

**Scope of the Environmental Assessment
For the
Proposed EnCana Corporation
Deep Panuke Offshore Gas Development Project**

September 21, 2006 Draft

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1. Purpose

This document provides scoping information for the environmental assessment (EA) of the proposed Deep Panuke Offshore Gas Development Project (Deep Panuke). The EA will be reviewed by the federal government, in accordance with the *Canadian Environmental Assessment Act* (the Act). Deep Panuke was previously assessed as a comprehensive study which concluded in 2002, at which time the Minister of the Environment determined that the project was not likely to cause significant adverse effects. This new assessment is required because the manner in which the project is proposed to be carried out has been modified from what was originally proposed.

Included in this document is a description of the scope of the project that will be assessed, the factors to be considered in the assessment, and the scope of those factors. These are based on the requirements for the federal EA process, as set forth in the Act. The rationale used to determine the scope of the project is related to the nature of the federal decisions (e.g. triggers) involved, as well as the requirements of section 24 of the Act, which oblige the use of the previously completed EA to the extent appropriate.

2. Regulatory Decisions

Deep Panuke is subject to federal environmental assessment in accordance with the Act and its regulations. Those requirements include identification of federal authorities that are likely to require an environmental assessment of the project, or are in possession of specialist or expert information or knowledge that is necessary to conduct the environmental assessment. This is referred to as the federal coordination process. The EA document should summarize the outcome of the Deep Panuke federal coordination process in its discussion of regulatory context.

In order to proceed, the project will or may require the various approvals listed below.

- Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) authorizations under sub-sections 142(1)(b) and 143(4)(a) of the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*;
- National Energy Board (NEB) section 52 certificate of public convenience and necessity, or section 58 order, pursuant to the *National Energy Board Act*;
- Fisheries and Oceans (DFO) authorization under section 35(2) of the *Fisheries Act* for the harmful alteration, disruption or destruction (HADD) of fish habitat. Depending on the methods used to install the pipeline, the project may also

require a section 32 *Fisheries Act* authorization for the destruction of fish by means other than fishing (e.g. use of explosives);

- Environment Canada permit under paragraph 127(1) of the *Canadian Environmental Protection Act* for disposal of a substance at sea;
- Transport Canada approval under paragraph 5(1) of the *Navigable Waters Protection Act* for a work to be built or placed in, on, over, under, through or across any navigable water; and
- Industry Canada approval under paragraph 5(1)(f) of the *Radiocommunication Act* for sites on which radio apparatus may be located as well as the erection of such things as towers and masts, and for which Exclusion List paragraph 13 (Schedule I, Part I General) does not apply.

The above-named departments are hereafter collectively referred to as the Responsible Authorities. All authorizations named above are described in the Law List Regulations of the Act. Their issuance therefore constitutes a power as described in sub-section 5(1)(d) of the Act and results in the requirement to ensure that an EA is conducted.

In addition, there are other applicable federal statutes and regulations, notably the *Species at Risk Act* (SARA), the *Migratory Birds Convention Act* and the *Oceans Act*. The proponent must demonstrate how the project design will ensure compliance with all regulatory requirements.

3. Definitions

In this document,

“Environment” means the components of the earth and includes:

- (a) Land, water, air and all layers of the atmosphere;
- (b) All organic and inorganic matter and living organisms; and
- (c) The interacting natural systems that include components referred to in paragraphs (a) and (b).

“Environmental effect” means:

- (a) any change that the project may cause in the environment, including any change it may cause to a listed wildlife species, its critical habitat or the residences of individuals of that species, as those terms are defined in sub-section 2(1) of the *Species at Risk Act*,
- (b) any effect of any change referred to in paragraph (a) on
 - (i) health and socio-economic conditions,
 - (ii) physical and cultural heritage,
 - (iii) the current use of lands and resources for traditional purposes by aboriginal

- persons, or
 - (iv) any structure, site or thing that is of historical, archaeological, paleontological or architectural significance, or
 - (c) any change to the project that may be caused by the environment,
- whether any such change or effect occurs within or outside Canada;

4. Scope of the Project

The proposed Deep Panuke project is a modified version of one that was previously assessed as a federal comprehensive study in 2002. For this EA, two project options are proposed, both of which differ from the original proposal:

- a mobile offshore production unit (MOPU) with a dedicated pipeline to shore, with connection to the existing Maritimes and Northeast Pipeline (M&NP Option); and
- a MOPU with a sub-sea tie-in to the existing SOEP 26 inch pipeline downstream of the Thebaud Platform (SOEP Sub-sea Option).

The main differences between the new options and the 2002 proposal are: wet trees with sub-sea tie-backs versus dry trees drilled from a wellhead jacket; one installation (MOPU) versus three platforms, a new field center; a reduction of gas export capacity, and an increased produced water discharge rate. Additionally, the SOEP Sub-sea Option differs from the original proposal by using a multiphase export pipeline tied into the SOEP 26 inch pipeline at a sub-sea location downstream of the Thebaud Platform. The M&NP Option may include minor onshore route modifications and possibly a stream crossing. A comparison of the original proposal and the two proposed project options is presented in Table 1 (at the end of the document). Figure 1 (also at the end) provides an overview of the field layout for both options.

The project to be assessed will comprise undertakings differing from those originally proposed by the proponent, or those affected by information that has become available since 2002. These include:

- Construction, operation, decommissioning and abandonment of:
 - A mobile offshore production unit, including the gas processing system and associated produced water discharge;
 - The new route portion of a sub-sea gas pipeline from the platform to both the intersection of the previous pipeline route to shore and to the tie-in point with the SOEP pipeline;
 - The onshore and offshore pipeline route in the vicinity of the proposed landfall, due to new information on environmental conditions (including new contamination data, new wildlife data and the recent Keltic Petrochemicals Inc. proposal) or as a result of consultation; and
 - All well-sites, including injection wells and sub-sea wells, and associated flow lines.

- Dredging, trenching, blasting and other activities related to installation and construction of pipeline portions along new routes, including activities for the management of the dredged sediments. Any new information or methods being considered for the pipeline route assessed in 2002 should also be included.

5. Factors to be Considered

The assessment will include a consideration of the following factors as described in sub-sections 16(1) and (2) of the *Canadian Environmental Assessment Act*.

Factors to be considered in accordance with sub-section 16(1) are:

- The environmental effects of the project, including the environmental effects of malfunctions or accidents that may occur in connection with the project and any cumulative environmental effects that are likely to result from the project in combination with other projects or activities that have been or will be carried out;
- The significance of the environmental effects;
- Comments from the public that are received in accordance with the *Canadian Environmental Assessment Act* and its regulations; and
- Measures that are technically and economically feasible and that would mitigate any significant adverse environmental effects of the project.

In accordance with paragraph 16(1)(e) of the *Canadian Environmental Assessment Act*, the assessment will also include a consideration of the need for the project and alternatives to the project.

Factors to be considered in accordance with sub-section 16(2) are:

- The purpose of the project;
- Alternative means of carrying out the project that are technically and economically feasible and the environmental effects of any such alternative means;
- The need for, and the requirements of, any follow-up program in respect of the project; and
- The capacity of renewable resources that are likely to be significantly affected by the project to meet the needs of the present and those of the future.

The likelihood and significance of predicted adverse environmental effects should be considered in the context of sustainable development principles, as set forth in the *Canadian Environmental Assessment Act* and other legislation. Measures proposed for mitigating adverse environmental effects should be considered in a hierarchical sequence with a clear priority of avoidance of adverse environmental effects.

It is recognized that environmental assessment is conducted at the early phases of

project planning when alternative means of carrying out the project are under study and project details have yet to be finalized. As set out in this scope document, alternative means of carrying out the project must be considered in the environmental assessment.

It is expected that the project modifications, and alternative means of carrying them out, will reflect a consideration of sustainable development principles, incorporate the applicable best management practices and make provision for compliance with applicable legislative requirements. It is further expected that the consideration of alternative means will facilitate identification of site, configuration, design and management options for the revised project that would be preferable in terms of avoiding or minimizing adverse environmental effects.

Furthermore, the Offshore Waste Treatment Guidelines¹ complement EA needs in directing the proponent to examine and report upon the technical and economic feasibility of alternatives (e.g., produced water management options).

6. Scope of the Factors to be Considered

In accordance with section 24 of the Act, the Responsible Authorities are obliged to use the previous assessment to the extent it remains applicable, with adjustments as necessary to take into account any significant changes in the environment, in the circumstances of the project, and any significant new information relating to the environmental effects of the project.

Since the 2002 CSR was completed, there have been regulatory changes that may affect the significance thresholds for various potential effects. Key changes are designation of the Gully as a Marine Protected Area (MPA) pursuant to the *Oceans Act*, and the promulgation of the *Species at Risk Act* (SARA). The EA, in its consideration of the significance of the effects, must take these into account.

The EA must also verify commitments from the 2002 CSR and should provide any updates based on new scientific information/methods (e.g., recent studies on impacts of produced water or other discharges and monitoring results, pelagic seabird monitoring protocols, Sable Island monitoring efforts). Also, work undertaken by EnCana for other recent projects in the offshore, which would be applicable to the Deep Panuke project (e.g., bird protocol developed for the Cohasset Panuke decommissioning spill response plan) should be identified and considered in the EA.

The review will consider the potential effects of the proposed project within spatial and temporal boundaries that encompass the periods and areas during and within which the proposed project may potentially interact with, and have an effect on, components of the environment. Relevant factors in determining boundaries include such matters as ocean currents, wind conditions, and species migration patterns.

The EA should demonstrate how every reasonable effort to adopt best available technologies and best management practices is being taken. Specifically, the EA will include consideration of environmental effects related to:

¹ “Offshore Waste Treatment Guidelines”, National Energy Board, Canada-Newfoundland Offshore Petroleum Board and Canada Nova Scotia Offshore Petroleum Board, August 2002.

- **Accidental Releases:** Accidental releases during the development drilling, construction and production phases of the project must be considered. The revised well count and project life, the new multiphase export pipeline (SOEP Subsea Option), the subsea tie-in construction activity (SOEP Subsea Option), and the new subsea flowlines will change the probability of spills during the project. As a result, the spill probability assessment must be updated with these new parameters. The relocation of the field center, production wells and acid gas injection well, the presence of flowlines, and, for the SOEP Subsea Option, the multiphase pipeline to SOEP, result in new potential scenarios for marine spills and atmospheric releases which are closer to Sable Island and the workers at the SOEP sites. Marine spill probability and behaviour from new well locations, pipeline routes and inter-field flow lines should be analyzed and presented in the EA. Lessons learned from recent spill events in Atlantic Canada should also be considered in the assessment, as well as how the export of condensate (rather than its use as the primary project fuel) and the associated need to transport and store additional fuel on the MOPU affects conclusions of the 2002 spill assessment.
- **Increased Produced Water Discharge:** The approved CSR Base Case was based on produced water overboard rates of 1080 to 1560 m³/day (45 to 65 m³/hr). The proposed Project options now include a design rate of 6400 m³/day (265 m³/hr). This discharge rate must be used in a new produced water dispersion modeling study and the results used to update effects predictions. The new information must be presented in the EA. In addition to the new dispersion modeling that is to be conducted, the following should be discussed:
 - characterization of expected produced water constituents and a recognition of those sensitive environmental components which could be affected
 - consideration of potential effects of sheens from produced water and other sources on migratory birds (Reference could be made to the proposed Environmental Studies Research Fund study to examine the potential effect of sheens on seabirds); and,
 - additional monitoring that may be required based on outcomes of a revised analysis.
- **Air emissions:** Air dispersion modeling was conducted for the original design based on normal operation emissions data and the original flare design. If emission estimates and operating conditions (i.e. stack height, flow rates, temperatures) have not changed appreciably from 2002 assessment, it would be appropriate for the EA to reference this previous work and comment on the effects of the changes. If there are appreciable differences in emissions and operating conditions, new dispersion modeling must be performed and presented in the EA.

The following considerations need to be included in a revised assessment of impacts to air quality, based on relevant project modifications:

- revised emissions estimates for both options with emissions identified according to source; and
 - potential local effects and contributions to atmospheric loadings as they pertain to ambient air quality objectives in the immediate area.
- **Presence of new sub-sea infrastructures:** New sub-sea flowlines, umbilicals, sub-sea protection structures, and the export pipeline to the SOEP pipeline and associated sub-sea templates for the SOEP Sub-sea Option will result in the loss of access to fisheries resources and risk for gear damage. In particular there is a new quahog fishery that opened on the Sable Bank in 2005. The EA should assess the effects of new sub-sea infrastructure on fishing activity, including the new quahog fishery.
 - **Construction work for subsea infrastructures:** The installation of flowlines, umbilicals, subsea protection structures, pipeline to subsea tie-in, tie-in activities (SOEP Subsea Option) and new portion of the pipeline route resulting from the relocated field center (M&NP Option) will require assessment of fisheries interaction, noise, air emissions and marine discharges from construction activities, including hydrotest fluid discharge from the flowlines and pipeline. In addition, these new subsea installations will impact benthic habitat in areas that were not surveyed for the 2002 proposal. Therefore, an updated benthic report is required to serve as baseline data for the EA.
 - **Drill Waste Discharges:** The EA must update the analysis of drilling waste discharge and associated effects in light of the modified number of wells, locations, and changes in the discharge of water-based drilling fluids and associated cuttings.
 - **Near-Shore and Onshore Effects:** The EA must analyze potential interactions and effects of the pipeline (M&NP Option) with onshore contamination related to past mining activity and potential for acid rock drainage. Also, interactions related to the proposed Keltic Petrochemical and LNG facility need to be addressed. The need for additional consequence analysis should be considered, building on the onshore pipeline risk analysis work completed for the 2002 CSR. Also, consideration should be given to the outcomes of the risk assessment work conducted as part of the Keltic regulatory review process.
 - **Wildlife and Habitat:** The EA must evaluate any modification to the previously assessed onshore pipeline route, including any stream crossing, and potential interactions and cumulative effects on wetlands taking into account the *Federal Policy on Wetland Conservation* (FPWC). Potential project effects on terns and other near-shore and onshore birds, including the endangered Roseate Tern, must be considered. Reference should be made to new data available on the Country Island Common, Arctic and endangered Roseate Tern colonies, specifically in relation to foraging activity and to the draft Recovery Strategy for the Roseate Tern. The wildlife information that has been collected for the onshore pipeline route since the 2002 CSR was completed (e.g. Terrestrial Field Survey Results from 2001 and 2002), should also be considered.

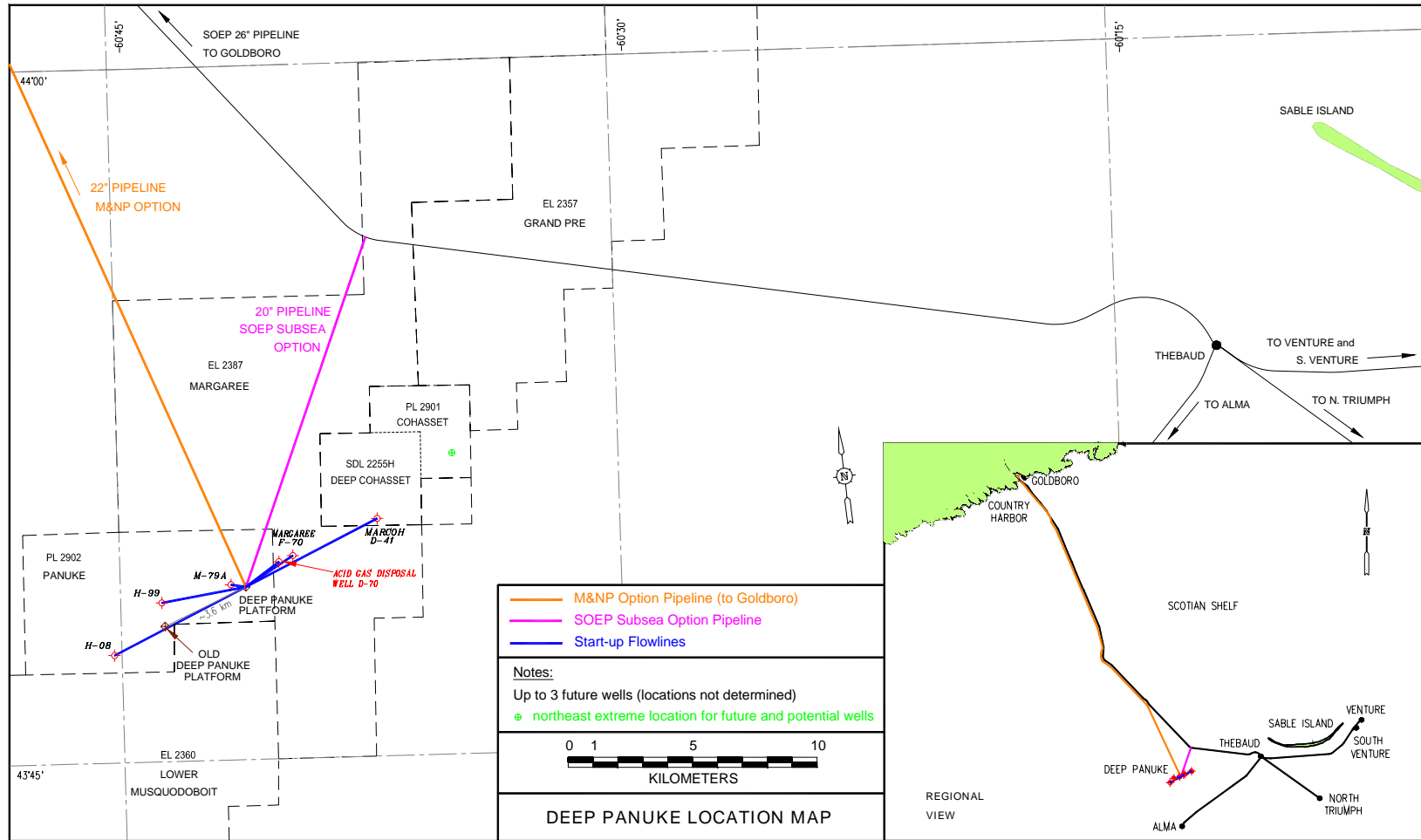
- **Impediments to Navigation:** The EA will evaluate the project's possible effects on navigation in the near-shore, with particular attention to safety.
- **Species at Risk:** Since the 2002 CSR was completed, several species in the project area have been newly listed, or re-designated under the SARA. The EA must evaluate project effects on SARA-listed species as required under section 79 of SARA. In addition to SARA-listed species, consideration of project effects on all species of conservation concern is encouraged. EC's 2004 publication "*Environmental Assessment Best Practice for Wildlife at Risk in Canada*" should be considered for guidance.
- **Cumulative Effects:** The new EA must provide a revised cumulative effects assessment based on the project modifications and changes to the environmental setting. For example, consideration of the proposed Keltic project, and cumulative effects on seabirds from ongoing oil and gas activity in the Newfoundland and Labrador offshore (particularly along the NL-NS border) will be important to the analysis.
- **Effects of the Environment on the Project:** The EA must consider how the proposed mobile production unit could be affected differently by storms/winds/waves/ice than the previously proposed fixed platforms.

Table 1.1 Comparison of Approved Base Case and New Project Options¹

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Project Item	Base Case (Approved CSR)	M&NP Option	SOEP Subsea Option
Well count and configuration	Maximum of 8 – Platform Wells <ul style="list-style-type: none"> • 5-6 new drill prod wells: H08, PI-1B, M79A, PP3C and 1-2 futures • 1-2 new drill injection wells 	Maximum of 9 – Subsea Wells <ul style="list-style-type: none"> • 4 re-entry wells: H-08 [PL 2902], M-79A [PL 2902], F-70 [EL 2387], and D-41 [SDL 2255H] • 1 new production well: H-99 [PL 2902] • 1 new injection well: D-70 [EL 2387] • up to 3 future wells [currently undefined location on PL 2901, SDL 2255H, PL 2902 or EL 2387] • Buried flowlines and umbilicals from wellheads to installation 	
Project Life	Expected mean case: 11.5 years	Expected mean case: 13.3 years Expected range: 8 – 17.5 years	
Field Center	Base Case	Relocated 3.6 km NNE	
Base Structure	3 fixed platforms including <ul style="list-style-type: none"> • production platform • utilities/quarters platform • wellhead platform 	1 MOPU integrated facility	
Discharge of muds / cuttings for new wells	drilled from field center WBM/cuttings overboard SBM/cuttings skipped and shipped or injected	drilled from individual well locations WBM/cuttings overboard no SBM	
Delivery Point	M&NP tie-in onshore, adjacent to SOEP		SOEP subsea tie-in SOEP 26” pipeline
Export pipeline	24 inch, 176 km single phase Trenched ~ 50% of route	22 inch, 176 km single phase Trenched ~ 50% of route	20 inch, 15 km multiphase Trenched 100% of route
Export gas	11300 10 ³ m ³ /day 400 MMscfd sales quality	8500 10 ³ m ³ /day 300 MMscfd [at plateau production rate] sales quality	8500 10 ³ m ³ /day 300 MMscfd [at plateau production rate] sweet and dehydrated
Export condensate	N/A		200 m ³ /day sweet and stabilized, commingled with gas
Condensate Use	Fuel, surplus injected		Sales product
Produced water	1100 to 1600 m ³ /day [7000 to 10,000 bpd] discharged overboard	6,400 m ³ /day [40,000 bpd] discharged overboard	
Acid Gas	dedicated injection well approximately 180 10 ³ m ³ /day [6 MMscfd]	dedicated injection well approximately 130 10 ³ m ³ /day [4.5 MMscfd]	

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Figure 1: Deep Panuke Field Layout¹



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