris as identified in any of the other test pits completed as part of the current investigation. No bedrock was encountered in any of the test pits completed as part of this site investigation.

- Groundwater seepage was observed in the test pits at depths ranging from 2.0 m to 4.5 mbgs at the time of the excavation. Based on site topography and site observations, the direction of shallow groundwater flow at the site is inferred to be southeast towards the waters of Argentia Harbour.

- No free liquid phase petroleum hydrocarbons were observed at the site during the current investigation, and no field evidence of petroleum hydrocarbon impacts were observed in any of the test pits during excavation.

Table 2-8 Available metals in Soil Test Pit Samples from the Graving Dock

Parameter	Units	RDL	Guideline[1]	TP8-BS2	TP9-BS1	TP10-BS3	TP11-BS3	TP12-BS2	TP12-BS2 Lab-Dup	TP13-BS2	TP14-BS3	TP15-BS4	TP16-BS1	TP17-BS3
				1.0 - 2.0 mbgs	0.5 - 1.0 mbgs	2.0 - 3.0 mbgs	2.0 - 3.0 mbgs	1.0 - 2.0 mbgs	-	1.0 - 2.0 mbgs	2.0 - 3.0 mbgs	3.0 - 4.0 mbgs	0.5 - 1.0 mbgs	2.0 - 3.0 mbgs
Aluminum (Al)	mg/kg	10	-	13,000	14,000	13,000	12,000	13,000	13,000	12,000	12,000	13,000	10,000	11,000
Antimony (Sb)	mg/kg	2	40	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
Arsenic (As)	mg/kg	2	12	4.8	4.5	4.4	4.5	4.3	4.2	4.1	4.0	4.2	4.1	3.0
Barium (Ba)	mg/kg	5	2,000	55	55	39	40	32	32	26	34	43	17	10
Beryllium (Be)	mg/kg	2	8	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
Bismuth (Bi)	mg/kg	2	-	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
Boron (B)	mg/kg	5	-	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
Cadmium (Cd)	mg/kg	0.3	22	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
Chromium (Cr)	mg/kg	2	87	27	26	24	24	24	25	25	23	26	23	19
Cobalt (Co)	mg/kg	1	300	13	14	12	12	13	13	12	12	13	11	11
Copper (Cu)	mg/kg	2	91	40	40	34	36	39	38	32	35	41	28	7.3
Iron (Fe)	mg/kg	50	-	29,000	29,000	27,000	26,000	27,000	27,000	25,000	26,000	27,000	21,000	24,000
Lead (Pb)	mg/kg	0.5	600 (260)	45	44	34	30	28	28	44	33	60	32	14
Lithium (Li)	mg/kg	2	-	21	21	18	19	20	20	17	18	18	15	18
Manganese (Mn)	mg/kg	2	-	1,100	1,100	990	880	1,100	1,200	1,100	1,200	1000	780	590
Mercury (Hg)	mg/kg	0.1	50 (24)	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
Molybdenum (Mo)	mg/kg	2	40	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
Nickel (Ni)	mg/kg	2	50	20	20	19	19	19	21	18	19	21	19	17
Rubidium (Rb)	mg/kg	2	-	3.3	3.1	2.7	2.1	2.0	nd	nd	nd	3.0	nd	nd
Selenium (Se)	mg/kg	2	2.9	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
Silver (Ag)	mg/kg	0.5	40	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
Strontium (Sr)	mg/kg	5	-	20	18	22	17	18	17	15	15	63	12	16
Thallium (Tl)	mg/kg	0.1	1	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
Tin (Sn)	mg/kg	2	300	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd	nd
Uranium (U)	mg/kg	0.1	300 (33)	0.42	0.38	0.42	0.38	0.42	0.36	0.33	0.36	0.41	0.25	0.36
Vanadium (V)	mg/kg	2	130	37	38	38	34	36	36	35	33	39	28	34
Zinc (Zn)	mg/kg	5	360	98	110	83	79	86	80	85	78	98	68	63

Notes:

[1] = Canadian Council of Ministers of the Environment (CCME) Soil Quality Guidelines for the Protection of Environmental and Human Health for industrial/commercial land use (current as of October 2012). Typically guideline the same for both land uses; where they differ industrial guideline shown outside, and commercial guideline shown in brackets.

RDL = Reportable Detection Limit.

nd = Not detected above RDL.

Lab-Dup = Laboratory QA/QC duplicate sample.

- Concentrations of petroleum hydrocarbons, PCBs, VOCs, available metals, dioxins/furans and PAHs in all soil samples analyzed were either non-detect or detected at levels below the applicable assessment criteria, and are thus not considered to be an environmental concern in evaluated areas of the site.

Based on the results of the test pit investigation, the report (Stantec 2012a) makes the following recommendation:

> This program was limited to the evaluation of surface and subsurface soils at the site; and did not include any investigation of groundwater. While results of the current program suggest that it is unlikely that any significant groundwater impacts are present at the site, this would require verification through completion of a groundwater sampling and analysis program.

Husky has therefore initiated the following groundwater quality investigation:

- Collect groundwater samples from two observation wells to be installed at the site as part of the hydrogeological program. Note the locations of the two proposed observation wells to be sampled are OW1 and OW8 in Figure 2-7.
- Analyze groundwater samples from each of the two observation wells for petroleum hydrocarbons, dissolved metals, general chemistry, PCBs, PAHs and volatile organic compounds (VOCs).
- Collect post-pumping groundwater samples from test well PW1 following the 96-hour hydrogeological pump test and analyze for petroleum hydrocarbons, dissolved metals, general chemistry, PCBs, PAHs and VOCs.
- Document the groundwater sampling program scope, methodology and results in a written report to be submitted to the NLDEC.

The results of the groundwater analysis will be tabulated and compared to applicable guidelines. In addition, previous results of groundwater sampling from former monitor well BH-A1 will also be included in the report and will be used to characterize baseline groundwater conditions at the site.

As further investigation of potential contamination at the graving dock construction site, soil samples from six boreholes were analyzed from above and below the water table at each borehole. The results of this draft report (Golder 2012) are:

- BTEX (benzene, toluene, ethylbenzene and xylene) was not detected in any of the 12 soil samples.
- Hydrocarbons were detected in 4 of the 12 samples with TPH concentrations ranging from 27 to 38 ppm. However, the concentrations of TPH in the soil samples did not exceed the Atlantic PIRI Tier I RBSL for lube oil on an industrial/commercial site with non-potable groundwater use and coarse-grained soil (i.e., 10,000 mg/kg). The analytical results indicated that the product impacting the two soil samples from each of BH13 and BH14 resembled lube oil.
- PAHs were not detected in any of the 12 soil samples.

- PCBs were not detected in any of the 12 soil samples.
- VOCs and semi-volatile organic compounds (sVOC) were not detected in any of the 12 soil samples.
- The available metals analysis from the 12 soil samples reported all metal concentrations were either not detectable or well below the CCME guideline for industrial/commercial land use.

A report containing the results of the soil chemistry from the borehole samples (Golder 2012) will be submitted to the NLDEC once finalized.

2.6.3.4 Site Dewatering and Disposal

The method and degree of drainage required to maintain a dry graving dock during the construction of the CGS will be determined during the FEED and design engineering stage for the WREP.

To estimate the degree of dewatering that maybe required from the excavation of the graving dock, hydraulic response (bail down) tests will be carried out on seven monitor wells to determine the permeability of the underlying overburden and bedrock stratigraphy at each location. Bail-down tests will be conducted by removing a volume of water from each well and recording the water levels in the well at specific time intervals as the water levels recover.

The purpose of this hydrogeological investigation is to evaluate the groundwater flow conditions. In particular, estimates of various hydraulic properties including transmissivity, hydraulic conductivity and storativity will be determined to provide information on potential groundwater inflows into the graving dock in support of engineering dewatering design.

Appropriate retaining structures and pumps will be designed to minimize the water infiltration and to remove the excess water. Water removed from the graving dock will be pumped to a lined 2,700 m^2 settling pond, where it will be aerated and tested against applicable regulations prior to ocean disposal. This settling pond will also be used to contain and test runoff from the site prior to ocean disposal, once the graving dock construction is complete. Water will be treated with a mobile treatment unit as required prior to discharge to ensure compliance with provincial and federal requirements.

Contaminated groundwater is not expected to be drawn from adjacent land during the graving dock excavation. Adjacent land has been remediated and during the remediation, groundwater testing indicated the general absence of free phase separated product (Dillon 2011). Groundwater monitoring from eight monitoring wells around the perimeter of NFSA (see Figure 2-7) in August 2011 revealed petroleum hydrocarbons in five wells ranging from 0.04 to 1.3 mg/L. The impacts are sporadic occurrences and reflective of residual non-point source impacts (K. Knight, PWGSC, pers. comm.). There are no known users of groundwater on the Argentia Peninsula.

2.6.4 The Pond

Approximately 250,000 m^3 of the material excavated from the graving dock site is intended to be used for infilling and grading of the Husky lease area. The entire site will be elevated to 8 m above chart datum to reduce the risk of marine-sourced flooding at the site. However, before the material is used on site, it will be tested for environmental and geotechnical suitability.

Material that is not used on site is intended to be disposed of in The Pond, provided it meets established criteria and the activity is in compliance with the provincial Policy for Infilling Bodies of Water, should it be applicable. The Pond is not within 15 m of the high water mark of Placentia Bay (highest line of beached kelp). Nonetheless, Husky is committed to testing and treating material as required.

If it is assumed that all the material from the graving dock that is not used for levelling and grading (approximately 850,000 m^3) and all the material to be dredged (approximately 368,000 m^3; Section 2.7.2) is disposed of in The Pond, the material volume would exceed the water volume presently in The Pond. The Pond therefore would be completely filled in above the existing water level. However, the volume of material to be disposed would not exceed the volume of the natural basin of The Pond. A recent survey by C-CORE has estimated the volume of The Pond's basin is approximately 1,504,000 m^3, which would contain the approximately 1,218,000 m^3 of material to be disposed (C-CORE 2012a).

As the excavated material is disposed of along the eastern side of The Pond by dump trucks and spread over the site, water from The Pond will be displaced. To control the discharge of displaced water, Husky will construct a weir and a well at the west side of The Pond. This would allow the settlement of suspended sediments and testing of water quality to ensure compliance prior to discharge to the marine environment.

A biophysical description of The Pond is provided in Section 2.6.4.1. An overview of the historical and more recent assessment of sediment and water chemistry in The Pond is provided in Sections 2.6.4.2 and 2.6.4.3, respectively. An assessment of disposal options for the excavated and dredged material is provided in Section 2.3.2.

2.6.4.1 Biophysical Description of The Pond

The Pond, measuring approximately 15 hectares surface area, is the only water body on the Argentia Peninsula (Figure 2-8). It is elongated in the east-west direction and is 775 m long by 300 m wide, with a maximum water depth of 7.8 m and a water volume of approximately 792,990 m^3 (C-CORE 2012a). The substrate is primarily fines/clay (anoxic) and the surface area of the bottom is approximately 148,300 m^2. The Pond appears to have been altered from its natural marine environment and used for waste disposal. The Pond is present in known historical photos; however, it was open to the ocean via a channel (Figure 2-9). Between 1941 and 1943, it was used for the disposal of an estimated 240,700 m^3 (8.5 million cubic feet) of peat excavated during construction of the nearby runway (http://www.heritage.nf.ca/law/argentia_base.html#peat), as illustrated in Figure 2-10.

Figure 2-8 The Pond – Looking East

Figure 2-9 Argentia Peninsula Aerial Photo Showing the Open Channel of The Pond circa 1939

Figure 2-10 Argentia Peninsula Aerial Photo Showing Peat Disposal in The Pond

The Pond's water is brackish, with a probable seawater intrusion from Placentia Bay through the gravel ridge between The Pond and the ocean and by waves and spray overtopping the gravel divider during severe storms or high tide events (ARG 1995). It is believed to be hydraulically connected through a cobble barasway/berm, with in-flow through a groundwater stream at the southeast end of The Pond (ARG 1995).

A debris survey by divers was conducted in The Pond in 2003 and found dory remnants, concrete pipe and blocks, creosote wooden piles, corroded steel pipe, car battery, wire, sheet metal, steel and aluminum boxes, remnants of drums, tires and decking. PWGSC have intentions of removing selected items of debris prior to any further commercial/ industrial use of The Pond (K. Knight PWGSC, pers. comm.). Remaining debris would be buried by the excavation material from the graving dock, rather than being removed and buried offsite.

Few species and individual fish are present in The Pond, as concluded in the study conducted by PWGSC in 1998 (ARG 1998). Under the direction of DFO, Husky also conducted a fish survey of The Pond in June and September 2012 using gillnets and baited char and minnow traps and underwater video and the only observed fish species were three-spine stickleback (*Gasterosteus aculeatus*).

DFO has been consulted about use of The Pond for excavated and dredge spoil material disposal. After considerable sampling effort within The Pond, a fish habitat characterization report (Stantec 2012b) was submitted to DFO for review. DFO has subsequently determined that The Pond does not constitute productive fish habitat and may be considered for the purpose of material disposal (DFO letter to Husky, October 2, 2012).

2.6.4.2 History of the Environmental Sampling and Remediation Studies at The Pond

The ARG studied the contaminant levels in The Pond and identified TPH and PAH contamination likely resulting from subsurface transport and runway runoff and metals contamination possibly from air emissions. Water samples also showed signs of copper and nickel contamination from sediment and subsurface transport (ARG 1995).

As a follow-up, the ARG conducted an ecological risk assessment (ERA). The ERA concluded that terrestrial and avian species are not expected to be at risk from The Pond, but there was potential for sub-lethal effects on fish and other aquatic biota from PAHs (ARG 1998). As part of the ERA, The Pond was assessed to determine whether remedial action was warranted to reduce exposure to fish (ARG 1998). In the assessment of whether remediation was warranted, remedial action objectives (RMOs) were set. RMOs are the levels above which sediments would be considered for remediation. The RMOs for each contaminant assessed and the corresponding sediment chemistry results from The Pond are summarized in Table 2-9. One sample from The Pond exceeded the total PAH RMO of 11.4 mg/kg at a concentration of 18.9 ppm. Based on this review, it was determined that additional remediation was not required.

Table 2-9 Remedial Action Objective for The Pond

Parameter	RMO (ppm)	Concentration (ppm)
Lead	187	<1 to 71
TPH	1,900	<30.2 to 1,600
Total PAHs	11.4	0 to 18.9
PCBs	1.7	<0.05 to 1.7
Source: ARG 1998		

2.6.4.3 Husky's Environmental Sampling at The Pond

Recognizing the history of The Pond, Husky completed a recent investigation of water and sediment contamination in The Pond. The locations for eight sediment and water stations were randomly selected throughout The Pond and all samples were tested for available metals, PAHs, PCBs, TPH and BTEX.

The PAH fluoranthene was found to exceed the CCME marine probable effect level (PEL) (1.494 mg/kg) at one sediment station, with a concentration of 2.6 mg/kg. As well, pyrene was reported at 1.8 mg/kg from the sediments at the same station, which exceeds the CCME PEL of 1.398 mg/kg. Marine PELs are used for comparison with sediments from The Pond following the *Protocol for the Derivation of Water Quality Guidelines for the Protection of Aquatic Life* (CCME 2007).

Total PCBs were reported from four of the eight sediment samples ranging from 0.25 to 0.38 mg/kg, which exceeds the CCME PEL of 0.189 mg/kg.

The CCME PEL guideline for copper (108 mg/kg) was exceeded in the sediment of one station, reporting a concentration of 130 mg/kg.

Analysis of pond sediment samples for TPH revealed the presence of lube oil range hydrocarbons ($>C_{21}$-$<C_{32}$) at all eight stations, ranging from 170 to 500 mg/kg. One station reported fuel oil range hydrocarbons at 130 mg/kg ($>C_{10}$-C_{16}) and 54 mg/kg ($>C_{16}$-C_{21}). BTEX compounds were not detected in any of the sediment samples. None of the TPH results exceed the Atlantic RBCA guidelines for commercial sites or the CCME soil quality guidelines.

Eight water samples were also taken at random locations throughout The Pond and all were tested for available metals, PAHs, PCBs, TPH and BTEX.

BTEX, TPH and PCBs were not detected in any of the eight water samples.

Only one PAH was reported - phenanthrene, at the reportable detection limit of 0.01 µg/L. Of the metals with guidelines, only mercury exceeded the CCME PEL guideline of 0.016 µg/L at two stations, with concentrations of 1.2 and 0.14 µg/L. Eight additional water samples were collected approximately two months after the initial eight and mercury was not detectable in any sample.

The Pond water chemistry results were compared to the maximum content in Schedule A of the Newfoundland and Labrador *Environmental Control Water and Sewage Regulations* (2003); however, none of the parameters exceeded the guidelines of these regulations.

2.7 Construction

2.7.1 Concrete Gravity Structure Construction at Graving Dock

The CGS will be constructed in the dry, which means completing the CGS in the graving dock, prior to towing to the deep-water site for topsides mating. The primary materials for the CGS are cement, sand, gravel and steel rebar for the concrete, and structural steel and pipe for the shaft. The current estimate of the required volume of concrete is approximately 64,000 m^3. Slip-forming and other standard CGS construction methods will be used for the caisson and central shaft construction after completion of the base slab (Figure 2-11). The CGS as currently designed is approximately less than 50 percent of the size of the Hibernia (165,000 m^3 base, 37,000 tonne topsides) and Hebron (120,000 m^3 base 40,000 tonne topsides) gravity base structures. Construction work is expected to occur over a period of 20 to 24 months.

A concrete batch plant will be used on site for concrete production. Washwater from the cleaning of cement mixers, trucks and concrete delivery systems will be directed to a closed system rinsing/settling basin. In the event that water from the closed settling system is to be released, it will be tested prior to release for parameters related to any concrete additives to be used in the production of concrete (e.g., total hydrocarbons, pH and total suspended solids). The water to be released will meet the limits specified in Schedule A of the *Environmental Control Water and Sewage Regulations*. Aggregate for the high-strength concrete will be obtained from an existing, permitted quarry in the Province with an existing capacity for the order. Over the estimated 20 to 24 months required to construct the CGS, aggregate could be delivered by road at a rate of 12 to 15 trucks per day, depending on the location of the aggregate source. Marine transportation of aggregate will also be considered, given a suitable loading site near the producing quarry.

The selection of the quarry will be subject to testing of the aggregate to ensure it is suitable for the high-strength concrete required for the CGS. Caisson and shaft supports will be cast into the concrete for future use when completing the mechanical fit-out of the CGS. Sourcing aggregate from the dredge spoils in the CGS tow-out channel is not a feasible option because the dredging is planned four to six months prior to the CGS tow-out to ensure the channel does not fill back in prior to tow-out. A reliable channel cannot be dredged during construction of the CGS, approximately two years prior to tow-out.

The mechanical fit-out of the CGS will consist of prefabricated components that will be installed at various phases of the base slab, caisson and shaft construction. The typical mechanical components are seawater ballast pipework, deep-water pump caissons, disposal caissons, risers, J-tubes and conductor guide frames.

A list of potential activities during CGS construction and installation and associated emissions and discharges is provided in Table 2-10.

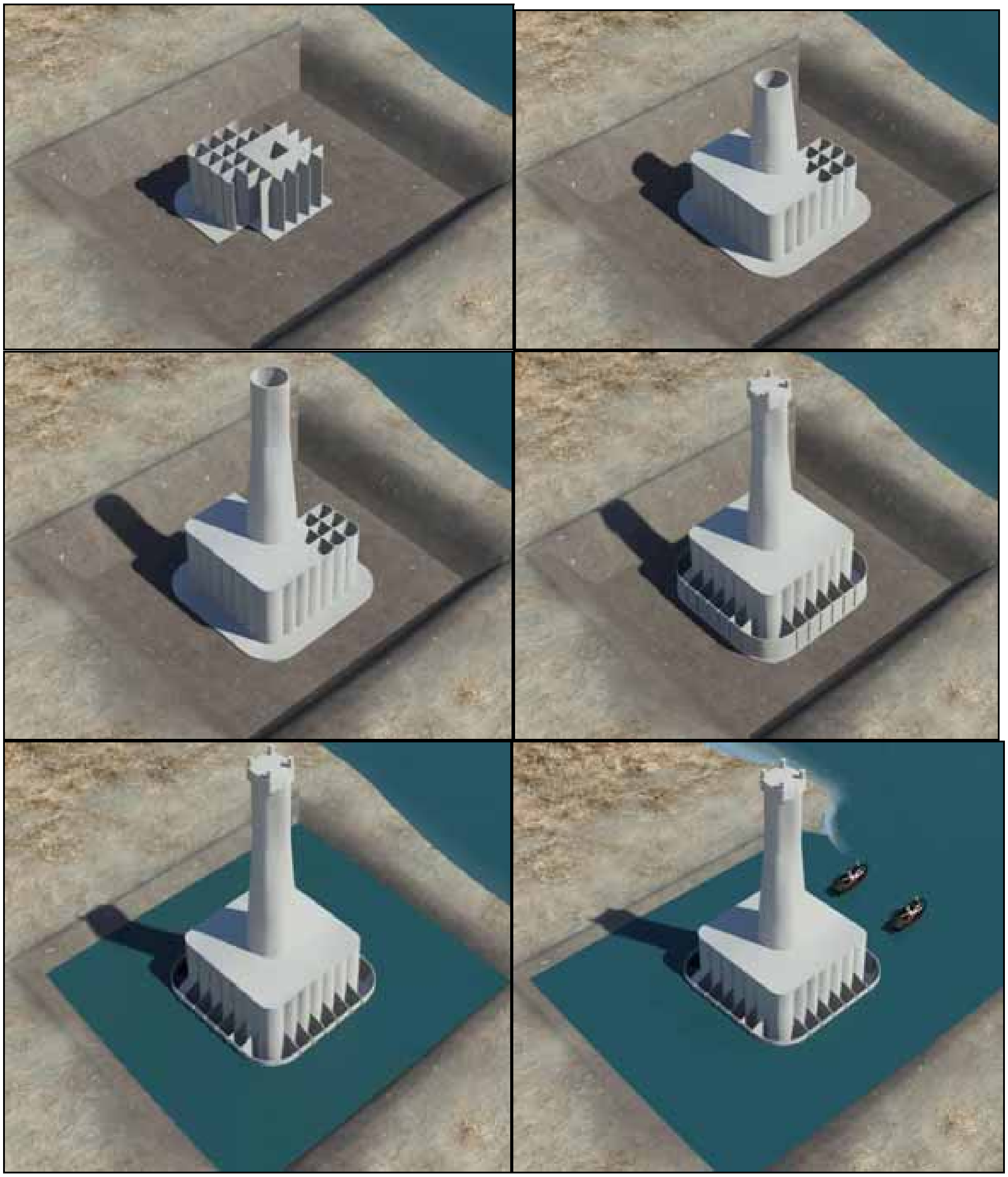


Figure 2-11 Construction of the Concrete Gravity Structure

Table 2-10 Potential Discharges and Emissions Associated Concrete Gravity Structure Construction Activities

Potential Activities	Potential Discharges/Emissions/Wastes from all Activities
Concrete production Back-up power generation Slip-forming Chemical/fuel storage Road transportation of materials, equipment, and personnel Water requirements (potable water, fire water and industrial water) Waste generated (domestic waste, construction waste, hazardous, sanitary waste) Use of new sewage treatment plant Continued use of fabrication and laydown yards Bulk material handling (sand, cement, crushed rock, aggregate) Welding and x-ray inspections	Air emissions Site run-off and water from the graving dock Concrete waste water Noise (including underwater) Solid, construction, hazardous, domestic and sanitary waste disposal

2.7.2 Shoreline Dredging

2.7.2.1 Overview of Dredging Activities

Once the CGS is completed, the graving dock will initially be flooded to equalize the hydrostatic pressure, then a combination of land-based excavation equipment and a coastal dredger will be used to remove the shoreline berm, after which the float-out will occur. The dredger will be used to create an exit channel from the graving dock to a water depth of approximately 18 to 20 m to accommodate the draft of the CGS (approximately 165,400 m^3). It is currently estimated that this excavation/dredging work will take between six and eight weeks to complete. During this period, the marine activities from the dredging operation will be closely coordinated with the Port of Argentia.

Shoreline dredging activities can be executed with the use of a cutter suction dredge or a backhoe dredger (approximately 200,300 m^3). Earth-moving equipment will be required to lower the level of the shoreline to the minimum dredging depth of the cutter suction dredge. Once the soil is loosened by the cutter suction dredge, the soil will be sucked into the dredger and pumped through a floating pipeline from the stern of the barge to the shoreline, where it will be connected to a land-based pipeline for discharge to The Pond on the tip of the Argentia Peninsula. If a backhoe dredger is used, it will deposit the excavated material into a transportation barge alongside the dredger. The barge will transport the dredged material to quayside for offloading and transportation to The Pond by earth-moving equipment.

DFO has been consulted about the dredging requirements for tow-out of the CGS. A fish and fish habitat survey of the dredge areas (Stantec 2012b) was conducted by Husky following established DFO protocol (see section 8.3.1.2).

2.7.2.2 Sediment Chemistry in the Nearshore Dredge Area

Samples from the four boreholes along the shoreline of the graving dock were too coarse to retain for chemical analysis. Several attempts with different recovery techniques were unsuccessful. The soils from seabed to -19 m were described as very loose gravel, some sand and trace silt.

However, surficial sediment samples from 20 locations at various water depths within the area planned to be dredged were tested for available metals, PAHs, PCBs, TPH and BTEX.

BTEX compounds were not detected in the marine sediment samples.

Total PAH levels were reported in 13 of the 20 samples, ranging in concentrations from 0.01 to 4.16 mg/kg. Three samples exceeded the marine sediment CCME PEL guideline of 0.544 mg/kg for phenanthrene, with concentrations of 0.55, 0.57 and 0.58 mg/kg. The commercial or industrial use soil quality CCME Guideline for phenanthrene is 50 mg/kg.

Hydrocarbons were not detected in the 10 shallow subtidal (1 to 2 m) sediment samples collected close to the shoreline. However, hydrocarbons were detected in all 10 samples from the deeper water (13 to 20 m) sediment samples, with TPH concentrations ranging from 93 to 460 mg/kg. All samples were below the Atlantic RBCA guidelines for commercial sites (7,400 mg/kg), but 5 of the 20 samples exceeded the residential use guideline of 140 mg/kg.

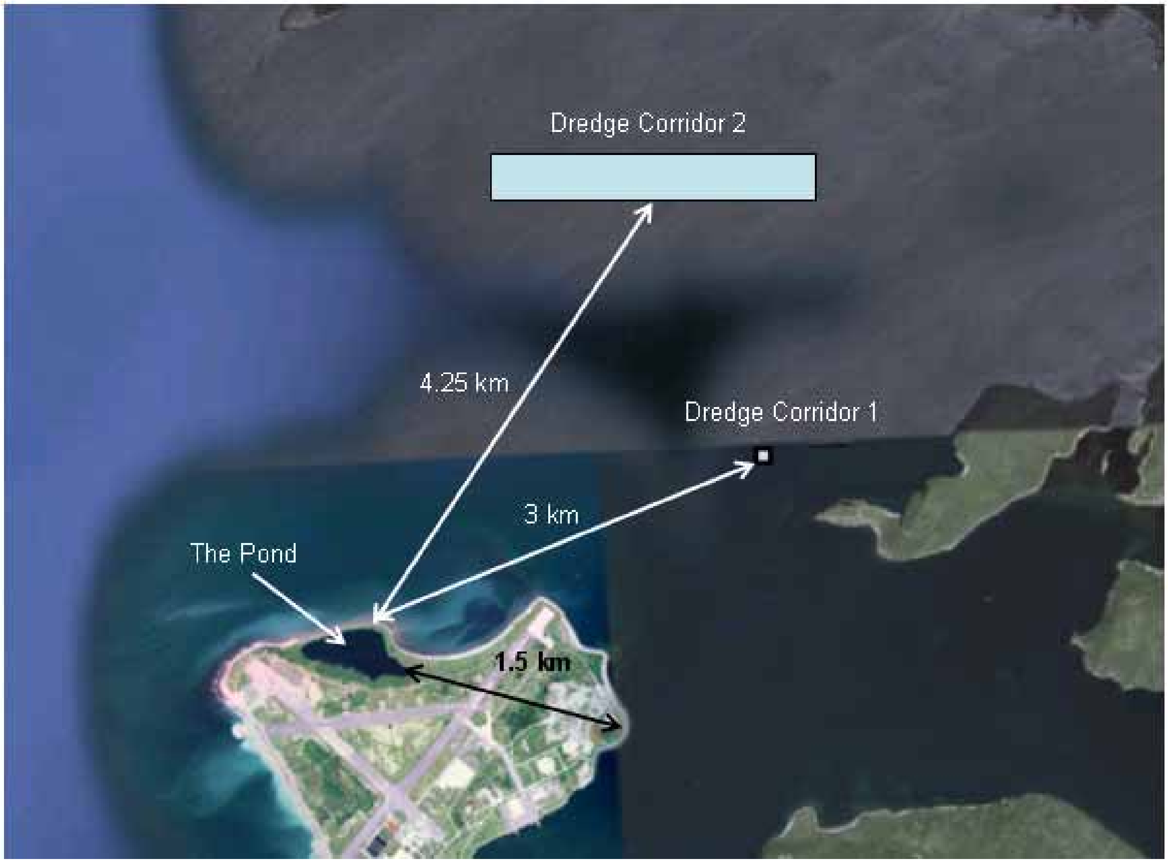
PCBs were detected at 1 of 20 stations at a concentration of 0.19 mg/kg, which is marginally above the CCME PEL of 0.189 mg/kg, but not above the CCME SQG of 33 mg/kg for commercial and industrial use.

Of the 26 metals tested, none were above the CCME marine sediment PEL or SQG.

2.7.3 Tow-out Channel Dredging

2.7.3.1 Overview of Dredging Activities

Husky has completed a bathymetric survey of the CGS tow-out route to ensure adequate water depth exists for the draft of the CGS. The survey identified that dredging will be required in two sections of the tow-out channel (as noted in Figure 2-12). At Corridor 1, approximately 25 m^3 of sediment is required to be dredged over an area roughly 280 m^2 and at Corridor 2, approximately 165,000 m^3 is required to be dredged over an area approximately 215,000 m^2. It is anticipated that the work could be completed in four to six weeks using a trailing suction hopper dredger.



Source: Google Earth 2012

Figure 2-12 Corridors Requiring Dredging along the Concrete Gravity Structure Tow-out Route

As part of the WREP environmental assessment, a site-specific sediment suspension model (AMEC Environment & Infrastructure (AMEC) 2012a) demonstrated that using this dredge method, suspended sediment levels will not exceed the *Canadian Water Quality Guidelines for the Protection of Aquatic Life* (CCME 2002). Suspended sediment concentrations above 25 mg/L are expected to persist for no more than four hours within an area of approximately 0.7 km^2, in all wind scenarios. Concentrations above 10 mg/L would persist for approximately six hours, and total suspended solid levels above 5 mg/L would last for about 10 hours for a single dredging operation. A trailing suction hopper dredger will transfer the sediment into the hopper of the vessel. The soft material within the tow-out corridors could be removed easily with a trailing suction hopper dredger; if necessary, the assistance of a backhoe dredger for harder material may be required.

Once full, the dredge vessel will transit to quayside where it will be connected to a temporary land-based pipeline and the material pumped ashore for discharge to The Pond. These pipelines can be extended and repositioned in such a way that the sediment will be placed evenly over The Pond area. At the end of the pipeline, earth-moving equipment will be used for the final spreading and levelling of the material, if necessary.

The marine logistics associated with the dredging operation will be coordinated with the Port of Argentia. As previously stated, The Pond at the head of the Argentia Peninsula has been evaluated as the primary spoils disposal site. Disposal at sea has also been evaluated and based on consultations with fish harvesters, Environment Canada and DFO, Husky has determined that The Pond is the preferred option (see Section 2.3.2.3). During the construction of the CGS and its subsequent float-out, there will be no requirement for a breakwater.

2.7.3.2 Sediment Chemistry along the Concrete Gravity Structure Tow-out Route

Husky has conducted extensive sampling within the areas to be dredged to test sediment chemistry and to assess effects to fish habitat. A fish habitat report summarizing the results of the survey (Stantec 2012b) was submitted to DFO in September 2012.

Ten surficial substrate samples within Corridors 1 and 2 (Figure 2-12) were primarily sand with fractions of silt and clay. Each sample was tested for available metals, PAHs, PCBs, TPH and BTEX. BTEX compounds were not detected in the marine sediment samples.

One sample reported detectable concentrations of hydrocarbons from Corridor 1 at a concentration of 24 mg/kg. Two samples from Corridor 2 reported TPH concentrations of 19 and 32 mg/kg. Each of these three reports of hydrocarbon were in the lube oil range ($>C_{21}<C_{32}$) and all were below applicable guidelines.

PAHs were detected in both samples from Corridor 2, with total PAH concentrations of 0.47 and 0.96 mg/kg, respectively. Individual PAHs were below CCME marine PEL guidelines and commercial/industrial SQG.

In Corridor 1, PAHs were reported in three of eight samples, with phenanthrene being detected at concentrations of 0.013, 0.007, and 0.010 mg/kg. The phenanthrene CCME PEL is 0.544 mg/kg and for commercial/industrial SQG is 50 mg/kg.

Total PCBs were not detected in either dredge corridor.

Of the 26 metals tested, none were above the CCME PEL or SQG.

2.7.4 Topsides Fabrication and Assembly

The topsides will consist of drilling facilities, wellheads and support services such as accommodations for 120 to 130 persons, utilities and a helideck. The topsides will be constructed at an existing fabrication facility and are therefore not considered part of this environmental assessment.

Upon completion of the fabrication and commissioning work, the topsides structure will be loaded onto a heavy-lift transportation vessel, and transported to the deep-water mating site in Placentia Bay.

2.7.5 Tow-out to Deep-water Site

Once construction of the CGS is complete, the structure will be floated out of the graving dock and towed to a deep-water site in Placentia Bay for installation of the topsides. Two potential deep-water sites have been identified, west of Red Island and west of Merasheen Island (Figure 2-13). A decision between the two potential mating sites will be made after further site evaluation, including local stakeholder consultation, to obtain all necessary information about the tow-out route and the deep-water location.

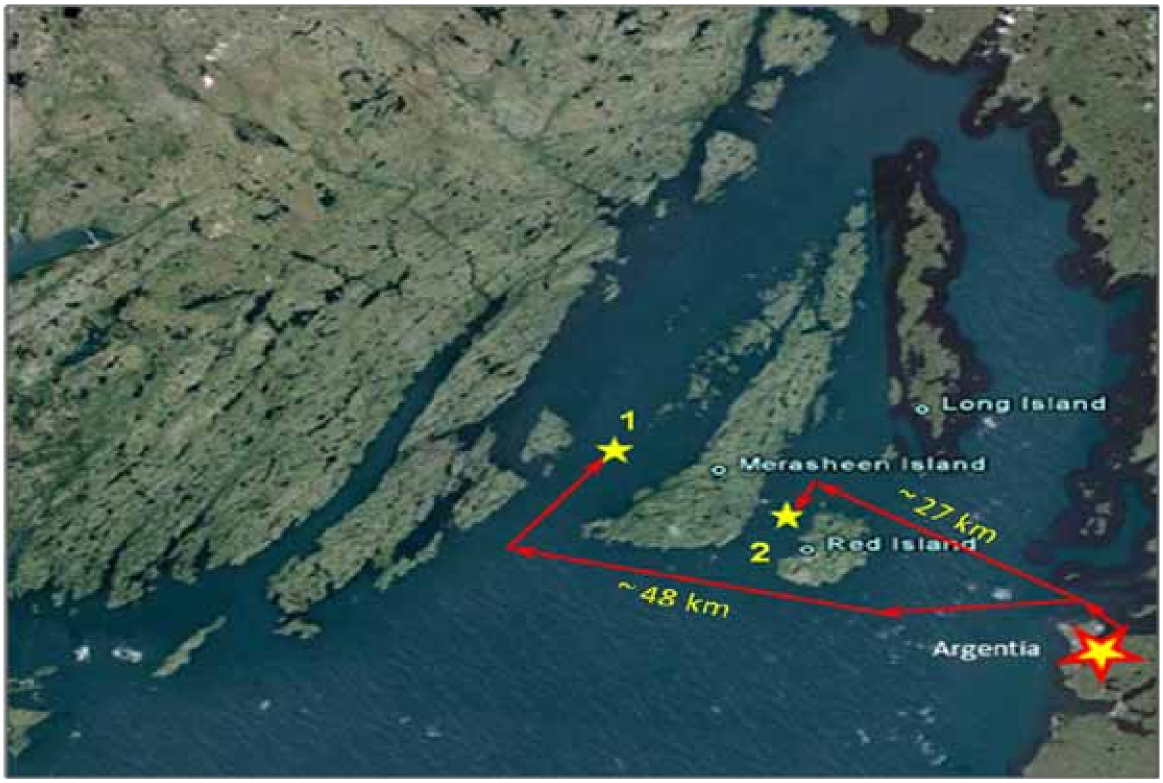


Figure 2-13 Potential Deep-water Mating Sites

Husky anticipates that four tugs, each of a capacity between 12,000 and 15,000 horsepower, will be used for the transit. It is currently estimated that two to four days will be required for the CGS transit to the deep-water site. Upon arrival at the deep-water site, the tow tugs will hold the structure at the required location while four moorings are connected to the structure and tightened to maintain position for the installation of the topsides. The tow tugs will then be disconnected.

The CGS will be ballasted to a predetermined depth for the installation of the topsides. The initial ballasting will use water to achieve the required draft for the CGS. Once installation of the topsides is complete, a transition from water ballast to solid ballast will occur at the deep-water mating site; this activity will be integrated with the topsides/CGS hook-up.

2.7.6 Topsides Mating and Commissioning

Two methods for the installation of a topsides structure are contemplated; float-over or heavy lift with the use of a single or dual crane heavy-lift vessel. The method that will be used will be determined during FEED.

The position of the CGS will be maintained by four pre-installed seabed anchors, which will be connected to mooring points on the CGS by anchor chain approximately 1,500 m each in length. Husky does not anticipate the need for cables connected to the land. Each leg of the overall mooring system will be comprised of a seabed anchor, pennant wire and buoy for deployment and recovery of the anchor, a chain connecting the anchor to the CGS and a tension pontoon aligned with the chain. These moorings will be set and marked just prior to the float out of the CGS from the graving dock. The mooring systems will be recovered and removed from the deep-water site once the topsides facility has been mated with the CGS and is under tow to the offshore site. The CGS itself will not be in contact with the seafloor.

During the mating operation and inshore hook-up work, the Port of Argentia will be used as a logistics base for the supply of materials, equipment and personnel. There will be limited marine traffic between the deep-water site and the Port of Argentia throughout the time that the WHP is at the deep-water site, currently estimated to be six to eight weeks.

During the topsides mating, there will be an accommodation vessel for the estimated 100 workers engaged in this component of the work. At all times, the accommodation vessel will have an assistant tug of approximately 5,000 horsepower, with a supply boat of similar size used for logistic runs to the Port of Argentia. Regulated marine vessel discharges can be expected at the deep-water mating site. Air emissions can be expected from the topsides standby generator, as well as from the various support vessels. All waste material will be sorted, recycled and disposed of on land.

Husky anticipates the logistics vessel will visit the Port of Argentia approximately three to four times per week. The transit time will be approximately two hours.

A list of potential marine activities at the deep-water mating site and associated emissions and discharges is provided in Table 2-11.

Table 2-11 Potential Discharges and Emissions Associated with CGS Tow-out and Deep-water Mating Site Activities

Potential Activities	Potential Discharges/Emissions/Wastes from All Activities
Additional nearshore surveys (e.g., geotechnical, geophysical, environmental) Dredging/spoils disposal CGS solid ballasting (which may include disposal of water containing fine material) CGS water ballasting and de-ballasting Waste generated (domestic waste, construction waste, hazardous, sanitary waste) Topsides mating Additional hook-up and commissioning of topsides Operation of helicopters, supply, support, standby, mooring and tow vessels/barges/ROVs Welding and x-ray inspection	Stormwater, potable water, fire water, cooling water and industrial water Noise (including underwater) Shoreline runoff (e.g., erosion) Solid, construction, hazardous, domestic and sanitary waste disposal Air emissions Bilge/ballast water Deck drainage

2.7.7 Tow-out and Offshore Installation of the Wellhead Platform

Upon completion of the topsides mating and associated hook-up between the CGS and the topsides, the WHP's designated towing draft will be established by water ballast/deballast activities. Once the towing draft has been established, the structure will remain at this draft until it arrives at the offshore location in the White Rose field. The WHP draft is expected to be approximately 115 m.

The WHP will be towed at the maximum possible water depth to minimize wave action on the topside facilities and the best time to do so is from the end of May through to September. A tow-out route (based on existing bathymetry) to accommodate the WHP draft is illustrated in Figure 2-14. The tow-out route will be surveyed in advance to provide the level of information required to establish an accurate final route for tow-out of the structure. Detailed contingency planning will be developed to manage the tow in the event of bad weather. Continuous weather forecasting will be undertaken during the tow.

For tow-out of the WHP, four ocean-going tugs, each with a capacity of a minimum of 17,000 horsepower, will be connected to towing points on the CGS structure. The four moorings at the deep-water site will be disconnected and the tow to the White Rose field will commence. Husky anticipates the WHP will exit from Placentia Bay within 48 hours from the commencement of the tow and the transit to the White Rose field from the deep-water site will take between 12 and 15 days.

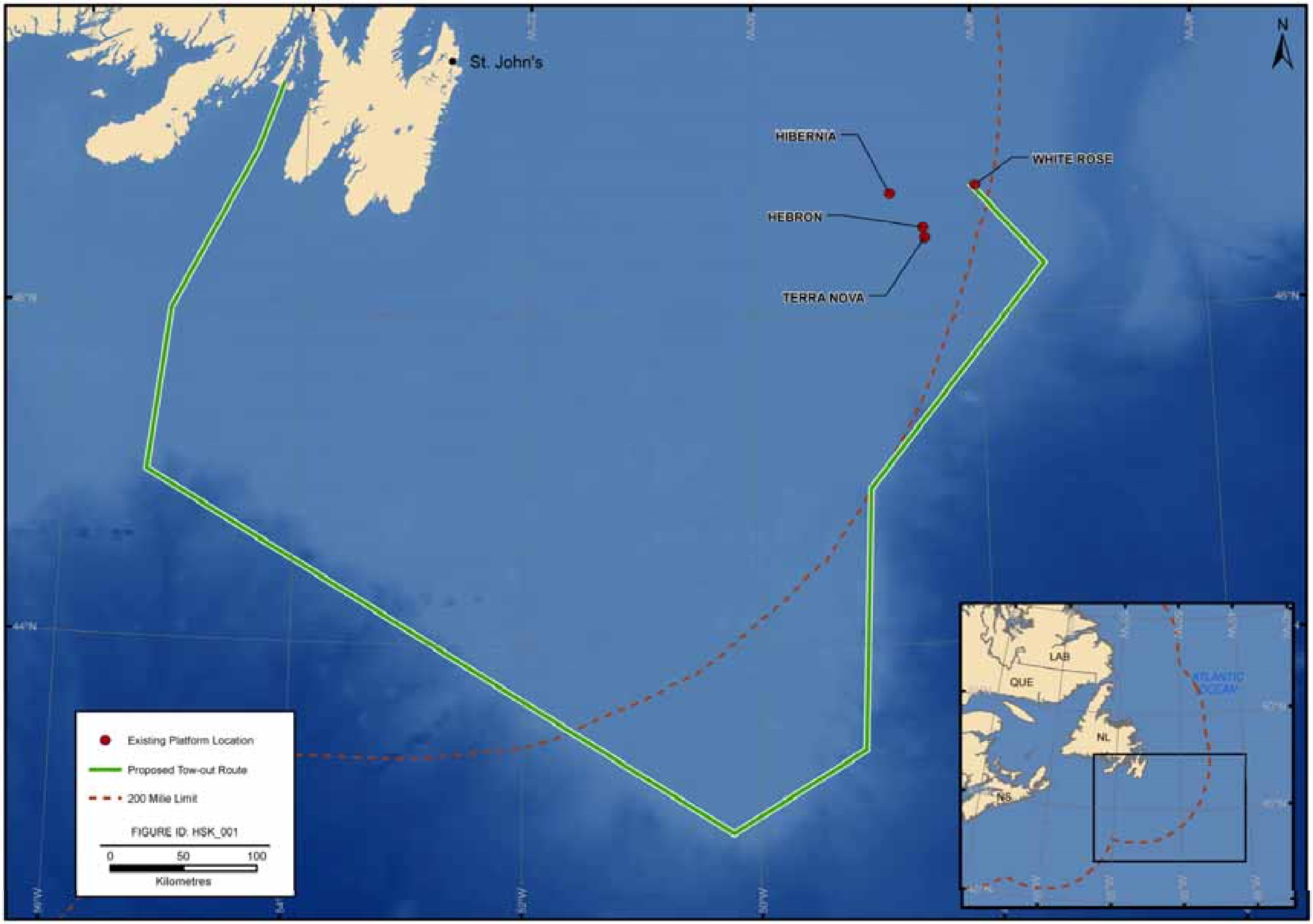


Figure 2-14 Potential Tow-out Route from Placentia Bay to the Wellhead Platform Location

2.8 White Rose Extension Project: Installation

Regardless of the development option selected, the WHP and subsea drill centre will be tied back to the *SeaRose FPSO*, where all oil storage and offloading will occur. Activities associated with both options are described in this section.

2.8.1 Wellhead Platform

At the offshore location, the WHP will be positioned by the four towing vessels. Once the structure has been situated in the correct location and heading, the CGS will be ballasted with water onto the seabed by controlled flooding of cells within the main base caisson. The CGS foundation will penetrate the seabed, therefore scour protection is not required. Once on the seabed, solid ballast will be placed in specific caisson cells to provide long-term stability for the WHP.

The flowlines from the WHP will connect to the CDC production lines at a location between the CDC and *SeaRose FPSO*. There will also be a gas line connected from the NDC to the WHP and a water injection line from the CDC to the WHP (Figure 2-15). The need for additional flowline tie-in modules and associated valves will be evaluated during FEED. Flowline tie-in modules will sit on the seafloor and range between an estimated 20 and 40 m^2.

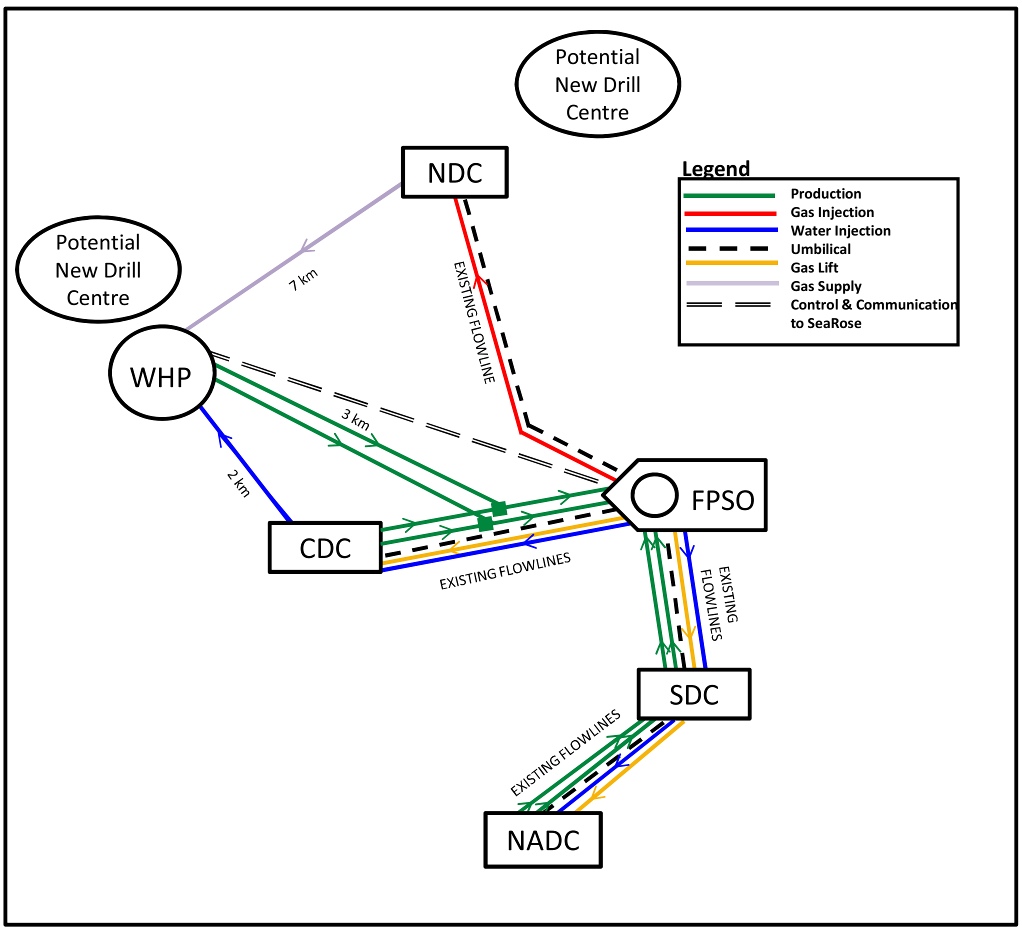


Figure 2-15 Potential Wellhead Platform Concept Integration into Existing White Rose Facilities

Potential activities that may be associated with WHP installation/commissioning and potential environmental interactions are listed in Table 2-12.

Table 2-12 Potential Discharges and Emissions Associated with Wellhead Platform Installation/Commissioning Activities

Potential Activities	Potential Discharges/Emissions/Wastes from All Activities
Clearance surveys (e.g., sidescan sonar) prior to installation of WHP or pipelines/flowlines Tow-out/offshore installation Operation of helicopters and supply, support, standby and tow vessels/barges Diving activities Operation of ROVs Installation of flowlines from WHP to subsea drill centre(s) Potential rock berms or concrete mats/sleeves for flowline protection rock berms Installation of control and communications to *SeaRose FPSO* Additional hook-up, production testing and commissioning Hydrostatic test fluid (flowlines) Water requirements (potable water, fire water and industrial water) Waste generated (domestic waste, construction waste, hazardous waste, sanitary waste) Surveys (environmental, geotechnical and geophysical)	Air emissions Bilge/ballast water Storm water, potable water, fire water and industrial water Noise (including underwater noise) Solid, construction, hazardous, domestic and sanitary waste disposal

2.8.2 Subsea Drill Centre

Any future subsea drill centres will be installed and operated in a similar manner as existing subsea drill centres in the White Rose field. The subsea infrastructure will be designed to minimize the need for diver intervention during installation and provide maximum clearance for ROV operations during inspection and maintenance of the equipment.

Offshore construction and installation will include: dredging a subsea drill centre; installation of the subsea infrastructure; installation of flowlines to connect a new subsea drill centre to existing subsea infrastructure; and modifications to existing subsea infrastructure.

Dredging for placement of subsea wells below the level of the sea floor will be required to protect equipment from iceberg scour. Construction methods for a new subsea drill centre will be similar to those employed for development of the White Rose and North Amethyst fields.

Dredging will be conducted using a trailing suction hopper dredger vessel. Dredged material will be disposed of in the approved spoils disposal area, used during construction of the subsea drill centres for White Rose and North Amethyst. It is anticipated that the subsea drill centre will be excavated to a measured depth of 9 to 11 m below existing seabed level. The maximum base dimension will be approximately 45 m by 80 m, with 1 vertical by 3 horizontal graded sloped sides as required for stability and flowline ramps.

Subsea facilities to support any new subsea drill centres will include all equipment necessary for the safe operation and control of the subsea wells and transportation of production and injection fluids. Husky will use designs currently used in the White Rose field. Procedures for installation of subsea facilities and subsequent operations are anticipated to be similar to those currently employed for the existing White Rose field. A subsea construction vessel will support the installation of the equipment and a diving support vessel will support the hook-up of the equipment by divers.

Iceberg protection measures applied to the current White Rose project will also be applied to any new subsea drill centre, including placement of wellheads and xmas trees with the top of the equipment a minimum of 2 to 3 m below the seabed level and use of flowline weak link technology.

Subsea flowlines will interconnect a new subsea drill centre (Figure 2-16) with the *SeaRose FPSO.* Flowlines will be laid directly on the seafloor, similar to installation methods used for flowlines currently in the White Rose field. The need for additional flowline tie-in modules and associated valves will be evaluated during engineering. Flowline tie-in modules will sit on the seafloor and range between an estimated 20 and 40 m^2. Dropped object proection on the flowline near the subsea drill centres is also being evaluated and maybe composed of rock berms, as for SCD and NADC, or concrete mats or sleeves.

Modifications may be required to existing subsea drill centres under the subsea drill centre development option. This could include removal of excess mud and cuttings from existing subsea drill centres. Husky does not anticipate that any existing subsea drill centres will increase in size; modifications would be to equipment only.

Potential activities that may be associated with subsea drill centre excavation/installation and potential environmental interactions are listed in Table 2-13.

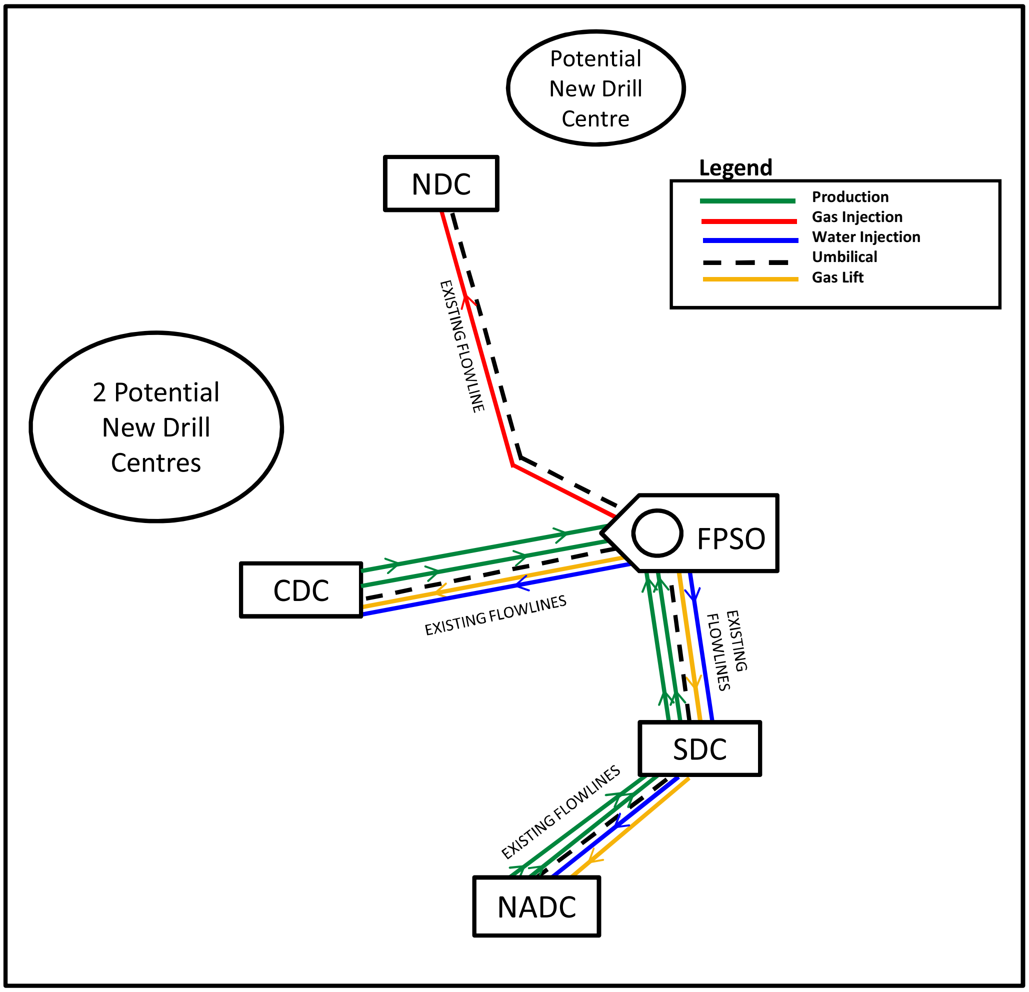


Figure 2-16 Potential New Subsea Drill Centres Location in Relation to the Existing White Rose Facilities

Table 2-13 Potential Discharges and Emissions Associated with Subsea Drill Centre Excavation/Installation Activities

Potential Activities	Potential Discharges/Emissions/Wastes from All Activities
Dredging Ocean disposal of dredge material Clearance surveys (e.g., sidescan sonar) prior to installation of pipelines/flowlines Operation of helicopters and supply, support, standby and tow vessels/barges Diving activities Operation of ROVs Installation of flowlines and tie-in modules to existing subsea drill centre(s) Installation of control and communications to *SeaRose FPSO* Additional hook-up, production testing and commissioning Hydrostatic test fluid (flowlines) Water requirements (potable water, fire water and industrial water) Waste generated (domestic waste, construction waste, hazardous waste, sanitary waste) Surveys (environmental, geotechnical and geophysical)	Dredge spoil discharge Air emissions Bilge/ballast water Storm water, potable water, fire water and industrial water Noise (including underwater noise) Solid, construction, hazardous, domestic and sanitary waste disposal

2.9 White Rose Extension Project Operation

Regardless of the development option selected, the produced crude will be transported directly to the *SeaRose FPSO*. All production from the WHP or new drill centres will be processed through the *SeaRose FPSO* currently operating at White Rose. The effects of production (including produced water discharge rates, which will not be exceeded by the WREP) have been previously assessed (Husky Oil 2000; LGL 2007a), and will not be further addressed in this document.

The WHP or MODU will be managed and controlled by an installation manager. However, the Offshore Installation Manager on the *SeaRose FPSO* will take responsibility for routine coordination of all concurrent offshore operations. Most routine activities will be similar regardless of the development option selected. One key difference between the two development options is the disposal of SBM cuttings; they will be re-injected if the WHP development option is selected and treated and discharged overboard if the subsea drill centre development option is selected. WBM cuttings will be discharged from either development option.

Potential activities that may be associated with offshore production/operation (applicable to both development options) and potential environmental interactions are listed in Table 2-14.

Table 2-14 Potential Discharges and Emissions Associated with Offshore Production/ Operation Activities

Potential Activities	Potential Discharges/Emissions/Wastes from All Activities
Maintenance activities Power generation and flaring Welding and x-ray inspection Normal platform operational activities Operation of seawater systems (cooling, firewater) Waste generated (domestic waste, construction waste, hazardous, sanitary waste) Operation of utilities systems Corrosion protection system (use of corrosion inhibitors or biocides (e.g., hypochlorite) flowlines and pipelines [A]) Chemical/fuel management and storage Operation of helicopters, supply, support, standby and tow vessels/barges/ROVs Well interventions and workovers Preparation and storage of drilling fluids Management of drilling fluids and cuttings (reconditioning, discharge or injection) [B] Management and storage of blowout preventer fluids and well treatment fluids Cementing and completing wells Operation of corrosion protection systems Gas injection systems Seawater injection system (to maintain reservoir pressure) Artificial lift (gas lift, electric submersible pumps or a combination) Oily water treatment [C] Vent and flare system [D] Ongoing geotechnical and environmental wellsite and VSP surveys Diving activities Operation of ROVs	Air emissions (including waste incinerator) Bilge/ballast water Deck drainage/open drains Stormwater, potable water, fire water, cooling water, and industrial water Drilling fluids and cuttings (WBM and non-aqueous fluid) disposal [B] Noise (including underwater noise) Solid, hazardous, domestic and sanitary waste disposal Well treatment fluids

Potential Activities	Potential Discharges/Emissions/Wastes from All Activities
Notes: (A) Husky will evaluate the use of biocides other than chlorine. The discharge from the hypochlorite system will be treated to meet a limit approved by the C-NLOPB's Chief Conservation Officer (B) Water-based drilling fluids and cuttings will be discharged overboard. Husky will evaluate best available cuttings management technology and practices to identify a waste management strategy for spent non-aqueous fluid and non-aqueous fluid cuttings from the MODU. Synthetic-based mud cuttings will be re-injected into a dedicated well from the WHP, pending confirmation of a suitable disposal formation (C) Water (including from open drains) will be treated prior to being discharged to the sea in accordance with OWTG (D) Small amounts of fuel gas will be used for flare pilots and may also be used to sweep the flare system piping	

2.9.1 Wellhead Platform Operation and Maintenance

The WHP is designed to perform drilling, completions, well interventions and transport of product to the *SeaRose FPSO*. Under the WHP development option (which will have up to 40 wells, plus up to two additional subsea drill centres (each with up to 16 wells)), the total number of wells could be as much as 72. SBM cuttings will be re-injected into a dedicated well from the WHP, pending confirmation of a suitable disposal formation.

2.9.2 Subsea Drill Centre Operation and Maintenance

A MODU is expected to perform the drilling, completions and well interventions. The subsea drill centre will produce crude, which will be transported directly to the *SeaRose FPSO*. Developing the WREP using subsea drill centres (West White Rose plus up to two additional, each with 16 wells), the total number of wells could be 48. SBM cuttings will be treated and discharged from the MODU in accordance with the OWTG (NEB et al. 2010).

2.9.3 Operational Support

As is the case for the White Rose field, WREP operations will be managed by Husky, employing both company and third-party services. The WREP will be managed and operational decisions will be made from offices in St. John's, Newfoundland and Labrador.

2.10 Logistics and Other Support

2.10.1 Onshore/Nearshore Wellhead Platform Construction

Under the WHP development option, the excavation of the graving dock in Argentia is scheduled to take approximately six to eight months. The logistics support for this work will be very localized. The equipment required for the excavation of the graving dock will be mobilized by road. Fuelling of equipment will be by road tanker, to be replenished from the local market.

The contractor responsible for the construction of the CGS will establish site infrastructure in accordance with the execution plan for the work. Specific site facilities will be established to support the work and the construction personnel. At this time, Husky does not anticipate the need for a labour camp. However, workforce and area accommodations availability will be assessed in the SEIS, submitted to the C-NLOPB as part of the Development Plan Amendment.

2.10.2 Offshore Operation

Husky currently maintains logistical support to the *SeaRose FPSO* and to a MODU on a full-time basis. At times, logistical support is also provided to a second MODU. Therefore, much of the required infrastructure and support services are already in place to support both development options. Key areas of support during operation and maintenance of both development options include shore-based marine logistics, warehouse services, personnel transportation, supply and standby vessels, communications, ice management services, marine fuel supply, waste management, medical services and weather forecasting.

2.11 Communications

2.11.1 Wellhead Platform

The method of control and communications to *SeaRose FPSO* is under evaluation and will be further defined during engineering. The connection will be designed to convey control and communication signals between the WHP and the *SeaRose FPSO*. If a cable option is selected, it will contain static sections, which will remain stable on the seabed, and dynamic sections, designed to be compatible with the design of the dynamic risers and *SeaRose FPSO* mooring lines.

2.11.2 Subsea Drill Centre

Communications between the new subsea drill centre and the *SeaRose FPSO* will be via a subsea umbilical. The location of the umbilical tie-in will be determined during FEED.

2.12 Shipping/Transportation

Oil will stored on the *SeaRose FPSO* and offloaded onto tankers as per current practice. Activities associated with shipping and transportation of the oil has been previously assessed under the original environmental assessment (Husky Oil 2000) and will not be further addressed in this document.

2.13 Surveys and Field Work

Geohazard/well site surveys and vertical seismic profiling (VSP) using an airgun array may be conducted as part of the drilling activities. The VSP is used to assist in further defining a petroleum resource. The array is similar to that employed by two-dimensional (2-D) or three-dimensional (3-D) seismic surveys but is typically smaller and deployed in a smaller area over a shorter time period (12 to 36 hours). Well site or geohazard surveys may also deploy a small array and sonar. They are used to identify and avoid geotechnically unstable areas (e.g., shallow gas deposits) or hazards (e.g., shipwrecks) prior to drilling.

2.14 Decommissioning and Abandonment

2.14.1 Onshore/Nearshore

Under the WHP development option, consideration will be given during the design phase to designing the CGS construction facility as a permanent graving dock, which could be used for the construction of future CGSs or for other industrial applications. Design of the graving dock for future use could include provision for a gated system allowing the graving dock to be flooded and drained as required. If it is determined that the graving dock will be designed for a single CGS construction use only, consideration will be given to other potential uses in consultation with local stakeholders and authorities. In any case, the facility will comply with applicable regulations governing all activities associated with the site.

The graving dock will be retained either with dock gates installed or if no gates have been constructed, then the graving dock will be left flooded and open to the tidal conditions within the Argentia Port. In the latter option, the condition of the graving dock side slopes will be fully assessed and where any erosion mitigation is required, then preventive work will be performed.

2.14.2 Offshore

Under the WHP development option, the WHP will be decommissioned and abandoned by first abandoning the wells in accordance with standard oil field practices, then decommissioning the topsides, followed by decommissioning and abandonment of the CGS. All infrastructure will be abandoned in accordance with the relevant regulations. The topsides will be removed from the CGS in a manner evaluated to be most effective at the time of decommissioning. The WHP will not be abandoned and disposed of offshore, nor converted to another use on site.

Under the subsea drill centre development option, the wells will be plugged and abandoned and the subsea infrastructure will be removed or abandoned in accordance with the relevant regulations.

2.15 Potential Future Activities

Regardless of the development drilling option selected, potential future activities include excavating and installing up to two additional drill centres within the White Rose field. Note that these drill centres have been previously assessed (LGL 2007a), but are included in this environmental assessment in order to extend the temporal scope of these activities.

Other potential future activities include geotechnical and geohazard surveys (e.g., wellsite/VSP surveys) associated with installation of the potential additional subsea drill centres as discussed in Section 2.8.2. WREP activities do not include 2-D or 3-D seismic surveys, which have recently been assessed separately (LGL 2012).

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3.0 SUMMARY OF WHITE ROSE EXTENSION PROJECT-SPECIFIC MODELS

In addition to an analysis of the probability of a hydrocarbon spill (Section 3.6), the following models were conducted to support the environmental assessment of the WREP:

- Air emissions (Stantec 2012c)
- Underwater noise (JASCO Applied Sciences (JASCO) 2012)
- Nearshore dredging (AMEC Environment & Infrastructure (AMEC) 2012a)
- Offshore drill cuttings deposition (AMEC 2012b)
- Offshore synthetic-based mud (SBM) whole mud spill (AMEC 2012c)
- Nearshore hydrocarbon spill trajectory (SL Ross Environmental Research Ltd. (SL Ross) 2012)
- Offshore hydrocarbon spill trajectory (SL Ross 2012).

3.1 Air Quality Dispersion

Stantec conducted an emissions inventory and dispersion modelling study to aid in determining the potential environmental effects that the WREP could have on the atmospheric environment. Both the sub-sea drill centre (MODU) and WHP development options were modelled. The full report is provided in Stantec (2012d).

The proposed WREP is located within the Jeanne d'Arc Basin and is therefore regulated by the C-NLOPB. There is no one specified dispersion model required for use by the C-NLOPB or Environment Canada.

NLDEC has developed a guidance document for dispersion modelling, *Guideline for Plume Dispersion Modelling* (NLDEC 2006). The document outlines those models approved by the NLDEC for the purpose of determining compliance with the provincial ambient air quality standards, the Newfoundland and Labrador *Air Pollution Control Regulations, 2004*. The province's preferred model, when the following conditions are present, is that of CALPUFF (derived from the California Puff Model):

- Long range transport (>50 km)
- Overwater and coastal interaction effects
- Temporal analysis required.

Husky has chosen to carry out the Air Emissions Study for the WREP using the province's preferred model, CALPUFF.

3.1.1 Model Inputs

The modelling domain, or computational grid, selected for this study consisted of a 85 km by 85 km grid area centered at the following coordinate (NAD 83, Zone 22): 700,080 m easting; 5,187,208 m northing, which represents an area central to the location of the proposed WREP and existing platforms, with cells spaced 1 km apart.

A sampling grid (set of gridded receptors) was positioned within the computational grid covering a domain of 76 km by 76 km. To avoid potential boundary effects, the sampling grid was set a few kilometres from the edge of the computational grid (90 km by 90 km). The spacing of the sampling grid was set to 500 m and receptor height was set to sea-level.

In addition to the sampling grid, a nested grid of receptors was centred on the proposed WHP location (724,080 m easting; 5,187,208 m northing). The nested grid extended approximately 2 km from the proposed WREP location, with receptor spacings of 50 m within 500 m of the WHP, 100 m spacing's between 500 and 1,000 m and 200 m spacing's within 2,000 m from the WHP. The receptor height of the nested grid was at sea level.

Three discrete receptors were also incorporated into each model run and they represent the locations of the existing offshore platforms located within the Jeanne d'Arc Basin (Hibernia, Terra Nova and the existing *SeaRose FPSO*). The height of the platforms was set at 30 m above sea-level to represent the first deck.

CALMET is the meteorological model that pre-processes meteorological data for input into the CALPUFF model. CALMET develops 3-D gridded hourly wind and temperature fields, as well as two-dimensional fields such as mixing heights.

As the modelling domain is offshore, there are no national surface meteorological stations in close proximity of the primary modelling area that would be considered representative of the meteorological conditions near the sources. As a result, a Mesoscale Metrological Model (version 5) (MM5) dataset was procured from TRC Solutions for use in the study. The data set consisted of one year (2006) of MM5 data at 12 km resolution. The meteorological domain that was set up within CALMET (version 6.334 – level 110421) consisted of a 85 km by 85 km grid with 1 km spacings, centred at the following coordinate (NAD 83 Zone 22): 700,080 m easting; 5,187,208 m northing, which represents an area central to the location of the proposed WREP and existing platforms.

The CALPUFF model is a non-steady-state Gaussian puff dispersion model which incorporates simple chemical transformation mechanisms, wet and dry deposition, complex terrain algorithms and building downwash. The CALPUFF model is suitable for estimating ground-level air quality concentrations on both local and regional scales, from tens of metres to hundreds of kilometres. It can accommodate arbitrarily varying point sources and gridded area source emissions. Most of the algorithms contain options to treat the physical processes at different levels of detail depending on the model application.

The Lakes Environmental CALPUFF View Model Version 6.4 (CALPUFF Version 6.42 – Level 110325) was used for this study for modelling as it contains the latest CALPUFF model released by TRC in April 2011.

Under Section 7 of the Newfoundland and Labrador modelling guidance document (NLDEC 2006) the following contaminants are to be modelled in regards to combustion related sources:

- Sulphur dioxide (SO_2)
- Total suspended particulate matter (TSP)
- Particulate matter less than 10 microns in diameter (PM_{10})
- Particulate matter less than 2.5 microns in diameter ($PM_{2.5}$)
- Nitrogen dioxide (NO_2)
- Carbon monoxide (CO).

Ground level concentrations have been predicted for all these listed air contaminants.

Five scenarios were modelled:

- Normal wellhead (WHP) operation
- Normal operation of a MODU
- Accidental flaring as a result of a wellhead blowdown
- Cumulative operation of the proposed WREP WHP with the existing platforms (White Rose, Hibernia and Terra Nova) and the proposed Hebron Platform
- Cumulative operation of the MODU with the existing platforms (White Rose, Hibernia and Terra Nova) and the proposed Hebron Platform.

The sources of emissions modelled are point sources from the oil and gas production installations (offshore platforms), including the turbines and flares.

Other sources of emissions related to platform operations, as discussed above, include the operation of helicopters, supply vessels, maintenance activities and fugitive sources. These sources have been included in the WREP's emission inventory (Stantec 2012c), but have not been incorporated into the dispersion modelling scenarios.

3.1.2 Results

3.1.2.1 Normal Operation – Wellhead Platform

The maximum predicted 1-hour ground level concentrations at each of the three discrete installations for CO, NO_2, SO_2, total particulate matter (TPM), PM_{10} and $PM_{2.5}$ during normal operation of the proposed WHP are listed in Table 3-1.

Table 3-1 Maximum Predicted 1-Hour Ground Level Concentrations under Normal Wellhead Platform Operation

Receptor	UTM		CO ($\mu g/m^3$)	NO_2 ($\mu g/m^3$)	SO_2 ($\mu g/m^3$)	TPM ($\mu g/m^3$)	PM_{10} ($\mu g/m^3$)	$PM_{2.5}$ ($\mu g/m^3$)
	Easting (m)	Northing (m)						
White Rose	727708	5186021	1.7	7.5	0.10	0.15	0.14	0.13
Hibernia	669419	5179807	0.17	0.68	0.01	0.014	0.013	0.012
Terra Nova	693372	5149964	0.18	0.78	0.01	0.016	0.0148	0.014
NL Regulatory Limit	--	--	35,000	400	900	--	--	--

The maximum predicted 3-hour ground level concentrations at each of the three discrete installations for SO_2 during normal operation of the proposed WREP WHP is listed in Table 3-2.

Table 3-2 Maximum Predicted 3Hour Ground Level Concentrations for Normal Wellhead Platform Operation

Receptor	UTM		SO_2 ($\mu g/m^3$)
	Easting (m)	Northing (m)	
White Rose	727708	5186021	0.10
Hibernia	669419	5179807	0.007
Terra Nova	693372	5149964	0.005
NL Regulatory Limit	--	--	600

The maximum predicted 8-hour ground level concentrations at each of the three discrete installations for CO during normal operation of the proposed WREP WHP is shown in Table 3-3.

Table 3-3 Maximum Predicted 8-Hour Ground Level Concentrations under Normal Wellhead Platform Operation

Receptor	UTM		CO ($\mu g/m^3$)
	Easting (m)	Northing (m)	
White Rose	727708	5186021	1.47
Hibernia	669419	5179807	0.083
Terra Nova	693372	5149964	0.069
NL Regulatory Limit	--	--	15,000

The maximum predicted 24-hour ground level concentrations at each of the three discrete installations for NO_2, SO_2, TPM, PM_{10} and $PM_{2.5}$ during normal operation of the proposed WREP WHP are listed in Table 3-4.

Table 3-4 Maximum Predicted 24-Hour Ground Level Concentrations under Normal Wellhead Platform Operation

Receptor	UTM		NO_2 ($\mu g/m^3$)	SO_2 ($\mu g/m^3$)	TPM ($\mu g/m^3$)	PM_{10} ($\mu g/m^3$)	$PM_{2.5}$ ($\mu g/m^3$)
	Easting (m)	Northing (m)					
White Rose	727708	5186021	0.70	0.052	0.073	0.070	0.066
Hibernia	669419	5179807	0.11	0.002	0.002	0.002	0.002
Terra Nova	693372	5149964	0.17	0.002	0.003	0.003	0.003
NL Regulatory Limit	--	--	200	300	120	50	25

The maximum predicted annual ground level concentrations at each of the three discrete installations for NO_2, SO_2 and TPM during normal operation of the proposed WHP are shown in Table 3-5 and illustrated in Figure 3-1.

Table 3-5 Maximum Predicted Annual Ground Level Concentrations under Normal Wellhead Platform Operation

Receptor	UTM		NO_2 (µg/m³)	SO_2 (µg/m³)	TPM (µg/m³)
	Easting (m)	Northing (m)			
White Rose	727708	5186021	0.20	0.003	0.004
Hibernia	669419	5179807	0.004	0.0001	0.0001
Terra Nova	693372	5149964	0.005	0.0001	0.0001
NL Regulatory Limit	-	-	100	60	60

3.1.2.2 Normal Operation Mobile Offshore Drilling Unit

The maximum predicted 1-hour ground level concentrations at each of the three discrete installations for CO, NO_2 and SO_2 during normal operation of the WREP MODU are listed in Table 3-6.

Table 3-6 Maximum Predicted 1-Hour Ground Level Concentrations under Normal Mobile Offshore Drilling Unit Operation

Receptor	UTM		CO (µg/m³)	NO_2 (µg/m³)	SO_2 (µg/m³)	TPM (µg/m³)	PM_{10} (µg/m³)	$PM_{2.5}$ (µg/m³)
	Easting (m)	Northing (m)						
White Rose	727708	5186021	6.5	24.5	1.26	0.56	0.45	0.39
Hibernia	669419	5179807	0.21	0.81	0.042	0.02	0.01	0.01
Terra Nova	693372	5149964	0.30	1.12	0.058	0.03	0.02	0.02
NL Regulatory Limit	--	--	35,000	400	900	-	-	-

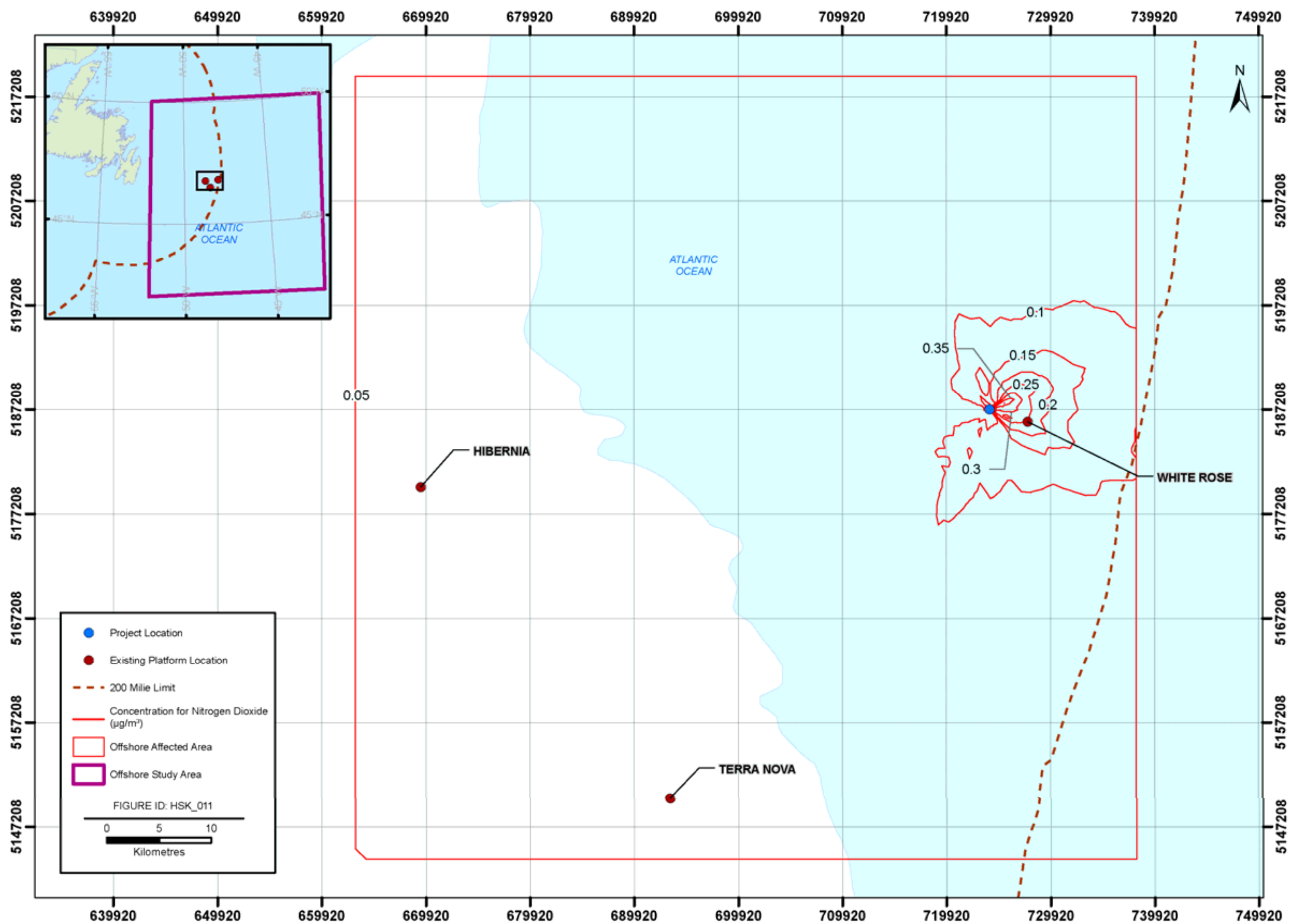


Figure 3-1 **Maximum Predicted Annual Ground Level Concentration for Nitrogen Dioxide, µg/m^3 – Normal Operation Wellhead Platform**

The maximum predicted 3-hour ground level concentrations at each of the three discrete installations for SO_2 during normal WREP MODU operation is listed in Table 3-7.

Table 3-7 Maximum Predicted 3-Hour Ground Level Concentrations for Normal Mobile Offshore Drilling Unit Operation

Receptor	UTM		SO_2 ($\mu g/m^3$)
	Easting (m)	Northing (m)	
White Rose	727708	5186021	0.98
Hibernia	669419	5179807	0.026
Terra Nova	693372	5149964	0.049
NL Regulatory Limit	--	--	600

The maximum predicted 8-hour ground level concentrations at each of the three discrete installations for CO during normal WREP MODU operation is shown in Table 3-8.

Table 3-8 Maximum Predicted 8-Hour Ground Level Concentrations under Normal Mobile Offshore Drilling Unit Operation

Receptor	UTM		CO ($\mu g/m^3$)
	Easting (m)	Northing (m)	
White Rose	727708	5186021	3.8
Hibernia	669419	5179807	0.072
Terra Nova	693372	5149964	0.14
NL Regulatory Limit	--	--	15,000

The maximum predicted 24-hour ground level concentrations at each of the three discrete installations for NO_2 and SO_2 during normal WREP MODU operation are listed in Table 3-9.

Table 3-9 Maximum Predicted 24-Hour Ground Level Concentrations under Normal Mobile Offshore Drilling Unit Operation

Receptor	UTM		NO_2 ($\mu g/m^3$)	SO2 ($\mu g/m^3$)	TPM ($\mu g/m^3$)	PM_{10} ($\mu g/m^3$)	$PM_{2.5}$ ($\mu g/m^3$)
	Easting (m)	Northing (m)					
White Rose	727708	5186021	8.1	0.42	0.18	0.15	0.13
Hibernia	669419	5179807	0.16	0.008	0.004	0.003	0.003
Terra Nova	693372	5149964	0.27	0.014	0.006	0.005	0.004
NL Regulatory Limit	--	--	200	300	120	50	25

The maximum predicted annual ground level concentrations at each of the three discrete installations for NO_2 and SO_2 during normal WREP MODU operation are shown in Table 3-10 and illustrated in Figure 3-2.

Table 3-10 Maximum Predicted Annual Ground Level Concentrations under Normal MODU Operation

Receptor	UTM		NO_2 ($\mu g/m^3$)	TPM ($\mu g/m^3$)	SO_2 ($\mu g/m^3$)
	Easting (m)	Northing (m)			
White Rose	727708	5186021	0.57	0.013	0.029
Hibernia	669419	5179807	0.005	0.0001	0.0003
Terra Nova	693372	5149964	0.009	0.0002	0.0005
NL Regulatory Limit	--	--	100	60	60

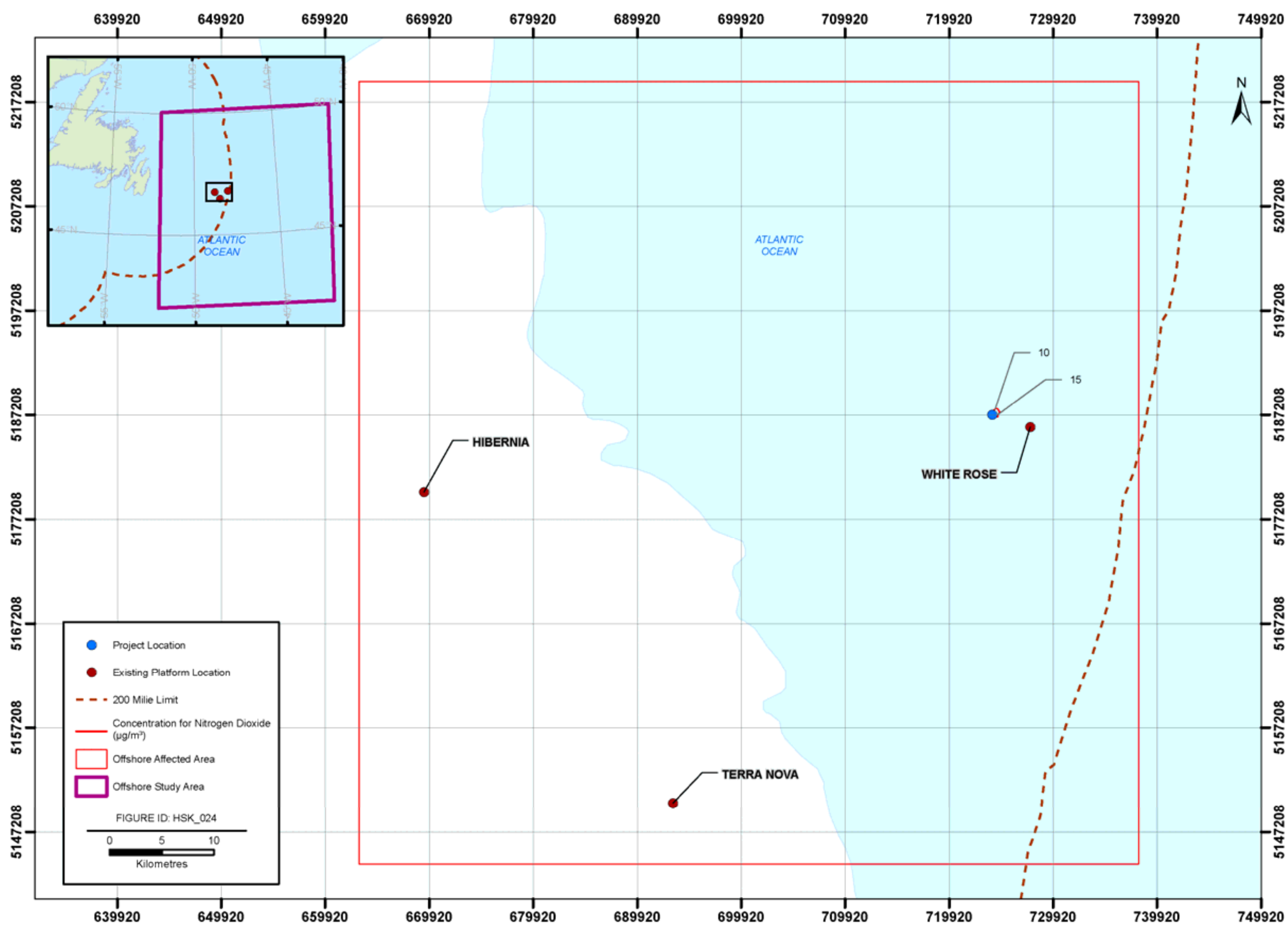


Figure 3-2 **Maximum Predicted Annual Ground Level Concentration for Nitrogen Dioxide, µg/m^3 – Normal Operation Mobile Offshore Drilling Unit**

3.1.2.3 Wellhead Blowdown

The maximum predicted 1-hour ground level concentrations at each of the three discrete installations for CO, NO_2, SO_2, TPM, PM_{10} and $PM_{2.5}$ during a wellhead blowdown of the proposed WREP WHP are included in Table 3-11.

Table 3-11 Maximum Predicted 1-Hour Ground Level Concentrations for a Blowdown

Receptor	UTM		CO ($\mu g/m^3$)	NO_2 ($\mu g/m^3$)	SO_2 ($\mu g/m^3$)	TPM ($\mu g/m^3$)	PM_{10} ($\mu g/m^3$)	$PM_{2.5}$ ($\mu g/m^3$)
	Easting (m)	Northing (m)						
White Rose	727708	5186021	1.7	7.5	0.10	0.15	0.14	0.13
Hibernia	669419	5179807	0.15	0.68	0.0096	0.014	0.013	0.012
Terra Nova	693372	5149964	0.18	0.78	0.011	0.016	0.015	0.014
NL Regulatory Limit	--	--	35,000	400	900	--	--	--

The maximum predicted 3-hour ground level concentrations at each of the three discrete installations for SO_2 during a wellhead blowdown of the proposed WREP WHP are listed in Table 3-12.

Table 3-12 Maximum Predicted 3-Hour Ground Level Concentrations for a Blowdown

Receptor	UTM		SO_2 ($\mu g/m^3$)
	Easting (m)	Northing (m)	
White Rose	727708	5186021	0.10
Hibernia	669419	5179807	0.007
Terra Nova	693372	5149964	0.005
NL Regulatory Limit	--	--	600

The maximum predicted 8-hour ground level concentrations at each of the three discrete installations for CO during a wellhead blowdown of the proposed WREP WHP are shown in Table 3-13.

Table 3-13 Maximum Predicted 8-Hour Ground Level Concentrations for a Blowdown

Receptor	UTM		CO ($\mu g/m^3$)
	Easting (m)	Northing (m)	
White Rose	727708	5186021	1.5
Hibernia	669419	5179807	0.07
Terra Nova	693372	5149964	0.059
NL Regulatory Limit	--	--	15,000

The maximum predicted 24-hour ground level concentrations at each of the three discrete installations for NO_2, SO_2, TPM, PM_{10} and $PM_{2.5}$ during a wellhead blowdown of the proposed WREP WHP are in Table 3-14.

Table 3-14 Maximum Predicted 24-hour Ground Level Concentrations for a Blowdown

Receptor	UTM		NO_2 ($\mu g/m^3$)	SO_2 ($\mu g/m^3$)	TPM ($\mu g/m^3$)	PM_{10} ($\mu g/m^3$)	$PM_{2.5}$ ($\mu g/m^3$)
	Easting (m)	Northing (m)					
White Rose	727708	5186021	3.7	0.052	0.073	0.070	0.065
Hibernia	669419	5179807	0.10	0.002	0.002	0.002	0.002
Terra Nova	693372	5149964	0.16	0.002	0.003	0.003	0.003
NL Regulatory Limit	--	--	200	300	120	50	25

The maximum predicted annual ground level concentration at each of the three discrete installations for NO_2, SO_2 and TPM during a wellhead blowdown of the proposed WREP WHP are listed in Table 3-15 and illustrated in Figure 3-3.

Table 3-15 Maximum Predicted Annual Ground Level Concentrations for a Blowdown

Receptor	UTM		NO_2 (µg/m^3)	SO_2 (µg/m^3)	TPM (µg/m^3)
	Easting (m)	Northing (m)			
White Rose	727708	5186021	0.20	0.003	0.004
Hibernia	669419	5179807	0.004	0.0001	0.0001
Terra Nova	693372	5149964	0.005	0.0001	0.0001
NL Regulatory Limit	--	--	100	60	60

3.1.2.4 Cumulative Effects – Normal Operation of the Wellhead Platform

The maximum predicted 1-hour ground level concentrations at each of the three discrete installations for CO, NO_2, SO_2, TPM, PM_{10} and $PM_{2.5}$ for the cumulative WREP WHP operation are shown in Table 3-16.

Table 3-16 Maximum Predicted 1-Hour Ground Level Concentrations for Cumulative Wellhead Platform Operation

Receptor	UTM		CO (µg/m^3)	NO_2 (µg/m^3)	SO_2 (µg/m^3)	TPM (µg/m^3)	PM_{10} (µg/m^3)	$PM_{2.5}$ (µg/m^3)
	Easting (m)	Northing (m)						
White Rose	727708	5186021	1.	12.8	0.10	0.50	0.50	0.49
Hibernia	669419	5179807	3.1	15.0	0.01	0.69	0.69	0.69
Terra Nova	693372	5149964	1.9	34.3	0.01	0.37	0.37	0.37
NL Regulatory Limit	--	--	35,000	400	900	--	--	--

The maximum predicted 3-hour ground level concentrations at each of the three discrete installations for SO_2 for the cumulative WREP WHP operation are listed in Table 3-17.

Table 3-17 Maximum Predicted 3-Hour Ground Level Concentrations for Cumulative Wellhead Platform Operation

Receptor	UTM		SO_2 (µg/m^3)
	Easting (m)	Northing (m)	
White Rose	727708	5186021	0.10
Hibernia	669419	5179807	0.007
Terra Nova	693372	5149964	0.005
NL Regulatory Limit	--	--	600

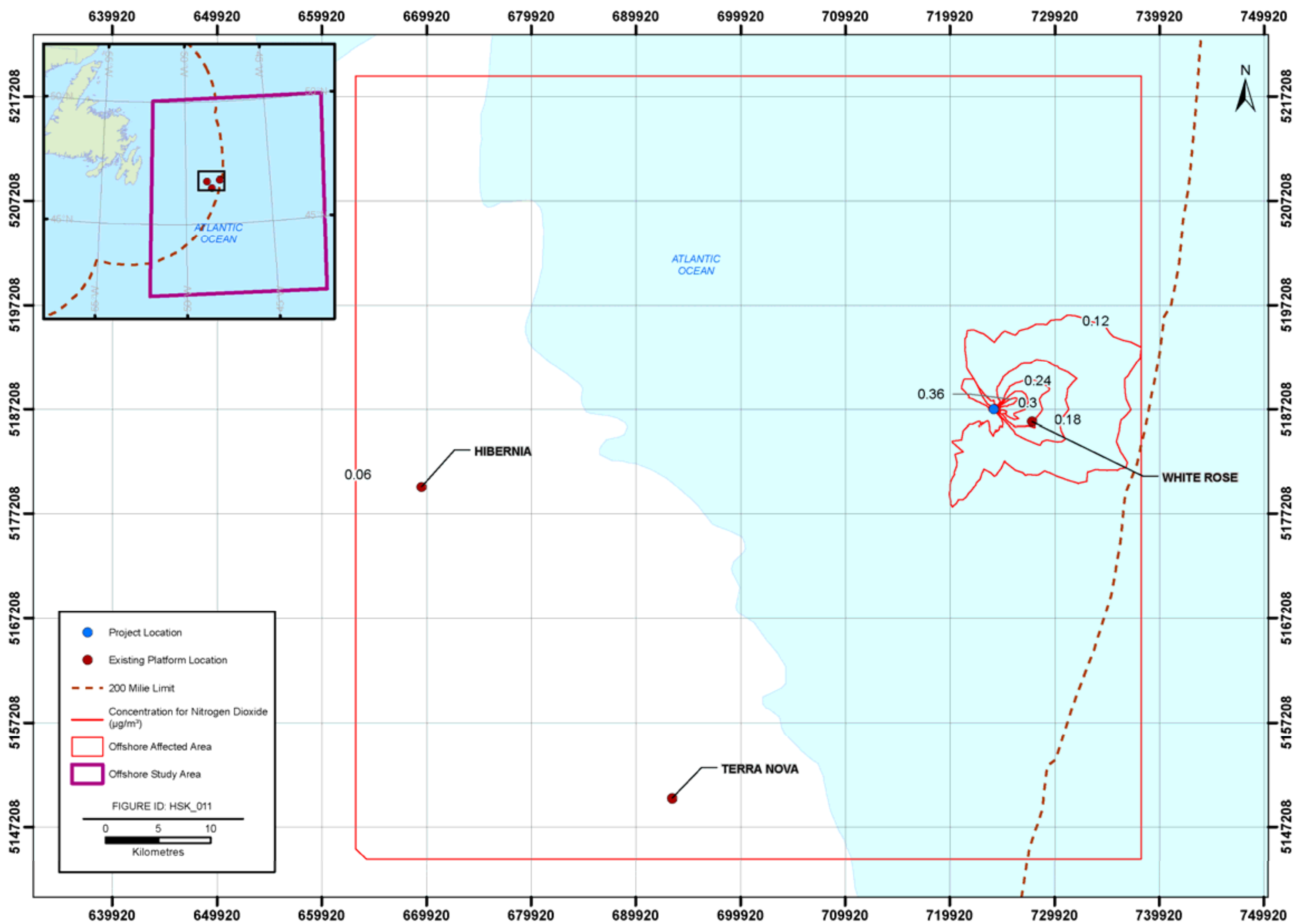


Figure B6 Maximum Predicted Annual Ground Level Concentration for Nitrogen Dioxide (NO_2), µg/m^3 – WHP Blowdown

Figure 3-3 Maximum Predicted Annual Ground Level Concentration for Nitrogen Dioxide, µg/m^3 – Wellhead Platform Blowdown

The maximum predicted 8-hour ground level concentrations at each of the three discrete receptors for CO for the cumulative operational scenario are included in Table 3-18.

Table 3-18 Maximum Predicted 8-Hour Ground Level Concentrations for Cumulative Operation

Receptor	UTM		CO ($\mu g/m^3$)
	Easting (m)	Northing (m)	
White Rose	727708	5186021	1.5
Hibernia	669419	5179807	0.71
Terra Nova	693372	5149964	1.43
NL Regulatory Limit	--	--	15,000

The maximum predicted 24-hour ground level concentrations at each of the three discrete installations for NO_2, SO_2, TPM, PM_{10} and $PM_{2.5}$ for the cumulative WREP WHP operation scenario are shown in Table 3-19.

Table 3-19 Maximum Predicted 24-Hour Ground Level Concentrations for Cumulative Wellhead Platform Operation

Receptor	UTM		NO_2 ($\mu g/m^3$)	SO_2 ($\mu g/m^3$)	TPM ($\mu g/m^3$)	PM_{10} ($\mu g/m^3$)	$PM_{2.5}$ ($\mu g/m^3$)
	Easting (m)	Northing (m)					
White Rose	727708	5186021	4.8	0.052	0.073	0.070	0.067
Hibernia	669419	5179807	3.9	0.002	0.068	0.068	0.068
Terra Nova	693372	5149964	18.0	0.002	0.11	0.11	0.11
NL Regulatory Limit	--	--	200	300	120	50	25

The maximum predicted annual ground level concentrations at each of the three discrete installations for NO_2, SO_2 and TPM for the cumulative WREP WHP operation are listed in Table 3-20 and illustrated in Figure 3-4.

Table 3-20 Maximum Predicted Annual Ground Level Concentrations for Cumulative Wellhead Platform Operation

Receptor	UTM		NO_2 ($\mu g/m^3$)	SO_2 ($\mu g/m^3$)	TPM ($\mu g/m^3$)
	Easting (m)	Northing (m)			
White Rose	727708	5186021	0.50	0.0028	0.013
Hibernia	669419	5179807	0.15	0.0001	0.005
Terra Nova	693372	5149964	0.54	0.0001	0.01
NL Regulatory Limit	--	--	100	60	60

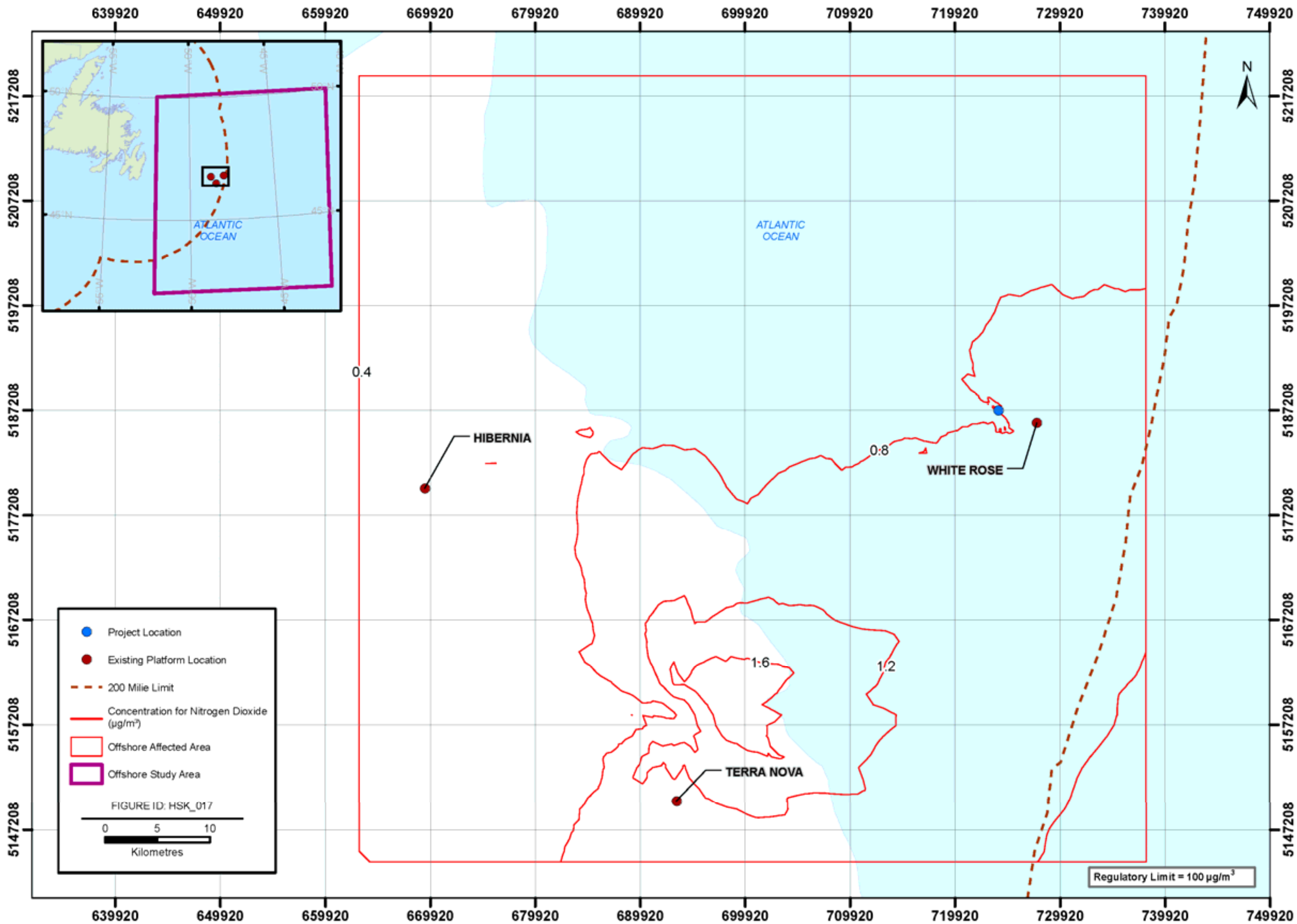


Figure 3-4 **Maximum Predicted Annual Ground Level Concentration for Nitrogen Dioxide, µg/m³ –Cumulative Operation Wellhead Platform**

3.1.2.5 Cumulative Effects – Normal Operation of the Mobile Offshore Drilling Unit

The maximum predicted 1-hour ground level concentrations at each of the three discrete installations for CO, NO_2 and SO_2 for the cumulative operation of the WREP MODU are shown in Table 3-21.

Table 3-21 Maximum Predicted 1-Hour Ground Level Concentrations for Cumulative Mobile Offshore Drilling Unit Operation

Receptor	UTM		CO (µg/m³)	NO_2 (µg/m³)	SO_2 (µg/m³)	TPM (µg/m³)	PM_{10} (µg/m³)	$PM_{2.5}$ (µg/m³)
	Easting (m)	Northing (m)						
White Rose	727708	5186021	6.23	23.6	1.59	0.57	0.50	0.49
Hibernia	669419	5179807	3.14	15.0	0.056	0.69	0.69	0.69
Terra Nova	693372	5149964	1.94	34.3	0.076	0.37	0.37	0.37
NL Regulatory Limit	-	-	35,000	400	900	-	-	-

The maximum predicted 3-hour ground level concentrations at each of the three discrete installations for SO_2 for the cumulative WREP MODU operation are listed in Table 3-22.

Table 3-22 Maximum Predicted 3-Hour Ground Level Concentrations for Cumulative Mobile Offshore Drilling Unit Operation

Receptor	UTM		SO_2 (µg/m³)
	Easting (m)	Northing (m)	
White Rose	727708	5186021	1.2
Hibernia	669419	5179807	0.034
Terra Nova	693372	5149964	0.065
NL Regulatory Limit	--	--	600

The maximum predicted 8-hour ground level concentrations at each of the three discrete installations for CO for the cumulative WREP MODU operation are included in Table 3-23.

Table 3-23 Maximum Predicted 8-Hour Ground Level Concentrations for Cumulative Mobile Offshore Drilling Unit Operation

Receptor	UTM		CO (µg/m³)
	Easting (m)	Northing (m)	
White Rose	727708	5186021	3.7
Hibernia	669419	5179807	0.70
Terra Nova	693372	5149964	1.4
NL Regulatory Limit	--	--	15,000

The maximum predicted 24-hour ground level concentrations at each of the three discrete installations for NO_2 and SO_2 for the cumulative WREP MODU operation are shown in Table 3-24.

Table 3-24 Maximum Predicted 24-Hour Ground Level Concentrations for Cumulative Mobile Offshore Drilling Unit Operation

Receptor	UTM		NO_2 (µg/m^3)	SO_2 (µg/m^3)	TPM (µg/m^3)	PM_{10} (µg/m^3)	$PM_{2.5}$ (µg/m^3)
	Easting (m)	Northing (m)					
White Rose	727708	5186021	8.0	0.54	0.18	0.15	0.13
Hibernia	669419	5179807	3.9	0.011	0.07	0.07	0.07
Terra Nova	693372	5149964	18.1	0.018	0.11	0.11	0.11
NL Regulatory Limit	--	--	200	300	120	50	25

The maximum predicted annual ground level concentrations at each of the three discrete installations for NO_2 and SO_2 for the cumulative WREP MODU operation are listed in Table 3-25 and illustrated in Figure 3-5.

Table 3-25 Maximum Predicted Annual Ground Level Concentrations for Cumulative MODU Operation

Receptor	UTM		NO_2 (µg/m^3)	TPM (µg/m^3)	SO_2 (µg/m^3)
	Easting (m)	Northing (m)			
White Rose	727708	5186021	0.85	0.021	0.037
Hibernia	669419	5179807	0.15	0.005	0.0004
Terra Nova	693372	5149964	0.54	0.010	0.0006
NL Regulatory Limit	-	-	100	60	60

The cumulative effects analysis may be underestimated as downwash may be present in the other platforms, as is evident in the concentration mapping for the proposed WHP. If the downwash is of a comparable amount, then the cumulative effect due to the operation of the proposed WREP with the existing and planned platforms would likely still meet the Newfoundland and Labrador *Air Pollution Control Regulations* and National Ambient Air Quality (NAAQ) Objectives.

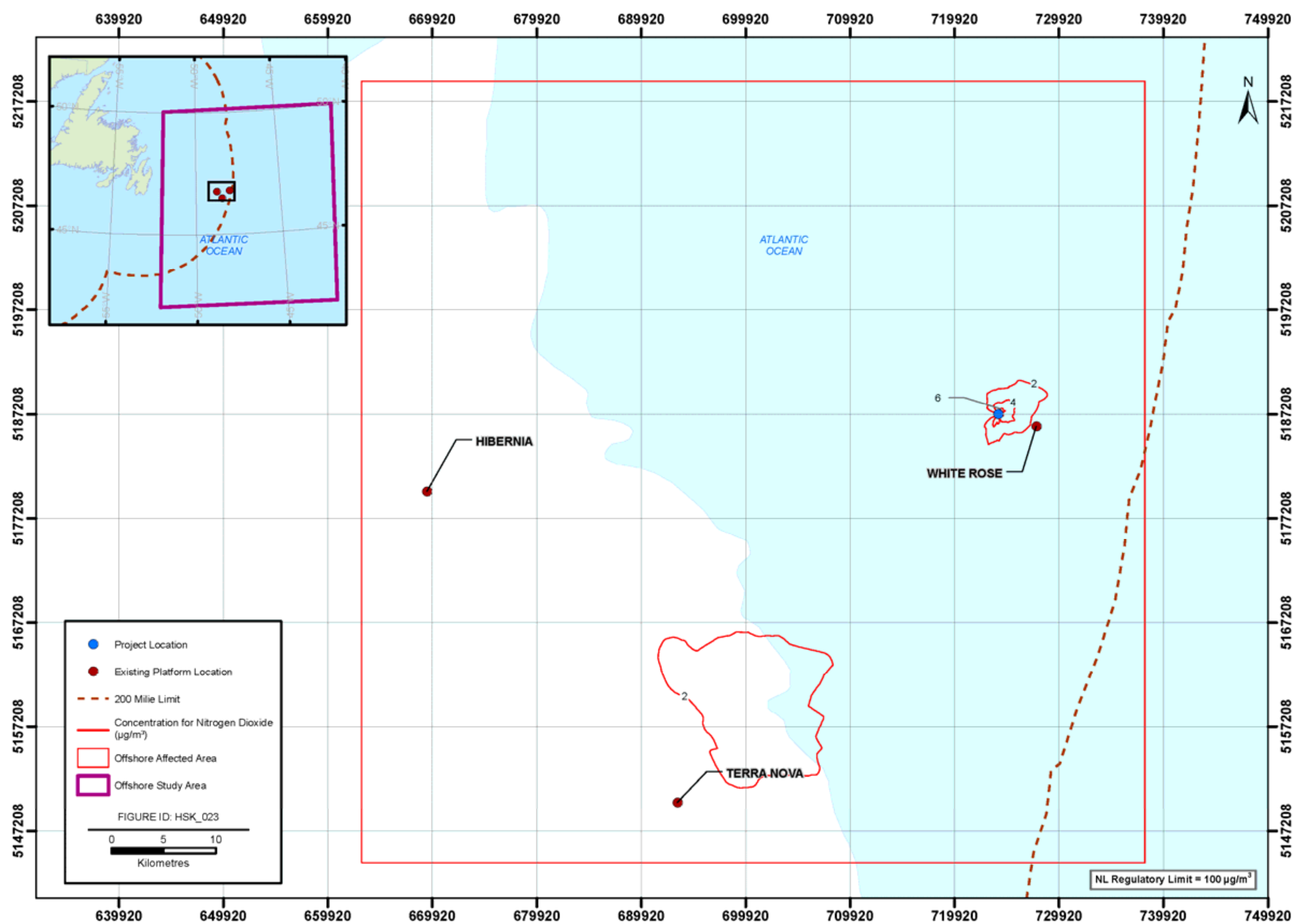


Figure 3-5 Maximum Predicted Annual Ground Level Concentration for Nitrogen Dioxide, µg/m³ – Cumulative Operation Mobile Offshore Drilling Unit

3.1.2.6 Greenhouse Gas Emissions (Wellhead Platform and Subsea Drill Centre)

A summary of the estimated greenhouse gases (GHGs) during the operation of the proposed WHP and MODU are provided in Table 3-26.

Table 3-26 Estimated Greenhouse Gas Emissions for Operation

Activity	CO_2	CH_4	N_20	$CO2_{eq}$ (tonnes/year)
Option 1 - WHP				
Operation of Support Vessel	47,485	-	0 (A)	47,485
Operation of Helicopters	403	0.01	0.04	416
Power Generation	89,645	6.52	2.27	90,486
Normal Operations - Flaring	11,139	0.01	0.01	11,142
TOTAL	**148,672**	**6.54**	**2.3**	**149,529**
Option 2 - MODU				
MODU	14,800	0.83	1.01	15,132
Operation of Support Vessel	47,485	0 (A)	0 (A)	47,485
Operation of Helicopter	403	0.01	0.04	416
Total	**62,688**	**0.84**	**1.05**	**63,033**
Source: US EPA 1991, 1998, 2000a, 2000b, 2005; Climate Registry 2012 (A) Emissions for CH_4 and N_2O have been determined to be minimal				

A comparison of the estimated GHG emissions for the operation of the WHP and MODU, and the emissions from the other platforms in operation as reported to Environment Canada for the 2010 reporting year, is provided in Table 3-27. These include the Terra Nova, Hibernia and *Sea Rose FPSO* platforms.

Table 3-27 2010 Greenhouse Gas Emissions Data by Platform

Facility	GHG Emissions (tonnesCO_{2eq}/year)			
	CO_2	CH_4	N_2O	Total
Terra Nova (A)	569,634	22,976	11,616	604,227
Hibernia (A)	491,117	31,121	4,644	526,882
Sea Rose FPSO (A)	394,690	27,691	9,405	431,786
WHP Operation	148,672	137	719	149,529
MODU Operation	14,800	17.4	313	15,132
(A) Environment Canada 2012				

As presented in Table 3-27, the emissions from the proposed WHP and the MODU are significantly less than the other platforms currently in operation.

3.1.3 Summary

As currently planned, the air emissions related to the operation of the proposed WREP (Options 1 and 2) would meet the NAAQ Objectives as well as the Newfoundland and Labrador *Air Pollution Control Regulations*.

3.2 Underwater Noise

JASCO modelled underwater sound propagation around potential underwater acoustic sources resulting from the WREP, to estimate distances to sound level thresholds. The modelled sources represent: dredging activities in the nearshore; towing the CGS from the construction site in Argentia; and dredging, drilling, support vessel and helicopter activities at the White Rose field. Distances to sound level thresholds were estimated for water temperature profiles representative of months that are the most (February) and least (August) conducive to long-range sound propagation, accounting for source directivity and the range-dependent environmental properties in the area. Distances to level thresholds from all sources (impulsive and continuous) are provided as un-weighted and M-weighted root-mean-square sound pressure level (rms SPLs) of 200 through 120 dB re 1 µPa. Acoustic source specification for the model are provided in Table 3-28.

Table 3-28 Acoustic Source Specifications

Source	Operation	Source Depth	BB SL (dB re 1 µPa @ 1 m)	Frequency Range (kHz)	Propagation Model	Location
1	dredging, cutter suction dredge	5 m, 1 m above seafloor (A)	189.3	0.01–10	MONM	Graving Dock
2	dredging, trailing suction hopper dredge	5 m, 1 m above seafloor (A)	195.4	0.01–10	MONM	Corridors 1 & 2, White Rose
3	drilling	36 m	162.3	0.01–10	MONM	White Rose
4	support vessel	5 m	182.5	0.01–10	MONM	White Rose
5	helicopter	91 m above sea surface	169.7	0.01–10	N/A	White Rose

Notes: The source depths are in metres (m)
(A) Dredging was modelled as two point sources, a low-frequency source close to the surface and the high-frequency source close to the seafloor

The underwater sound fields predicted by the propagation models were sampled such that the received sound level at a surface sampling location is taken as the maximum value occurring over the entire water column. The predicted distances to specific SEL and rms SPL thresholds were computed from these “maximum-over-depth” sound fields.

The full report is provided in JASCO (2012).

3.2.1 Nearshore

Dredging is planned for three locations in near Argentia to facilitate the transportation of the CGS to the deepwater mating site. Nearshore dredging operations were modelled at three locations along the CGS tow track (see Figure 3-6).

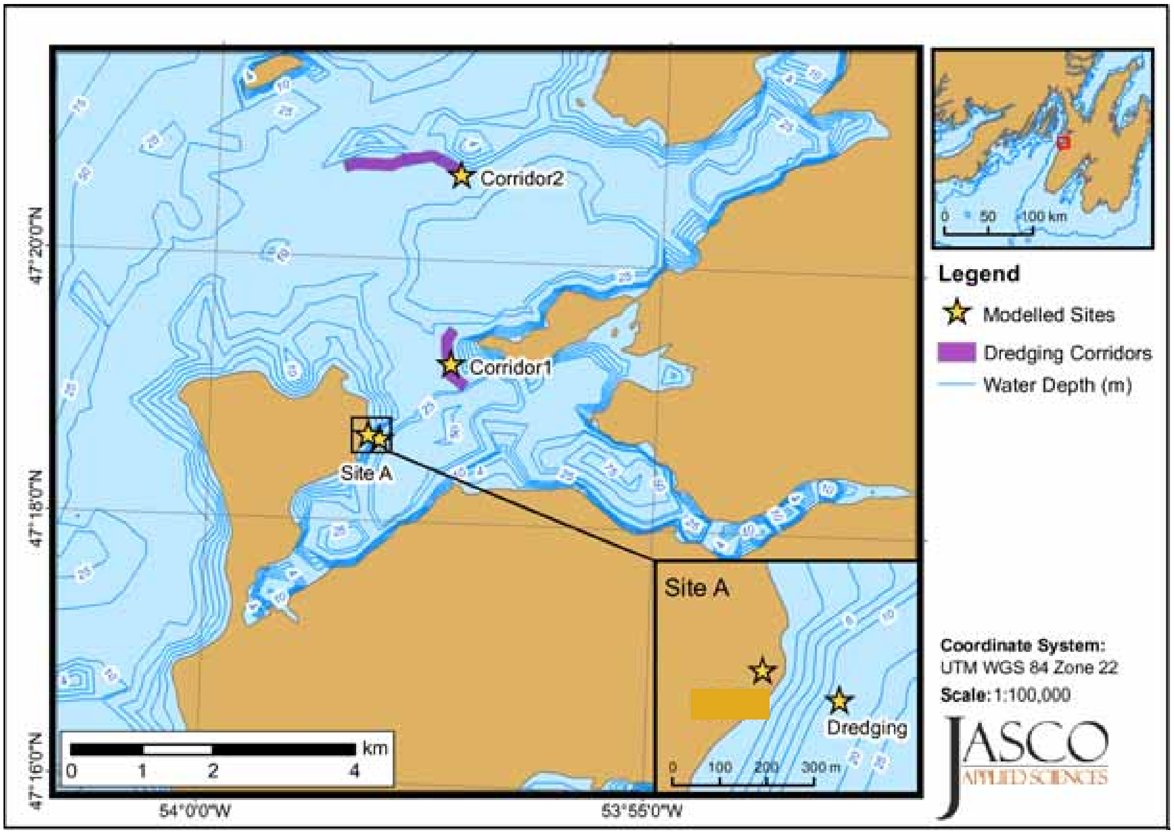


Figure 3-6 Overview of Modelled Sites in Argentia Bay

Modelled results for Scenario 2 represent (continuous) noise from a cutter suction dredge (Figures 3-7 and 3-8).

Modelled results for Scenario 4 represent (continuous) noise from a trailing suction hopper dredge (TSHD) operating in the southern section of Corridor 1 (Figures 3-9 and 3-10).

Modelled results for Scenario 5 represent (continuous) noise from a TSHD operating in the eastern section of Corridor 2 (Figures 3-11 and 3-12).

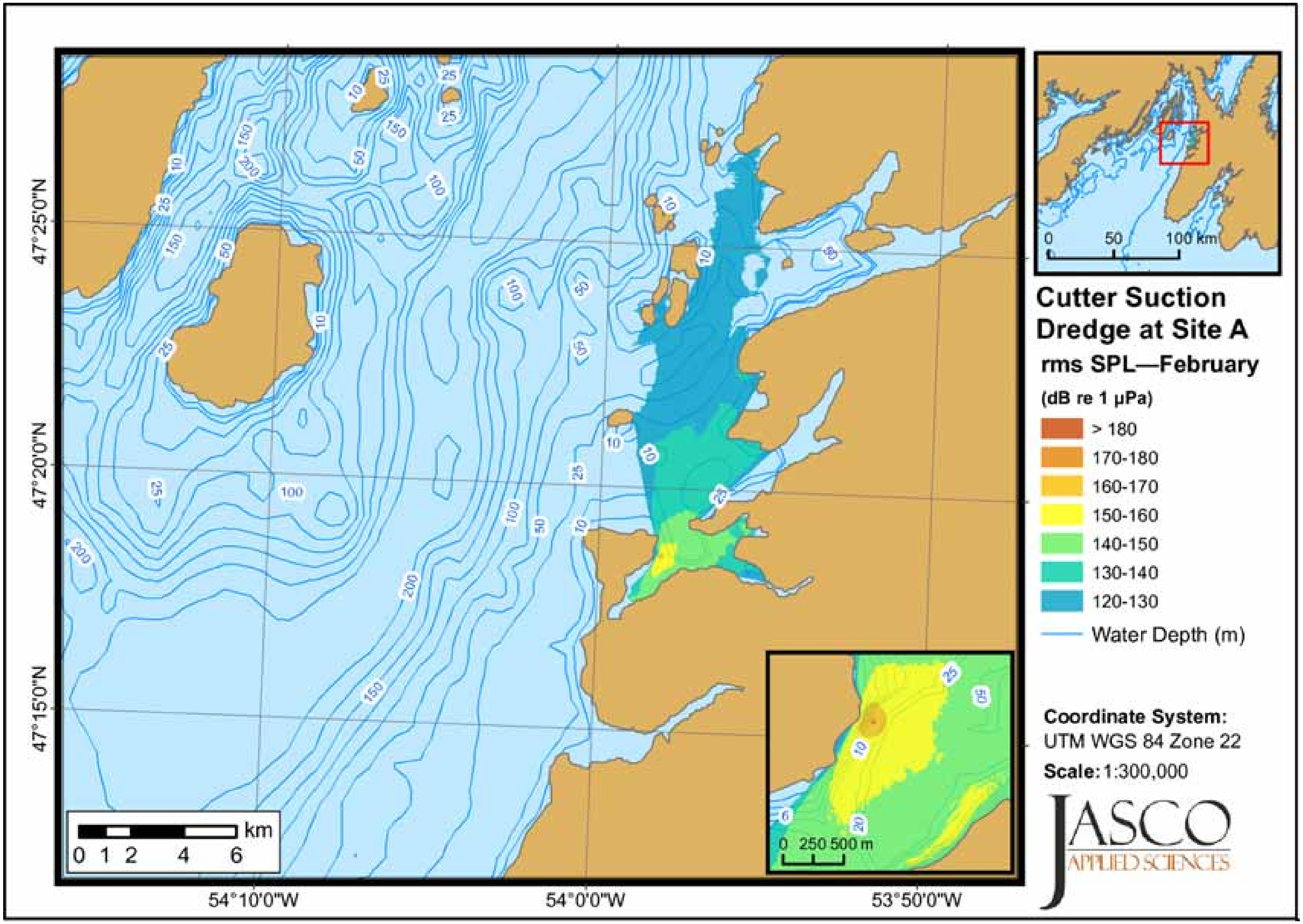


Figure 3-7 Received Maximum-over-depth Sound Levels from the Cutter Suction Dredge in Operation at Graving Dock: February

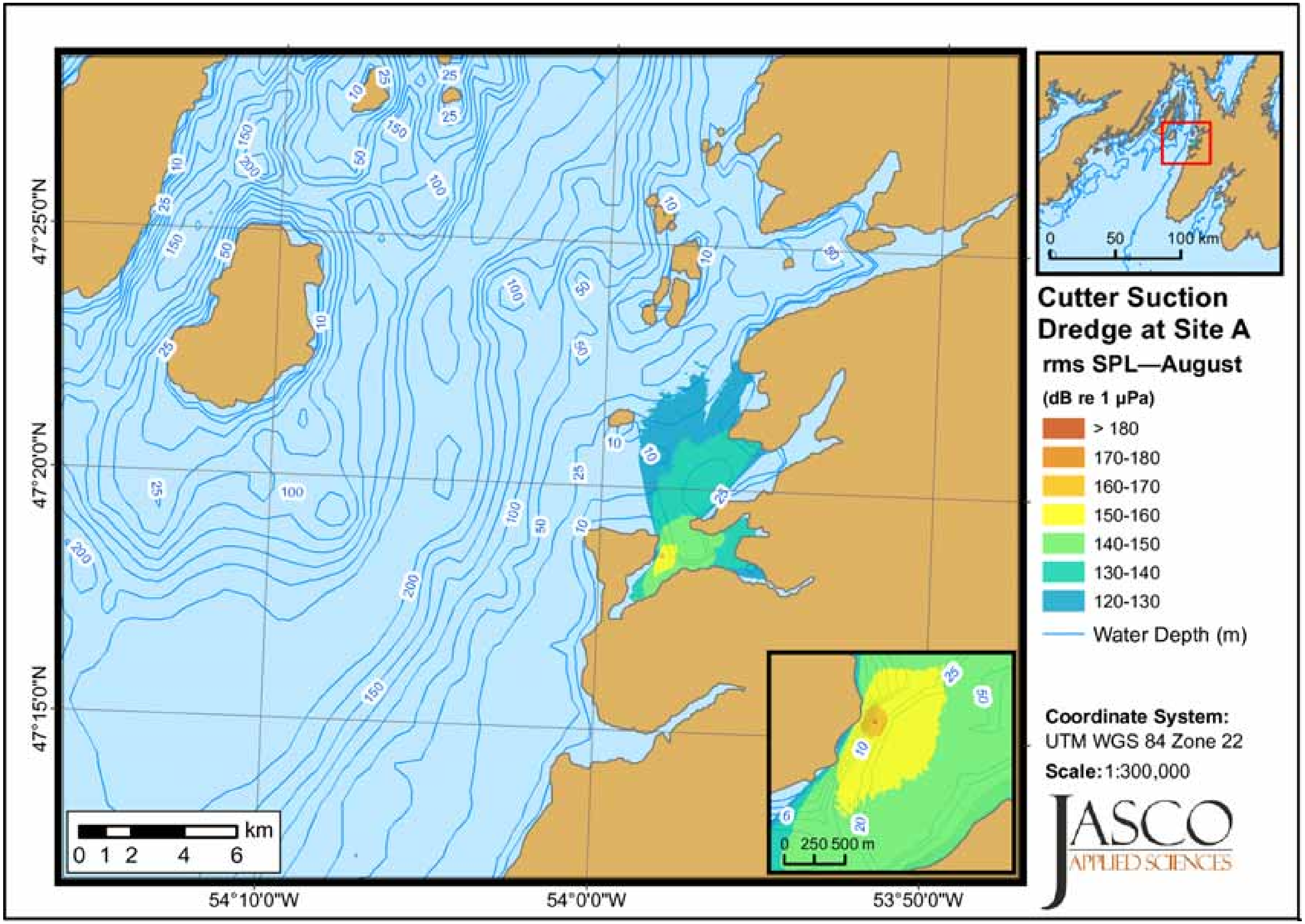


Figure 3-8 **Received Maximum-over-depth Sound Levels from the Cutter Suction Dredge in Operation at Graving Dock: August**

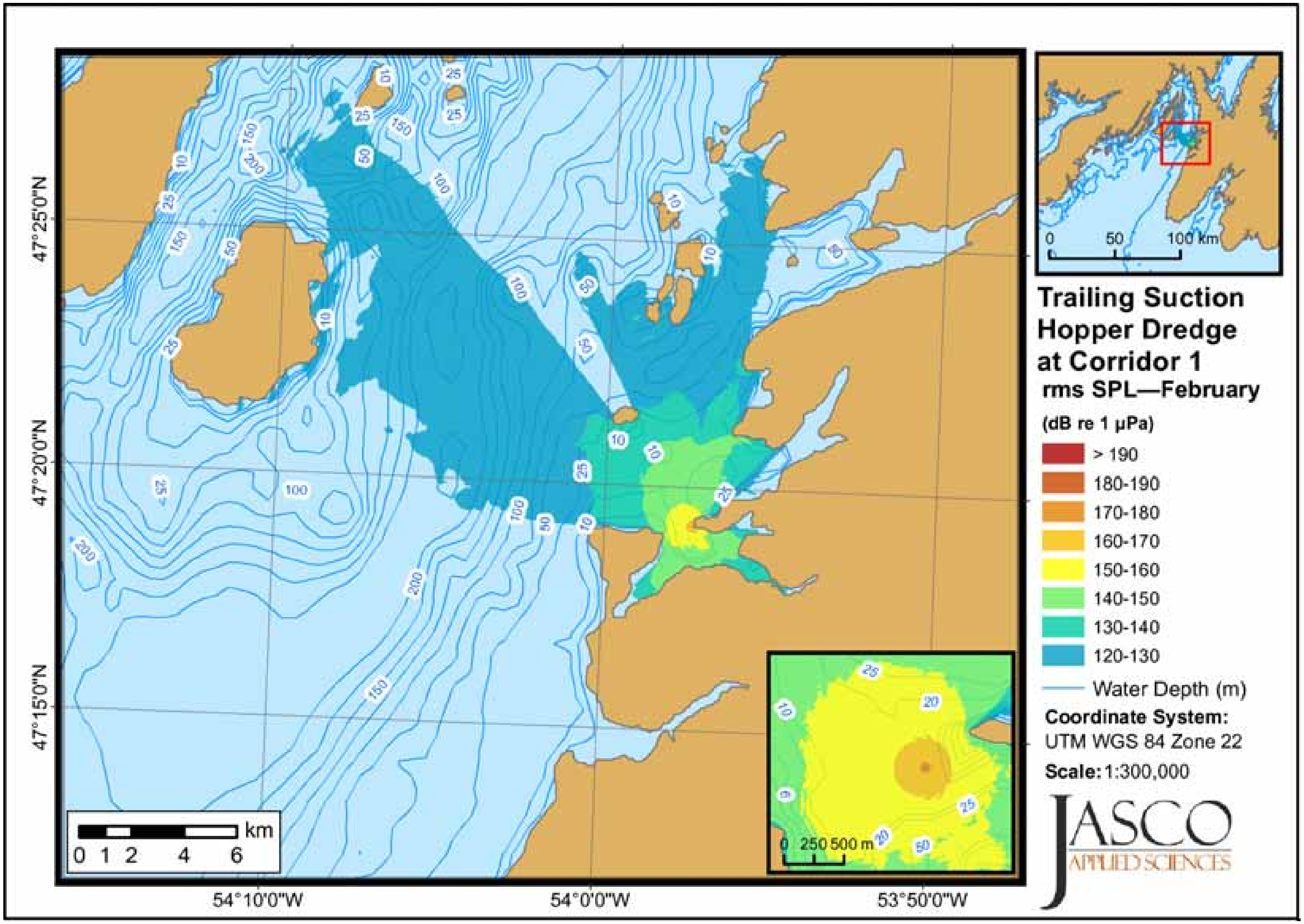


Figure 3-9 Received Maximum-over-depth Sound Levels from the Trailing Suction Hopper Dredge in Operation at Corridor 1: February

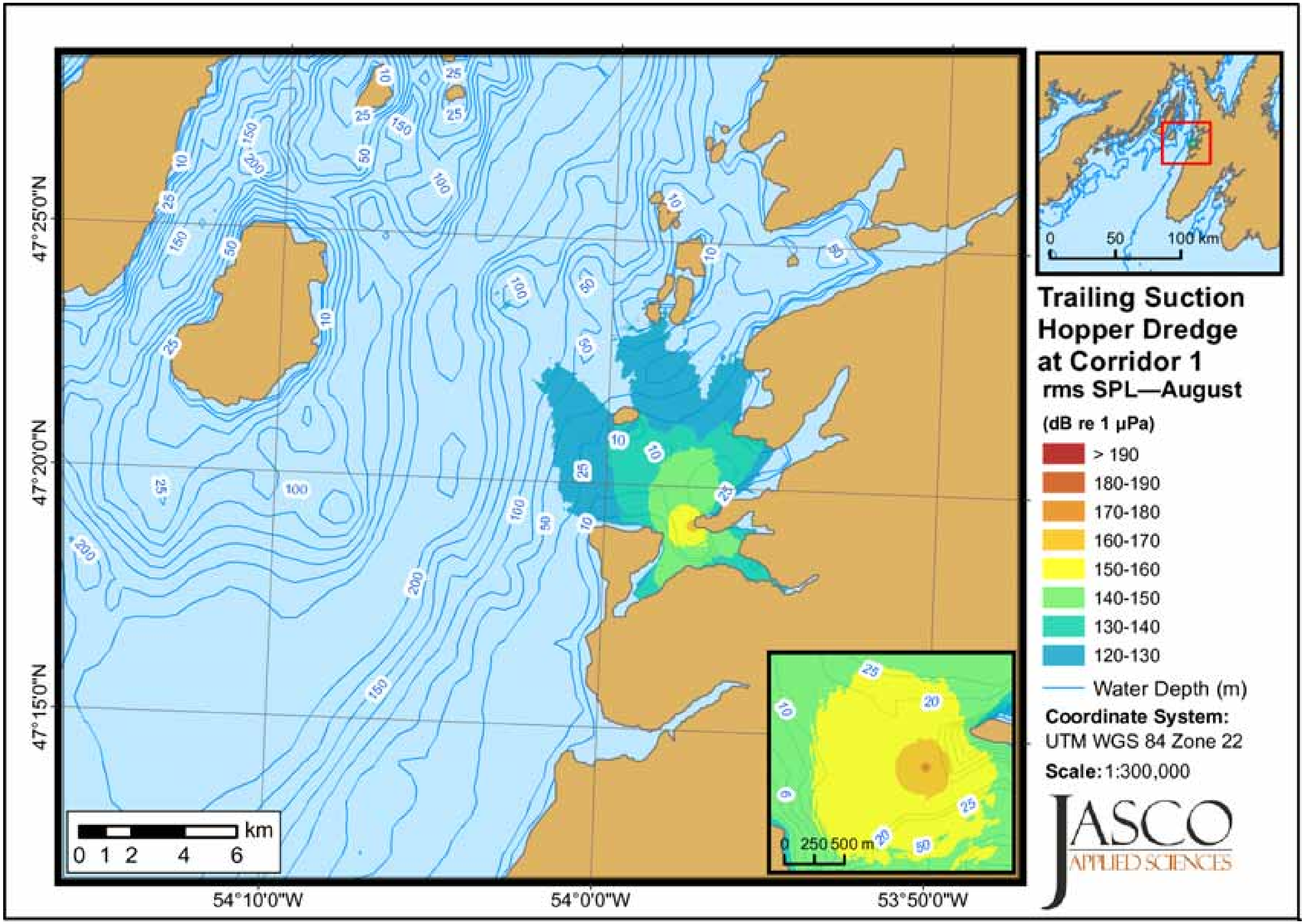


Figure 3-10 Received Maximum-over-depth Sound Levels from the Trailing Suction Hopper Dredge in Operation at Corridor 1: August

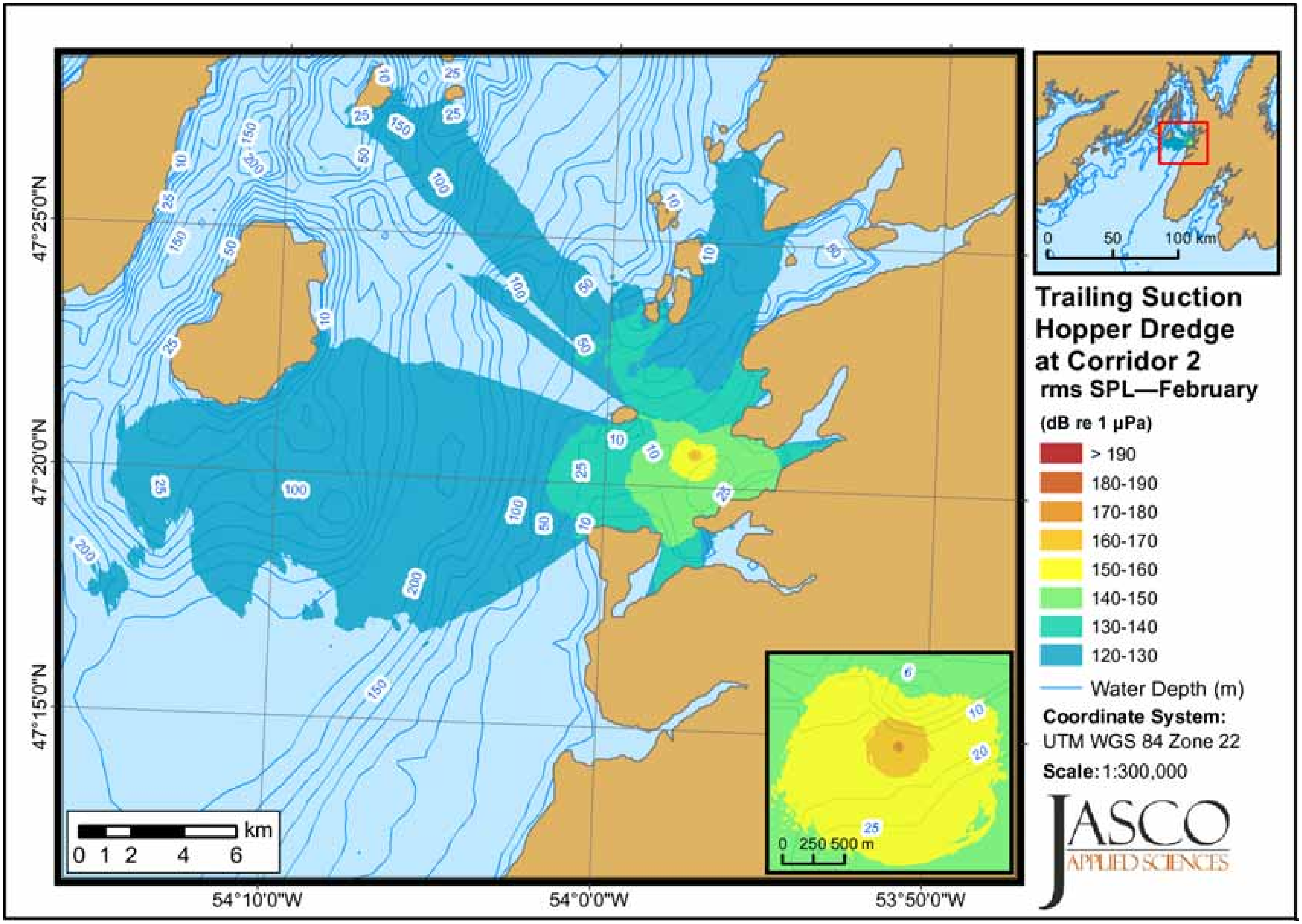


Figure 3-11 Received Maximum-over-depth Sound Levels from the Trailing Suction Hopper Dredge in Operation at Corridor 2: February

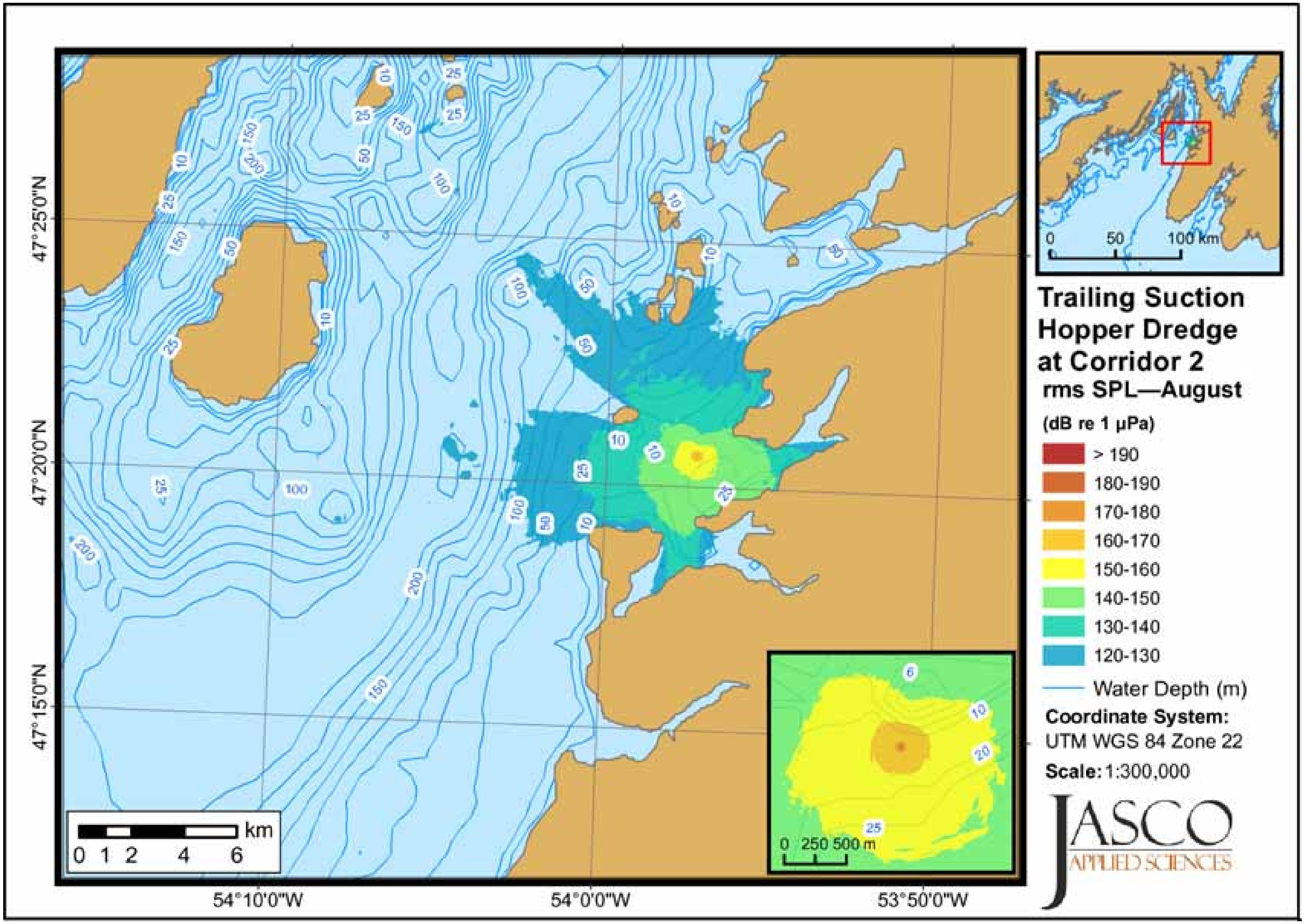


Figure 3-12 **Received Maximum-over-depth Sound Levels from the Trailing Suction Hopper Dredge at Corridor 2: August**

3.2.2 Offshore

Offshore operations were modelled at one site - White Rose field, where the WHP or subsea drill centre will be located. The dredging operations, expected to occur before the installation of the subsea drill centre, were modelled, as well as various operations associated with the WHP or subsea drill centre itself (drilling, support vessel and helicopter operations).

Modelled results for Scenario 6 represent (continuous) noise from a trailing suction hopper dredge operating at the White Rose field site (Figures 3-13 and 3-14).

Modelled results for Scenario 7 represent (continuous) noise from the drilling operations from a WHP at the White Rose field site (Figures 3-15 and 3-16).

Modelled results for Scenario 8 represent (continuous) noise from a support vessel (5,000HP tug) operating at the White Rose field site (Figures 3-17 and 3-18).

Underwater received sound levels around a helicopter at an altitude of 91 m (300 ft) were estimated using the source levels from a Bell 206 helicopter and Young's (1973) model. Broadband-received levels no higher than 157 dB re 1 μPa are estimated at 3 m below the surface, directly under the source, and broadband-received levels no higher than 120 dB re 1 μPa, at a lateral distance of 61 m from the source. Since the threshold of the 120 dB re 1 μPa rms SPL is reached at a lateral distance of less than half the water depth (128 m), distances to received sound level thresholds of 130 to 150 dB re 1 μPa were estimated assuming spherical spreading.

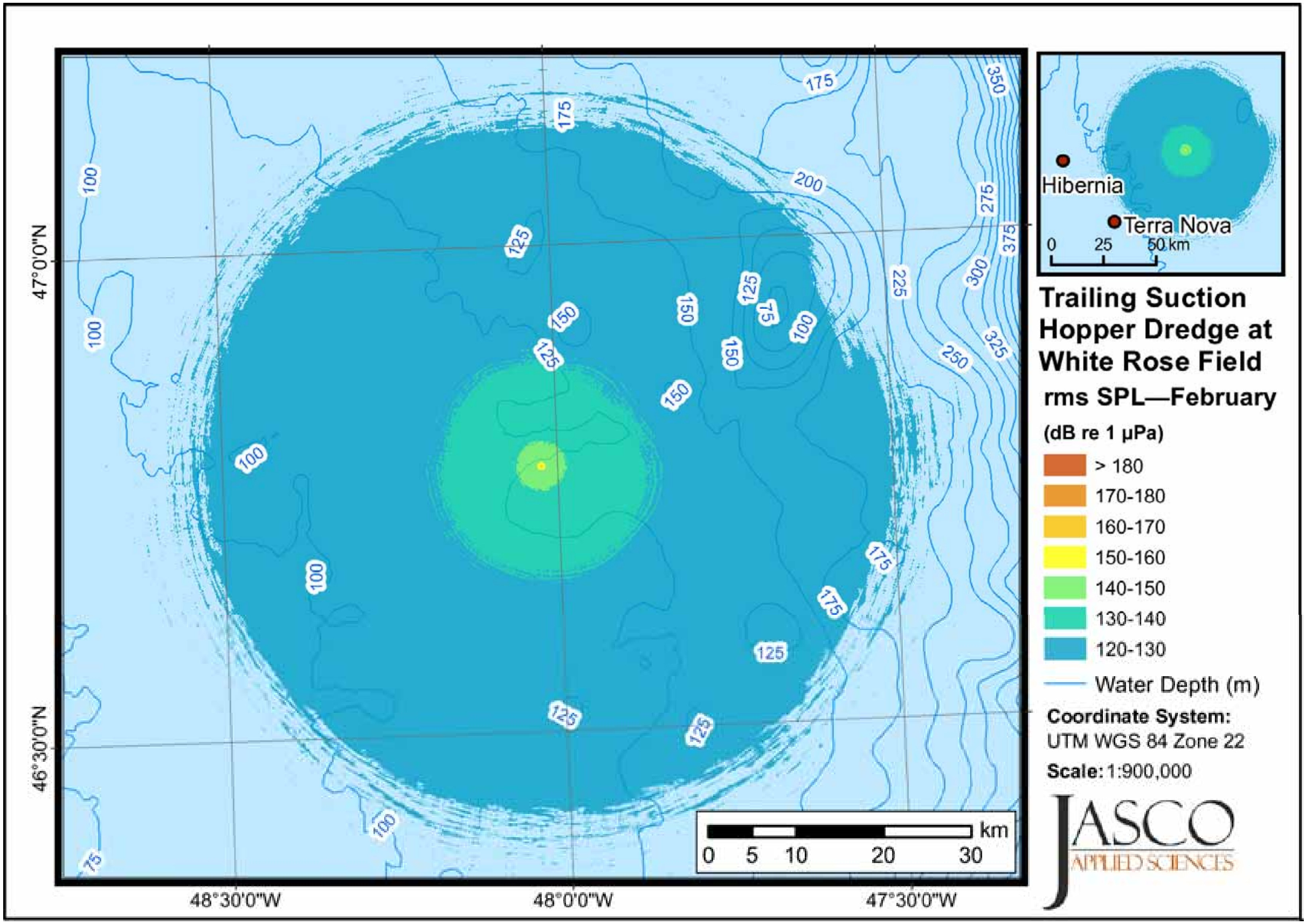


Figure 3-13 Received Maximum-over-depth Sound Levels from the Trailing Suction Hopper Dredge in Operation at the White Rose Field: February

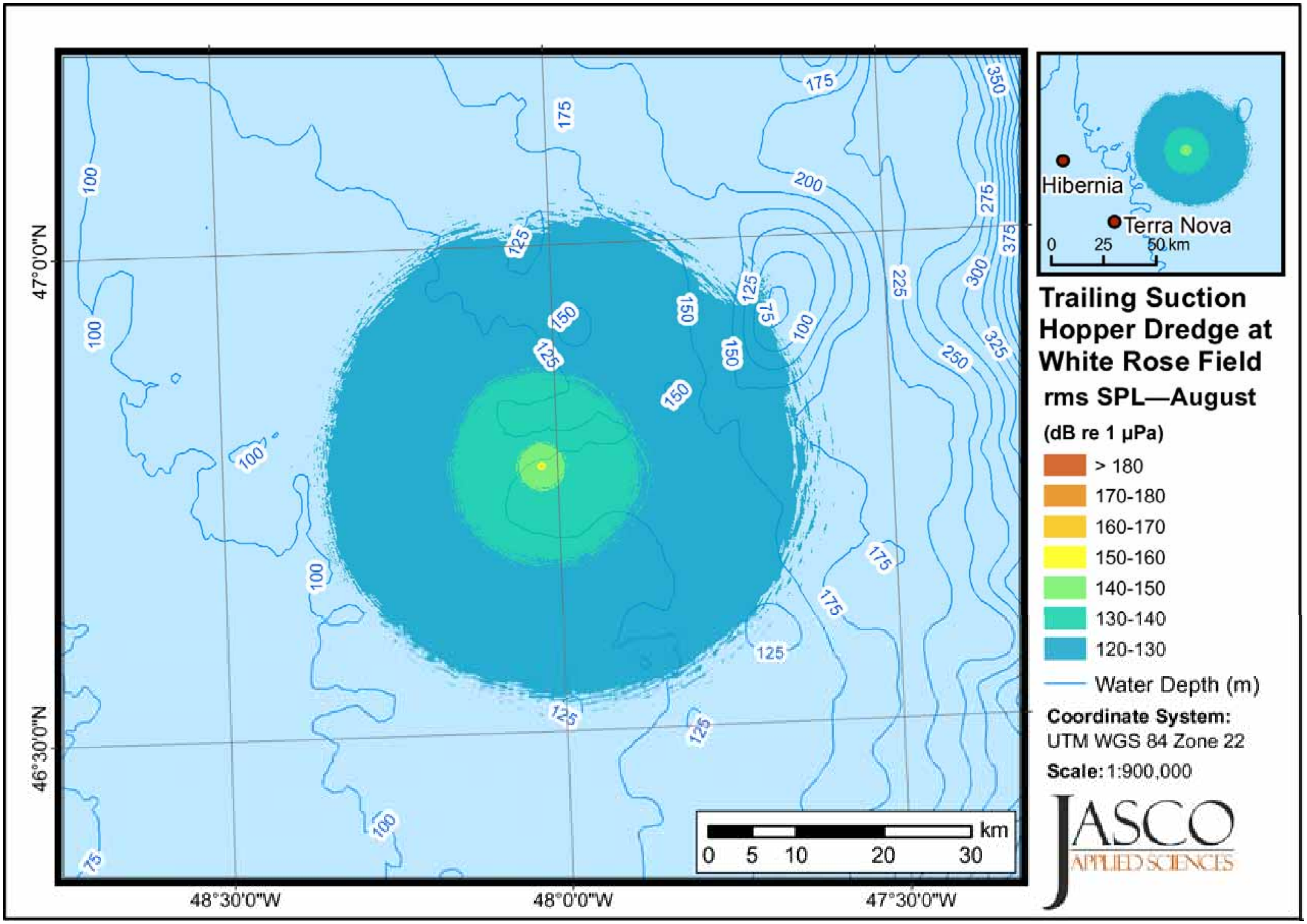


Figure 3-14 **Received Maximum-over-depth Sound Levels from the Trailing Suction Hopper Dredge in Operation at the White Rose Field: August**

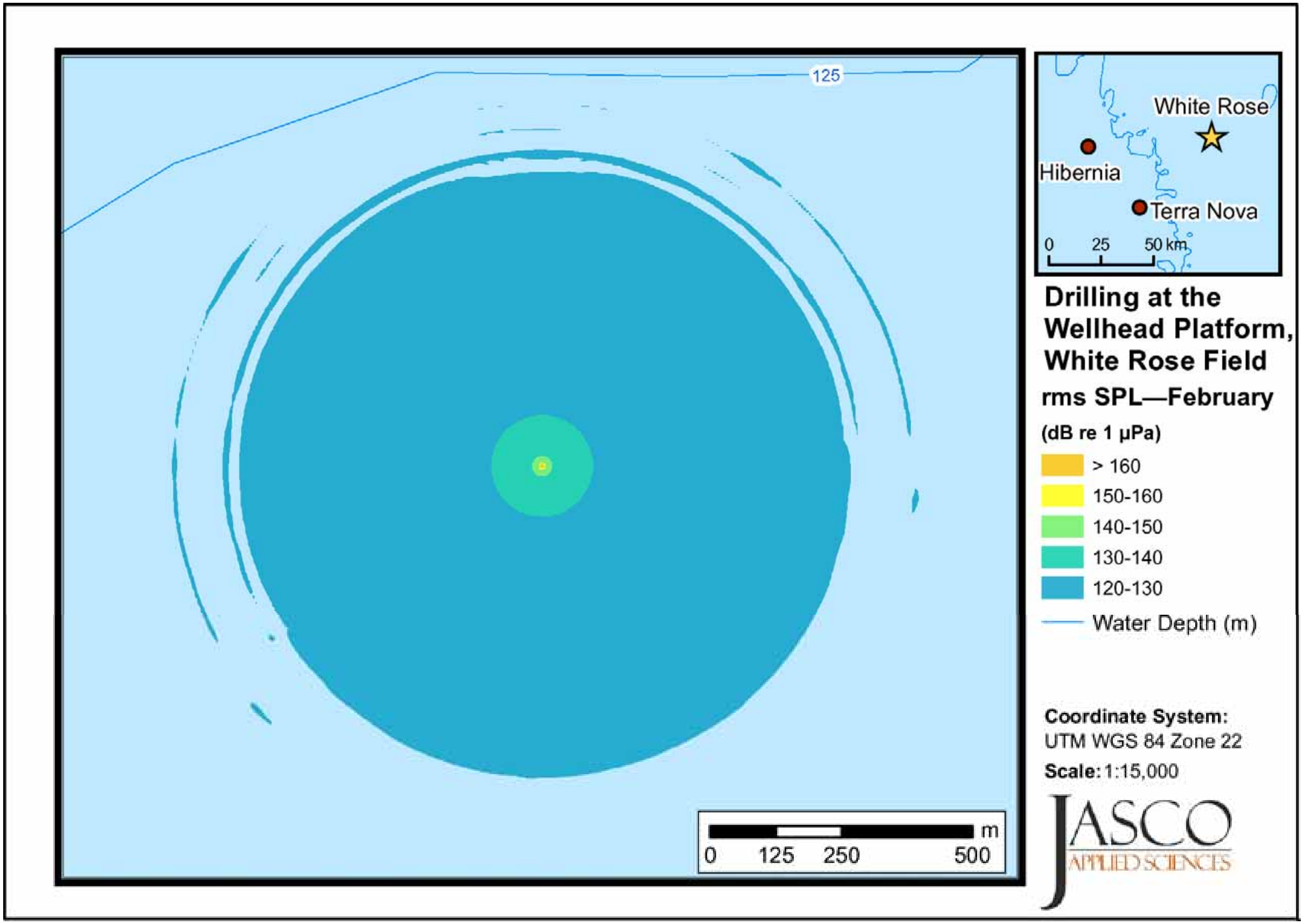


Figure 3-15 Received Maximum-over-depth Sound Levels from the Wellhead Platform in Operation at the White Rose Field: February

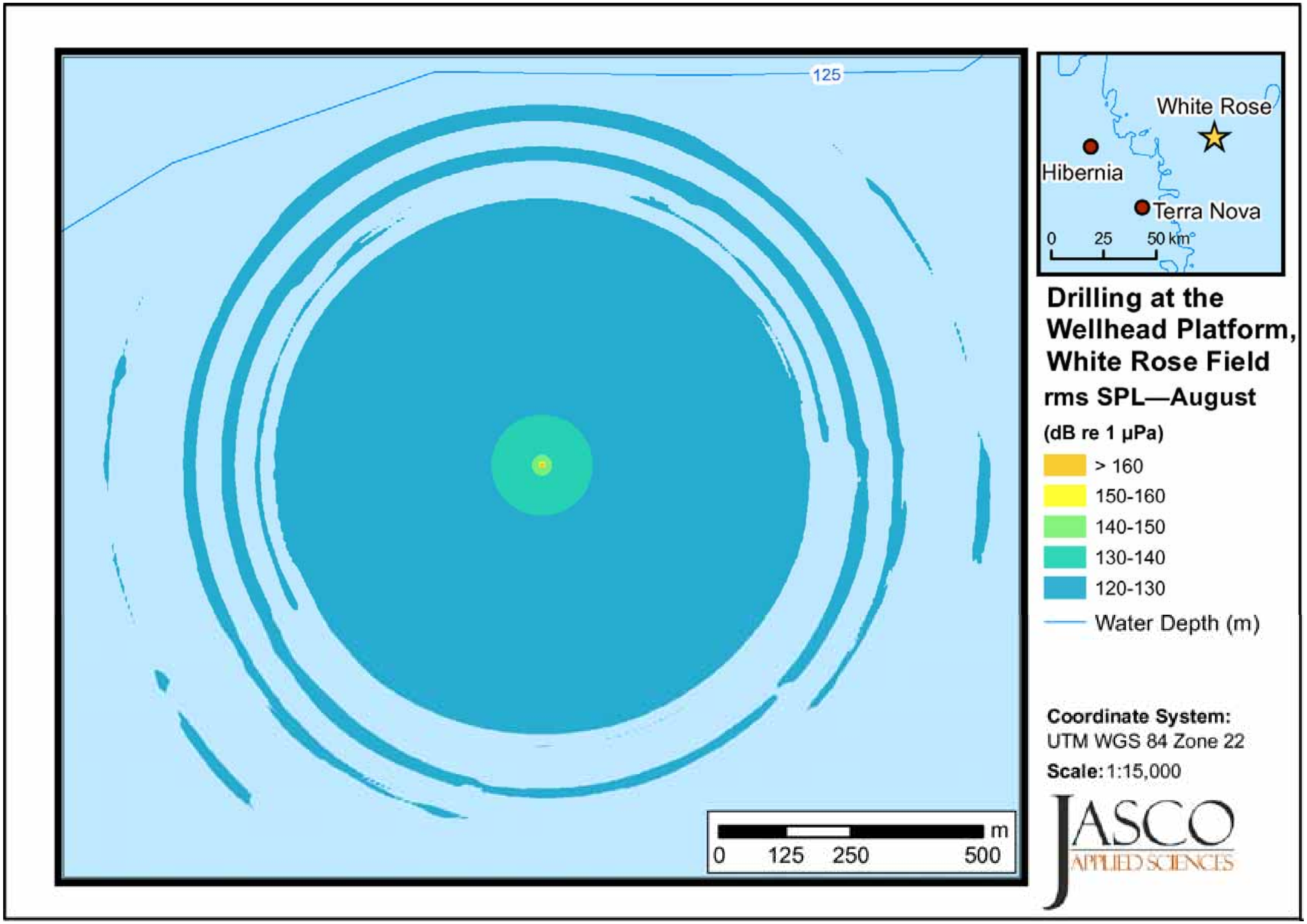


Figure 3-16 Received Maximum-over-depth Sound Levels from the Wellhead Platform in Operation at the White Rose Field: August

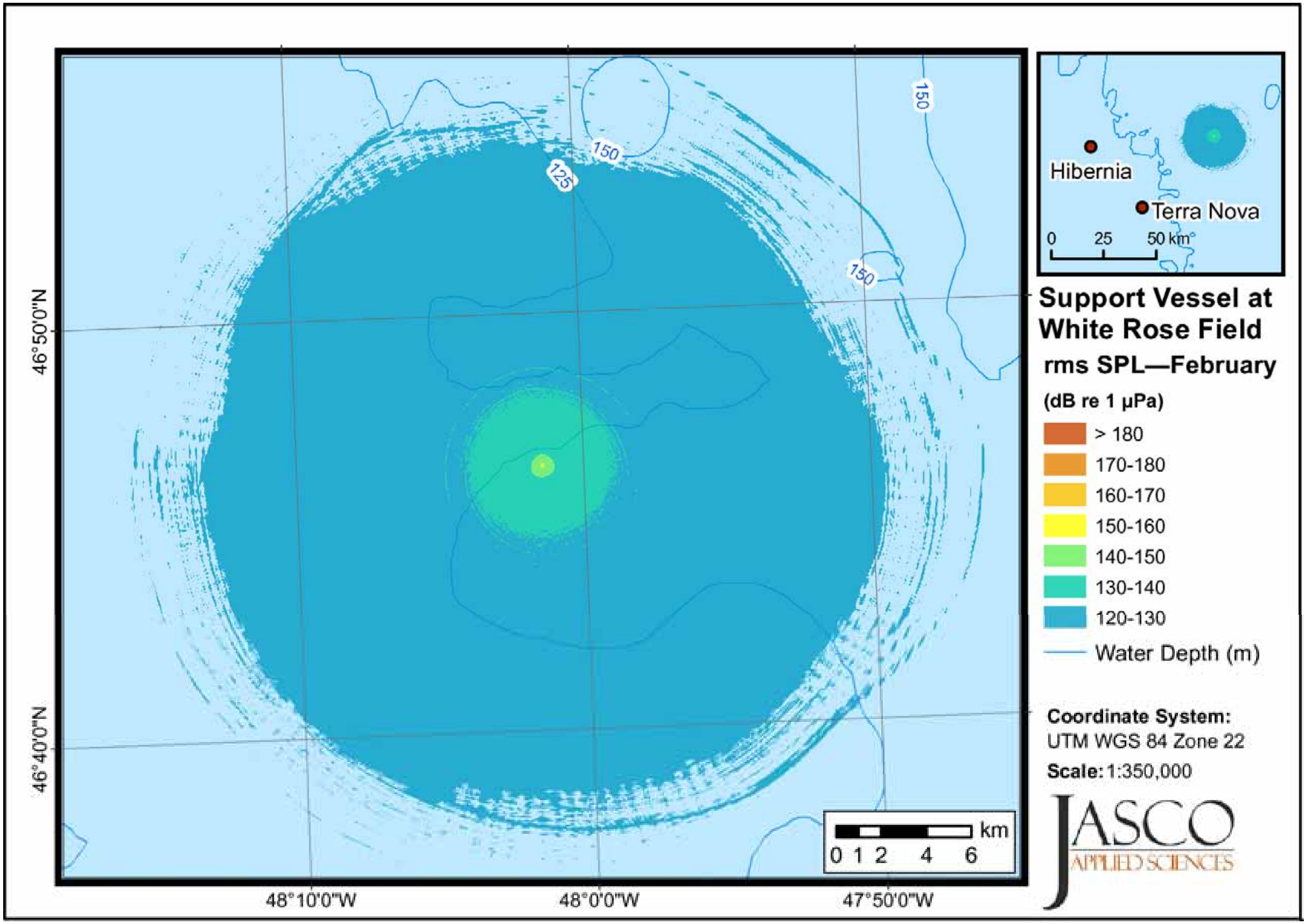


Figure 3-17 Received Maximum-over-depth Sound Levels from the Support Vessel in Operation at the White Rose Extension Project Site: February

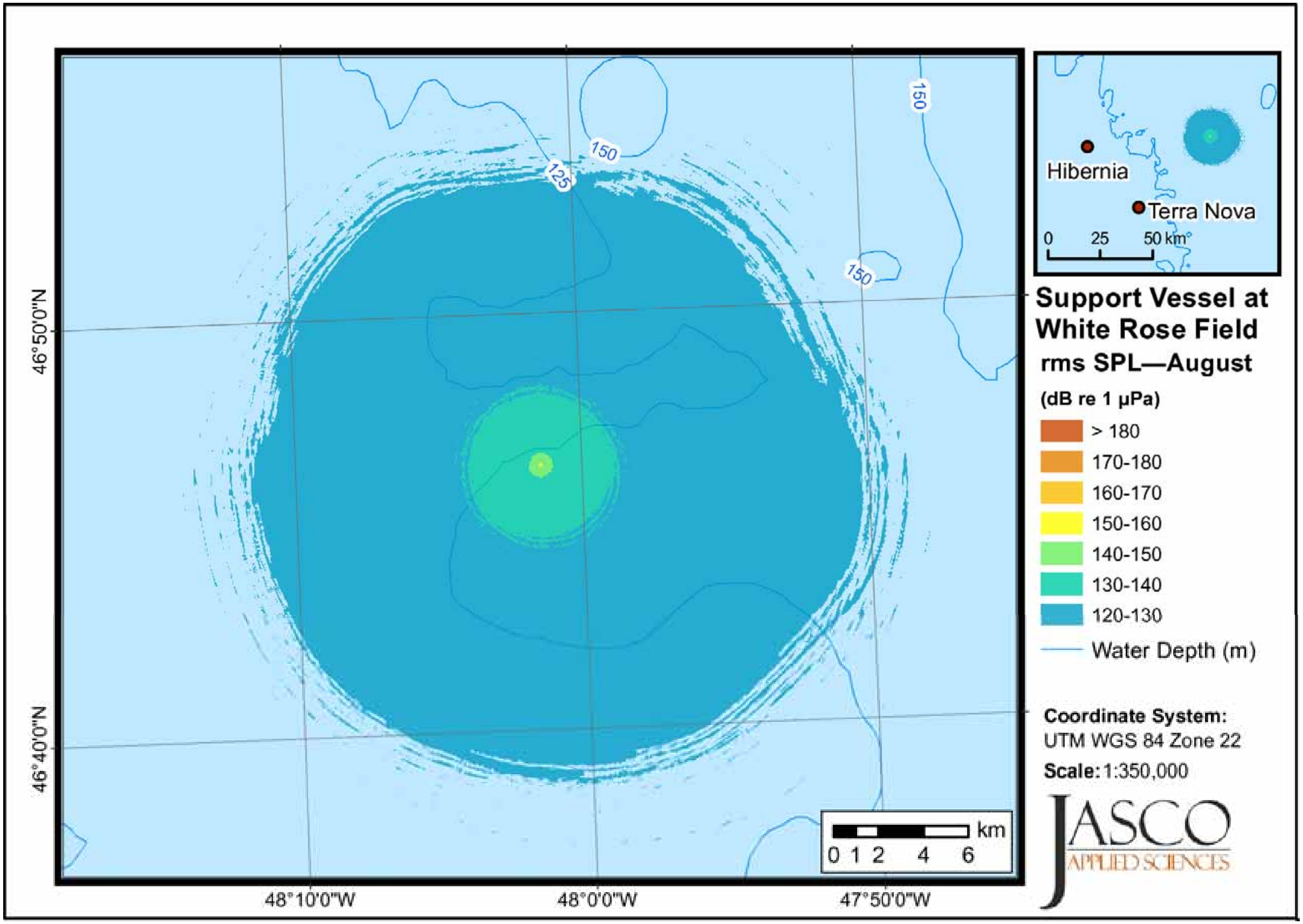


Figure 3-18 Received Maximum-over-depth Sound Levels from the Support Vessel in Operation at the White Rose Field: August

3.3 Dredging Modelling

AMEC conducted modelling of total suspended solids (TSS) dispersion due to dredging in the Nearshore Project Area. The full report is provided in AMEC (2012a).

Shoreline dredging activities will include loosening of the soil by a choice of a backhoe dredge (BHD) or a cutter suction dredge (CSD); dredging in Corridor 1 and Corridor 2 would be completed in four to six weeks using a TSHD. In the case of a four-week program, a loading cycle would be completed once every 40 hours. The shorter dredging program duration is considered a conservative scenario in terms of the levels of suspended sediments in the environment, as there would be less available time for the plumes to dissipate between dredging cycles.

3.3.1 Model Inputs

The aim of the present study is to assess the potential for suspension of the fine sediments during dredging activities, and to predict the likely fate and dispersion of these sediments through the duration of the dredging program and beyond, without any mitigation for the dispersion of sediment. These results are therefore considered to represent a worst case scenario. The assessment was based on ocean currents modelled by AMEC's implementation of the Delft3D modelling suite in the depth averaged mode, including tidal and wind-driven circulation near Argentia. Ocean current speeds were relatively low (5 cm/s or less) at the construction site, and higher (10 to 15 cm/s) within the dredging corridors.

It was considered that a 160 m-wide swatch is required to provide the necessary clearance for the CGS. The target depth within this swath was determined to be 16.5 m referenced to chart datum, resulting in a depth of approximately 18 m at high tide (C-CORE 2012b). It is apparent from the volumes given in Table 3-29 that the dredging operations will be conducted mostly in the vicinity of the graving dock, and within Corridor 2, with only minor amounts to be dredged in Corridor 1.

Table 3-29 Volumes of Dredged Sediment in the Dredging Areas

Range (chart datum)	Dredging Volumes (m^3)		
	Construction Site	Corridor 1	Corridor 2
-16.5 m to seabed	200,300	25	165,400
Source: C-CORE 2012b			

The composition of the sediment in each area was determined from samples taken during a field campaign (Stantec 2012b). Sand accounted for 55 percent of the material at the construction site, 17 percent in Corridor 1 and only 3 percent in Corridor 2.

The inputs for the DREDGE model (Tables 3-30 and 3-31) were determined based on the known and assumed equipment specifications (Van Oord 2012), the sediment composition and the current magnitude estimates from AMEC's hydrodynamic model at the graving dock. Hence, model runs were conducted with the mechanical dredge module for the three possible bucket sizes of BHD, two dredging depths representative of the beginning and the end of the dredging process, and two current speeds representing the range of currents expected at the site. The canonical value of 60 s was used for the cycle time, assuming a typical cycle time distribution of 30 percent for the bucket rising, 48 percent above the water surface and 22 percent for the bucket falling through the water column. The suspended sediments associated with the operation come from the disturbance of the sea bottom, as well as for the partial loss of fine materials when the bucket rises through the water column.

Table 3-30 Backhoe Dredger Modelling Inputs for the Graving Dock Shoreline

Parameter	Values Used
Bucket Size (m^3)	15, 20, 25
Cycle Time (s)	60
Water Depth (m)	7, 20
Current Speed (m/s)	0.01, 0.05
Average Settling Velocity (m/s)	0.001
Fines Settling Velocity (m/s)	0.0003
In-situ Dry Density (kg/m^3)	1,560
Mean Particle Size (µm)	54
Fraction of Particles <74 µm	0.61
Fraction of Particles <50 µm	0.48
Lateral Diffusion Coefficient (cm^2/s)	100,000
Vertical Diffusion Coefficient (cm^2/s)	5

Table 3-31 Cutter Suction Dredger Modelling Inputs for Graving Dock Shoreline

Parameter	Values Used
Cutterhead Diameter (m)	2
Cutterhead Length (m)	3
Thickness of Cut (m)	2
Ladder Length (m)	23
Cutterhead Rotation Speed (rpm)	2
Dredge Flowrate (m^3/s)	2
Water Depth (m)	7, 20
Current Speed (m/s)	0.01, 0.05
Average Settling Velocity (m/s)	0.001
Fines Settling Velocity (m/s)	0.0003
In-situ Dry Density (kg/m^3)	1,560
Mean Particle Size (µm)	54
Fraction of Particles <74 µm	0.61
Fraction of Particles <50 µm	0.48
Lateral Diffusion Coefficient (cm^2/s)	100,000
Vertical Diffusion Coefficient (cm^2/s)	5

3.3.2 Graving Dock Shoreline

The sediment re-suspension and dispersion at the construction site were modelled using the ADDAMS-DREDGE model, including scenarios for all the anticipated combinations of equipment (BHD or CSD), three different bucket sizes (15 m^3, 20 m^3, 25 m^3) for the BHD option, current magnitudes (1 cm/s and 5 cm/s) and water levels (7 m and 20 m) (Tables 3-32 and 3-33).

Table 3-32 Backhoe Dredger Dredging Option (Current = 1 cm/s)

Depth (m)	Bucket Size (m^3)					
	15		20		25	
	Max TSS at Site (mg/L)	Distance TSS <1 mg/L (m)	Max TSS at Site (mg/L)	Distance TSS <1 mg/L (m)	Max TSS at Site (mg/L)	Distance TSS <1 mg/L (m)
7	12.0	230	18.9	300	27.8	370
20	12.2	430	19.6	620	28.5	790

Table 3-33 Backhoe Dredger Dredging Option (Current = 5 cm/s)

Depth (m)	Bucket Size (m^3)					
	15		20		25	
	Max TSS at Site (mg/L)	Distance TSS <1 mg/L (m)	Max TSS at Site (mg/L)	Distance TSS <1 mg/L (m)	Max TSS at Site (mg/L)	Distance TSS <1 mg/L (m)
7	5.5	220	8.8	400	12.9	650
20	5.5	270	8.9	570	12.9	950

The results show that for the BHD option, the concentrations at the site would be relatively low (5.5 to 28.5 mg/L), and fall below 1 mg/L within approximately 230 m to 1 km of the site. The fine sediment plumes are expected to propagate mostly along the shoreline (southwest to northeast direction), as the tidal currents are expected to be aligned with the shore in this area.

The local effect of the CSD on suspended sediment levels would be higher than that of the BHD, with predicted suspended sediment concentrations within 10 m of the source ranging from 291.6 to 718.3 mg/L (Table 3-34).

Table 3-34 Cutter Suction Dredger Dredging Option

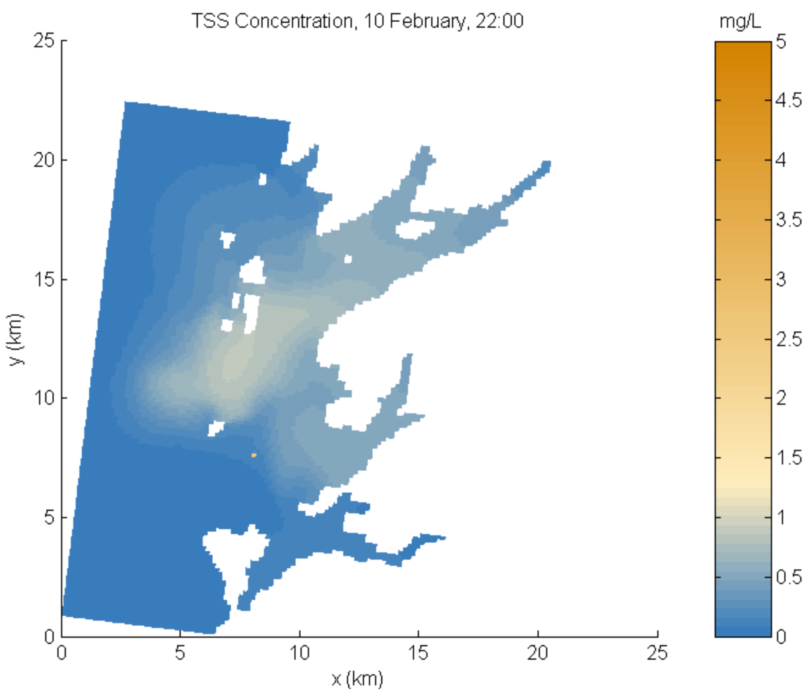
Depth (m)	Current Speed (cm/s)			
	1		5	
	Max TSS at Site (mg/L)	Distance TSS <1 mg/L (m)	Max TSS at Site (mg/L)	Distance TSS <1 mg/L (m)
7	291.6	440	302.3	1,120
20	692.9	570	718.3	1,650

A comparison of the far-field dispersion for the two dredging methods revealed that levels for the CSD are broadly comparable to those of the 20 and 25 m^3 BHD option at current speeds of 5 cm/s (440 to 1,650 m). It should be noted that the CSD dredging option has been indicated in the preliminary dredging plan as an alternative dredging method, to be employed only if coarse, hard material (rock) is encountered or anticipated at the dredging site. If the samples considered in the current study are representative of the full volume to be dredged, it is likely that the BHD would be the preferred option. For this reason, a CSD scenario including high percentages of fine sediments is relatively unlikely.

3.3.3 Corridors 1 and 2

The modelling of the TSHD operations showed that depending on the cruising speed of the TSHD, the end of the near-field mixing zone would be reached at distances of 30 to 95 m from the dredging location. The dilution factor reached within this initial zone is expected to range from 31.2 to 90.9, resulting in initial plume concentrations of 1,490 to 4,330 mg/L within the first 100 m.

The far-field model results show that during typical conditions there is a tendency for the plumes to be transported to the north of Corridor 2, with very limited transport to the south near the Argentia Tide Gauge and Fox Harbour monitoring points (Figures 3-19 to 3-22). Therefore, these two points would experience a miniscule increase of TSS levels (on the order of 0.1 mg/L) during the whole duration of dredging operations at Corridor 2, and most of the coastal stations generally see levels of less than 1 mg/L. The only exception is the Seal Cove location, where approximately half of the dredge cycles produce spikes in the TSS levels above 2.5 mg/L, and sometimes above 3 mg/L. However, the spikes in TSS levels are relatively short-lived, as the concentrations fall rapidly below 1 mg/L within a timescale of a day. The relatively high exposure of Seal Cove compared to the other monitoring points can be attributed not only to its relatively close proximity to Corridor 2, but also to the currents that are on average oriented toward the northeast of the dredging area.



Note the Pre-existing sediment from the previous 16 operations

Figure 3-19 Total Suspended Solids Concentrations at the Beginning of the 17th (last) Dredging Operation in Corridor 2

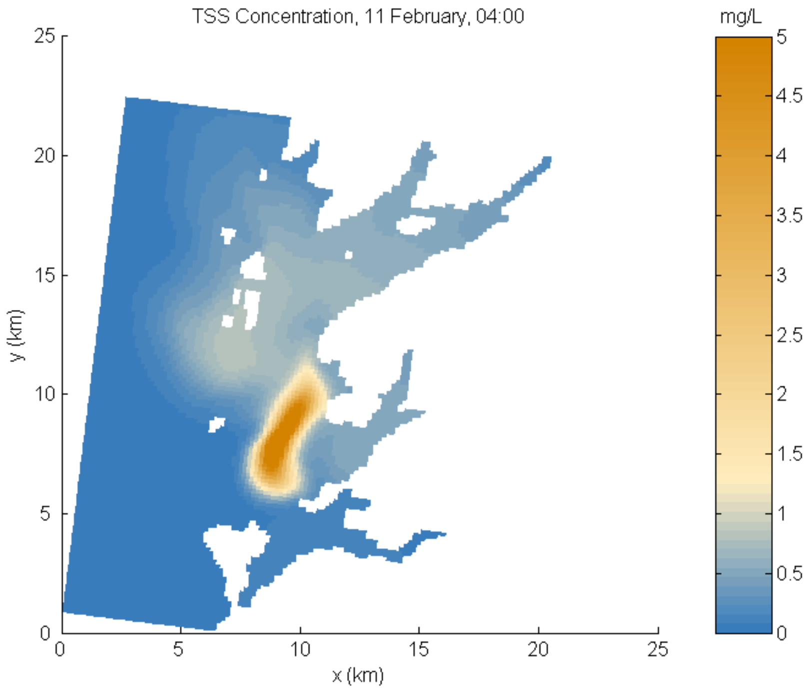


Figure 3-20 Total Suspended Solids Concentrations 6h after the Last of 17 Dredging Operations in Corridor 2

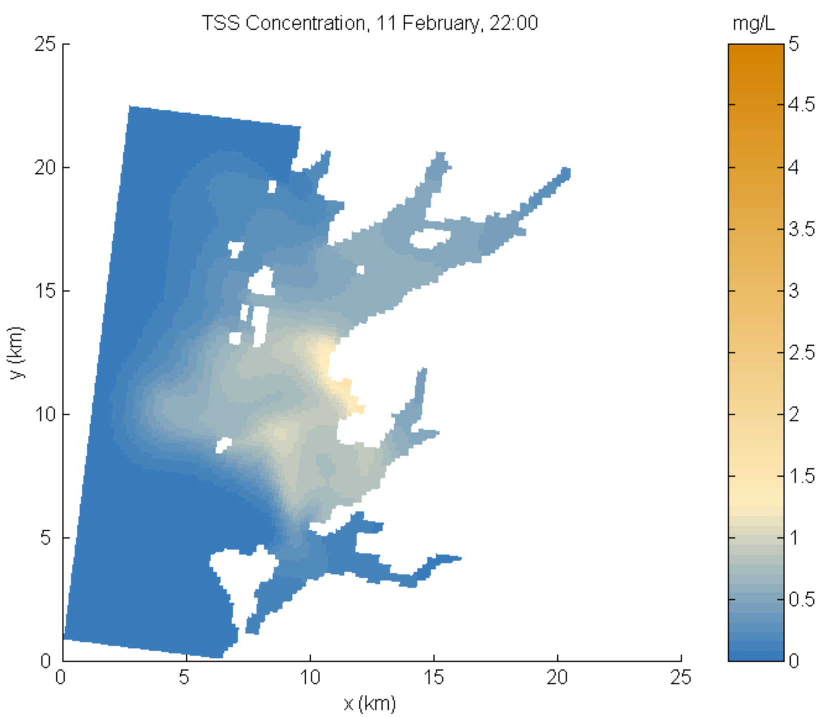


Figure 3-21 Total Suspended Solids Concentrations 24h after the Last of 17 Dredging Operations in Corridor 2

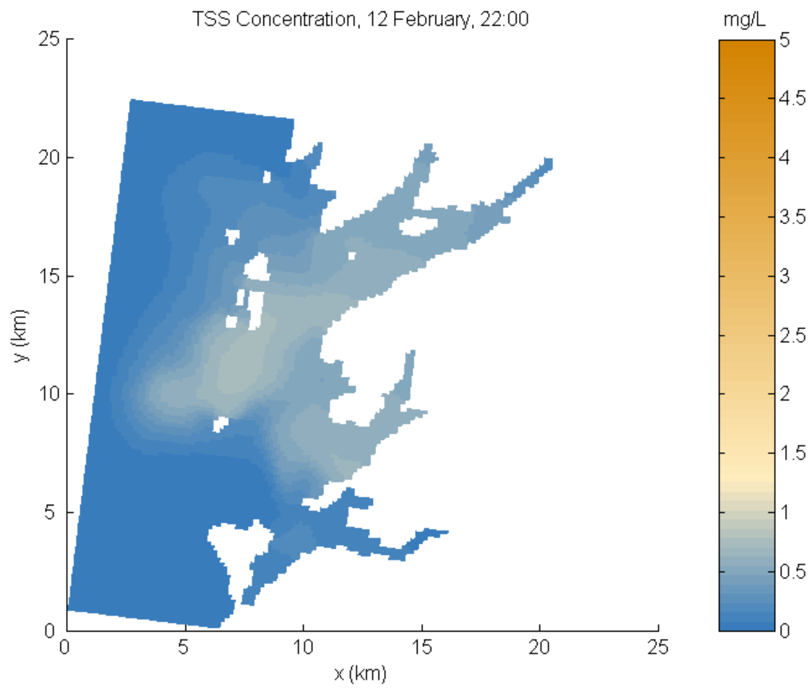


Figure 3-22 Total Suspended Solids Concentrations 48h after the Last of 17 Dredging Operations in Corridor 2

Maximum concentrations of 5 to 10 mg/L occur for the first 6 to 10 hours after the dredging cycle, and are generally restricted within an area of 3 km^2 around Corridor 2. Overall, suspended sediment concentrations are expected to fall to approximately 1 mg/L within the first 30 hours of a dredging operation. The vast majority of the fine sediments are expected to be transported out of the bay by the combined tidal and wind-driven currents.

The statistics describing the average plume characteristics for all wind scenarios are shown in Table 3-35. It is apparent that maximum plume concentrations are expected to fall below 25 mg/L within less than four hours from the end of operations in all cases, below 10 mg/L in approximately six hours from the end of operations and below 5 mg/L in 10 hours from the end of operations. Plume concentrations above 25 mg/L are expected to occur within limited areas of approximately 0.7 km^2. The only substantial difference between the wind scenarios is observed in the extent and persistence of plume concentrations above 1 mg/L (but below 5 mg/L), where the southwesterly winds are approximately twice as efficient at dispersing these low levels of suspended sediment (within 21.9 hours) compared to the northwesterly winds (37.8 hours) and the most frequent, westerly wind conditions. (32.6 hours).

Table 3-35 Sediment Plume Concentration at Source, Persistence and Extent for the Average Trailing Suction Hopper Dredger Dredging Cycle

Wind Direction	Max TSS at source (mg/L)	Period TSS >25 mg/L (h)	Period TSS >10 mg/L (h)	Period TSS >5 mg/L (h)	Period TSS >1 mg/L (h))	Area TSS >25 mg/L (km^2)	Area TSS >10 mg/L (km^2)	Area TSS >5 mg/L (km^2)	Area TSS >1 mg/L (km^2)
West	274	3.8	6.1	9.3	32.6	0.7	1.7	3.1	16.6
Southwest	240	3.7	5.9	9.2	21.9	0.7	1.6	2.7	10.4
Northwest	269	3.7	6.4	10.0	37.8	0.6	1.6	3.0	22.6

In order to assess the cumulative exposure to the suspended sediments associated with the unmitigated TSHD operations, the concentrations at all points in the model domain were averaged over sliding 24-hour and 30-day time windows over the duration of the program, and up to 30 days following the end of the dredging program. The results show that the mean exposure over 24-h would never reach higher than approximately 19 mg/L, and the highest mean exposure over 30 days is approximately 3.6 mg/L. These are the highest levels predicted to occur within the limits (200 m distance) of the actual dredging site (Corridor 2); however, within the first kilometre, the 24-h exposures fall to approximately 10 mg/L or less. The highest exposure levels over 24 hours for most of the model domain in the vicinity of Argentia are predicted to be approximately 5 mg/L or less. The trends are similar for the 30-day exposure results, where the highest exposure levels outside the vicinity of the dredging site are expected to remain at approximately 1.5 mg/L or less.

The results presented here are well below the thresholds for total particulate matter given in the *Canadian Water Quality Guidelines for the Protection of Aquatic Life* (CCME 2002). The guidelines specify that during clear flow periods, anthropogenic activities should not increase suspended sediment concentrations by more than 25 mg/L over background levels during any short-term exposure period (24 hours), while for longer term exposure (30 days or more), average suspended sediment concentrations should not be increased by more than 5 mg/L over background levels.

3.4 Drill Cuttings Deposition

AMEC conducted modelling of WBM and SBM drill cuttings deposition in the White Rose field. The full report is provided in AMEC (2012b).

Five base case scenarios were modelled:

- WHP option: 40 wells drilled from a WHP at WWRX1
- Subsea option: 16 wells drilled from a MODU at West White Rose (WWRX1)
- Two potential new drill centres – as introduced in LGL (2007a) – now with 16 wells each drilled by a MODU:
  - West White Rose Extension – a second drill centre (WWRX2)
  - North White Rose Extension (NWRX)
- New drill centre with 16 wells drilled by a MODU at South White Rose Extension:

Drilling of the South White Rose Extension was assessed in LGL (2007a), and is expected to begin in 2013. The drill cutting modelling results for this drill centre are included here to assist with the cumulative environmental effects assessment.

Drilling may commence potentially in Q4 2016 for the WHP or Q4 2015 for the subsea drill centre (Husky 2012a) (i.e., a Q4 seasonal start for either option).

While a drilling schedule has not been developed, the average well time is estimated to be 93 days. This assumes a straight drill and complete operation for each well with no batch drilling. Within this period, the associated operational mud and cuttings releases, for this modelling exercise, are estimated to take place as shown in Table 3-36, as applicable for the WHP or subsea options.

Table 3-36 Discharge of Mud and Cuttings

Well Hole Section	Duration of Discharge (days)	Comments
Conductor	1	• Half of the volume released during hole cleaning, drilling time of duration approximately 7 hr • Plus similar length of time estimated for displacement of hole section contents (second half of volume released) during cementing • Therefore, estimate approximately 1 day total as the period over which material is released to sea. Note that these times do not include time for preparing to spud, drilling, circulating, tripping, casing, cementing
Surface	2	• Half of the volume released during hole cleaning, drilling time of duration approximately 42 hr • Followed by bulk 'instantaneous' release of similar volume upon fluid (mud) swap out • These times not include time for preparing to spud, drilling, circulating, tripping, casing, cementing
Intermediate	3	• Estimate
Main	8	• Estimate

With an average of 93 days, there will be no temporal overlap between successive wells, with respect to mud and cuttings dispersion. Distribution of wells over the seasons (up to 72 or 48 wells for WHP or subsea drill centre options, respectively) is accounted for by running scenarios using seasonal current and density fields.

Cuttings drilled with SBM will be large, approximately 600 mm (2.5”) in length, 250 mm (1”) wide and 30 mm (1/8”) thick. To characterize these large cuttings as spherical particles for the model, their volume corresponds to a particle diameter of approximately 1 to 3 cm. This large cutting size type was added to the pebbles, coarse sand, medium sand and fines types used to characterize the WBM-cuttings noted above. It was assumed that most (approximately 70 percent) of the cuttings will be large, approximately 20 percent 0.5 to 1 cm, 5 percent 0.1 cm, and the remaining 5 percent being very fine particles, with diameters of 0.01 cm (Table 3-37).

Table 3-37 Cuttings Particle Size Composition

Well Type	Measured Weight Percent Material				
	Large Cuttings	Pebbles	Coarse Sand	Medium	Fines
WBM drill cuttings	--	10	2	1	87
SBM drill cuttings	70	20	5	--	5

It is assumed that the cuttings will enter the sea in a disaggregated form. The model considered the large cuttings, pebble and sand materials to remain disaggregated in their fall to the seabed. Any fines were assumed to aggregate into flocs of size of approximately 0.1 mm and settle with a constant speed. Cuttings particle size characterization is provided in Table 3-38.

Table 3-38 Cuttings Particle Size Characterization

Particle Parameter	Cuttings Material				
	Large Cuttings	Pebbles	Coarse Sand	Medium Sand	Fines
Particle diameter (mm)	20	7	1	0.25	0.1
Particle fall velocity (m/s)	0.594	0.351	0.133	0.066	0.0012

Three Acoustic Doppler Current Profiler (ADCP) depth bins, at depths of 28, 60 and 112 m, were selected to represent the currents at the surface, mid-depth and near the bottom. The seasonal statistics for the processed current for the three depth layers are presented in Table 3-39. It is assumed that the currents are representative of the WREP locations and are uniform over the deposition grids modelled.

Table 3-39 Seasonal Current Statistics for the Processed Currents Used as Model Inputs

Season	Depth	Max Speed (cm/s)	Mean Speed (cm/s)	Mean Velocity (cm/s)	Direction (to) (°True N)
Winter	Near surface	62	15	4	180
	Mid-depth	62	14	3	178
	Near bottom	40	13	4	165
Spring	Near surface	43	12	2	173
	Mid-depth	26	10	0	175
	Near bottom	31	10	2	170
Summer	Near surface	65	12	1	187
	Mid-depth	51	10	1	183
	Near bottom	31	8	1	174
Fall	Near surface	61	20	4	175
	Mid-depth	47	15	2	179
	Near bottom	40	12	5	163
Source: ADCP data from Oceans Ltd. 2011.					

3.4.1 Water-based Mud Cuttings

Cuttings from drilling the upper two well sections with WBM will all be released as per the OWTG close to the seafloor, under either the WHP option with chute release, or under the subsea option with MODU riserless drilling. Therefore, there is little time for the cuttings to be transported large distances by the ambient currents.

The WBM cuttings deposition predicted following completion of WHP option (40 wells) and subsea option (16 wells) drilling at the West White Rose location (WWRX1) are presented in Figures 3-23 and 3-24. Cuttings thicknesses of 0.1, 0.2 and 0.5 mm, 1, 2 and 5 mm and 10 mm are shown. The locations of the *SeaRose FPSO* and potential second West White Rose Extension drill centre (WWRX2) are shown for reference.

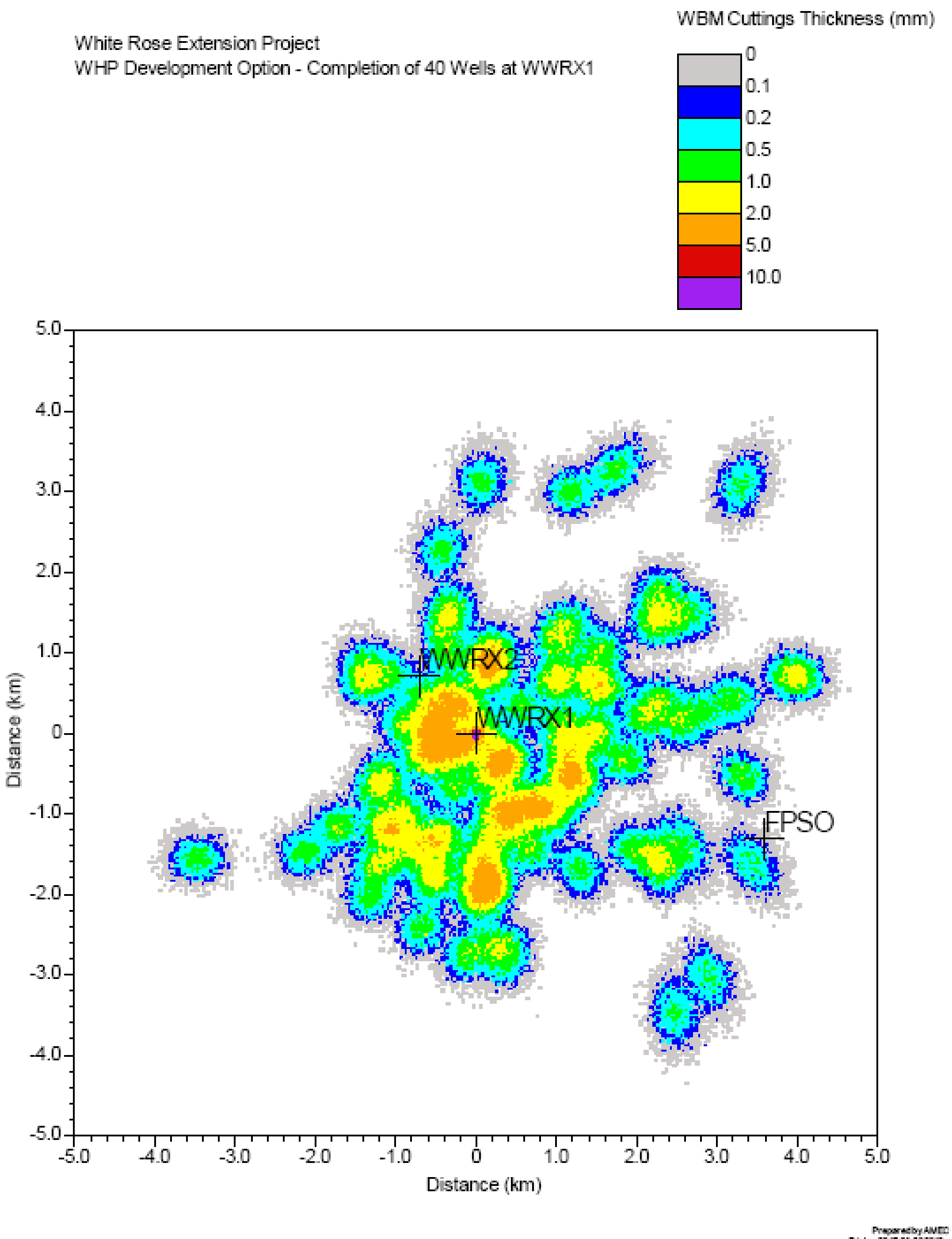


Figure 3-23 Water-based Mud Cuttings Deposition Following Wellhead Platform Option Drilling of 40 Wells, 5-km View

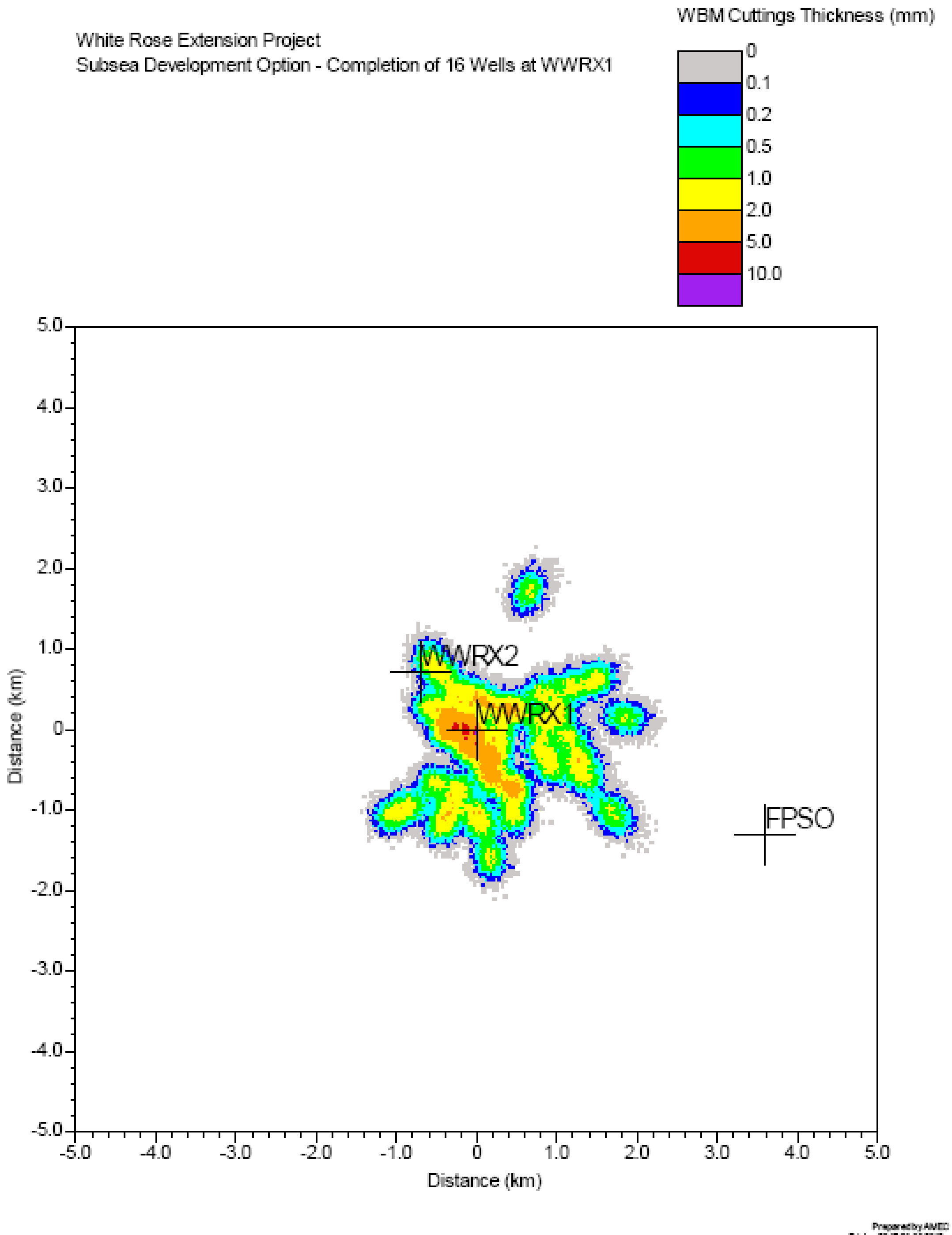


Figure 3-24 Water-based Mud Cuttings Deposition Following Subsea Option Drilling of 16 Wells, 5-km View

Under the WHP scenario, the drift of cuttings is restricted to a range generally within 2 to 4 km. The maximum extent is approximately 5 km to the southeast and northeast. Cuttings (exclusively WBM) thicknesses are 1 mm or less over these regions.

Cuttings thicknesses directly under the WHP are modelled to be 1.8 m. In the immediate vicinity of the WHP, within 100 m, initial cuttings thicknesses are predicted to be 1.4 cm on average, and as high as 8.6 cm. Due to the large volume of material generated by drilling the (initial) 40 wells, a maximum height of 1.8 m is predicted for the model grid cell at the WHP origin. These will be almost exclusively the fast-settling pebbles and coarse sand (a very small percentage of the fines will drift for a time and ultimately settle near the CGS) whereas at distances greater than about 50 to 200 m, the deposits will be exclusively fines. This maximum height of 1.8 m does not account for slumping of the cuttings ‘pile’. Assuming a likely angle of repose of approximately 30 degrees, one might estimate from these thicknesses, a maximum height more likely on the order of 0.5 to 1.0 m.

From 100 to 200 m out from the WHP, thicknesses are predicted to be 1.9 mm on average and a maximum of 3.4 mm. From 200 to 500 m, thicknesses average 1.8 mm and are a maximum of 4.6 mm.

The mean and maximum WBM cuttings thicknesses for distances out to 25 km from the well centre/origin are presented in Tables 3-40 and 3-41 and corresponding Figures 3-25 and 3-26. All five case drilling scenarios are shown. The figures show thicknesses in mm on a logarithmic scale. Zero values correspond to thicknesses less than 0.01 mm (10 microns).

Table 3-40 Mean Water-based Mud Cuttings Thickness (mm)

Scenario	Distance from Origin (m)							
	0	16 to 100	100 to 200	200 to 500	500 to 1,000	1,000 to 1,500	1,500 to 2,500	2,500 to 25,000
WHP Development Option; 40 Wells at WWRX1	1,765.4	14.2	1.9	1.8	1.0	0.9	0.5	0.3
Subsea Development Option; 16 Wells at WWRX1	717.2	5.0	3.2	2.0	0.8	0.6	0.3	0.0
New Subsea Drill Centre; 16 Wells at SWRX	715.1	3.5	1.8	1.6	1.0	0.6	0.3	0.3
New Subsea Drill Centre; 16 Wells at WWRX2	698.9	3.4	1.4	1.4	0.9	0.6	0.4	0.2
New Subsea Drill Centre; 16 Wells at NWRX	701.2	5.0	2.6	1.4	0.8	0.6	0.3	0.3

Table 3-41 Maximum Water-based Mud Cuttings Thickness (mm)

Scenario	Distance from Origin (m)							
	0	16 to 100	100 to 200	200 to 500	500 to 1,000	1,000 to 1,500	1,500 to 2,500	2,500 to 25,000
WHP Development Option; 40 Wells at WWRX1	1,765.4	86.2	3.4	4.6	4.3	3.9	4.4	1.9
Subsea Development Option; 16 Wells at WWRX1	717.2	19.2	5.8	5.5	3.5	2.4	1.7	0.0
New Subsea Drill Centre; 16 Wells at SWRX	715.1	18.3	3.0	3.4	3.4	3.5	2.4	2.0
New Subsea Drill Centre; 16 Wells at WWRX2	698.9	19.8	3.0	3.8	3.5	3.5	2.4	1.5
New Subsea Drill Centre; 16 Wells at NWRX	701.2	27.7	5.7	5.2	3.4	3.0	1.8	1.6

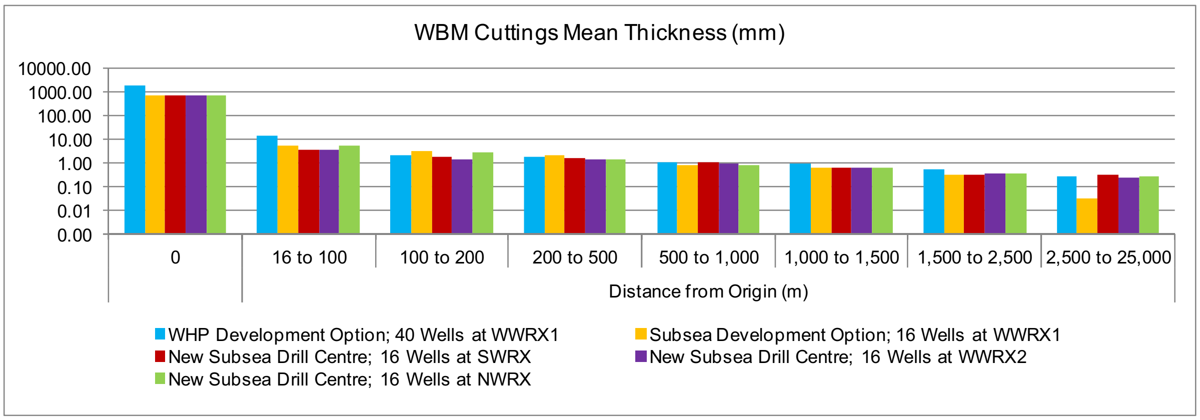


Figure 3-25 Mean Water-based Mud Cuttings Thickness (mm)

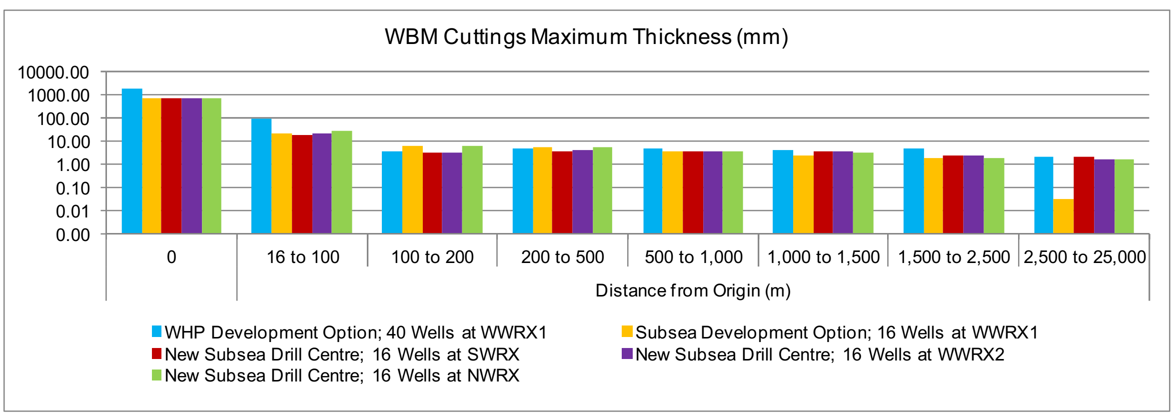


Figure 3-26 Maximum Water-based Mud Cuttings Thickness (mm)

Under the subsea scenario, the footprint of WBM cuttings is smaller than that for the WHP option just described, with a range generally restricted to within 2 km (Figure 3-26). The primary difference factor is the reduced number of wells drilled (16 as opposed to 40) and the reduced volume of cuttings material released (267 m^3 per well as opposed to 295 m^3) for the subsea option. Under the WHP option (40 wells), approximately 11,800 m^3 of WBM cuttings are deposited, while the volume under the subsea drill centre option (16 wells) is approximately two-thirds the volume of cuttings (4,272 m^3 of WBM, 4,304 m^3 of SBM).

Mean cuttings thicknesses directly under the MODU (subsea option) are modelled to be 72 cm (less than half that of the WHP option). Comparable values are predicted under the similar MODU drilling for the other subsea drill centre drilling scenarios (e.g., first column in Table 3-40).

Within 100 m of the subsea drill centre origin, initial cuttings thicknesses are predicted to be 5.0 mm on average, and as high as 19.2 mm. From 100 to 200 m out from the drill centre, thicknesses are predicted to be 3.2 mm on average and a maximum of 9.8 mm. From 200 to 500 m, thicknesses average 2.0 mm and are a maximum of 5.5 mm (Table 3-40 and 3-41). Thickness statistics are comparable for the other potential subsea drill centres. In general, the MODU drilling results in mean WBM cuttings thicknesses out to 100 m that are approximately one-third to one-quarter that for the WHP drilling; there is little difference outside of 100 m.

3.4.2 Synthetic-based Mud Cuttings

For drilling of the deeper intermediate and main hole sections - for both WHP and MODU (subsea option and potential future drill centres) - SBM will be used. Under the WHP option, the base case is to use two cuttings reinjection wells into which treated SBM and cuttings will be re-injected (i.e., no return of materials to the sea). In the summary statistics presented in this section, the WHP option is listed together with the subsea and future drill centre options for completeness; however, the SBM cuttings thicknesses are all zero or not applicable for the WHP. For MODU drilling, SBM cuttings will be treated and released in accordance with the OWTG.

The modelled SBM cuttings deposition predicted following completion of the subsea option (16 wells) drilling at the West White Rose location (WWRX1) on both 5 km and 28 km scales are presented in Figures 3-27 and 3-28, respectively.

Due to the large percentage of large cuttings pieces having fast settling speeds, the majority of SBM cuttings are deposited quite close to the drill centre. Patches of a light dusting (0.1 mm or less) of fines extend as far as approximately 20 to 25 km to the north and 18 to 20 km to the south.

Cuttings thicknesses directly under the MODU are modelled to be 2.2 m. Again, this maximum height does not account for slumping of the cuttings ‘pile’. Assuming a likely angle of repose of approximately 30 degrees, one might estimate from these thicknesses, a maximum height more likely on the order of 0.75 to 1.2 m. Nor, is there account made of the possibility of cuttings near the cuttings deposits directly about the excavated drill centre(s) being cleared by a seafloor cuttings transportation system and moved to another seafloor location.

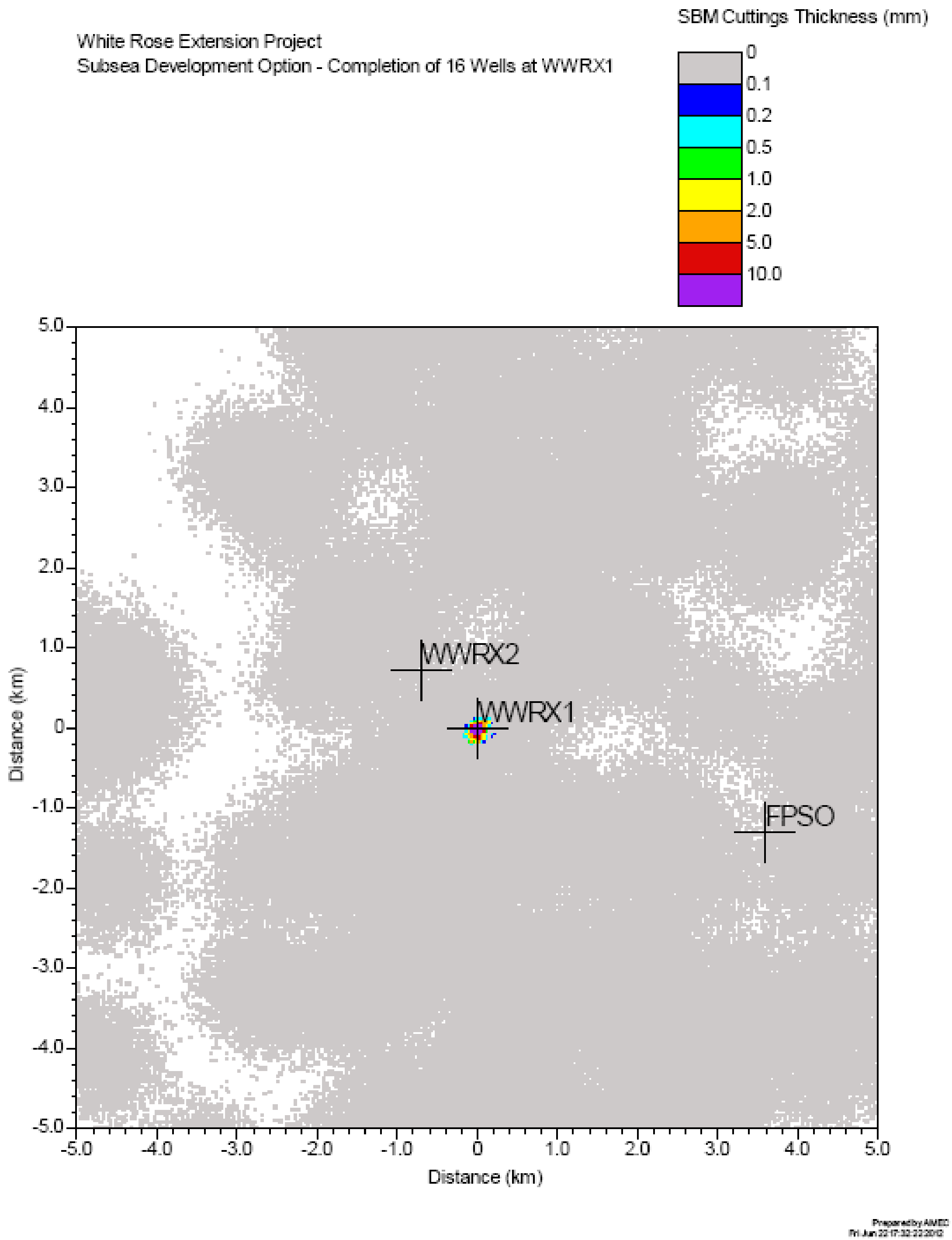


Figure 3-27 Synthetic-based Mud Cuttings Deposition Following Subsea Option Drilling of 16 Wells, 5-km View

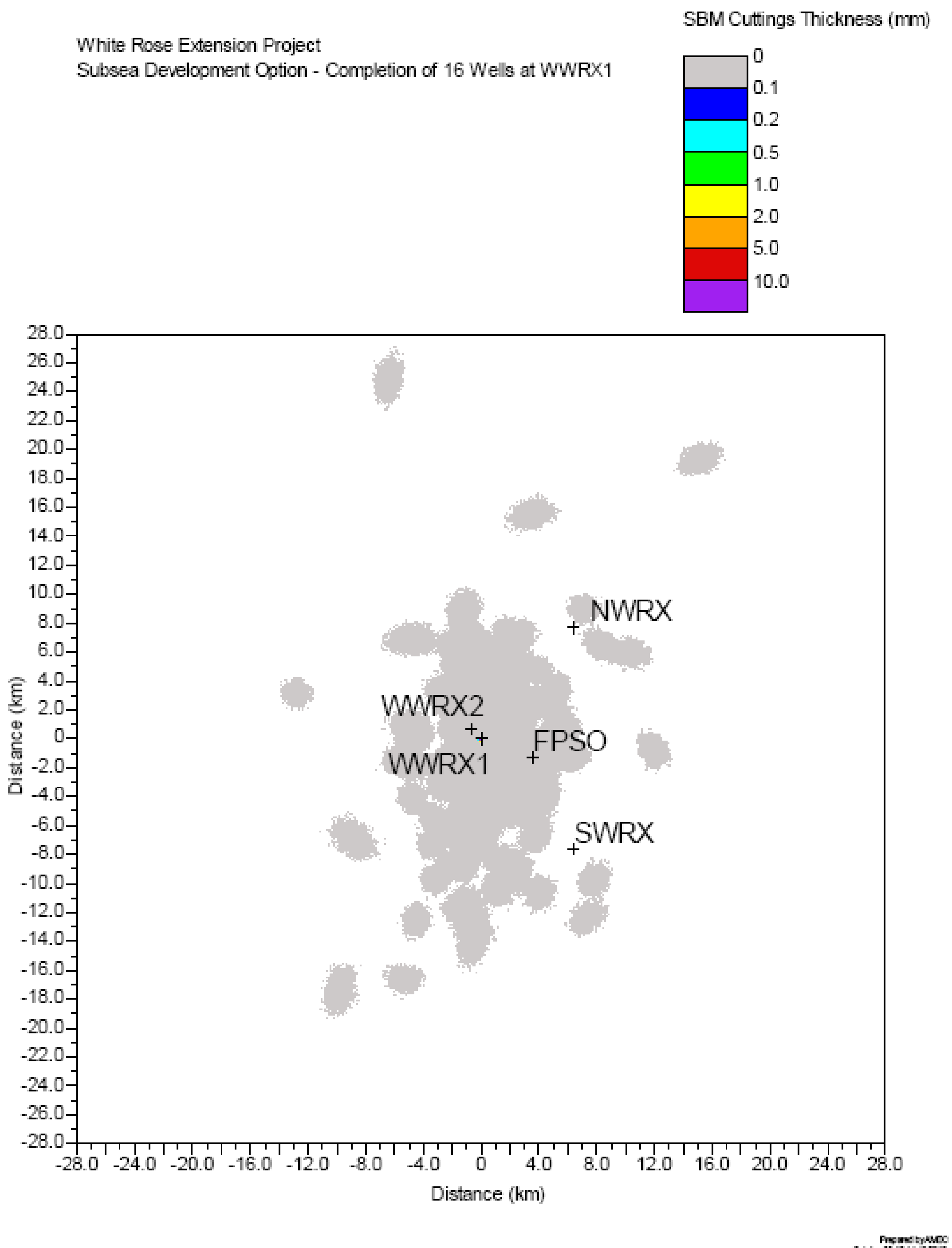


Figure 3-28 Synthetic-based Mud Cuttings Deposition Following Subsea Option Drilling of 16 Wells, 28-km View

In the immediate vicinity of the drill centre, within 100 m, initial SBM cuttings thicknesses, now overlain on top of WBM cuttings from drilling of the top two well sections, are predicted to be 11.7 cm on average, and as high as 98.9 cm. The mean and maximum SBM cuttings thicknesses for distances out to 25 km from the well centre/origin are presented in Tables 3-42 and 3-43 and corresponding Figures 3-29 and 3-30. All five case drilling scenarios are shown. The figures show thicknesses in mm on a logarithmic scale. Zero values correspond to thicknesses less than 0.01 mm (10 microns).

Table 3-42 Mean Synthetic-based Mud Cuttings Thickness (mm)

Scenario	Distance from Origin (m)							
	0	16 to 100	100 to 200	200 to 500	500 to 1,000	1,000 to 1,500	1,500 to 2,500	2,500 to 25,000
WHP Development Option; 40 Wells at WWRX1	no SBM cuttings released to sea							
Subsea Development Option; 16 Wells at WWRX1	2,234.53	116.84	1.02	0.01	0.00	0.00	0.00	0.00
New Subsea Drill Centre; 16 Wells at SWRX	2,206.66	116.88	1.23	0.02	0.00	0.00	0.00	0.00
New Subsea Drill Centre; 16 Wells at WWRX2	2,533.13	106.10	0.99	0.02	0.01	0.00	0.00	0.00
New Subsea Drill Centre; 16 Wells at NWRX	2,154.99	118.97	1.27	0.02	0.00	0.00	0.00	0.00

Table 3-43 Maximum Synthetic-based Mud Cuttings Thickness (mm)

Scenario	Distance from Origin (m)							
	0	16 to 100	100 to 200	200 to 500	500 to 1,000	1,000 to 1,500	1,500 to 2,500	2,500 to 25,000
WHP Development Option; 40 Wells at WWRX1	no SBM cuttings released to sea							
Subsea Development Option; 16 Wells at WWRX1	2,234.5	989.33	6.55	0.29	0.02	0.02	0.02	0.03
New Subsea Drill Centre; 16 Wells at SWRX	2,206.7	756.90	10.36	1.49	0.01	0.01	0.02	0.02
New Subsea Drill Centre; 16 Wells at WWRX2	2,533.1	644.18	8.56	1.98	0.03	0.03	0.02	0.02
New Subsea Drill Centre; 16 Wells at NWRX	2,155.0	701.97	10.14	1.54	0.02	0.01	0.02	0.03

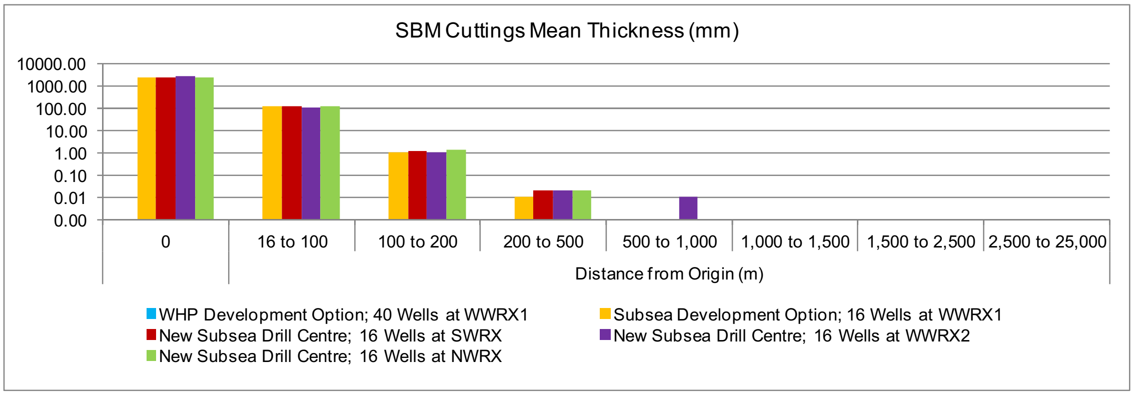


Figure 3-29 Mean Synthetic-based Mud Cuttings Thickness (mm)

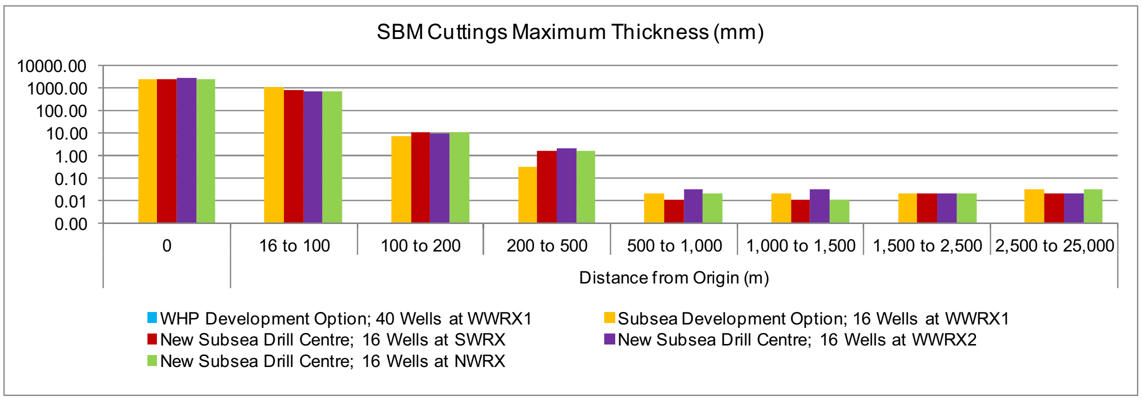
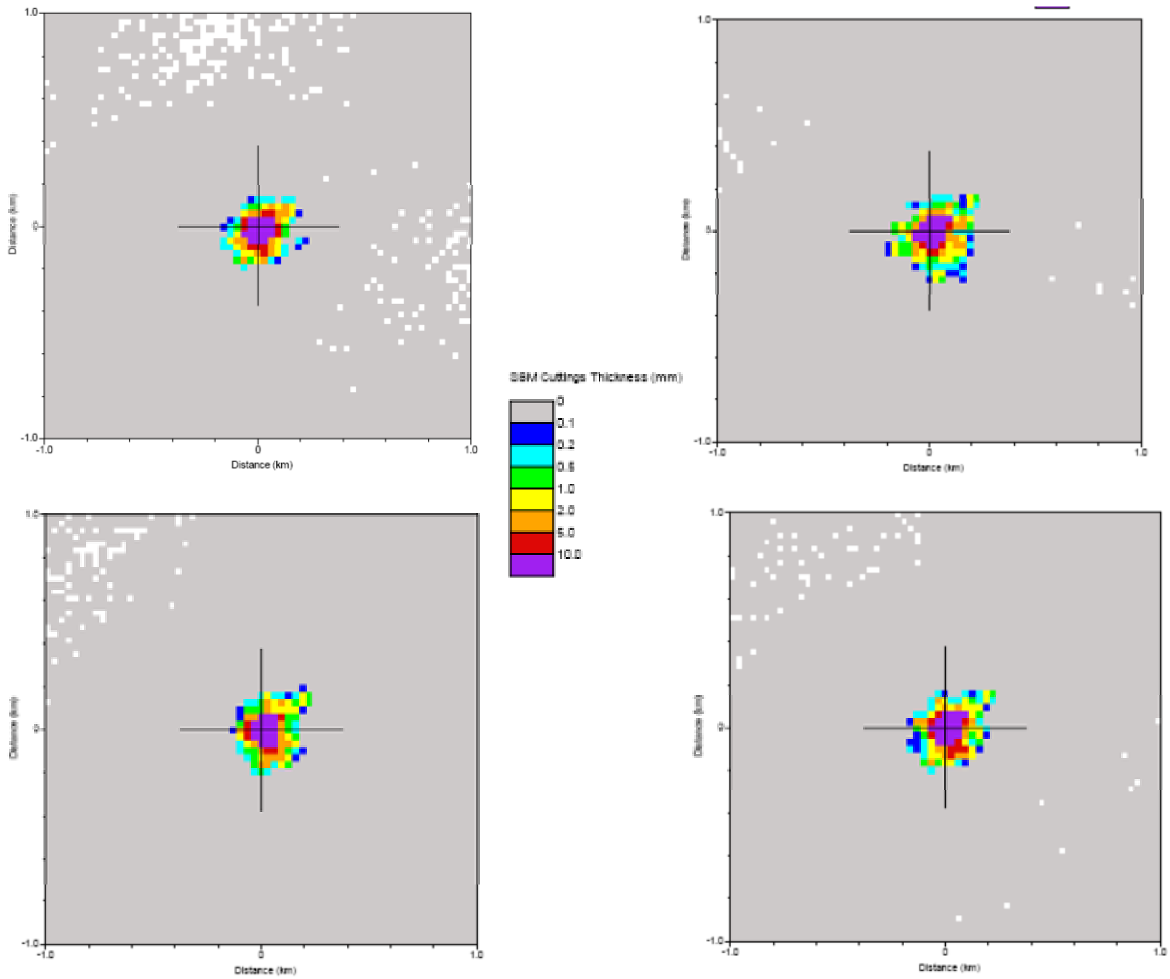


Figure 3-30 Maximum Synthetic-based Mud Cuttings Thickness (mm)

From 100 to 200 m out from the WWRX1 drill centre, thicknesses are predicted to be 1.0 mm on average and a maximum of 6.6 mm. From 200 to 500 m, thicknesses average 0.1 mm and are a maximum of 0.3 mm. Generally comparable values are predicted under the similar MODU drilling for the other potential subsea drill centre drilling scenarios (e.g., a maximum thickness of 2.0 mm out to 500 m is modelled for WWRX2, compared with 0.3 mm for WWRX1).

An additional comparison of SBM cuttings thickness near the drill centre is shown in Figure 3-31 for all modelled MODU-drilled options. The basic cuttings footprint thicknesses and distribution pattern are comparable for all scenarios.

The model estimates the oil concentration on cuttings as the weight of the cuttings material times its initial concentration, divided by the volume of an assumed thin benthic layer in which the cuttings are assumed to settle and mix with the seabed sediments (i.e., an oil concentration in the seabed layer is estimated based on the initial oil on cuttings).



Shown Clockwise from Upper Left are: West White Rose Extension (WWRX1), South White Rose Extension (SWRX), West White Rose 2 Extension (WWRX2), North White Rose Extension (NWRX)

Figure 3-31 Synthetic-based Mud Cuttings Thickness for Mobile Offshore Drilling Unit-drilled Options, 1-km View

3.5 Synthetic-based Whole Mud Spill Trajectory Modelling

It is anticipated that certain stages of the drilling operations in the development of the WREP will involve the use of SBMs, due to their unique performance characteristics, as well as their low toxicity and relatively low environmental effects compared to oil-based muds.

As part of the environmental assessment process, to characterize possible accidental SBM releases, a review was conducted of the latest scientific literature and industry spill databases from Atlantic Canada and the United States Outer Continental Shelf (OCS) to determine the most probable modes of accidental release. Four potential release spill scenarios were selected as being most representative for the WREP:

- Surface tank discharge
- Riser flex joint failure (two scenarios, two fall velocities)
- BOP disconnect.

Subsequently, a numerical dispersion modelling study was conducted to predict the potential seasonal footprints of SBM spills on the seafloor for each of the four scenarios. The numerical model used a full-year time series derived from ADCP current measurements at White Rose from 2008 to the end of 2010, with approximately 13,000 model realizations being simulated in each seasonal scenario per release mode. The total spill footprint area, length and distance from release site, as well as projected initial SBM layer thickness on the seafloor, were estimated for each simulated event, and seasonal median, maximum and average values were derived.

The interpretation of the predicted footprint areas and thicknesses should consider that these are only preliminary dimensions of the projected landing area for the SBM droplets, and the estimated SBM layer thickness if the full spill volume landing in each model cell, were to be equally distributed within that cell. The subsequent fate and the footprint are likely to evolve in a less predictable fashion, as the negatively buoyant SBM droplets are expected to coalesce into streams or pools, and flow under the influence of gravity and the local bathymetric features. As there is a tradeoff between the area covered by the spill and the thickness of the spill, it can be expected that an area of the seafloor that is relatively flat and with few roughness features is likely to result in a thinner and widely distributed SBM layer, while a localized depression in the seafloor could retain the received SBM as a thicker layer within a smaller area.

While the weathering properties for the SBM considered in the present study are not precisely known, it is expected that the biodegradation of the SBM on the seafloor would take place over periods on the order of several weeks. This timescale far exceeds the duration of the spill and settling of SBM to the floor; therefore, the SBM is considered to be stable during the entire duration of the physical dispersion of the droplets in all modelled scenarios.

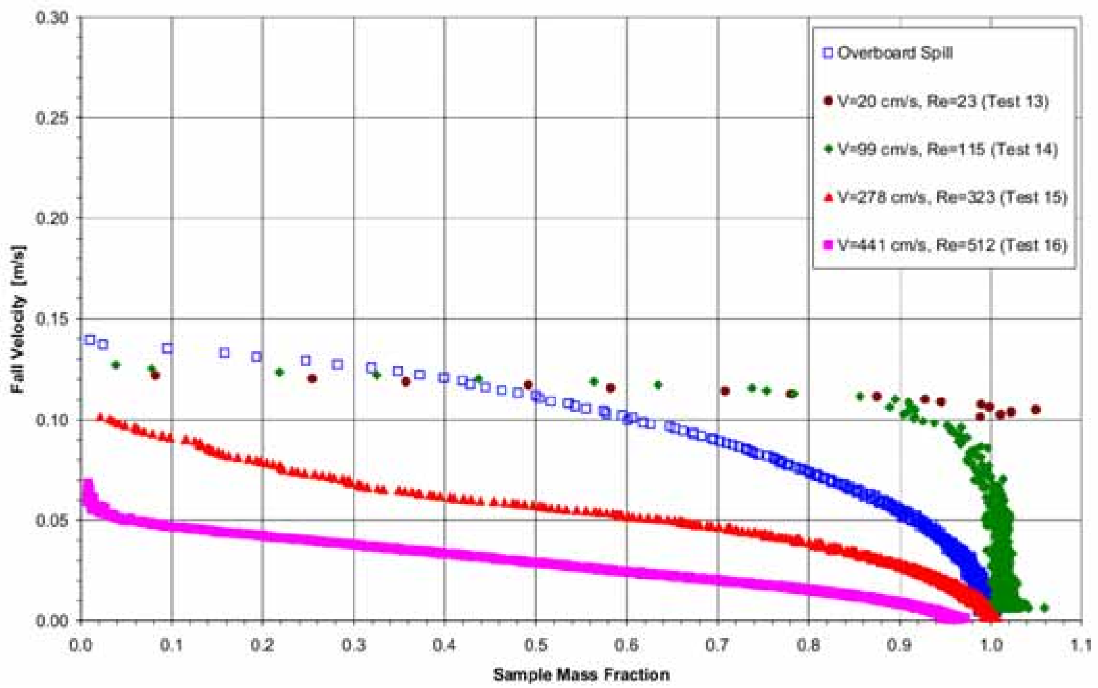
The full report is provided in AMEC (2012c).

3.5.1 Model Inputs

The scenario details are listed in Table 3-44 as they apply to the SBM dispersion model. Two main SBM flow regimes are considered in the modeled scenarios, the wide, low-speed jet that produces relatively uniform fall velocity distributions (approximately 11 cm/s), and a narrow, high-speed jet that produces droplets with a wider range of fall velocities (mostly within 1 to 5 cm/s). In order to capture the wide range of fall velocities expected for the subsea release mode resulting in a high-speed jet flow (e.g., a flex joint failure), this scenario was modelled separately at the two ends of the fall velocity range (plotted with pink markers in Figure 3-32). The four release scenarios were modelled for each of the four seasons, resulting in a total of 16 scenarios.

Table 3-44 Synthetic-based Mud Model Input Parameters for Each Release Scenario

Release Scenario	Total Volume (m^3)	Duration of Release (hours)	SBM Flow Type	Fall Velocity (cm/s)	Location of Release	Settling Time (seconds)
Surface Tank Discharge	60	0.5	Wide, low-speed jet	11	120 m above seafloor	1,091
Flex Joint Failure I	49	3	Narrow, high-speed jet	1	20 m above seafloor	2,000
Flex Joint Failure II	49	3	Narrow, high-speed jet	5	20 m above seafloor	400
BOP Disconnect	49	1	Wide, low-speed jet	11	20 m above seafloor	182



Source: Southwest Research Institute 2007

Figure 3-32 Fall Velocity Distributions for Synthetic-based Mud Droplets under Different Flow Regimes

The settling times shown in Table 3-44 are a function of the fall velocity, as well as the location of the release above the seafloor. It is expected that the SBM droplets would reach the seafloor within a period from 3 to 30 minutes.

3.5.2 Model Output

The outcomes of the modelled scenarios reveal several ways in which the mode of release and the ocean current conditions influence the spill footprint. The results for the modelled scenarios are presented in Table 3-45. These include the maximum and median seasonal values for the area of the predicted spill footprints, as well as the maximum and average values of the thickness of SBM within the projected spill area. In addition to the size of the spill area, it was important to characterize the location of the spill relative to the position of the release. This distance was calculated in each model realization as the location of the model cell that received the highest fraction of the spilled SBM volume. In the majority of the scenarios, the spill footprints exhibited an elongated shape, which was measured and recorded as the length of the footprint, and it represents the longest horizontal dimension of the area in which the SBM droplets land.

Table 3-45 Synthetic-based Mud Dispersion Modelling Results for All Scenarios

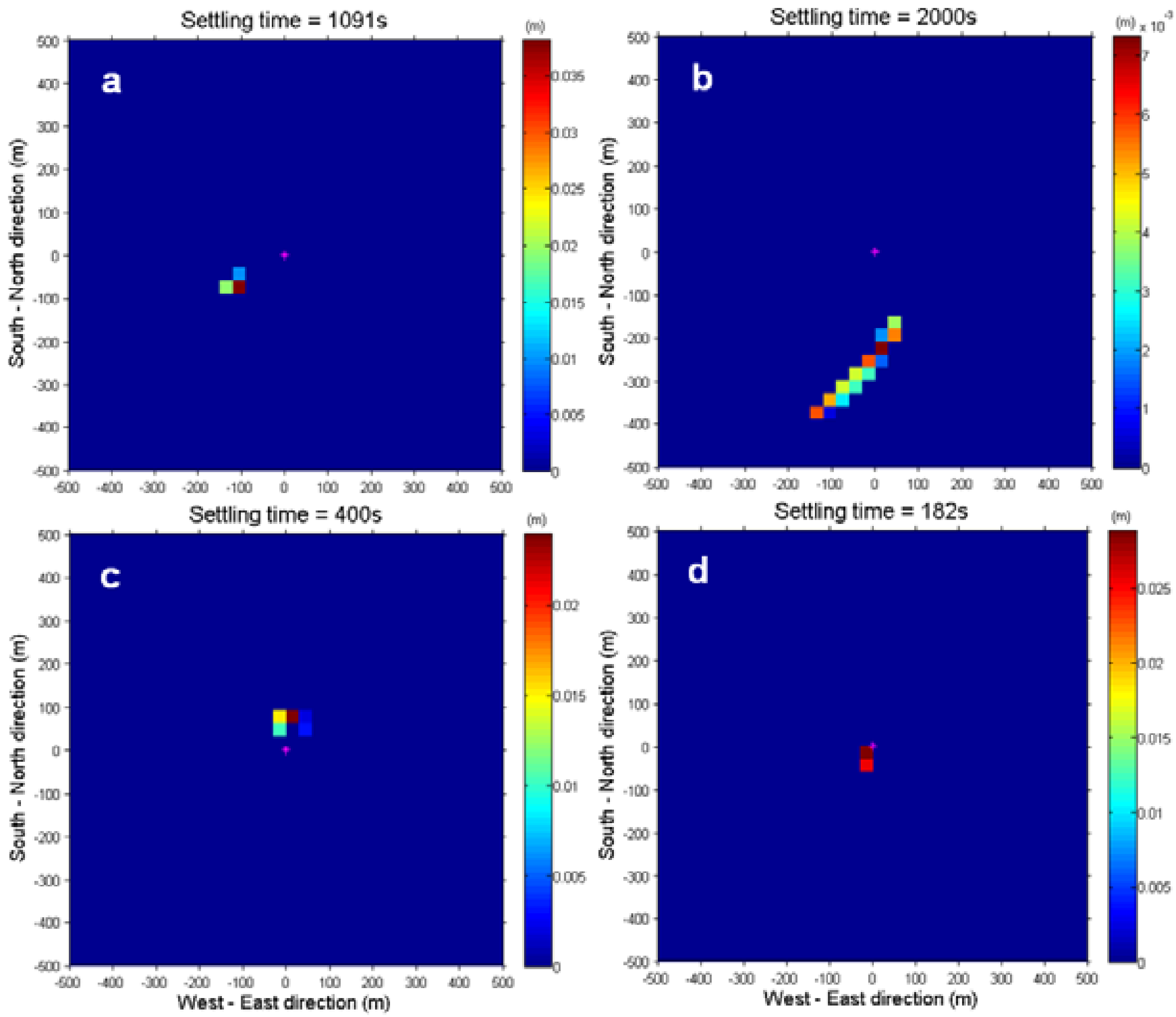
SBM Dispersion Scenario		Distance from Release Site (m)		Footprint Length (m)		Footprint Area (m^2)		SBM Layer Thickness (cm)	
		max	med	max	med	max	med	max	mean
Surface Tank Rel.	Winter	1,061	201	101	47	4,500	1,800	6.7	4.4
	Spring	458	162	81	47	3,600	1,800	6.7	4.5
	Summer	677	134	106	47	4,500	1,800	6.7	4.4
	Fall	834	212	133	51	5,400	1,800	6.7	4.1
Riser Flex Joint I	Winter	1,008	192	579	161	23,400	6,300	5.4	0.9
	Spring	443	175	465	164	18,900	6,300	5.4	0.9
	Summer	836	150	839	166	34,200	6,300	5.4	0.9
	Fall	757	234	826	206	32,400	8,100	5.4	0.7
Riser Flex Joint II	Winter	201	42	140	56	5,400	1,800	5.4	2.9
	Spring	108	30	117	57	5,400	1,800	5.4	2.8
	Summer	190	30	192	57	9,000	1,800	5.4	2.8
	Fall	175	60	189	65	8,100	2,700	5.4	2.4
BOP Disc.	Winter	108	30	46	34	2,700	900	5.4	4.9
	Spring	67	30	44	34	3,600	900	5.4	4.9
	Summer	108	30	53	34	3,600	900	5.4	4.8
	Fall	85	30	55	35	3,600	900	5.4	4.8

The distance from the release site at which most of the SBM droplets will land appears to be largely dependent not only on the height of release above the sea bottom and the droplet fall velocity, but also on the seasonal currents. Overall, there was no strong tendency for the spills to land in a particular direction from the spill site in any given season. The maximum predicted distances from the release site are those for the winter surface dispersion scenario and the first riser flex joint scenario (high-speed jet, low fall velocity), where the maximum concentrations of the footprint were found at 1,061 m and 1,008 m from the release site, respectively. For the other dispersion scenarios, the spill footprints remain within a maximum distance of 201 m (second riser flex joint scenario, high fall velocity), and 108 m (BOP disconnect scenario). These maximum distances are expected to occur during periods when the current magnitudes are at the seasonal maximum. However, this does not necessarily imply that the spill footprint is larger than normal, only that the footprints are shifted horizontally with respect to the release location.

The largest footprint areas were found for the first riser flex joint scenario, which had the lowest fall velocity and the longest release period of 3 h. The single largest spill area in this scenario was observed in the winter season, and represented an area spanning approximately 579 m long by 40 m wide. Since the SBM was dispersed over a large area, the average layer thicknesses were much lower for this dispersion scenario compared to the other three.

The majority of the spill footprints were 1800 m^2 or smaller, corresponding to spill areas measuring 30 m by 60 m. The smallest footprints (30 m by 30 m) were predicted for the BOP disconnect scenarios, which exhibited a combination of low height above sea bottom, relatively quick release time (1 hr), and high fall velocities.

Typical realizations of the spill footprints for the four selected modes of release are shown for the winter season in Figure 3-33.



Note: a) surface low-speed jet release; b) subsea high-speed jet – low fall velocity; c) subsea high-speed jet – high fall velocity; d) subsea low-speed jet (BOP disconnect)

Figure 3-33 Example Realizations for the Four Modelled Release Scenarios in Winter

3.6 Hydrocarbon Spill Probabilities

For the purposes of the environmental assessment, two types of accidental events during drilling and production operations are assessed, blowouts and "batch" spills. Blowouts are continuous spills that can last hours, days or weeks, if uncontrolled and involve the discharge of large volumes of associated gas into the atmosphere and discharge of crude oil and certain amounts of gas condensate (a very low viscosity, highly volatile type of liquid petroleum oil) into surrounding waters. Batch spills are instantaneous or short-duration discharges of hydrocarbon that could occur from accidents on the production platforms where hydrocarbon may be stored and handled.

Compared with other industries that have potential for discharging petroleum hydrocarbon into the marine environment, the industry of exploring, developing and producing offshore oil and gas (the offshore E&P industry) has a good record. A recent study on marine hydrocarbon pollution by the US National Research Council, National Academy of Sciences (NAS 2002) indicates that accidental petroleum discharges from platforms contribute only 0.07 percent of the total petroleum input to the world's oceans (0.86 thousand tonnes per year versus 1,300 thousand tonnes per year, Table 3-46).

Table 3-46 Best Estimate of Annual Releases (1990 to 1999) of Petroleum by Source

Source	North America (thousands of tonnes)	World-wide (thousands of tonnes)
Natural Seeps	160	600
Extraction of Petroleum	3.0	38
Platforms	0.16	0.86
Atmospheric Deposition	0.12	1.3
Produced Waters	2.7	36
Transportation of Petroleum	9.1	150
Pipeline Spills	1.9	12
Tank Vessel Spills	5.3	100
Operational Discharges (cargo washings)	na (A)	36
Coastal Facility Spills	1.9	4.9
Atmospheric Deposition	0.01	0.4
Consumption of Petroleum	84	480
Land-based (river and runoff)	54	140
Recreational Marine Vessel	5.6	nd (b)
Spills (non-tank vessels)	1.2	7.1
Operational Discharges (vessels 100 GT)	0.10	270
Operational Discharges (vessels <100 GT)	0.12	nd (c)
Atmospheric Deposition	21	52
Jettisoned Aircraft Fuel	1.5	7.5
Total	260	1,300

Source: NAS 2000.
(A) Cargo washing is not allowed in US waters, but is not restricted in international waters. Thus, it was assumed that this practice does not occur frequently in US waters.
(B) World-wide populations of recreational vessels were not available.
(C) Insufficient data were available to develop estimates for this class of vessels.

This section derives spill and blowout statistics for a production platform from world-wide statistics. The practices and technologies that will be used on the WREP are world-class and will be in accordance with Canadian regulations and best practices.

The petroleum industry usually uses the oil volume unit of petroleum barrel (bbl), which is different than a US bbl and a British bbl. There are 6.29 bbl in 1 cubic metre (m^3) and there are approximately 7.5 bbl per tonne. Most spill statistics used here are taken from publications that use the oil volume units of bbl, and bbl are used in the subsequent statistical analysis as a result. The statistics relating to small spills uses litres (L); 1 bbl = 159 L.

Data sources used in this chapter have varying dates of publication. Sources such as the US Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE, until recently known as the Minerals Management Service, MMS) are updated regularly, and the most recent data available are used in this report. Other sources used, notably Scandpower (2000), and NAS (2002), have not been updated. Newfoundland and Labrador statistics are only used to estimate small spill rates as there have been very few large spills related to development or production in Canadian waters.

Spill probabilities are calculated using an exposure variable base on the number of wells drilled and the number of well-years of production. The WREP may be developed with a:

- WHP (and up to two additional drill centres)
- Subsea drill centre (up to three drill centres total)

Each drill centre will have 16 wells. Based on this, the total number of wells could range from 48 under the subsea drill centre option and 72 wells under the WHP option. For calculation purposes, the number of wells to be drilled will be assumed to be 60 (average of the range of 48 to 72) and the production well-years assumed to be 300 (60 wells, half of which assumed to be producers, each with a producing life of 10 years).

Spill probabilities are discussed separately for blowouts and for other “batch” spills from drilling and production platforms, and for a range of spill sizes. The definitions of oil spill sizes are provided in Table 3-47.

Table 3-47 Definition of Hydrocarbon Spill Sizes

Hydrocarbon Spill Type	Spill Size	
	bbl	m^3
Extremely Large	>150,000	>23,850
Very Large	>10,000	>1,590
Large	>1,000	>159
Small	<1	<0.159

The top three categories are cumulative; for example, the large spill category (>1,000 bbl) includes the very large and extremely large spills, and the very large category includes extremely large spills. This follows the approach used by BOEMRE statisticians from which the “large” spill frequencies are derived. For the small category, more detailed statistics are available and a further breakdown is made with discrete size ranges, specifically: 50 to 999 bbl; 1 to 49 bbl; 1 L to 1 bbl (159 L); and less than 1 L

3.6.1 Extremely Large and Very Large Oil Spills from Blowouts

In the oil and gas industry, a distinction is made between two stages of petroleum field drilling: exploration drilling (including “delineation” drilling), where knowledge of the geological and depositional environment is speculative or limited; and development drilling, where the structure is better defined and drilling is under better control. Because exploration drilling at the White Rose site is now completed, the analysis concentrates on statistics related to development drilling, although reference is made to exploration-related statistics where appropriate. Blowouts can also happen during production, workovers and well completion activities, and these are also addressed.

In Canada, there have been no large petroleum spills from blowouts. In the US, since offshore drilling began in the mid-1950s, there have been three offshore oil-well blowouts involving hydrocarbon spills greater than 50,000 bbl. Therefore, data from jurisdictions beyond North America must be used to develop a reasonable database on very large and extremely large oil-well blowouts. All world-wide blowouts involving the spillage of more than 10,000 bbl each are listed in Table 3-48.

Table 3-48 Historical Extremely and Very Large Spills from Offshore Oil Well Blowouts

Area	Reported Spill size (bbl)	Year	Operation underway	Durations (days)	Intervention Method
Extremely Large Spills (>150,000 bbl)					
US Gulf of Mexico (GOM) [(a)]	4,000,000	2010	Exploratory Drilling	91	Relief Well
Mexico (*Ixtoc-1*) [(b)]	3,000,000	1979	Exploratory Drilling	293	Relief Well
Iran [(c)]	See note	1983	Production	--	
Mexico	247,000	1986	Workover	??	
Nigeria	200,000	1980	Development Drilling	14	Bridged
North Sea/Norway	158,000	1977	Workover	7	Capped
Very Large Spills (>10,000 bbl)					
Iran	100,000	1980	Development Drilling	8	Unknown
US, Santa Barbara	77,000	1969	Production (platform)	11	Capped
Saudi Arabia	60,000	1980	Exploratory Drilling	8	Capped
Mexico	56,000	1987	Exploratory Drilling	51	
US, S. Timbalier 26	53,000	1970	Wireline	138	Relief Well and Capping
US, Main Pass 41	30,000	1970	Production (platform)	49	Capped (three relief wells also initiated)
Australia [(d)]	30,000	2009	Development Drilling (primarily gas)	74	Relief Well
US, Timbalier Bay/Greenhill	11,500	1992	Production	11	Unknown
Trinidad	10,000	1973	Development Drilling	4	Unknown

(A) Varying estimates of spill volume, most recent estimate reported.
(B) Spill volume widely believed to be significantly underestimated.
(C) The Iranian Norwuz oil well blowouts in the Gulf of Arabia, which started in February 1983, were not caused by exploration or drilling accidents, but were a result of military actions during the Iran/Iraq war.
(D) Currently under investigation; spill volume is best estimate and may be subject to revision.

Using the definition of “extremely large” spills (i.e., hydrocarbon spills greater than 150,000 bbl), there have been six such spills in the history of offshore drilling, one of which occurred during development drilling, three of which occurred during production or workover activities and two occurred during exploration drilling.

3.6.1.1 Blowouts During Drilling

Spill frequencies are best expressed in terms of a risk exposure factor such as number of wells drilled. On a world-wide basis, it has been estimated that 85,796 offshore development wells were drilled as of December 2011 (Deloitte 2012).

There has been one extremely large spill during offshore development drilling, so the frequency to the end of 2011 is (1/67,703) 1.5 x 10^{-5} spills per well drilled, or one such spill for every 68,000 wells drilled. A similar analysis can be done for very large spills. Up to 2011, four development-drilling blowouts have produced spills in the very large spill category (Table 3-48, including the recent incident in Australia, and including the spill in the extremely large category). The spill frequency for these is (4/67,703) 5.9 x 10^{-5} spills per well drilled, or one such spill per every 17,000 wells drilled.

3.6.1.2 Blowouts During Production and Workovers

There have been two extremely large and six very large hydrocarbon spills from blowouts during production and workovers (Table 3-48, not including the war-related spill in Iran in 1983, and including the extremely large spills in the very large category as well). Lack of production statistics makes it difficult to develop an exact risk exposure for these events. However, it is estimated that the total oil produced offshore on a world-wide basis up to 2011 has been approximately 210 billion bbl, and that the total producing oil well-years has been 350,000 well-years (based on information in Deloitte 2012 and current internet sources). Generally, in analyzing accidents in the oil and gas industry, the exposure variable of "well-years" is used to normalize data for the continuous operation of production. This exposure is also convenient to use for workovers inasmuch as these maintenance activities, although not continuous, usually occur with regularity, approximately every five to seven years during the lifetime of a well.

On this basis, the world-wide frequency of extremely large hydrocarbon spills from oil-well blowouts that occurred during production or workovers is 5.7 x 10^{-6} blowouts/well-year. For very large, the number is 1.4 x 10^{-5} blowouts/well-year.

3.6.1.3 Summary of Extremely Large and Very Large Oil Spills from Blowouts

The above calculation of spill frequencies is based on an estimate of 350,000 oil well-years of world-wide experience and does not include gas-well experience, which, according to United States Outer Continental Shelf (US OCS) activity, could be 75 percent as much as oil-well experience. In other words, the frequencies calculated above, however low, are actually substantially lower when considering gas-well experience as well as oil-well experience. Because world-wide gas-well experience is not easy to estimate, the above spill frequencies will be used as a conservative case.

Finally, it is emphasized that the very low spill frequencies derived above for extremely large spills are based on spills in countries (except Norway) that do not generally have regulatory standards as stringent as those existing in North America. For example, one of the largest hydrocarbon spills in history, the *Ixtoc I* oil-well blowout in the Bay of Campeche, Mexico, that occurred in 1979, was caused by drilling procedures (used by PEMEX, Mexico's national oil company) that are not practised in US or Canadian waters and that are contrary to US and Canadian regulations and to the accepted practices within the international oil and gas industry. Therefore, extremely large spill frequencies in North America are expected to be even lower.

In spite of this declining trend, large blowout events can still occur. On April 20, 2010, a fire and explosion occurred on Transocean's Deepwater Horizon drilling rig while drilling an exploration well on BP's Macondo prospect, approximately 66 km offshore Louisiana in the US GOM. The well was initially reported to be discharging approximately 5,000 bbl per day; more recent estimates place the rate at more than 40,000 bbl/day, with a total spill volume over the 91-day event estimated at up to 4,000,000 bbl.

Despite this event, the overall trend of spills and blowouts is decreasing world-wide. A spill of the magnitude of the Macondo blowout in recent years is unprecedented. The investigation has resulted in lessons learned in terms of improved technology, operational, safety and environmental procedures. However, in spite of potential improvements and advancements in spill prevention technology and practices, there still remains an element of safety and environmental risk in any drilling operation.

With respect to the WREP, there will be approximately 70 development wells drilled, and an estimated 300 well-years of production. Using the above world-wide spill frequency statistics as a basis for prediction, the spill frequencies estimated for the WREP would be as follows:

- Predicted frequency of extremely large hydrocarbon spills from blowouts during a drilling operation, based on an exposure of wells drilled: $70 \times 1.5 \times 10^{-5} = 1.1 \times 10^{-3}$, or a 0.11 percent chance over the life of the WREP.
- Predicted frequency of very large hydrocarbon spills from drilling blowouts based on an exposure of wells drilled: $70 \times 5.9 \times 10^{-5} = 4.1 \times 10^{-3}$ or a 0.41 percent chance over the life of the WREP.
- Predicted frequency of extremely large hydrocarbon spills from production/workover blowouts, based on an exposure of well-years = $300 \times 5.7 \times 10^{-6} = 1.7 \times 10^{-3}$ or a 0.17 percent chance over the life of the WREP.
- Predicted frequency of very large hydrocarbon spills from production/workover blowouts, based on an exposure of well-years = $300 \times 1.4 \times 10^{-5} = 4.2 \times 10^{-3}$ or a 0.42 percent chance over the life of the WREP.

3.6.2 Blowouts Involving Smaller Discharges of Oil or Only Gas

Gas blowouts from offshore wells that do not involve a discharge of liquid petroleum are generally believed to be relatively innocuous to the marine environment. However, such blowouts may represent a threat to human life and property because of the possibility of explosion and fire.

Two sources are used for historical statistics on blowouts involving only gas or small hydrocarbon discharges. A particularly good source for US blowouts is the BOEMRE web page (www.boemre.gov), because BOEMRE keeps track of spills down to 1 bbl in size. (Unfortunately, the statistics are no longer maintained and more recent statistics than the 2006 data reported here are not available.) This is not the case in other parts of the world. Scandpower (2000) provides a report on blowouts in the North Sea and in the US Gulf of Mexico (US GOM), although the report provides no information as to whether or not hydrocarbon spills were involved in the reported blowouts.

The US Outer Continental Shelf (OCS) data, representing the 34-year period from 1972 to 2006, are provided in Table 3-49. There are no large spills in the entire database. The

2010 blowout in the US GOM would fit into the extremely large category, but is classified as an exploratory well.

Table 3-49 Blowouts and Spillage from US Federal Offshore Wells, 1972 to 2006

Year	Well Starts	Drilling Blowouts				Non-drilling Blowouts						OCS Production
		Exploration		Development		Production		Workover		Completion		
		No	Bbl	No	Bbl	No	Bbl	No	Bbl	No	Bbl	MMbbl
1972	845	2	0	2	0	1	0	0	0	0	0	396.0
1973	820	2	0	1	0	0	0	0	0	0	0	384.8
1974	816	1	0	1	0	4	275	0	0	0	0	354.9
1975	372	4	0	1	0	0	0	1	0	1	0	325.3
1976	1,038	1	0	4	0	1	0	0	0	0	0	314.5
1977	1,064	3	0	1	0	1	0	3	0	1	0	296.0
1978	980	3	0	4	0	0	0	3	0	1	0	288.0
1979	1,149	4	0	1	0	0	0	0	0	0	0	274.2
1980	1.307	3	0	1	0	2	1	1	0	1	0	274.7
1981	1,284	1	0	2	0	1	0	3	64	3	0	282.9
1982	1,035	1	0	4	0	0	0	4	0	0	0	314.5
1983	1,151	5	0	5	0	0	0	2	0	0	0	350.8
1984	1,386	3	0	1	0	0	0	1	0	0	0	385.1
1985	1,000	3	0	1	0	0	0	2	40	0	0	380.0
1986	1,538	0	0	1	0	0	0	1	0	0	0	384.3
1987	777	2	0	0	0	3	0	1	0	2	60	358.8
1988	1,007	1	0	1	0	0	0	1	0	0	0	332.7
1989	911	2	0	5 [a]	0	3	0	1	0	0	0	313.7
1990	987	1	0	1	0	0	0	3	9	1	0	304.5
1991	667	3	0	3 [b]	0	0	0	0	0	0	0	326.4
1992	943	3	100	0	0	0	0	0	0	0	0	337.9
1993	717 [c]	1	0	2	0	0	0	0	0	0	0	352.7
1994	717 [c]	0	0	0	0	0	0	1	0	0	0	370.4
1995	717 [c]	1	0	0	0	0	0	0	0	0	0	429.2
1996	921	1	0	1	0	0	0	0	0	2	0	433.1
1997	1,333	1	0	3	0	0	0	0	0	1	0	466.0
1998	1,325	1	0	1	0	2	0	3	0	0	0	490.5
1999	364	1	0	2	0	0	0	1	0	0	0	534.6
2000	1,061	5	200	4	0	0	0	0	0	0	0	551.6
2001	1,007	1	0	4	1	2	0	2	0	1	0	591.5
2002	828	1	0	2	0	2	350	1	1	0	0	602.1
2003	835	1	0	1	0	2	1	1	10	0	0	594.7
2004	861	2	16	0	0	0	0	2	1	0	0	567.0
2005	1,232	3	0	1	0	0	0	0	0	0	0	497.4
2006	1,586	0	0	0	0	0	0	1	0	1	50	503.1
Total	**34,576**	**67**	**316**	**91**	**1**	**24**	**627**	**39**	**125**	**15**	**110**	**13,963.9**

(A) Two of the drilling blowouts occurred during drilling for sulphur
(B) Two of the drilling blowouts occurred during drilling for sulphur
(C) Estimated: cumulative total correct

The total number of development wells drilled in the US OCS from 1972 to 2006 is not shown in Table 3-49, but an estimate of 21,000 can be inferred from other sections of MMS (1997), E&P Forum (1996) and from current internet sources. The number of blowouts from development drilling is 87 with the four blowouts from sulphur drilling removed); therefore, the blowout frequency is 4.1×10^{-3} blowouts per well drilled.

The statistic, based mostly on US OCS drilling and blowout records over the past 30 years, is derived on a conservative basis and does not take into account recent improvements in safety and blowout prevention that have tended to reduce blowout frequencies. There is also concern over gas releases and their effect on workers. For this reason, a more realistic assessment of the probability of a gas blowout is required. The main factors that need to be re-considered are: (1) the differences between “shallow gas” blowouts and deep-well blowouts; (2) special blowout prevention activities that exist for deep-well drilling in Canada; and (3) decreases in blowout frequency in recent years due to improvements in blowout prevention. All three issues are covered thoroughly in Scandpower (2000), and this source is used in the following analysis.

3.6.2.1 Shallow Gas versus Deep-well Blowout

A blowout might occur if shallow gas is encountered unexpectedly during drilling operations, which may be of concern from the mudline to approximately 914 m (3,000 feet) and below. Gas that is trapped in the shallow sediments can originate from deeper gas reservoirs, but can also come from biogenic activity in the shallow sediments. The probabilities of the various blowout categories are shown in Table 3-50, abstracted from Scandpower (2000).

Table 3-50 Development Drilling and Blowouts in the US Gulf of Mexico Outer Continental Shelf and North Sea, 1987 to 1997

Area	Number of Development Wells	Shallow Gas Blowout	Shallow Gas Release during Drilling	Deep Blowouts	Deep Well Releases during Drilling	Total Blowouts and Releases
US GOM	8,466	13	10	4	1	23
UK	3,086	1	0	0	2	3
Norway	1,202	1	1	0	0	2
Totals	**12,754**	**15**	**11**	**4**	**3**	**33**

Source: After Scandpower 2000
Notes:
A blowout is an incident where hydrocarbons flow from the well to the surface, all barriers are non-functional and well control can only be regained by means that were not available when the incident started
A deep blowout is defined as one that occurs after the Blowout Preventer (BOP) is set
A shallow gas blowout is a release of gas prior to the BOP being set
A well release is an incident where hydrocarbons flow from the well to the surface and is stopped by one or several barriers that were available when the incident started. In this case, hydrocarbons do not enter the environment

The values in Table 3-50 (for the US GOM) are reasonably consistent with the values in Table 3-49, which show 29 blowouts for the period 1980 to 1997. This means that the BOEMRE (the US regulator) classifies “blowouts” in Table 3-50 as “all” categories in Table 3-50 (i.e., well releases as well as blowouts). The blowout frequency from Table 3-50 for the US GOM is 28/8,466 = 3.3 x 10^{-3}, which is close to the value derived earlier (4.1 x 10^{-3}).

The important statistic to note in Table 3-50 is that the vast majority of blowouts and well releases are of the shallow gas variety. Specifically, the breakdown for shallow gas blowout frequency versus deep blowout frequency is shown in Table 3-51. It is clearly seen that: (1) shallow gas blowout frequencies are approximately four times lower in the North Sea compared to the US GOM OCS; and (2) deep blowout/release frequencies can be (e.g., for the US GOM) as much as six times lower than shallow gas blowout/ releases.

Table 3-51 Blowout Frequencies for the US Gulf of Mexico and North Sea, 1980 to 1997

	Shallow Gas Blowout/Release		Deep-well Blowout/Release	
	US GOM	North Sea	US GOM	North Sea
Blowouts/Releases per Wells Drilled	27×10^{-4}	7.0×10^{-4}	5.9×10^{-4}	4.7×10^{-4}
Wells Drilled per Blowout/Release	370	1,400	1,700	2,100

Deep-well blowouts (and not well releases) are the primary concern because releases by definition do not involve a discharge of hydrocarbons into the environment. There have been four deep blowouts from development drilling in the US GOM and none in the North Sea from 1987 to 1997 (Table 3-50). The reason for this, according to Scandpower (2000), is that North Sea operators are required by law to always have two barriers during exploration and development drilling, and this is not the case in the US. Regulations in Canada (i.e., two barriers) are similar to those in the North Sea, so it is fair to derive blowout frequencies for Canada on the basis of North Sea statistics.

Finally, it is worth noting (Table 3-52) that shallow gas blowout frequencies in the North Sea and in the US GOM have been on the decline in the most recent years of the record.

Table 3-52 Shallow Gas Exploration and Development Drilling Blowout Frequencies over Time, 1980 to 1997

Time Period	No. of Blowouts	Number of Exploration and Development Wells Drilled	Blowout Frequency
18 years (1980 to 1997)	53	22,084	24.0×10^{-4}
10 years (1988 to 1997)	53	13,870	16.6×10^{-4}
5 Years (1993 to 1997)	5	7,581	6.6×10^{-4}
3 Years (1995 to 1997)	1	4,924	2.0×10^{-4}
Source: Scandpower 2000			

A more recent analysis by IAOGP (2010) is based on the 20-year record to 2005 and indicates a deep-well blowout frequency of 4.8×10^{-5}. Using this figure results in a probability of one blowout for every 21,000 wells drilled. For a drilling program involving 70 wells, this statistic yields a deep-well blowout probability of 0.34 percent.

3.6.2.2 Blowouts During Production Operations

The best accident exposure variable to use for production and wireline operations is well-years. It is also convenient to link completions and workovers to well-years of operation. The number of oil and gas well-years in Table 3-49 from 1972 through 2006 can be estimated from other tables in MMS references; the number is approximately 240,000 producing well-years.

For all the gas-producing and oil-producing areas of the US OCS, 78 blowouts occurred during production, workovers and completions (Table 3-49). This yields a blowout frequency of $78/240,000 = 3.25 \times 10^{-4}$ blowouts per well-year. The equivalent number for the US OCS and North Sea areas for the period 1980 to 1997 is 1.83×10^{-4} blowouts per well-year (Table 3-53).

Table 3-53 Frequency over Time of Blowouts During Production, Wireline Operations, Workovers and Completions, US Gulf of Mexico and North Sea, 1980 to 1997

Period	Blowouts: Production and Wireline	Blowouts: Completions and Workovers	Total Blowouts	Well-years	Blowout Frequency
18 years (1980 to 1997)	10	21	31	168,586	1.83×10^{-4}
10 years (1988 to 1997)	3	7	10	108,357	9.92×10^{-5}
5 Years (1993 to 1997)	1	3	4	55,188	7.25×10^{-5}
3 Years (1995 to 1997)	1	3	4	34,895	1.15×10^{-4}
Source: Scandpower 2000					

As was done for the case of blowouts during development drilling, it is important to note that blowout frequencies during production operations in the North Sea and in the US GOM have been on the decline over the most recent years reported (Table 3-53).

IAOGP (2010), does not allow a comparison for each of the operations listed in Table 3-53, but confirms the overall blowout frequency for production, wireline operations, completions and workovers in recent years. The data, based on the 20-year record to 2005, indicate an overall blowout frequency for these operations of 1.85×10^{-4}, based on 33 incidents over 177,474 well-years.

A certain percentage of the blowouts involved some discharge of hydrocarbon. Of the 78 blowouts that occurred during the four operations of production, wirelining, workovers and completions, only 12, or 15.4 percent, involved hydrocarbon (note that the average size of the 12 spills was only 72 bbl). Therefore, the frequency of blowouts that produced a hydrocarbon spill from well blowouts during the four above-noted operations is calculated to be $0.154 \times 1.85 \times 10^{-4} = 2.8 \times 10^{-5}$ blowouts/well-year.

3.6.2.3 Summary of Blowout Frequencies Involving Smaller Discharges of Oil or Only Gas

There are an estimated 70 wells to be drilled for the WREP, so the calculated number of deep blowouts during development drilling becomes $70 \times 4.8 \times 10^{-5} = 3.4 \times 10^{-3}$.

For gas blowouts occurring during production and workovers, the statistic for the WREP becomes 300 well-years x 1.17×10^{-4} blowouts/well-year, or approximately 3.5 percent probability over the 20-year life of the WREP.

For gas blowouts that occur during production and workovers that involve some hydrocarbon discharge (>1 bbl), the statistic for White Rose becomes 300 well-years x 2.8×10^{-5} blowouts/well-year, or approximately 0.84 percent probability over the 20-year life of the WREP.

In summary, the probability of having a deep-well blowout is a 0.3 percent chance. During production, the risk of having a gas blowout is 3.5 percent over the life of the WREP; and gas blowouts with the possibility of discharged hydrocarbon (>1 bbl) would be 0.84 percent.

3.6.3 Large Platform Spills

There have been very few large spills from platforms operating in US OCS waters. In addition to the six from blowouts noted in Table 3-48, there have been eight others, which includes all US platform spills up to mid-2011 (Table 3-54). Note, this does not include the 2010 Macondo blowout, which occurred during exploration drilling.

Table 3-54 Hydrocarbon Spills of Greater than or Equal to 1,000 bbl from Platforms on the US Outer Continental Shelf, 1964 to June 2011

Date	Location	Size (bbl)	Cause
1964/04/08	Eugene Island Block 208	2,559	Collision
1964/10/03	Eugene Island Ship Shoal	11,869	Hurricane (7 platforms)
1965/07/19	Ship Shoal Block 29	1,688	Blowout (condensate)
1969/01/28	Santa Barbara Channel	80,000 [a]	Blowout
1969/03/16	Ship Shoal Block 72	2,500	Collision (weather)
1970/02/10	Main Pass Block 41	65,000	Blowout
1970/12/01	South Timbalier Block 26	53,000	Blowout
1973/01/09	West Delta Block 79	9,935	Storage Tank Rupture
1973/01/26	PL Block 023	7,000	Weather, Equipment Failure
1979/11/23	Main Pass Block 151	1,500 [b]	Collision, Weather, Tank Spill
1980/11/14	High Island Block 206	1,456	Pump Failure, Hurricane, Tank Spill
1992/09/29	Timbalier Bay/Greenhill	11,500 [c]	Production Well Blowout
2005/09/24	Cameron/Eugine Is./Green Canyon	5,680	Hurricane (9 platforms)

Source: BOEMRE OCS Spill Database, January 2012. www.boemre.gov/stats/index.htm.
(A) Estimates vary between 10,000 to 80,000 bbl
(B) Refined product
(C) This spill was in Louisiana State waters and not OCS waters, but is included for interest

All but two of the OCS spills in Table 3-54 occurred prior to 1980. BOEMRE statisticians responsible for analyzing and predicting hydrocarbon spill frequencies associated with offshore oil and gas activities in the OCS have decreased the estimate gradually over the past 15 years, mostly in recognition of a statistical trend towards a lower spill frequency. The estimate derived from statistics in Anderson and LaBelle (2000) is 1.5 x 10^{-5} spills/well-year for spills equal or greater than 1,000 bbl and 5.5 x 10^{-6} spills/well-year for spills equal or greater than 10,000 bbl.

The number of production well-years for WREP is 300; therefore, the probability over the WREP period would be 4.5 x 10^{-3} for a 1,000 bbl spill and 1.7 x 10^{-3} for a 10,000 bbl spill.

Note that the above statistic for spills >10,000 bbl (i.e., 5.5 x 10^{-6} spills/well-year) is almost four times smaller than the statistic derived earlier for production blowout spills >10,000 bbl (i.e., 2.0 x 10^{-5}). This is impossible because the first category includes blowout spills. The reason for the anomaly is that the US record was used for the former and the world-wide record was used for the latter. The world-wide statistic is higher than the US-derived one because the former was developed on a very conservative basis, which considered an exposure of only oil wells and not gas wells.

It is noted that there has been one production-related spill in Newfoundland and Labrador waters greater than 1,000 bbl, in 2004. There have been no spills greater than 10,000 bbl. Given the limited statistical database of Newfoundland and Labrador production operations, the US statistics are used in the frequency calculation.

3.6.4 Platform Spills Involving Small Discharges

Small spills occur with some regularity at offshore platforms. The data in Table 3-55 are derived from a more detailed table in MMS (1997) and covers small spills of all pollutants from facilities and operations on Federal OCS leases from the period 1971 to 1995. The spills involved various pollutants including crude oil, condensate, refined product, mineral oil and diesel. The period between 1971 and 1995 involved the production of 8.5 billion bbl of oil and condensate and 186,058 well-years of oil and gas production activity (MMS 1997).

Table 3-55 Frequency of Platform Spills in the Ranges of 1 to 49.9 bbl and 50 to 999 bbl (United States Outer Continental Shelf 1971 to 1995)

Spill Size Range	Number of Spills
1 to 49.9 bbl	1,898
50 to 99 bbl	90
Total volume of 1,898 + 90 spills = 123,023 bbl	

There have been very few large spills related to development or production in Canadian waters, which has necessitated the use of US and world-wide statistics. However, there is a reasonably-sized database on small spill incidents in Newfoundland and Labrador waters. Spill statistics are maintained and reported by the C-NLOPB (C-NLOPB 2012b, 2012c).

Production in Newfoundland and Labrador waters commenced in 1997 at the Hibernia location, with Terra Nova coming on stream in 2001, White Rose in 2005 and North Amethyst in 2010. Using the well statistics on the C-NLOPB website (C-NLOPB 2012b), these four fields have a total of 534 producing well-years to the end of 2011. An overview of spill statistics for the Newfoundland and Labrador Offshore area is provided in Tables 3-56 to 3-58. The spill incidents involving 1 bbl or more of hydrocarbon during that period are listed in Tables 3-56 and 3-57. These spills include spills of crude, diesel and other hydrocarbons resulting from production and loading operations. As noted in Section 3.6.3, there was one crude oil spill greater than 1,000 bbl, in 2004.

Table 3-56 Frequency of Production Platform Spills from 1 to 49.9 bbl and 50 to 99 bbl (Newfoundland and Labrador Waters, 1997 to 2011)

Spill Size Range	Number of Spills
1 to 49.9 bbl	13
50 to 99 bbl	0

Table 3-57 Frequency of Production Platform Spills from 1 to 49.9 bbl and 50 to 99 bbl (Newfoundland and Labrador Waters, 2000 to 2011)

Spill Size Range	Number of Spills
1 to 49.9 bbl	6
50 to 99 bbl	0

Table 3-58 Very Small Spills in Newfoundland and Labrador Waters, 1997 to 2011

Year	Spills Greater than 1 L and Less than 159 L (1 bbl)		Spills of 1 L and Less	
	Number	Total Volume (L)	Number	Total Volume (L)
1997	7	123	0	0
1998	20	632	3	1.6
1999	24	644	9	4.72
2000	2	62	2	1.1
2001	7	126	8	4.2
2002	5	26	19	5.2
2003	10	186	9	2.5
2004	18	193	30	9.0
2005	11	181	28	9.0
2006	5	20	27	9.2
2007	3	93	34	4.3
2008	11	336	23	3.9
2009	11	288	31	9.2
2010	3	20	17	4.2
2011	31	523	10	4.4
Total	**168**	**3,453**	**250**	**72.5**

A disproportionate number (7 of 13) of these spills occurred in the first three years of operations, so it is reasonable to focus on the more recent years of production experience (Table 3-57). For the years 2000 to 2011, there were a total of 514 producing well-years.

For the smallest size range, statistics from Newfoundland and Labrador operations can be used, but as there have been zero spills in the 50 to 99 bbl category, US GOM statistics will be used. Therefore, the frequency of spills in the range of 1 to 49.9 bbl is 1.2×10^{-2} (6/514) (based on Newfoundland and Labrador statistics) and for the range 50 to 99 bbl is 4.8×10^{-4} (90/186,058) (based on US GOM statistics.

The C-NLOPB also provides a statistical record of spills of greater than 1 L but less than 1 bbl (159 L), and of spills of 1 L and less; these are presented in Table 3-58. As in the previous category of spill size, a disproportionate number of these spills occurred in the first three years of operations, so it is reasonable to focus on the more recent years of production experience, 2000 to 2011. For these years (2000 to 2011), there were a total of 514 producing well-years, with 117 spills in the 1 to 159 L category, and 238 spills less than 1 L. Note that the totals in Table 3-58 indicate all spills from 1997 to 2011. Based on this, the average spill frequency is 0.23 spills per well-year in the 1 to 159 L category, and 0.46 spills per well-year less than 1 L.

3.6.5 Spills of Synthetic-based Muds

The C-NLOPB records spills of SBM and fluids, and these are summarized in Table 3-59 for the years 1997 through 2011. The largest such spill to date in 2004, approximately 96,600 L (608 bbl) of SBM was spilled from the diverter line of the GSF Grand Banks. The spill frequency is calculated based on the 229 wells spudded during this period.

Table 3-59 Spills of Synthetic-based Muds, 1997 to 2011

Spill Size Range	Number of Spills	Frequency per Well
>1 L	43	0.19
159 to 7,934 L (1 to 49.9 bbl)	22	0.096
7,935 to 159,000 L (50 to 999 bbl)	6	0.026
>159,000 L (1,000 bbl)	0	0

3.6.6 Summary of Blowout and Spill Frequencies

The calculated hydrocarbon spill probabilities for the WREP are summarized in Table 3-60.

Table 3-60 Predicted Probability of Blowouts and Spills for the White Rose Extension Project

Event	Historical Frequency	White Rose Exposure (A)	Probability over the WREP Life
Blowouts			
1. Deep blowout during development	4.8 x 10^{-5}/wells drilled	70 wells drilled	0.34%
2. Blowout during production involving some hydrocarbon spill >1 bbl	2.8 X 10^{-5}/well-years	300 well-years	0.84%
3. Development drilling blowout with hydrocarbon spill >10,000	5.9 x 10^{-5}/wells drilled	70 wells drilled	0.41%
4. Development drilling blowout with hydrocarbon spill >150,000 bbl	1.5 x 10^{-5}/wells drilled	70 wells drilled	0.11%
5. Production/workover blowout with hydrocarbon spill >10,000	1.4 x 10^{-5}/well-year	300 well-years	0.42%
6. Production/workover blowout with hydrocarbons spill >150,000	5.7 x 10^{-6}/well-year	300 well-years	0.17%
Platform Spills (B) (including blowouts)			
7. Hydrocarbon spill >10,000 bbl	5.5 x 10^{-6}/well-year	300 well-years	0.17%
8. Hydrocarbon spill >1,000 bbl	1.5 x 10^{-5}/well-year	300 well-years	0.45%
9. Hydrocarbon spill 50 to 999 bbl	4.8 x 10^{-4}/well-year	300 well-years	14%
10. Hydrocarbon spill 1 to 49 bbl	1.2 x 10^{-2}/well-year	300 well-years	3.6 spills over the life of the WREP
11. Hydrocarbon spill 1 L to 1 bbl (159 L)	0.23/well-year	300 well-years	69 spills over the life of the WREP
12. Hydrocarbon spill less than 1 L	0.46/well-year	300 well-years	140 spills over the life of the WREP

(A) White Rose Exposure is the number of events over the life of the WREP. This is either defined as number of well-years for production-related activities, or number of wells drilled for drilling-related activities

(B) Platform spills greater than 150,000 bbl are not included on the table as it would simply duplicate the statistic for blowouts greater than 150,000 bbl.

Over the 20-year life of the WREP, the probability of having a large or very large spill as a result of an accident on a platform is 0.5 and 0.2, respectively. This is calculated on the basis of US OCS experience.

Over the 20-year life of the WREP, the probability for an extremely large blowout spill during drilling is 0.1 and 0.4 percent for a very large spill. For similar sized blowouts from production activities and workovers that might occur over the 20-year production period, the probability of an extremely large oil well blowout is 0.2 and 0.4 percent for a very large oil well blowout.

Considering experience in the North Sea and the US GOM, and taking into account the trend toward fewer blowouts, the prediction for White Rose is that the probability of having a deep blowout is a 0.3 percent chance for the WREP. During operation of the WREP, blowouts with the probability of discharged hydrocarbon (>1 bbl) is 0.8 percent.

3.7 Fate and Behaviour of Hydrocarbon Spills in the Nearshore Study Area (Trajectory Modelling)

A spill trajectory modelling exercise, specific for WREP activities in Argentia, Placentia Bay, was undertaken. This section provides an overview of the results of the modelling. The full report is provided in SL Ross Environmental Research Ltd. (SL Ross) (2012).

3.7.1 Model Inputs and Spill Scenarios

The only potential sources of marine spills from the WREP near-shore operations are batch spills of fuel oil as a result of ship accidents or groundings during the tow-out activities from the graving dock to the deep-water mating site and the support vessel activities during the topsides installation. Batch spills are considered instantaneous events and are modelled by considering the surface spreading, evaporation, dispersion, emulsification and drift of a single patch or slick of oil.

The tugs and supply vessels that will be used in the near shore operations will be fueled by marine fuel oil, which is similar in makeup and spill behaviour to diesel fuel. Instantaneous batch spills of 100 and 350 m^3 have been modelled for diesel. The two spill sizes have been chosen as representative of a reasonably large spill and the maximum possible spill size based on the fuel on board of the vessels that will be operating in the nearshore.

Surface water current maps for spring (April to June), summer (July to September), and winter (January to March) seasons were used in the modelling. Coarse representations of the summer vector fields for the near shore study areas are provided in Figure 3-34. These water currents were combined with 3 percent of the average winds to determine the surface water currents influencing the initial formation and movement of the oil slicks.

Summer and winter average air temperatures of 13.5°C and -0.9°C, respectively, were used in the seasonal oil fate modelling. Summer and winter average water temperatures of 14°C and 2.0°C, respectively, were used in the seasonal oil fate modelling.

The data set has wind and wave data for the years 1954 to 2010. Six-hourly wind speed and direction data were extracted from the full MSC 50 data set at grid points with 0.5 degree spacing over the entire modelling area and at 0.1 degree spacing within Placentia Bay. The Placentia Bay seasonal spill behaviour modelling uses summer and winter average wind speeds of 6.2 m/s and 10.0 m/s, respectively.

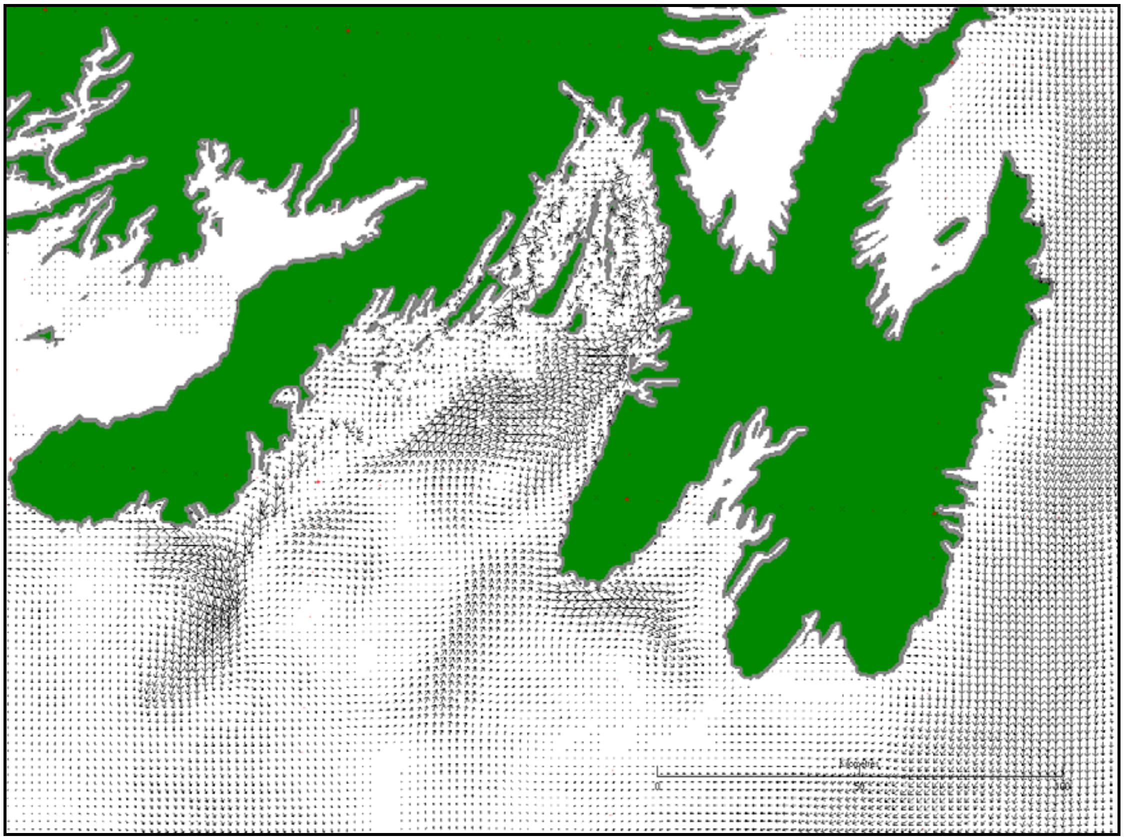


Figure 3-34 Nearshore Summer Surface Water Current Vectors

3.7.2 Model Outputs

A total of 8,721 trajectories from batch diesel spills were run. These trajectories used the 57 years of wind data available from the MSC50 dataset as described in Section 3.7.1. Trajectories were completed in the months of March, April, May, June and July, as these are the months when marine-based activities are most likely to occur in the nearshore. A high percentage of slicks reach shore due to the close proximity of the spill sites to land and the prevailing west or southwest winds. The minimum time to shore values ranged from 2 to 5 hours. The minimum survival times were approximately 0.5 to 1 day and the maximum survival times between 4.5 to 8 days.

3.7.2.1 Spills from Graving Dock Area

The shoreline contact statistics on a monthly basis from the hypothetical spills are provided in Table 3-61 for near the graving dock location. The minimum and maximum survival times for slicks that did not reach shore but instead evaporated and dispersed offshore are shown in the last two columns of Table 3-61.

Table 3-61 Slick Shoreline Contact and Slick Life at Sea for 350 m^3 Batch Diesel Spills at Graving Dock

Month	Number of Slicks Tracked	# of Slicks Tracked Reaching Shore	Minimum Time to Shore (h)	Maximum Time to Shore (h)	Minimum Slick Life at Sea (h)	Maximum Slick Life at Sea (hr)
March	1,767	1,548	4	94	12	130
April	1,710	1,476	4	122	16	132
May	1,767	1,530	4	126	22	184
June	1,710	1,554	4	143	16	165
July	1,767	1,532	5	131	17	194

The trajectory data were further processed, on a monthly basis, to identify the probability of a slick reaching specific areas. The slick movements for all spills released in a given month of the year, for the 57 years of data, have been processed to identify the percent of the spills released in the month that enter each grid area in a 1 km x 1 km grid placed over the nearshore. The spill movement probabilities on a month by month basis for releases in the channel dredging location are illustrated in Figures 3-35 to 3-39. The total sweep area of each slick has been used in this assessment. The zones on these figures represent areas where 1 to 5 percent of the slicks released over the 57 years of trajectory processing will pass (light green), 5 to 10 percent (yellow), 10 to 25 percent (brown), 25 to 50 percent (red) and 50 to 100 percent (black). These figures provide insight into the most likely path of oil and which shore zones are most likely to be oiled based on the 57 years of available wind data. These figures do not show areas covered by oil at a point in time but rather identify the probability that oil from a release on any given day will pass through the zone. For releases from the channel dredging location, the figures indicate that the oil will generally move to the east and is more likely to contact shore along the western shore of the Avalon Peninsula in Placentia Bay. The likelihood of oil reaching the Burin Peninsula from spills at the channel dredging location is small.

Figure 3-35 Batch Spill Trajectory Probabilities for Channel Dredging Location Release: March

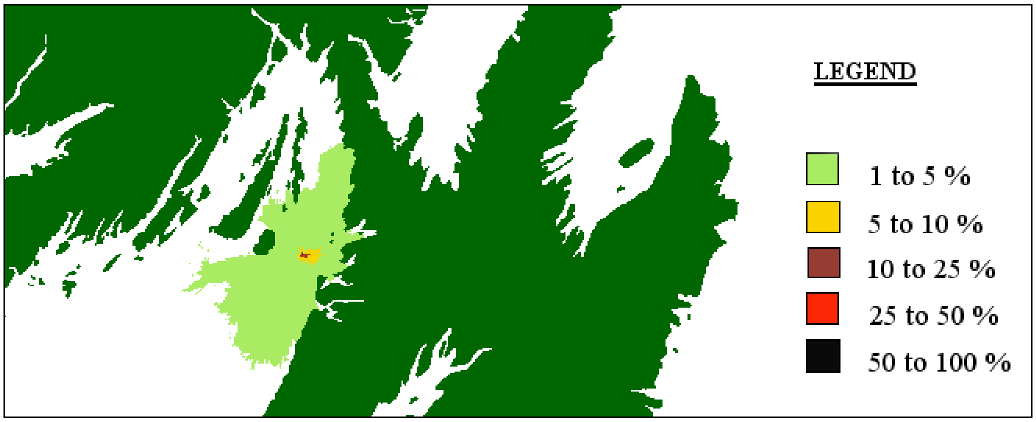


Figure 3-36 Batch Spill Trajectory Probabilities for Channel Dredging Location Release: April

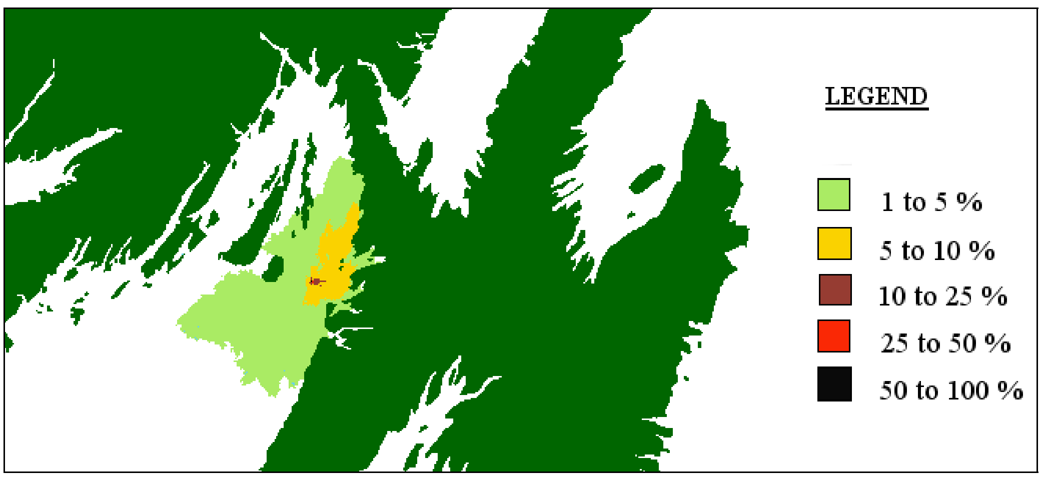


Figure 3-37 Batch Spill Trajectory Probabilities for Channel Dredging Location Release: May

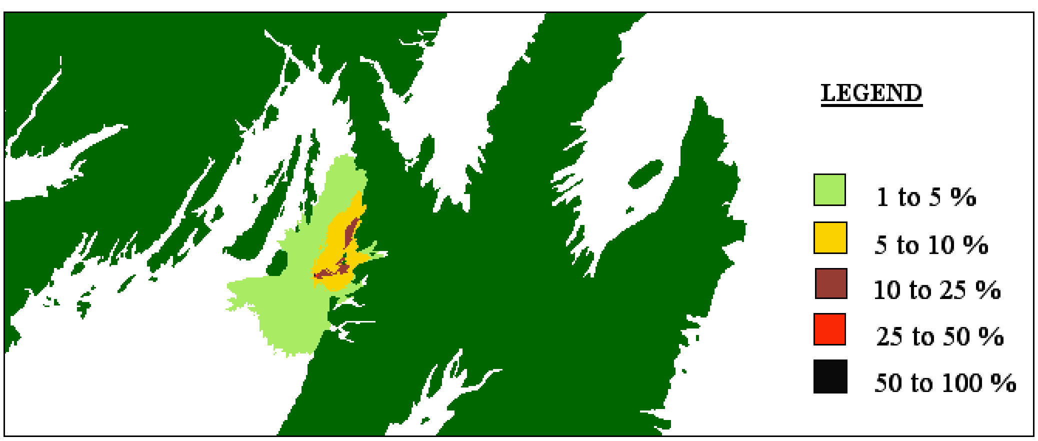


Figure 3-38 Batch Spill Trajectory Probabilities for Channel Dredging Location Release: June

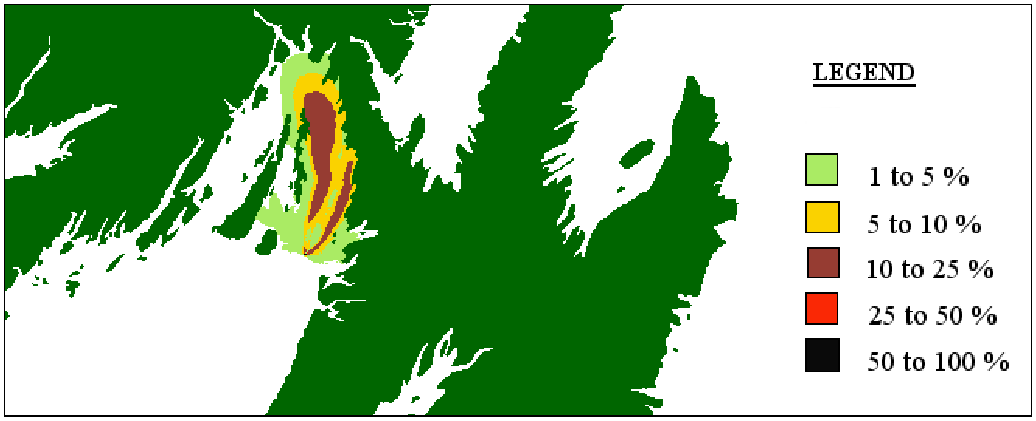


Figure 3-39 Batch Spill Trajectory Probabilities for Channel Dredging Location Release: July

3.7.2.2 Spills from Deep-water Mating Site

The shoreline contact statistics on a monthly basis from the hypothetical spills are provided in Table 3-62 for one of the deep-water mating site location. The minimum and maximum survival times for slicks that did not reach shore but instead evaporated and dispersed offshore are shown in the last two columns of Table 3-62.

Table 3-62 Slick Shoreline Contact and Slick Life at Sea for 350 m^3 Batch Diesel Spills from Location B

Month	Number of Slicks Tracked	# of Slicks Tracked Reaching Shore	Minimum Time to Shore (hr)	Maximum Time to Shore (hr)	Minimum Slick Life at Sea (hr)	Maximum Slick Life at Sea (hr)
March	1,767	1,636	2	111	13	106
April	1,710	1,611	2	137	16	104
May	1,767	1,657	3	159	21	165
June	1,710	1,551	3	159	20	152
July	1,767	9,74	4	145	17	195

The spill movement probabilities on a month by month basis for releases from a deep-water mating site are show in in Figures 3-40 to 3-44. Spills from this location will tend to contact shore areas in the upper reaches of Placentia Bay and the eastern shores of the Burin Peninsula. In May, June and July, there is a stronger tendency for the oil to move consistently to the northeast.

Figure 3-40 Batch Spill Trajectory Probabilities for Deep-water Mating Site Release: March

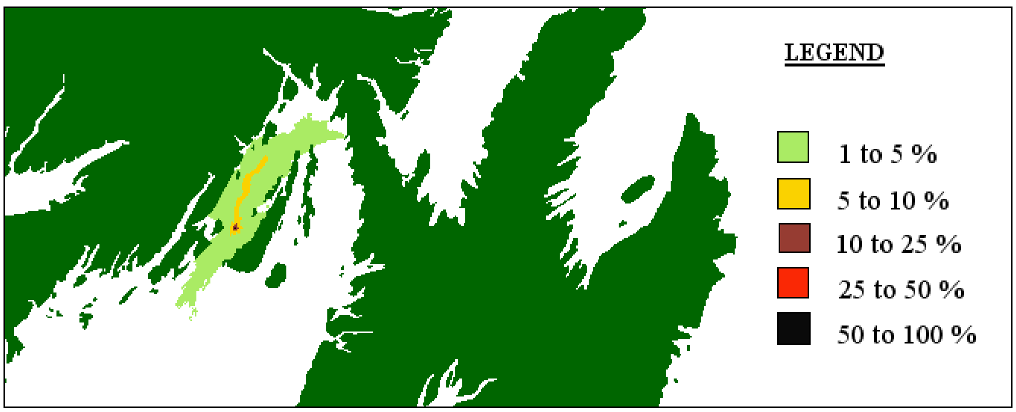


Figure 3-41 Batch Spill Trajectory Probabilities for Deep-water Mating Site Release: April

Figure 3-42 Batch Spill Trajectory Probabilities for Deep-water Mating Site Release: May

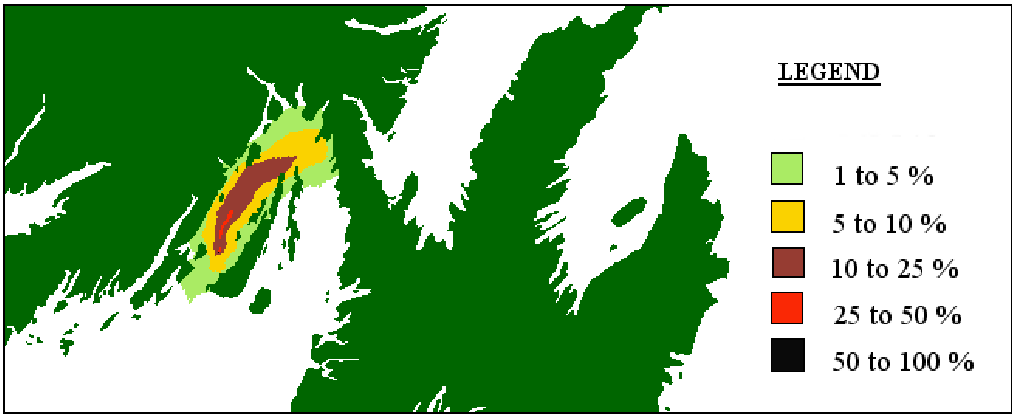


Figure 3-43 Batch Spill Trajectory Probabilities for Deep-water Mating Site Release: June

Figure 3-44 Batch Spill Trajectory Probabilities for Deep-water Mating Site Release: July

3.7.3 Model Summary

Modelling was conducted for the nearshore region in Placentia Bay in the vicinity of the proposed graving dock and deep-water topsides mating sites. The nearshore modelling evaluated batch diesel spills in the months of March through July, as this is the period that marine WREP activities are most likely. The basic fate and trajectory of diesel spills under average seasonal conditions is presented to provide the user with typical slick characteristics and trajectories over time. Long-term wind data (MSC50 data) are then used to model the trajectory of slicks released on a daily basis over a 57 year period to assess the likely trajectory of spills in this area. Water current mapping provided by DFO was used in the modeling. Slick 'time to shore' assessments and trajectory probabilities have been processed from these historical trajectories. Oil will come to shore within a few hours to a few days, depending on the wind conditions, from spills in this area and will most often affect the western and northwestern shores of the Avalon Peninsula within Placentia Bay. The extent of the diesel spills will be confined to Placentia Bay environs.

3.8 Fate and Behaviour of Hydrocarbon Spills from a Platform or Seafloor Blow-out in the Offshore Study Area (Trajectory Modelling)

Hydrocarbon spill trajectory analysis for the Grand Banks has been previously carried out for environmental assessments for production platforms (Mobil Oil 1985; SL Ross 1984, 1995, Petro-Canada 1995; Husky Oil and Operations 2000). Trajectory analyses have also been conducted for exploration drill programs in the Flemish Pass (JWEL 2003) and Lewis Hill (LGL 2003) areas. A spill trajectory modelling exercise, specific for WREP activities was undertaken using the most recent current and wind data available for the White Rose field. This section provides an overview of the results of the modelling. The full report is provided in SL Ross (2012).

3.8.1 Model Inputs and Spill Scenarios

The spill scenario types modelled for offshore activities are small fuel oil batch spills from vessels or the platform and subsea and above surface crude oil blowouts.

Husky has indicated that the crude oil presently being produced from the existing White Rose operation will be representative of the crude likely to be encountered in other areas of the field. A recent characterization of White Rose crude was used to input into this model (SL Ross 2012). Diesel was used in the batch spill scenario.

Instantaneous batch spills of 1.6 m^3 (10 bbl), 16 m^3 (100 bbl), 100 m^3 (630 bbl) and 350 m^3 (2,200 bbl) have been modelled for marine diesel. The two smallest spill sizes were chosen as they are representative of small and medium sized platform spills based on historical records. The larger spill sizes were chosen to illustrate the behaviour of large diesel spill sizes. The modelling of the continuous releases of gas and oil from well blowouts has been completed using the gas and oil flow rates shown in Table 3-63.

Table 3-63 Spill Flow Rates and Volumes Used in Modelling

Spill Type	Source	Flow	Gas-to-Oil Flow Ratio (m^3/m^{3+})
Crude Oil Well Blowout (Max Flow at Start of Blow)	Subsea	6,435 m^3/day (40,476 BOPD)	138
	Platform	6,435 m^3/day (40,476 BOPD)	138
Crude Oil Well Blowout (Flow after 120 Days)	Subsea	3,963 m^3/day (24,927 BOPD)	275
	Platform	3,963 m^3/day (24,927 BOPD)	275
Batch Oil Spills	Transfer	1.6 m^3 (100 bbl)	na
	Transfer	0.16 m^3 (10 bbl)	na
	Vessel Accident	100 m^3 (630 bbl)	na
	Vessel Accident	350 m^3 (2,200 bbl)	na

Surface water current fields developed by the Ocean Sciences Division, Maritimes Region of Fisheries and Oceans Canada (Wu and Tang 2011) were used in the spill trajectory modelling in the offshore study area. Seasonal mean surface water velocities were provided by Fisheries and Oceans Canada and these were converted to a map format used by the SL Ross Oil Spill model. Surface water current maps for spring (April to June), summer (July to September), fall (October to December) and winter (January to March) seasons were used in the modelling. Coarse representations of the summer and winter vector fields for the offshore study area are provided in Figures 3-45 and 3-46, respectively. These water currents were combined with 3 percent of the average winds to determine the surface water currents influencing the initial formation and movement of the oil slicks.

Figure 3-45 Offshore Summer Surface Water Current Vectors

Figure 3-46 Offshore Winter Surface Water Current Vectors

Summer and winter average air temperatures of 12.9°C and 0.1°C, respectively, were used in the seasonal oil fate modelling. Summer and winter average water temperatures of 12.3°C and 0.5°C were used in the seasonal oil fate modelling.

The data set has wind and wave data for 57 years from 1954 to 2010. Six-hourly wind speed and direction data were extracted from the full MSC 50 data set at grid points with 0.5 degree spacing over the modelled area. The seasonal spill behaviour modelling used summer and winter average wind speeds of 6.7 m/s (southwest) and 10.6 m/s (west), respectively.

3.8.2 Model Output

A Gaussian model of atmospheric plume behaviour has been used to predict the concentrations of oil downwind from the release point of a surface blowout, following the method described by Turner (1970).

3.8.2.1 Subsea (seafloor) Blow-out Spill

Oil flow rates of 6,435 and 3,963 m^3/day (with gas-to-oil ratios of 138 and 275 m^3/m^3) were used in the modelling. These flows represent the maximum unmitigated, open-hole oil flow rate estimated from the reservoir and the reduced flow expected after a 120 day release period, respectively (Husky 2012c). At the beginning of a blowout, the oil fate will most closely match the results provided for the higher flow rate. By the end of a 120 day release, the results presented for the lower flow rates will be more representative.

In this scenario the fluids are assumed to erupt from the seabed with the formation of small oil droplets in the turbulent jet region of the discharge. The oil drops are then quickly carried to the surface with entrained water and gas.

At the surface, the oil drops spread to form a slick in the summer, since the ambient temperature is above the fresh oil's initial pour point. However, in the winter, the oil is assumed to remain in the form of small drops of approximately 1 mm in diameter because the ambient water temperature is well below the oil's pour point. Because the oil drops are essentially semi-solid spheres, it is assumed that they will not mix and coalesce into a traditional oil slick. The small drops have a larger surface area than a traditional slick and this allows for a more rapid evaporation and further increase in the oil's pour point and viscosity. If high concentrations of these droplets were to form offshore during a sunny day with calm conditions, then solar radiation could warm the oil to the point where the drops might coalesce and form a more traditional oil slick. The entrained water flow from the blowout creates a hyperbolic-shaped oil distribution at the surface that extends several hundred metres up-current of the gas boil zone and that is between about 1.7 to 2.8 km wide down-current of the gas boil, depending on the season.

The oil slicks are predicted to be very persistent due to the formation of water-in-oil emulsions in the summer and because the water is colder than the oil's pour point in the winter. As such, the oil does not naturally disperse and will remain on the surface for an extended period of time.

After approximately one day of exposure on the water surface, the oil will have lost between 18 to 21 percent of its volume to evaporation. The maximum amount expected to be removed through evaporation over the life of the surface oil is 31 to 36 percent.

The initial oil viscosity at the summer temperature is 65 cP, in winter it would be 712 cP. Under average summer conditions, evaporation and emulsification raises the viscosity of the oil to 10,000 cP after 9.7 to 15 hours (depending on the spill flow rate). The viscosity of the oil is predicted to increase to a maximum of between 39,350 to 45,600 cP by the end of the slick's life. In the winter, the water temperature is more than 15°C lower than the oil's pour point, so the oil will remain in the form of drops, will not coalesce to form a slick and will not form water-in-oil emulsions. The maximum viscosity of the drops is estimated to be about 7,500 cP.

Natural dispersion will be minimal in all of the subsea blowout scenarios either due to emulsion formation or the high oil pour point and cold water. In-water oil concentrations from these spills will remain below 0.001 ppm.

Two random dates were selected to provide sample trajectories of oil from a 120-day subsea blowout in the summer and winter months. The spatially and temporally variable winds of the MSC50 data set are used rather than seasonal average values to illustrate how the time-varying winds will affect the motion of slicklets that are released over the 120 day discharge period. Slicklets were released at the beginning of each day, starting on the first day of the month, over the 120 day releases. The position of each slicklet is plotted on the final graph after every six hours of movement. Average summer and winter air temperatures have been used in the modelling. The summer and winter model results are shown in Figures 3-47 and 3-48, respectively. These plots do not represent the area of the ocean covered by oil at any given time but merely identify the area that could be influenced by the oil over the release period, assuming no spill response. The dots in the figures represent the positions of 28 or 31 slicks of oil reported every six hours. Each parcel was released at the start of each day in the month and then tracked for 120 days or until the average surface oil coverage dropped to below 1 g/25 m^2. This level of contamination of highly weathered crude is considered innocuous to wildlife (French-McCay 2004).

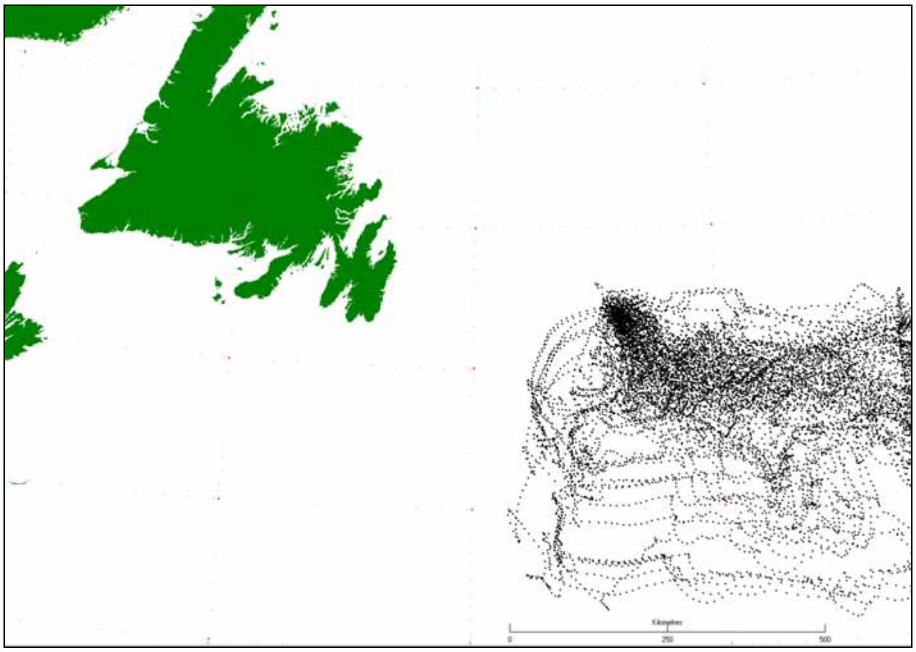


Figure 3-47 Trajectory Envelope for a 120 day Summer Subsea Blowout: started September 1, 2009

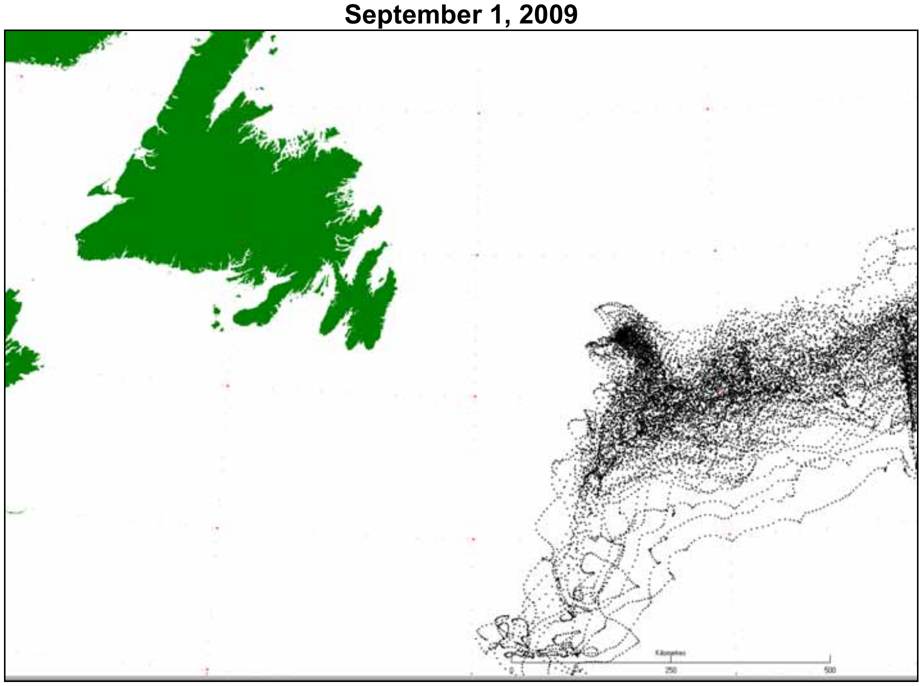


Figure 3-48 Trajectory Envelope for a 120 day Winter Subsea Blowout: started February 1, 2009

3.8.2.2 Surface (Platform) Spill

In this modelled scenario, a blowout occurs on the on-site rig 43 m above the water surface, resulting in a discharge of oil and gas into the air. Oil flow rates of 6,435 and 3,963 m^3/day (with gas-to-oil ratios of 138 and 275 m^3/m^3) were used in the modelling. These flows represent the maximum oil flow rate estimated from the reservoir at the start of the release and the reduced flow expected after a 120 day release period (Husky 2012c). The platform and rig are not damaged and they remain in position throughout the blowout period. The modelling assumes no spill response is applied for the duration of the 120 day spill. The gas exits 43 m above the water surface at high velocity and shatters the oil into small diameter droplets. These droplets are shot upward by the jet of gas, impact on the derrick and agglomerate to a size of approximately 0.75 mm. This median drop size has been selected for all surface blowout modelling based on model calibration results using data from the Ekofisk blowout. These droplets rain down on the surface of the water down-wind of the rig. Most of the droplets fall onto the water surface within a few hundred metres of the rig in a swath approximately 150 m wide and re-coalesce to form a slick approximately 1 to 3.5 mm thick. A 'traditional' oil slick is assumed to form in both summer and winter in this above-water blowout scenario. Winter and summer seasonal temperatures and wind speeds have been used in the modelling of the fate of this oil. Minor differences in the initial slick characteristics and change in oil property over time will exist depending on the season (due to temperature and wind speed differences). The results of the fate modelling are described below.

The slick at source will be between 116 and 160 m wide and 1.0 to 3.4 mm thick. The oil making up the slick will have lost between 4 and 7 percent (depending on the season) of its volume through evaporation of the oil droplets in the air. The oil droplets will re-coalesce to form a slick on the water surface and this oil will immediately begin to emulsify. The initial oil will have a viscosity of 110 cP in the summer scenario and 960 cP in the winter.

After approximately one day of exposure on the water surface, the slicks will have lost between 10 to 13 percent of their volume to evaporation; this increases to a maximum of approximately 27 percent over the life of the surface oil slicks.

Evaporation and emulsification raises the viscosity of the slicks to 10,000 cP within one hour in the winter and between 136 and 190 hours in the summer, depending on the spill flow rate. The viscosity will increase to maximums of approximately 21,000 cP in the summer and 195,000 cP in the winter; the higher winter viscosities are due to the colder conditions.

Under both average summer and winter conditions, the model predicts that the surface slicks will persist for periods greater than 30 days with very little natural dispersion. As the oil drifts from the site, wave action will break the slicks up into viscous particles of oil that move away from each other under the influence of oceanic turbulence. The makeup of this oil will depend on the harshness of the environment over this period. It is likely that after a several weeks of exposure to the energetic conditions of the North Atlantic Ocean, the oil will be broken into small tar-balls spread over a large area, with the oil particles separated by large expanses of water.

The trajectories for the surface blowout scenarios will be identical to those from the subsea discharges because the oil from both types of spills will be very persistent. The starting slicklet sizes and oil thicknesses will be different but the paths that the slicklets take will not vary. The trajectories provided in Section 3.8.2.1 are thus indicative of typical trajectories for the surface blowouts as well.

3.8.2.3 Historical Spill Trajectory Assessment

The modelling in this section looks at which surface areas on the Grand Banks are more likely to be swept by surface oil and the likelihood of crude oil slicks reaching Newfoundland shorelines. Because the oil is very persistent the mode in which it is released (subsea or surface blowout or batch spill) is not a critical factor in determining the long term trajectory of spills.

A total of 83,220 trajectories were run in this analysis from a spill release site at the proposed WHP location (46.800728 N, 48.063392 W). These trajectories used the 57 years of wind data available from the MSC50 dataset. The data were further processed on a monthly basis, to identify the probability of a slick reaching specific areas in the offshore. The slick movements for all spills released in a given month of the year, for the 57 years of data, were processed to identify the percent of the spills released in the month that enter each cell in a 1 km x 1 km grid. The results are shown in Figures 3-49 to 3-60. The total sweep area of the slicks (as defined using an oceanic diffusion model, Okubo 1971) has been used in this modelling analysis. The contours Figure 3-49 to 3-60 represent the boundaries where 0 to 1 percent of the slicks may pass 1 to 5 percent, 5 to 10 percent, 10 to 25 percent, 25 to 50 percent and 50 to 100 percent. These figures provide insight into the most likely path of oil over when spilled in a given month based on the 57 years of available wind data.

Trajectories have been run for 120 days or until the oil evaporates and disperses from the surface or the average oil concentration on the surface has dropped below 1 g/25 m^2. This level of contamination of highly weathered crude is considered innocuous to wildlife (French-McCay 2004).

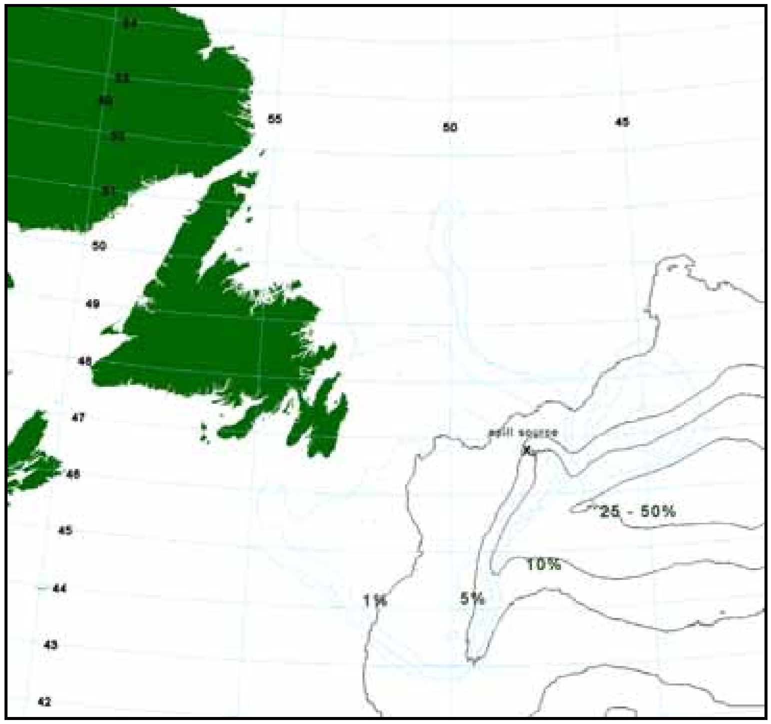


Figure 3-49 Spill Trajectory Probabilities for Releases from White Rose: January

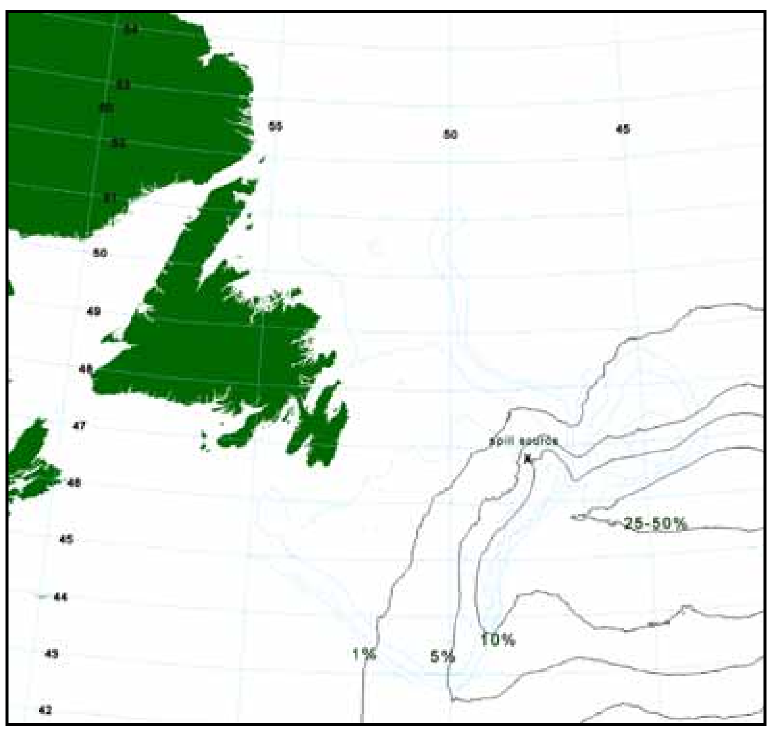


Figure 3-50 Spill Trajectory Probabilities for Releases from White Rose: February

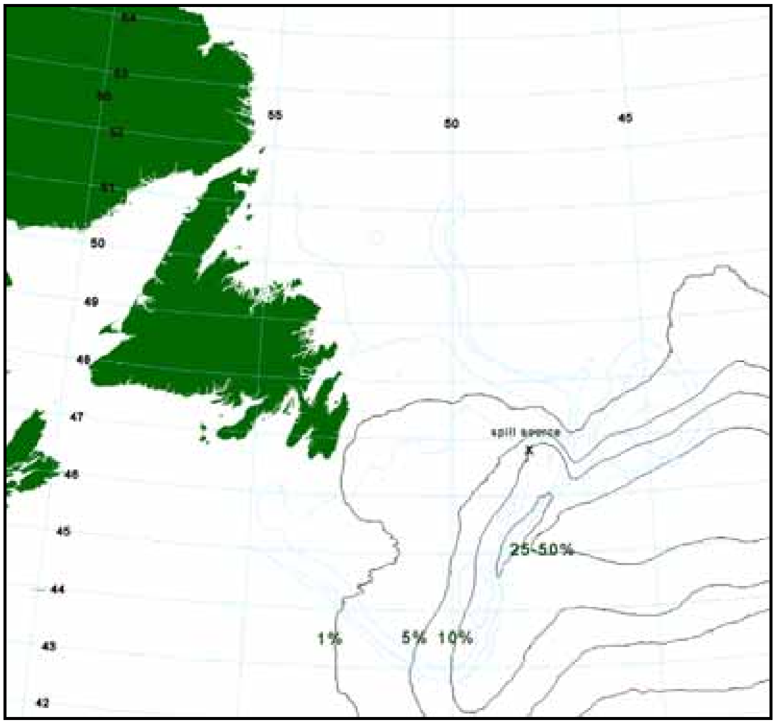


Figure 3-51 Spill Trajectory Probabilities for Releases from White Rose: March

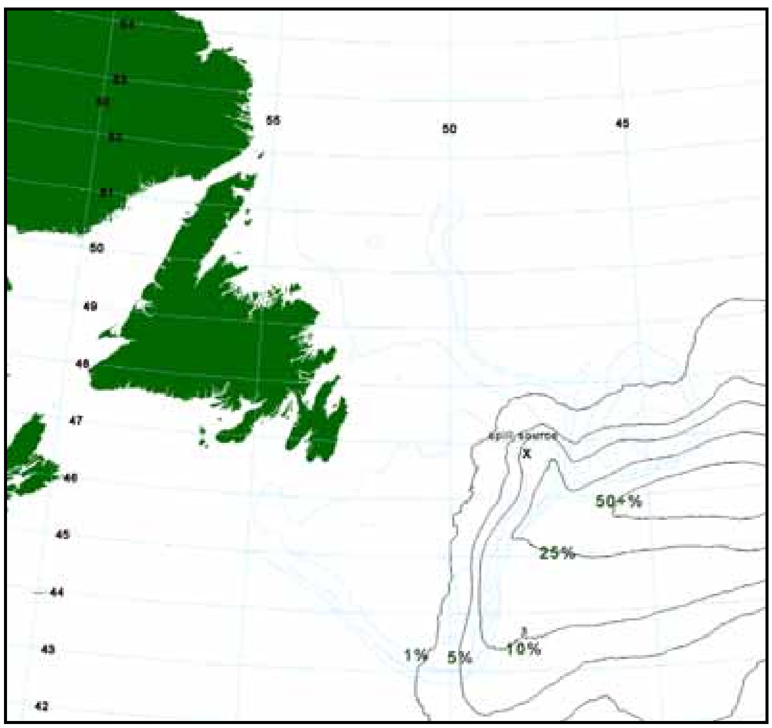


Figure 3-52 Spill Trajectory Probabilities for Releases from White Rose: April

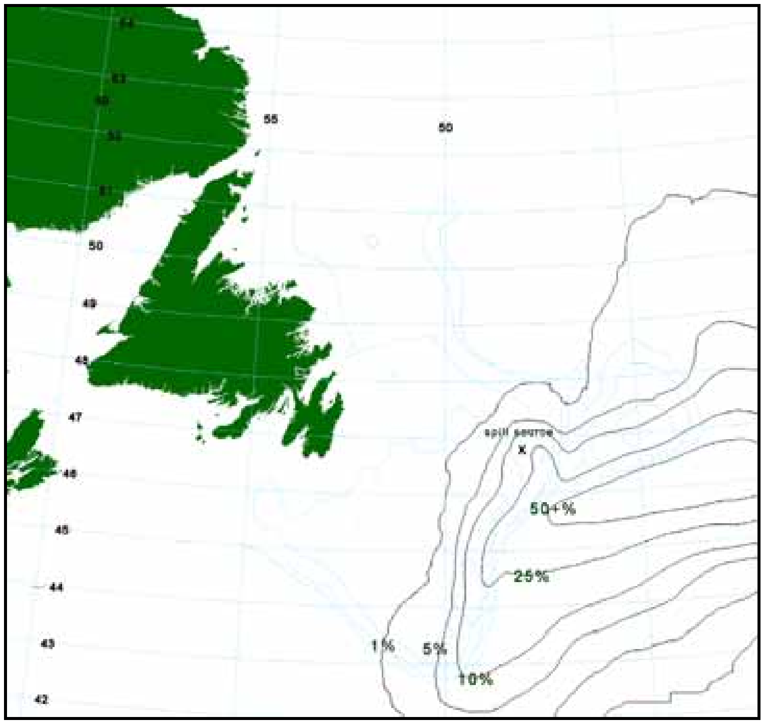


Figure 3-53 Spill Trajectory Probabilities for Releases from White Rose: May

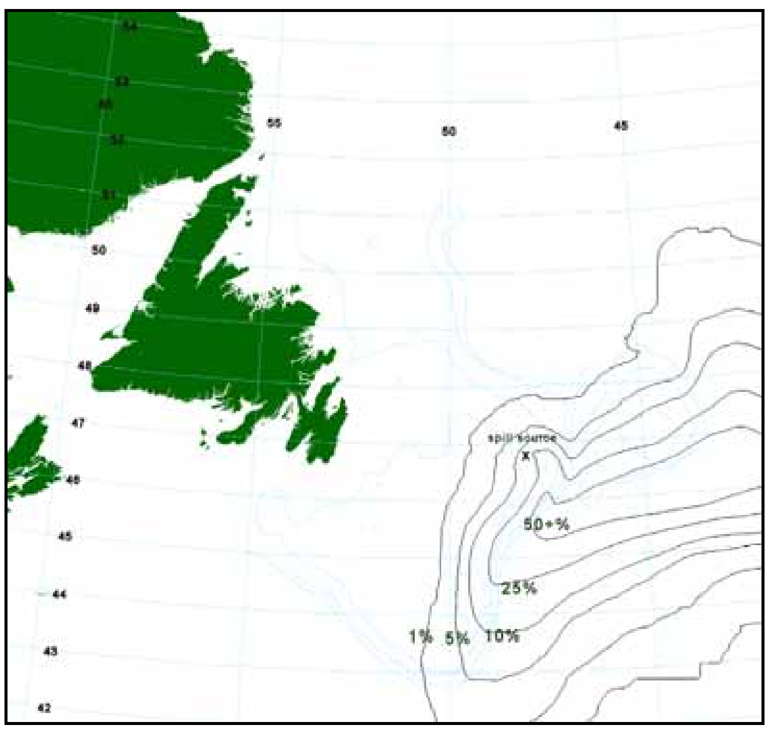


Figure 3-54 Spill Trajectory Probabilities for Releases from White Rose: June

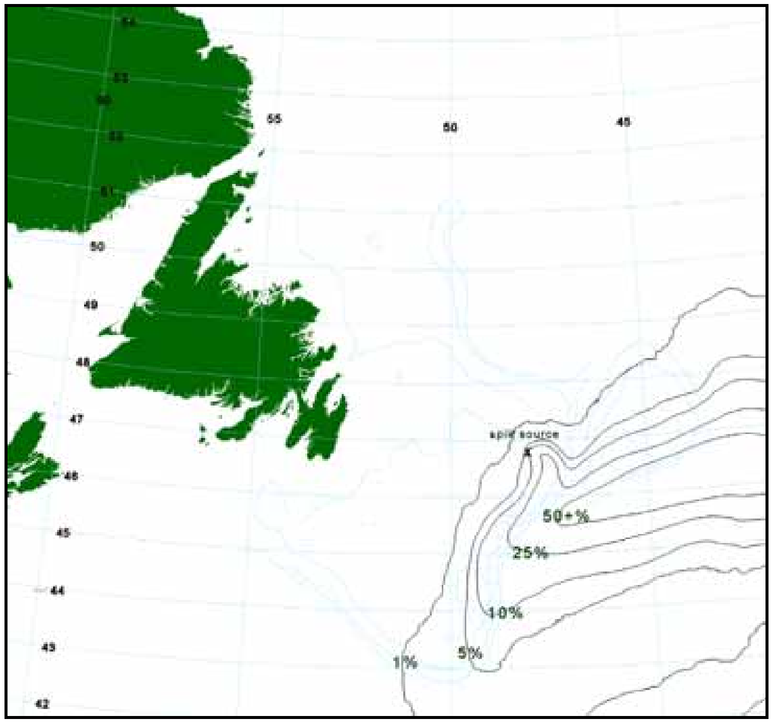


Figure 3-55 Spill Trajectory Probabilities for Releases from White Rose: July

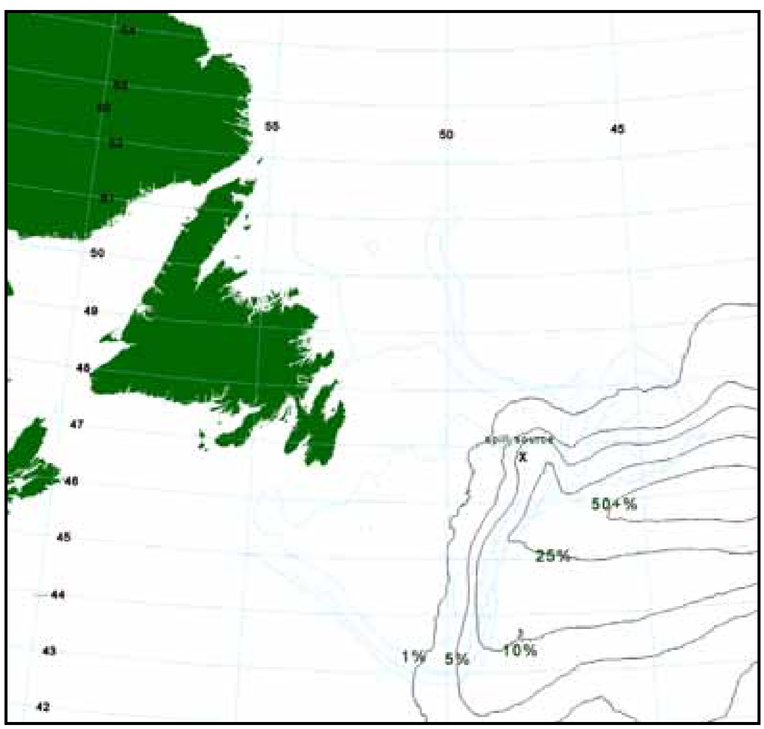


Figure 3-56 Spill Trajectory Probabilities for Releases from White Rose: August

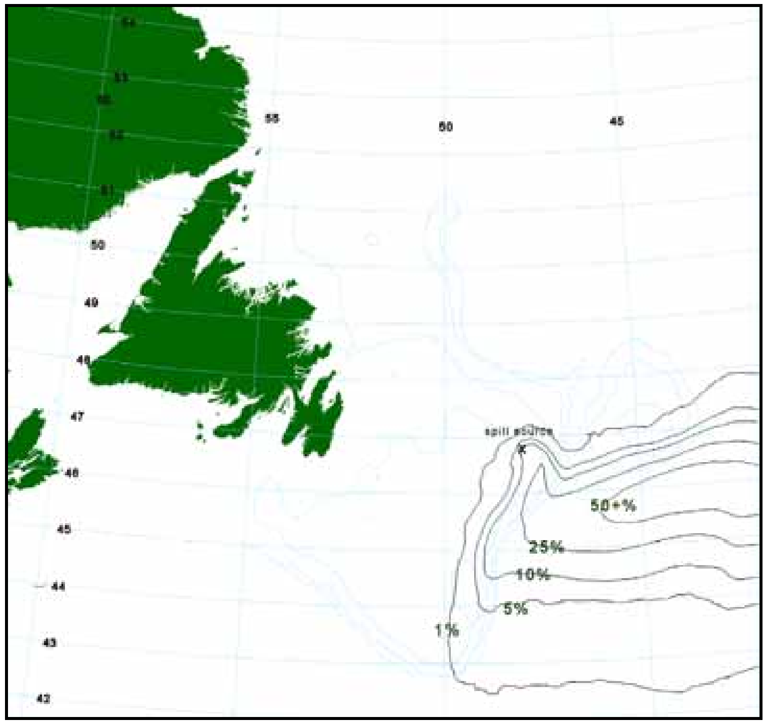


Figure 3-57 Spill Trajectory Probabilities for Releases from White Rose: September

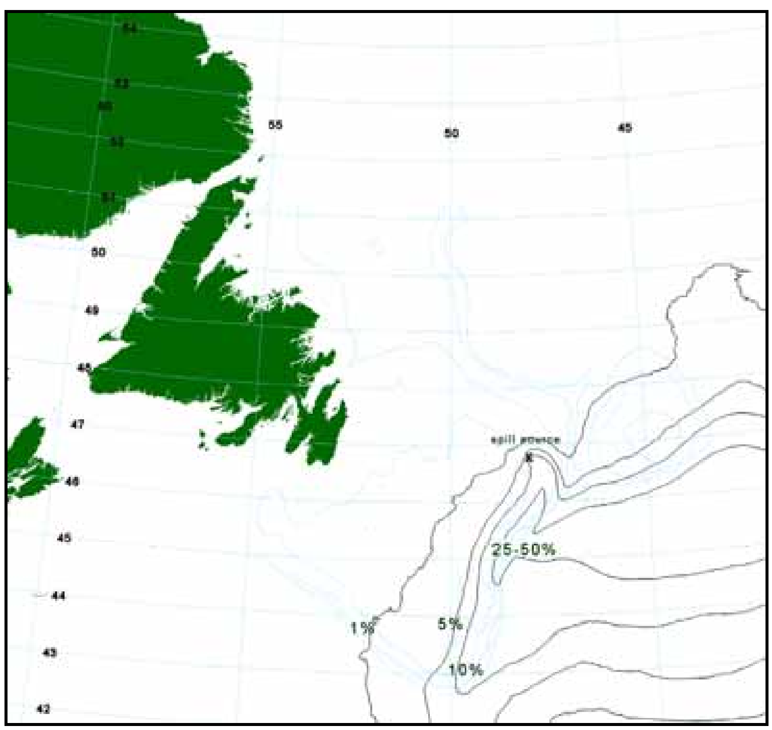


Figure 3-58 Spill Trajectory Probabilities for Releases from White Rose: October

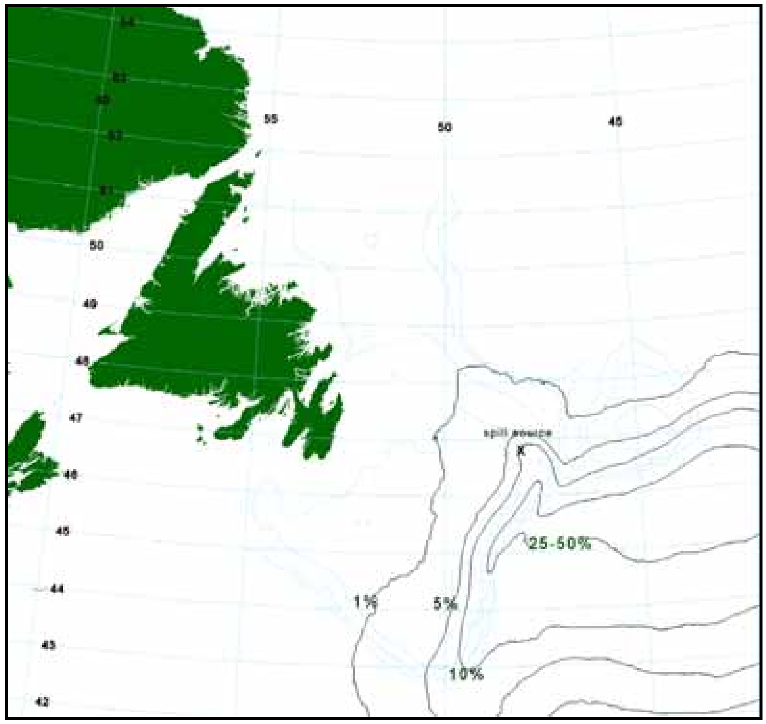


Figure 3-59 Spill Trajectory Probabilities for Releases from White Rose: November

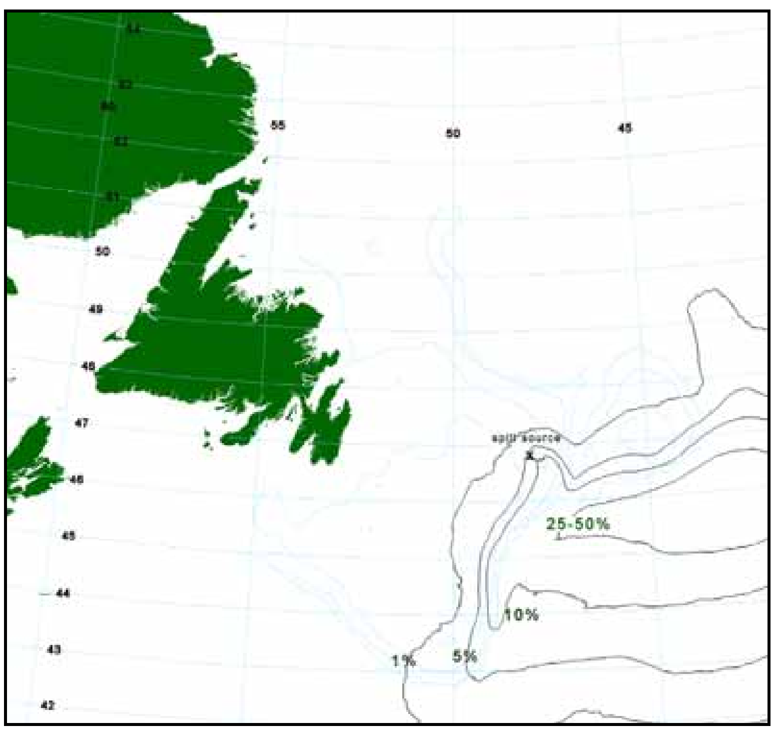


Figure 3-60 Spill Trajectory Probabilities for Releases from White Rose: December

It cannot be stressed enough that our confidence in accurately modelling the fate of crude oil on the open ocean past a few weeks is not high. Very little data has ever been collected on the long-term fate of different oil types in the offshore (past even one-week of exposure). A study completed for the US Minerals Management Service reviewed the worldwide data on the persistence of crude oil spills on open water (SL Ross et al. 2003). The study found that the persistence of large spills (>1,000 bbl) was predicted best with the following equation:

PD= 0.0001S-1.32T+33.1

where: PD = spill persistence in days

S = spill size in bbl

T = Water temperature in degrees Celsius

If the single day's release of oil is considered as a unique slick with a volume of 40,500 bbl then its long term persistence would be about 34 days in the winter and approximately 20 days in the summer. These estimated surface slick persistence values (based on the equation above) are somewhat shorter than those predicted in the detailed spill modeling prepared for this report and are presented only to provide additional insight into the possible survival time of surface slicks based on historical records.

A small number of slicks came to shore only in the months of March (nine slicks), October (29 slicks) and November (one slick). This amounts to only 0.04 percent of the 83,220 oil slicks tracked that reached shore as seen in Figure 3-61. The slicks arrived at shore between 45 and 92 days after release.

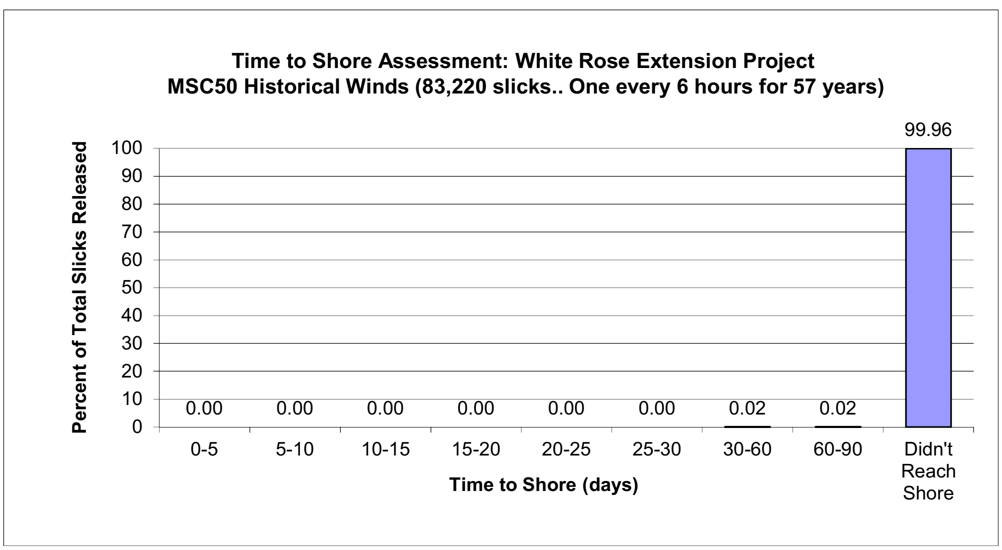


Figure 3-61 Slick Survival Time Statistics for the White Rose Extension Project, all Months and Years

3.8.2.4 Batch Fuel Oil Spills

Four diesel fuel spill scenarios have been considered with spill volumes of 1.6, 16, 100 and 350 m^3. The summer discharges lose 36 to 38 percent of the diesel to evaporation, while the winter scenarios lose about 25 to 27 percent by evaporation; this is due to a combination of the warmer summer temperatures and the more energetic winter conditions that disperse the oil more quickly, thus reducing the opportunity for evaporation. The slicks in the winter are lost from the surface more quickly (13 to 37 hours in winter versus 25 to 62 hours in summer, depending on initial volume spilled) due to the higher winds and thus more energetic wave action. Surface oil will persist for 16 to 49 km from the source in the winter versus 22 to 62 km in the summer; the shorter distance in winter again due to the more rapid natural dispersion. The faster dispersion in the winter months results in higher peak in-water oil concentrations (0.6 to 3 ppm in winter versus 0.24 to 1.2 ppm in summer). The naturally dispersed oil in the water column is assumed to mix to a conservative depth of 30 m. The clouds of dispersed oil from the winter spills will grow to widths of 0.3 to 10.2 km at the point where the oil has diffused to below 0.1 ppm oil concentration. The winter dispersed oil clouds will sweep distances of 10 to 130 km prior to diffusing to a 0.1 ppm in-water oil concentration. The size of the summer spill clouds will be somewhat smaller (0.3 to 9.7 km) and they will sweep smaller distances (5 to 102 km). The in-water concentration of 0.1 ppm of total petroleum hydrocarbon is the exposure concentration below which no significant biological effects are expected (French-McCay 2004).

The maximum viscosity that the surface oil will reach in these batch spills is approximately 1,700 cP in the winter and 3,700 cP in the summer. The higher summer viscosity is due to the higher evaporation that results in a greater increase in viscosity than that caused by the colder winter water temperatures.

Spill trajectories have been run from the White Rose platform location using average summer and winter wind speeds and prevailing water currents for the four diesel fuel spill volumes. The summer and winter trajectory results are shown in Figures 3-62 and 3-63, respectively. These basic trajectories illustrate the general movement of batch fuel oil spills from hypothetical spill at the offshore site. The locations where the surface oil slicks have completely evaporated and dispersed are marked on the Figures 3-62 and 3-63, as are the locations where the dispersed oil cloud concentrations drop to below 0.1 ppm concentration. For the smaller spills, the plume concentrations are below this level prior to loss of the surface oil.

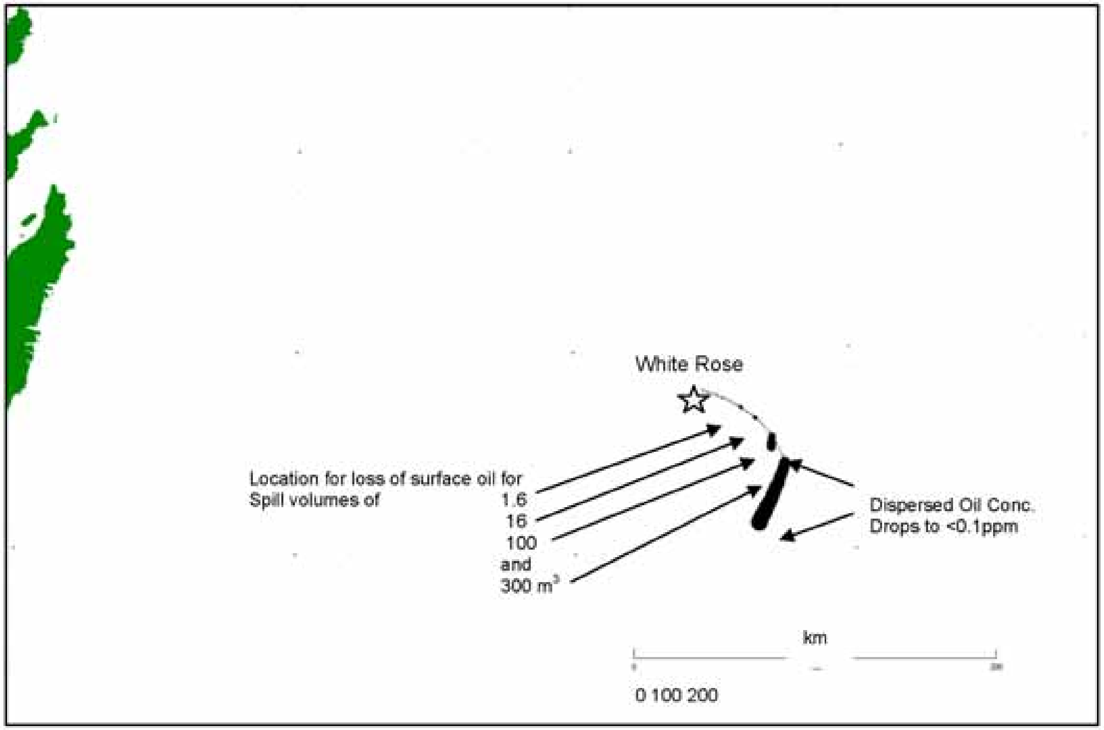


Figure 3-62 Offshore Summer Diesel Spill Trajectories: Average Environmental Conditions

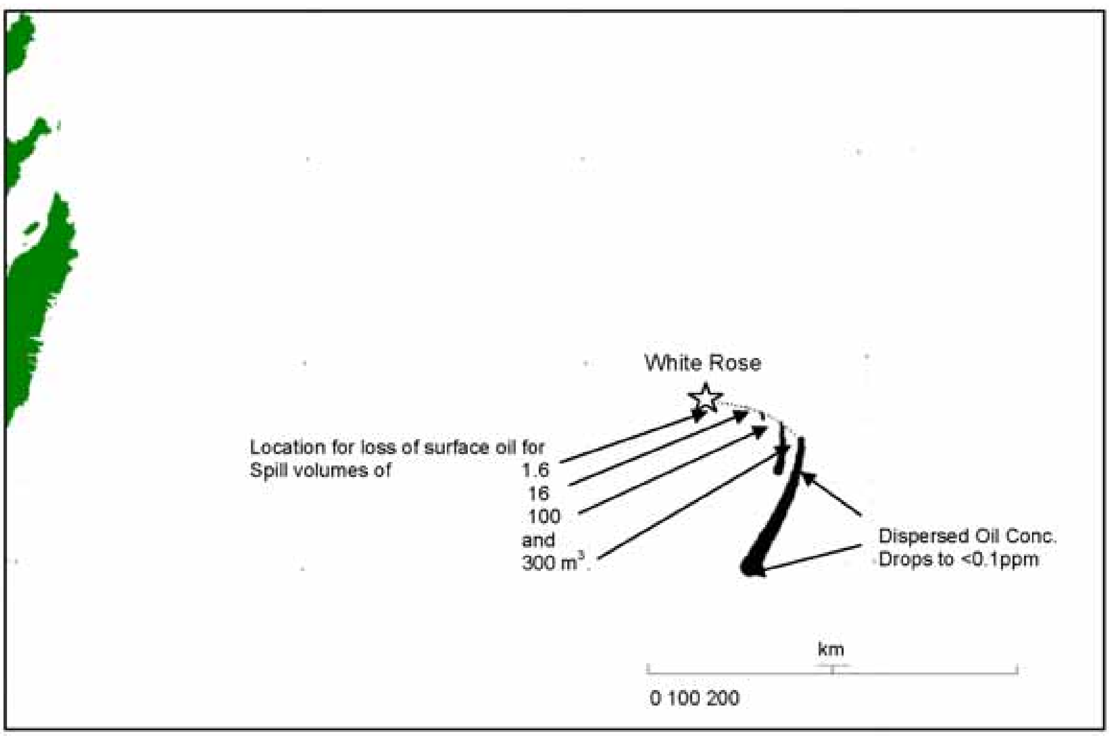


Figure 3-63 Offshore Winter Diesel Spill Trajectories: Average Environmental Conditions

3.8.3 Trajectory Modelling Summary

Modelling was conducted for the broader offshore region surrounding the White Rose field. Batch spills of diesel fuel and subsea and surface blowouts of crude oil were modelled in the Offshore Study Area. The basic fates of oil from these spill types have been modelled under average environmental conditions to provide users with typical slick characteristics and trajectories over time for the different spill types. For the blowout scenarios, slick characteristics are provided for both the maximum oil and gas flows possible at the start of a release and the lower flows that would be likely 120 days into a release (without the application of spill containment measures). Historical spill trajectories are modelled in the offshore region using the 57 year MSC50 data set and DFO's east coast water current data. The modelling results indicate that shoreline contacts from these releases are very unlikely. Slick trajectory probability contours are provided on a monthly basis to identify the zones of most likely oil movement in the offshore.