equinor

Bay du Nord Project Development Plan

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1 Development Plan Summary

1.1 Introduction

Equinor Canada Ltd. (Equinor), as operator on behalf of the project co-venturers Equinor and BP Canada Energy Group ULC (bp), is leading the development of the Bay du Nord Project (Project). The Project comprises a combination of discovered resources, where hydrocarbons have been proven, and adjacent prospects with future development potential. This application is for the planned development of the Bay du Nord and Cambriol fields, and considers the deferred developments of the Cappahayden, Harpoon, and Baccalieu fields.

The development concept is based on a Floating Production, Storage, and Offloading (FPSO) facility connected to a Subsea Production System (SPS). The FPSO will be a ship-shaped facility with a disconnectable turret, designed to process, store, and offload crude oil to shuttle tankers. Estimated recoverable resources for the initial phase are approximately 429 MBO. Peak production will be approximately 160 kbbl/sd, using Water-Alternating-Gas (WAG) and Water Injection (WI) drainage strategies over a 20-year production life. During the operational phase, an optimization/debottlenecking process will be in place to capture potential incremental capacity gain.

The Project includes activities such as offshore surveys, drilling and well operations, construction, installation, hook-up and commissioning, operations and maintenance, and the eventual decommissioning of facilities, and supported by applicable surveys, fieldwork, and supply and servicing activities.

The FPSO will be delivered and executed under a lease and operate model, with the FPSO contractor responsible for design, construction, installation, operations and maintenance, and eventual decommissioning, adhering to international specifications and standards within a Canadian regulatory framework.

The Canada-Newfoundland and Labrador Offshore Energy Regulator (C-NLOER) requires that a Development Plan be completed for offshore oil and gas development projects, pursuant to the *Canada-Newfoundland and Labrador Atlantic Accord Implementation and Offshore Renewable Energy Management Act* and *Canada-Newfoundland and Labrador Atlantic Accord Implementation and Offshore Renewable Energy Management Newfoundland and Labrador Act* (*Accord Acts*) and is intended to support a Development Application.

This Development Plan has been prepared in accordance with applicable requirements of the above referenced legislation and processes, and draws upon the *Development Plan Guideline* [1].

Purpose and Organization of the Development Plan

The preparation and submission of the Development Plan is an important step in the Development Application process for the Project. It provides the proposed approach of developing the fields, describes the selected concept, and outlines aspects such as, but not limited to, construction and installation, operations and maintenance, safety and environmental management, and decommissioning.

Based on the results of the Development Application and the associated reviews and input, the Governments of Newfoundland and Labrador (NL) and Canada will determine whether the Project can proceed, including associated terms and conditions.

The information in this chapter is subject to change during the Front-End Engineering Design (FEED) and detailed design phases.

Table 1.1 provides and outline of the Development Plan structure and an overview of the content.

Table 1.1 Development Plan Structure and Content

Chapter	Overview
Chapter 1: Development Plan Summary	An overall summary of the Development Plan
Chapter 2: Geology	A description of the geological setting and features of the Bay du Nord and Cambriol fields
Chapter 3: Petrophysics	A summary of the petrophysical data and analytical procedures for the Bay du Nord and Cambriol fields
Chapter 4: Geophysics	A description of seismic data acquisition, processing, and interpretation for the Bay du Nord and Cambriol fields
Chapter 5: Reservoir Models	A description of the static and uncertainty reservoir modelling workflow for the Bay du Nord and Cambriol fields
Chapter 6: Reservoir and Production Engineering	A description of the oil production capacity for the life of the field and a description of the reservoir data for the Bay du Nord and Cambriol fields
Chapter 7: Reservoir Exploitation	A description of the proposed reservoir exploitation scheme for the Bay du Nord and Cambriol fields
Chapter 8: Deferred Development	A description of the deferred developments associated with the Bay du Nord, Cambriol, Cappahayden, Baccalieu, and Harpoon fields, as well as other opportunities
Chapter 9: Reserves and Resource Estimates	Estimates of reserves for each hydrocarbon-bearing reservoir, and for each individual fault block and reservoir subdivision
Chapter 10: Development Drilling and Completions	An overview of past drilling activities, the proposed drilling program and typical completion designs for the development wells
Chapter 11: Design Criteria	An overview of the design philosophy for the production installation, including the regulatory, certification, and classification basis, and physical and environmental, functional, and geotechnical criteria
Chapter 12: Production Installation	A description of the production installation, including the vessel, export system, turret, topsides, safety systems, and subsea production system, and provisions for future expansion
Chapter 13: Construction, Installation and Commissioning	A description of the construction, installation and commissioning approach for the production installation
Chapter 14: Management System	A description of the management system
Chapter 15: Asset Operating Model	A description of the field asset operating model, procedures, organization, training and competency, contingency plans, logistics, and physical and environmental conditions monitoring
Chapter 16: Safety Management	A summary of safety management associated with the design and execution phases
Chapter 17: Environmental Management	A summary of environmental management, and proposed approach to protection, compliance, and effects monitoring
Chapter 18: Decommissioning and Abandonment	A description of the provisions included in the design to facilitate decommissioning and abandonment of the production installation at the end of its production life
Chapter 19: Part II	
Chapter 20: Acronyms and Abbreviations	A list of acronyms and abbreviations used throughout the Development Plan
Chapter 21: Select Terminology	A list of select terminology used throughout the Development Plan

1.1.1 Regulatory Context

The *Accord Acts*, administered by the C-NLOER, govern offshore energy activities in the region. According to the C-NLOER website, the C-NLOER's mandate is to interpret, assess, and oversee compliance with the *Accord Acts* and applicable regulations for activities in the Canada-NL offshore area. These processes are administered under various legislation, regulations, guidelines, memoranda of understanding, and other applicable frameworks.

From an oil and gas perspective, the C-NLOER's responsibilities under the *Accord Acts* include:

- The issuance and administration of petroleum, exploration, and development rights;
- Administration of regulatory requirements regulating offshore exploration, development, and production; and
- Approval of Canada-NL benefits and development plans.

The Canada-NL offshore area includes those lands within Canada's Exclusive Economic Zone (EEZ) or to the edge of the continental margin, whichever is greater. The Project is located within this area and under C-NLOER jurisdiction.

The *Accord Acts* establish the requirements that proponents of offshore petroleum development projects must fulfil in order to obtain approval of a Development Plan. The following plans and reports are required as part of the Development Application:

- Development Plan and Development Plan Summary;
- Benefits Plan and Diversity & Inclusion (D&I) Plan;
- Socio-Economic Impact Statement (SEIS); and
- Environmental Impact Statement (EIS) (managed by the Impact Assessment Agency of Canada, formerly the Canadian Environmental Assessment Agency, under the memorandum of understanding [2]).

The Bay du Nord Environmental Assessment (EA) was approved on April 2022, when the Minister of Environment and Climate Change issued the EA Decision Statement under the *Canadian Environmental Assessment Act, 2012* [3].

1.1.2 Identification and Overview of the Operator

Equinor ASA is an international energy company, headquartered in Stavanger, Norway with offices in more than 20 countries around the world. Since 1972, Equinor ASA has explored, developed, and produced oil and gas on the Norwegian Continental Shelf (NCS), where it is a leading operator. Equinor ASA produces around 2 MBO equivalent every day and is responsible for about 70% of overall Norwegian oil and gas production. The Norwegian State is a major shareholder of Equinor ASA, which is listed on the Oslo and New York Stock Exchanges. Equinor ASA strives to be an industry leader on safety and is actively shaping its portfolio to deliver high value. Equinor employs approximately 25,000 individuals worldwide and is a values-based organization where empowered people collaborate to shape the future of energy.

In 1996, Equinor established a Canadian office in St. John's, NL. The company currently holds interest rights in the Canada-NL offshore area. Equinor is the operator of three Exploration Licences (ELs) and nine Significant Discovery Licences (SDLs). It is also an interest holder in 28 other SDLs and four Production Licences (PLs) including Hibernia, Hibernia Southern Extension, and Hebron.

The principal Equinor contacts concerning the Project and its Development Application are located in the St. John's office[1], and are as follows:

- Primary Contact for Development Application: Colin Moores - Bay du Nord Safety, Sustainability and Authority Manager;
- Primary Contact for the Project: Asbjørn Haugsgjerd – Bay du Nord Project Director; and
- Primary Contact for Equinor Canada Ltd: Jim Beresford – Vice President, Canada.

1.1.3 Project Area

The Project Area is located approximately 475 km offshore NL, within the Flemish Pass Basin, and approximately 230 km from existing offshore infrastructure in the Jeanne d'Arc Basin.

The initial phase of the Project contains two discovered fields, Bay du Nord and Cambriol, and encompasses SDL 1055 and SDL 1060, as shown in Figure 1.1. These fields, as well as deferred development, are within the project area defined in the EIS [4].

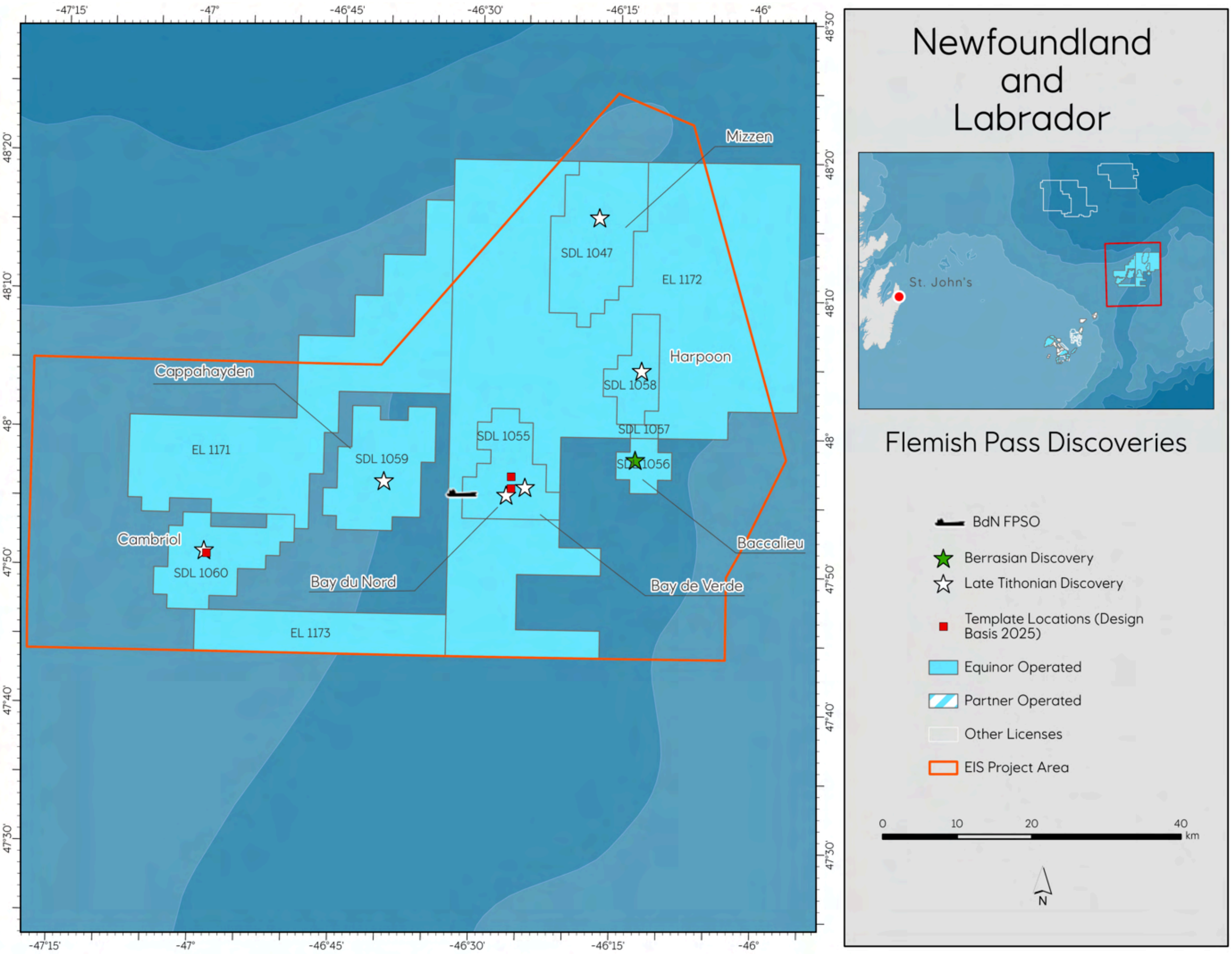


Figure 1.1 Bay du Nord Project Area

Potential future expansion of the Project may include:

- Additional development within the Bay du Nord and/or Cambriol fields;
- Development of the Cappahayden, Harpoon, and/or Baccalieu fields; and/or
- Additional opportunities identified through further studies, seismic surveys, exploratory drilling, and/or delineation drilling.

Any future expansion will depend on technical and economic feasibility. In addition, any future expansion will be required to fall within the project area defined in the EIS [4] (unless captured under another approved EA), and will comply with applicable regulatory requirements. Under current regulatory requirements, Development Plan amendment(s) would be required for such expansion(s).

Proposed locations of the FPSO and subsea templates, along with their approximate water depths, are detailed in Table 1.2 [5] and also illustrated in Figure 1.1. These locations are subject to change during the FEED and detailed design phases.

Table 1.2 Proposed FPSO and Template Locations, and Approximate Water Depths

Infrastructure	Water Depth (approximate)	Longitude	Latitude
Proposed location - FPSO	1,161 m	46° 31' 29.99" W	47° 55' 48.76" N
Proposed location - Bay du Nord North template	1,168 m	46° 26' 12.52" W	47° 57' 03.66" N
Proposed location - Bay du Nord South template	1,170 m	46° 26' 12.07" W	47° 56' 12.65" N
Proposed location - Cambriol template	621 m	46° 58' 49.73" W	47° 51' 04.81" N
Datum: NAD83 (CSRS)			

1.1.4 Project Proponents

The Project proponents have varying participating interests in the six SDLs as identified in Table 1.3. A licence unitization for the Bay du Nord and Cambriol fields will be in place prior to the Final Investment Decision (FID).

Table 1.3 Overview of Licences

Field	Licence	Ownership
Bay du Nord	SDL 1055	Equinor Canada Ltd. (65%; operator) BP Canada Energy Group ULC (35%)
Cambriol	SDL 1060	Equinor Canada Ltd. (60%; operator) BP Canada Energy Group ULC (40%)
Deferred Development - Cappahayden	SDL 1059	Equinor Canada Ltd. (60%; operator) BP Canada Energy Group ULC (40%)
Deferred Development - Harpoon	SDL 1058	Equinor Canada Ltd. (65%; operator) BP Canada Energy Group ULC (35%)
Deferred Development - Baccalieu	SDL 1056 and SDL 1057	Equinor Canada Ltd. (65%; operator) BP Canada Energy Group ULC (35%)

1.1.5 Project Need and Justification

The Project will be a major contributor to the economic development of NL as the province's fifth major offshore oilfield development project. The Project is set to deliver lasting value to NL's offshore industry, generating sustained opportunities in subsea fabrication, supply chain development, skilled labour, and long-term operations and maintenance. With a projected multi-billion-dollar spend, the Project will inject substantial capital into the province, stimulate Gross Domestic Product (GDP) growth, and generate long-term employment across sectors. The Project will activate local supply chains—from fabrication and marine services to technology and logistics—creating sustained business activity and confidence. For the business community, the Project represents not just opportunity, but economic momentum that can be felt province-wide. The SEIS [6] and Benefits Plan [7] outline the Project's contribution to a sustainable economic development within NL.

Given the known resources and the extensive remaining prospectivity as described herein (Section 1.2 Subsurface), over the life of the Project Equinor anticipates the development of one of the largest subsea infrastructure projects in its history. This activity represents opportunities to develop a local centre of excellence in subsea construction and installation and long-term economic activity for both onshore and marine industries. During the operational phase, there will be employment opportunities in areas such as logistics, engineering and technical support, drilling and production, and marine transportation and support services (e.g., helicopters, supply vessels, shuttle tankers, etc.). Opportunities during the construction and operational phases will continue to develop the capabilities of NL companies and individuals working on the Project, and thereby contribute to the provincial ambition for a globally competitive offshore industry.

Throughout its operations, the Project will contribute to energy security and supply, as well as generate substantial revenues for the Governments of Canada and NL through corporate taxes and royalty payments. Subject to regulatory approval and Equinor's achievement of the FID milestone, the Project will advance the offshore oil and gas sector in the Canada-NL offshore area into a frontier basin, marking a significant step toward a more sustainable industry.

1.1.5.1 Local Benefits

The Benefits Plan [7] outlines Equinor's approach to delivering industrial, economic, and social benefits from the Project in NL. The Benefits Plan applies to all Project phases, including development, operations, and decommissioning, and covers onshore and offshore activities. It has been prepared in accordance with Section 45 of the *Accord Acts* and the *Canada-Newfoundland and Labrador Benefits Plan Guidelines.* It reflects applicable commitments set out in the Benefits Agreement with the Government of NL related to integrated operations centre, procurement and contracting, supplier development, D&I, Research and Development (R&D), Education and Training (E&T), and reporting.

A key part of developing the Benefits Plan was early and ongoing engagement with stakeholders and NL Indigenous groups to understand their interests in the Project and to obtain input on benefits initiatives. This engagement followed a proactive approach, incorporating a combination of face-to-face meetings, group and topic-specific presentations, participation in industry events, focus group discussions, and community and site tours. Feedback from these engagements informed the development and refinement of the Benefits Plan and will continue to guide its implementation.

The Project represents a significant long-term offshore development, with an anticipated production life of approximately 20 years and the potential for future tie-back developments. It is expected to generate substantial economic activity, including billions in provincial GDP contribution, tens of millions of person hours of employment, and sustained demand for local supply and service providers [8]. The Benefits Plan is designed to ensure benefits are realized in a structured, measurable, and compliant manner.

The Project is expected to generate substantial employment across all phases. Current estimates indicate approximately 8 million direct person-hours during the development phase, including engineering, fabrication, drilling and construction activities, and approximately 23 million direct person-hours during operations over the life of the Project [8]. These activities will support a wide range of roles, including skilled trades, engineering and technical professionals, offshore operations personnel, and onshore support functions, with long-term employment sustained over 20 years. Potential future development would deliver additional benefits and may include expansion within discovered fields and/or prospectivity in the area.

A central objective of the Benefits Plan is to maximize employment and business opportunities for NL and Canadian residents and companies. The Project will provide first consideration to qualified NL residents for employment and training, and to NL-based suppliers for procurement, where they are competitive in terms of price, quality, and delivery. These requirements extend to Tier 1 contractors and subcontractors through contractual obligations, oversight, and reporting.

Procurement and local participation are key drivers of benefits delivery. The Project will apply transparent, competitive procurement processes that provide full and fair opportunity to NL and Canadian suppliers. Early engagement with industry, publication of procurement forecasts, and structured supplier development initiatives will support increased participation by local businesses. Tier 1 contractors will be required to demonstrate how they will incorporate local content, supplier engagement, and technology transfer into their execution strategies.

The Plan also emphasizes workforce development through targeted E&T initiatives. Equinor will continue to work with educational institutions, training providers, and government to align workforce capacity with Project needs. Commitments include support for apprenticeships, co-operative education, graduate programs, and customized training. A minimum participation target for apprentices in the skilled trades workforce will be pursued, alongside measures to address potential labour gaps through early planning and collaboration.

A dedicated D&I Plan establishes measures to increase participation by under-represented groups, including women, Indigenous Peoples, racialized individuals, and persons with disabilities. This includes aspirational employment targets, inclusive recruitment practices, supplier diversity initiatives, and ongoing engagement with community organizations.

The Project will also continue to invest in R&D and innovation, building on existing provincial strengths in offshore and ocean technologies. Planned investments will support collaboration with educational institutions and industry in areas such as advanced manufacturing, artificial intelligence, marine technologies, autonomous systems, and robotics.

Implementation of the Benefits Plan will be supported by a structured governance framework, with clear accountability, contractor oversight, and formal monitoring and reporting processes. Quarterly and annual reports will be submitted to the C-NLOER, ensuring transparency and compliance.

The Benefits Plan articulates Equinor's comprehensive framework for delivering sustainable, long-term benefits to NL, in alignment with regulatory requirements and the evolving opportunities associated with a complex deepwater offshore development.

1.1.5.2 Community Investment

In addition to the Project's local benefits, Equinor will continue to invest in communities across NL, with a focus on education, biodiversity, and innovation. Examples of these initiatives include STEMforGirls, the Marine Advanced Technology Education Centre, and a sponsor of the NL Folk Festival for over a decade, among many others as proposed in the Benefits Plan.

As the Project progresses, Equinor will engage with stakeholders to explore additional opportunities for community partnerships.

1.1.5.3 Socio-Economic Impact Assessment

The SEIS [6] is a component of the Development Application and satisfies the requirements under section 44(2)(c) of the *Accord Acts*. The SEIS evaluates the Project's socio-economic impacts, focusing on economy, employment, business, and community infrastructure and services. The SEIS presents a range of baseline data which have been used for the socio-economic assessment of the Project. This includes information on the capacity of the community services and infrastructure in areas that might be affected by the Project, in order to determine their ability to absorb any Project-related demands.

As with previous SEISs for offshore oil and gas projects in NL, this assessment considers distinct 'potential impact areas', which are regions within commuting distance of potential project-related activities. However, since fabrication contracts have not yet been awarded, the SEIS considers several 'potential impact areas'. It is anticipated that some of these areas may ultimately not experience any fabrication activity.

Socio-economic effects of the Project may be adverse, beneficial, or a combination of both. Managing these effects involves implementing measures to mitigate or prevent adverse impacts while enhancing positive outcomes. Potential impacts on the economy, employment, and business stem from Project-related expenditures on labour, goods, and services, as well as shifts in labour demand. These expenditures are expected to generate positive economic outcomes through direct, indirect, and induced employment and economic activity. However, increased labour demand may also contribute to labour shortages and wage inflation. Additionally, Project activities and any associated population growth could place added pressure on community and regional infrastructure and services, including water, sewer, waste management, healthcare, transportation, and emergency services.

The Project is expected to generate economic opportunities, and existing infrastructure and services within the 'potential impact areas' are anticipated to accommodate short-term increases in demand. With the implementation of the mitigation measures described in the SEIS, the Project's residual socio-economic effects are expected to be largely positive.

1.1.6 Equinor History in Offshore Newfoundland

The company has been present in the Canada-NL offshore area since 1996, when Norsk Hydro first acquired assets in the Jeanne d'Arc Basin. Norsk Hydro's Oil & Gas Division merged with Statoil in 2007, and Statoil became Equinor in 2018.

Table 1.4 summarizes wells drilled by Equinor. Key historical activities in the Canada-NL offshore area include:

- 2009: first offshore oil discovery at Mizzen (SDL 1047/1048) in the Flemish Pass Basin;
- 2011: continued geophysical and exploratory drilling programs in the Flemish Pass and Jeanne d'Arc Basins in 2011, with additional Mizzen delineation and the Fiddlehead exploratory well;
- 2012 and 2014: additional geophysical surveys;
- 2013: further exploratory drilling resulted in the Harpoon (SDL 1058) and Bay du Nord (SDL 1055) discoveries;
- 2015: continued exploratory and appraisal drilling program in the Flemish Pass Basin through a 19-month drilling program, during which a total of nine exploration and/or appraisal wells were drilled and resulted in two oil discoveries at the Bay de Verde (SDL 1055) and Baccalieu (SDL 1056/1057) prospects;
- 2017: two-well exploratory drilling program (Bonaventure O-96 and Portugal Cove E-38);
- 2020: exploratory drilling resulted in the Cambriol (SDL 1060) and Cappahayden (SDL 1059) discoveries;
- 2022: exploratory drilling program at Cambriol J-31A and continued diligent pursuit of the Sitka prospect; and
- 2024: two-well exploratory drilling program at Sitka C-02 and Cappahayden C-85.

Additionally, Equinor has executed seismic surveys, wellhead removals, seabed surveys, and geotechnical programs, among others, while also participating in various partner-operated development and exploratory drilling initiatives.

Table 1.4 Wells Drilled by Equinor in the Canada-NL Offshore Area

Delivery year	Well Name	Basin	License
2009	Mizzen O-16	Flemish Pass	EL 1049 (SDL 1047/1048)
2011	Mizzen F-09	Flemish Pass	SDL 1047
2011	Fiddlehead D-83	Jeanne d'Arc	EL 1101
2013	Harpoon O-85	Flemish Pass	EL 1112/EL 1124 (SDL 1058)
2013	Federation K-87	Jeanne d'Arc	EL 1100
2013	Bay du Nord C-78	Flemish Pass	EL 1112 (SDL 1055)
2013	Bay du Nord C-78Z	Flemish Pass	EL 1112 (SDL 1055)

Delivery year	Well Name	Basin	License
2014	Bay de Verde F-67	Flemish Pass	EL 1112 (SDL 1055)
2015	Bay de Verde F-67Z	Flemish Pass	EL 1112 (SDL 1055)
2015	Bay du Nord P-78	Flemish Pass	EL 1112 (SDL 1055)
2015	Bay du Nord L-76	Flemish Pass	EL 1112 (SDL 1055)
2015	Bay du Nord L-76Z	Flemish Pass	EL 1112 (SDL 1055)
2015	Cupids A-33	Orphan	EL 1123
2016	Bay d'Espoir B-09	Flemish Pass	EL 1112
2016	Fitzroya A-12	Flemish Pass	EL 1126
2016	Fitzroya A-12Z	Flemish Pass	EL 1126
2016	Bay de Loup M-62	Flemish Pass	EL 1112
2016	Baccalieu F-89	Flemish Pass	EL 1143 (SDL 1056/1057)
2017	Bonaventure O-96	Flemish Pass	SDL 1047
2017	Portugal Cove E-38	Flemish Pass	EL 1143
2020	Cambriol G-92	Flemish Pass	EL 1156 (SDL 1060)
2020	Cappahayden K-76	Flemish Pass	EL 1156 (SDL 1059)
2020	Cappahayden K-76Z	Flemish Pass	EL 1156 (SDL 1059)
2020	Sitka O-02	Flemish Pass	EL 1156
2022	Cambriol J-31A	Flemish Pass	EL 1156 (SDL 1060)
2022	Sitka O-02A	Flemish Pass	EL 1156
2024	Sitka C-02	Flemish Pass	EL 1156
2024	Cappahayden C-85	Flemish Pass	SDL 1059

1.1.7 Scope of the Project

The Project scope consists of the following components:

- Construction of the production installation, including, but not limited to the FPSO, turret, and SPS;
- Pre-clearance seabed surveys;
- Marine construction, installation, and hook-up and commissioning of the SPS;
- Well operations including drilling, completion, recompletion, re-entry, intervention, workover, suspension, or abandonment of a well;
- Operation of one or more drilling installations;
- Transport of FPSO to the production site;
- Installation, hook-up and commissioning of the production installation at the production site, including, but not limited to the FPSO, turret, and SPS;
- Production and maintenance operations, and modifications of the asset, including FPSO, turret, SPS, and wells;
- Supply and servicing:
  - Support craft, including offshore supply vessels, standby vessels, and helicopters;
  - Ice management vessels;
  - Crude oil shipping (including movement, hook-up / disconnect, and offloading of crude oil to shuttle tankers);
- Supporting surveys (as required):
  - Geohazard / wellsite and seabed surveys;
  - Geophysical surveys (e.g., 2D/3D/4D seismic surveys, Vertical Seismic Profiling [VSP]);
  - Geotechnical / geological surveys;
  - Environmental surveys (e.g., oceanography, meteorology, and ice/iceberg surveys; biota, water, and sediment collection, etc.);

- Remotely Operated Vehicle (ROV)/Autonomous Underwater Vehicle (AUV)/video surveys; and
- Decommissioning and abandonment.

1.1.8 Approach to Project Management

Project management is a core competency of Equinor ASA, and the Project provides an opportunity to bring this Norwegian sector experience to the Canada-NL offshore area.

Within Equinor ASA, Projects, Drilling, and Procurement (PDP) delivers all large projects. The PDP comprised of technical specialists and is responsible for safely delivering projects to the operating entity. The Project Management Team (PMT) includes several technical professionals from Equinor's St. John's, NL office. The PMT is responsible for delivering the complete development scope of the Project, including procurement, contracting, engineering, regulatory compliance, safety and environmental management, and operational readiness. Once commissioned, the Project will be handed over to the Exploration and Production International (EPI) business area based in Equinor's St. John's, NL office. Equinor will be the field operator of the Project, and will apply an integrated, "One Team" approach with contractors (e.g., drilling, subsea, FPSO).

The PMT, together with Equinor's senior management team, have established an office in St. John's, NL. Serving as the Project's primary leadership office, it encompasses a range of project management functions, including safety, environment, regulatory, procurement, commercial, technical management, drilling and well, subsurface, operations, and emergency preparedness.

The Capital Value Process (CVP; Figure 1.2) is Equinor ASA's Decision Gate (DG) process for investment projects. The objective of the CVP is to secure predictable and competitive investment projects all the way from the first assessment of a new business opportunity to the start-up of profitable operations.

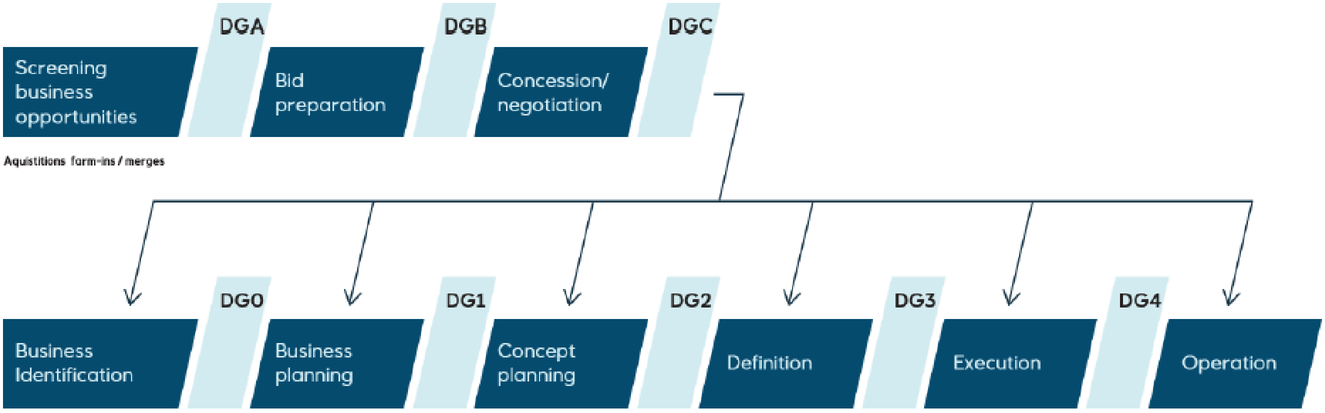


Figure 1.2 Capital Value Process

Business Identification

The objective of the business identification phase is to validate and document business ideas and provide sufficient basis to decide whether the business idea represents a technically and commercially viable business case. **DG0** is an approval to establish an investment project and to enter the business planning phase.

Business Planning

The objective of the business planning phase is to establish a shortlist of viable development concepts and to prepare the basis for the concept phase, including the concept selection criteria. **DG1** is an approval to start to mature the investment project in the concept development phase.

Concept Development

The objective of the concept development phase is to mature the shortlist of viable development concepts, select preferred concept based on the pre-defined selection criteria and to mature the selected concept towards a FEED. **DG2** is an approval to start FEED and prepare the investment project for the FID.

Definition

The objective of the definition phase is to develop the investment project to the required maturity level for an FID. **DG3** represents the sanction of the investment project and is an approval to start the execution phase.

Execution

The objective of the execution phase is to realize the investment project by performing detailed design, construction, commissioning, and preparation for operations. **DG4** is the start of operations and is passed when hand-over is accepted by the receiving business area.

Review Process

The review process at each DG ensures that decision-makers understand expectations for the end-result, that the risk exposure is adequately identified and mitigated, and that the safety, technical and commercial maturity meets our requirements.

1.1.9 Concept Selection

1.1.9.1 Screening Criteria

Alternative means of carrying out the Project that are both technically and economically feasible, along with their potential environmental effects, were evaluated. A range of globally recognized development concepts were considered as potential options for the Project, including:

1. FPSO;
2. Gravity Based Structure (GBS);
3. Tension-Leg Platform (TLP);
4. Semi-submersible platform;
5. Spar platform with storage; and
6. Spar platform without storage.

In selecting a development concept suitable for oil and gas activities in the Flemish Pass Basin, each option was assessed against a set of key criteria, including:

- Safety;
- Environmental effects;
- Suitability for water depths up to approximately 1,200 m;
- Distance from shore (approximately 475 km);
- Minimum distance from existing offshore facilities (approximately 230 km);
- Capacity for crude storage and offshore offloading to shuttle tankers;
- Ability to disconnect; and
- Ice protection capabilities.

These concepts were evaluated and screened during the DG0–DG1 CVP. Further details on the alternatives considered are provided in Section 1.1.9.2 Evaluation of Alternatives. Additional information, including environmental effects, can be found in the EIS [4].

1.1.9.2 Evaluation of Alternatives

FPSO

FPSOs may process, store and offload crude oil from a single installation. Stand-alone drilling installation(s) would be required to drill the development wells. FPSOs are commonly used offshore installations either in shallow or deepwater locations, and therefore are suitable for the water depths in the Project Area. While the FPSO would be moored in place, it would have the ability to disconnect and transit as a marine vessel in the event of a potential iceberg/sea ice encroachment, an extreme weather event, or if required for other purposes such as shore-based maintenance. The hull of the FPSO would be ice-strengthened to protect against ice. Stored crude oil may be offloaded to shuttle tankers. FPSOs have operated in the Canada-NL offshore area since 2002. Decommissioning costs associated with an FPSO tend to be lower than other options as the FPSO may be easily moved off location. Decommissioned FPSOs could also be used in other locations or re-purposed for other marine use. Overall, an FPSO is technically and economically favourable compared to other options.

GBS

A GBS is typically a concrete structure which has direct contact with the seabed and is fixed in location. GBS installations are suitable for shallower locations (e.g. the Hebron GBS installation in the Jeanne d'Arc Basin, with a water depth of approximately 93 m). Drilling and production activities may occur from a GBS installation. A GBS is typically unsuitable for deeper waters, such as those present in the Project Area. For instance, the Troll A platform, located off the west coast of Norway, has a GBS substructure of 376 m. This GBS is the tallest concrete GBS platform in the world and is also considered one of the tallest structures moved by humans. With a water depth of approximately 600 m to 1,200 m, it is not technically feasible to use a concrete GBS for the Project.

TLP

TLPs are suitable for deepwater locations ranging from 300 m to 1,500 m, and therefore could be suitable for the deeper waters in the Project Area. TLPs have four buoyant pontoon-like pillars that support the topsides and are vertically moored to a foundation installed on the seabed. However, they do not have the ability to disconnect and relocate in the event of a potential iceberg/sea ice encroachment or an extreme weather event. This type of installation is particularly suitable for hurricane-prone areas, such as the Gulf of Mexico, due to limited vertical movement. TLPs do not have on-board storage, and crude is typically transported via pipelines to other offshore installations or shore-based facilities. There would likely be a substantial amount of subsea infrastructure and associated protection measures required to transfer crude from the Project Area to shore (approximately 475 km) or to an existing production installation (approximately 230 km). TLPs are not technically or economically feasible as an option for the Project.

Semi-Submersible Platform

Semi-submersible platforms are suitable for deepwater locations ranging from 300 m to 3,000 m, and therefore could be suitable for the deeper waters in the Project Area. Semi-submersible platforms have buoyant pontoons and are moored to the seabed. However, they do not have the ability to disconnect and relocate in the event of a potential iceberg/sea ice encroachment or an extreme weather event. Semi-submersible platforms do not have on-board storage, and crude is typically transported via pipelines to other offshore installations or shore-based facilities. There would likely be a substantial amount of subsea infrastructure and associated protection measures required to transfer crude from the Project Area to shore (approximately 475 km) or to an existing production installation (approximately 230 km). Semi-submersible platforms are not technically or economically feasible as an option for the Project.

Spar Platform with Storage

Spar platforms are suitable for deepwater locations ranging from 300 m to 3,000 m, and therefore could be appropriate for the deeper waters in the Project Area. Spar platforms have a hollow cylindrical hull that is typically submerged into approximately 200 m of water. Spar platforms are similar to TLPs, but they have more conventional mooring systems. Spar platforms may move horizontally by adjusting the tension of mooring lines. However, horizontal movement is limited, and therefore do not have adequate capability to relocate in the event of a potential iceberg/sea ice encroachment or an extreme weather event. This type of installation is ideal for hurricane-prone areas, such as the Gulf of Mexico, due to increased stability. Unlike semi-submersibles and TLPs, spar platforms can be designed to store crude. The hull is a hard tank that provides buoyancy and variable ballast control, the middle tank may be used for crude storage, and an additional tank may be used for ballast control. Spar platforms with storage typically use an oil-water displacement method for crude storage, which is an open system and has the potential to discharge oily water residue to the marine environment. Since a spar platform with storage is not readily mobile, it would need to be designed to withstand iceberg impacts. A spar designed and constructed to withstand iceberg impacts is not an economically feasible option for the Project.

Spar Platform without Storage

A spar platform without crude storage is similar to a spar platform with storage. Since there is no crude storage capability, and as discussed for the TLP and semi-submersible platform options, crude oil would have to be transported via pipelines to other offshore installation or shore-based facilities. Spar platforms without storage are not technically or economically feasible as an option for the Project.

1.1.9.3 Preferred Concept

The alternative means analysis was based on the criteria outlined in Section 1.1.9.1 Screening Criteria. Table 1.5 provides a summary of the technical and economic feasibility of each option.

Table 1.5 Summary of the Analysis of Alternative Means for Selecting the Production Installation Concept

Alternative Considered	Technical Feasibility	Economic Feasibility
FPSO	√	√
GBS	X	X
TLP	X	X
Semi-submersible	X	X
Spar with storage	X	X
Spar without storage	X	X

Based on the established criteria, as well as assessments and studies completed within the DG1 phase, it was determined that the Project concept would be based on a ship-shaped FPSO with a disconnectable turret, production from an SPS, and offtake to shuttle tankers (Figure 1.3). Section 1.4 Design Criteria and Production Installation provides an overview of the selected concept.

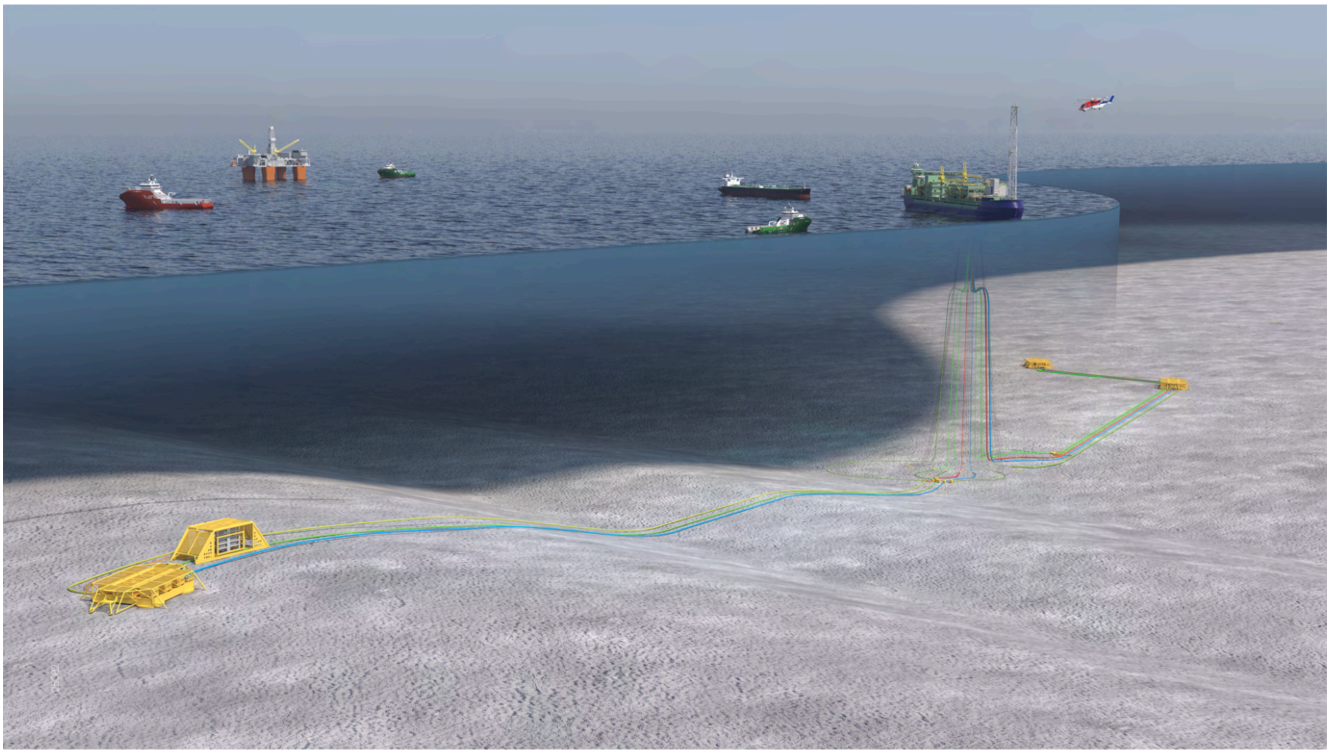


Figure 1.3 Bay du Nord Project Concept

1.1.10 Preliminary Project Schedule

Figure 1.4 illustrates the current Project schedule, subject to change based on regulatory approvals, as well as the FEED, detailed design, and execution planning phases.

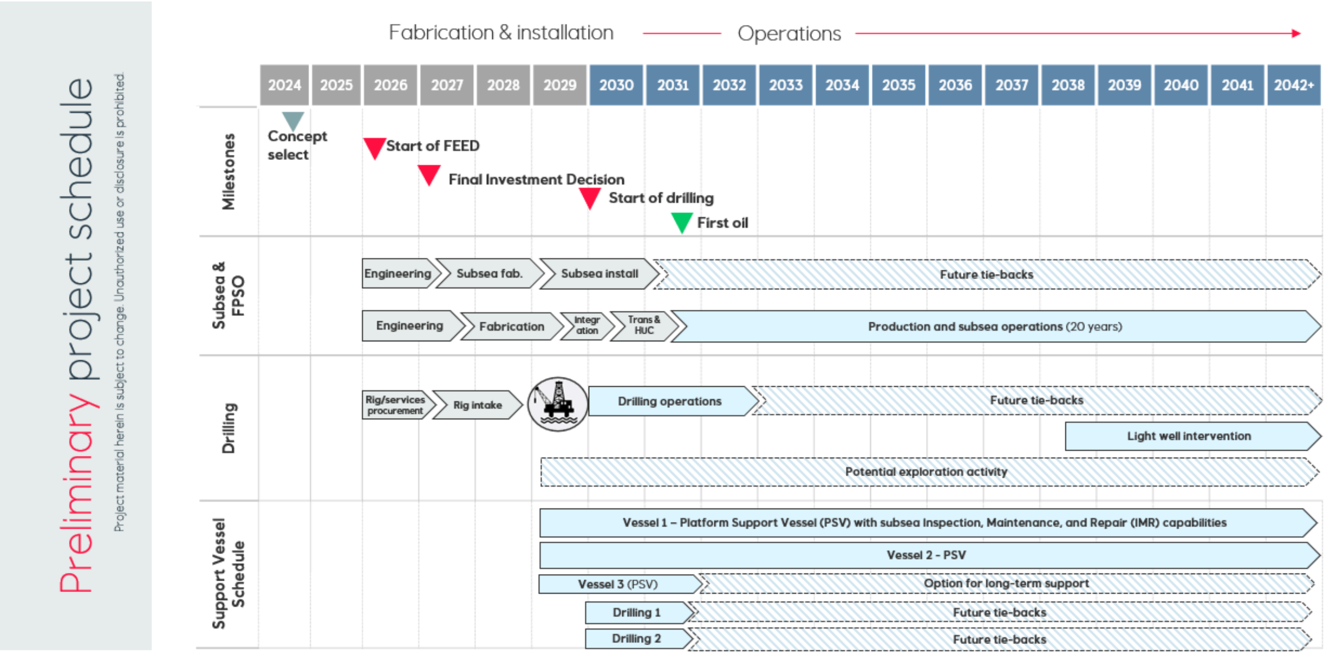


Figure 1.4 Preliminary Project Schedule

1.2 Subsurface

The Project is a combination of discovered resources, where hydrocarbons have been proven, and prospects, where there is the potential for hydrocarbons. This application is for the planned development of the Bay du Nord and Cambriol fields, and considers the deferred developments of the Cappahayden, Harpoon, and Baccalieu fields, as described in Section 1.1.3 Project Area.

The fields are penetrated by multiple exploratory and delineation wells, and contain commercial hydrocarbons in a combination of Tithonian and Cretaceous reservoirs. The Project's understanding of Flemish Pass stratigraphy and reservoir presence has evolved with each exploratory drilling program undertaken in the basin, and is described in detail in Section 2.2.1 Stratigraphy. The main reservoirs for the Project are the Late Tithonian Mizzen and Bay du Nord members. The architecture of these reservoirs, in relation to the greater stratigraphy, previous nomenclature, and regional seismic markers, is depicted in Figure 2.3. Schematic cross-sections depicting the main structural elements and lithostratigraphic members for each field are shown in Figure 1.5. Given that the Project spans several fields, and contains both vertically and laterally stacked reservoirs, there are multiple hydrocarbon columns within the Project Area. To date, only one Oil-Water-Contact (OWC) has been encountered, which is in the Bonaventure member in the Cappahayden Field. The remaining accumulations are oil-down-to scenarios.

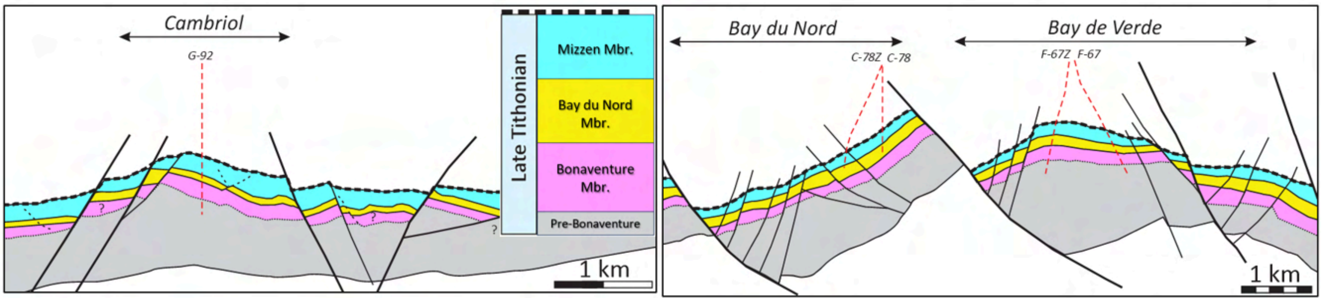


Figure 1.5 Field Descriptions Cross-sections illustrating the main structural elements and lithostratigraphic members comprising the Bay du Nord and Cambriol fields

The Bay du Nord Field has expected recoverable resources of 237 MBO, which corresponds to 55% of the total Project volumes. The field is delineated by six exploratory wells, Bay du Nord C-78, Bay du Nord C-78Z, Bay du Nord L-76, Bay du Nord L-76Z, Bay de Verde F-67, and Bay de Verde F-67Z. The Bay du Nord member is the primary reservoir target within the drainage strategy, as it contains the bulk of the oil-in-place and provides high-confidence reservoir targets and production potential to support a development decision. The Mizzen member is a secondary reservoir target. It features thinner, and unevenly distributed sands which are harder to define seismically compared to the Bay du Nord member. These factors make the Mizzen member a harder development target to incorporate into the drainage strategy. The single reservoir target within the Mizzen member in NC block has been included in commingled fashion in the initial field development along with a data acquisition strategy to allow for further development over the life of the Project. The Bonaventure member is a hydrocarbon-bearing reservoir but is not included in the drainage strategy due to the small resource potential. The field is split into two areas, the Bay du Nord area and Bay de Verde area as illustrated in Figure 7.1.

The Cambriol Field has expected recoverable resources of 192 MBO, which corresponds to 45% of the total Project volumes. The field has a single exploratory well, Cambriol G-92, and a single hydrocarbon-bearing reservoir, the Mizzen member. The field is separated into six regions (A to F). The development plan considers the discovery region, D, as well as the undrilled regions of B, C and F (Figure 7.7).

The Project has an expected recoverable resource of 429 MBO after 20 years of production. Section 7.6 Drilling Schedule and Production Forecasts presents production and injection profiles for Base, High and Low cases. Section 9.3 Recoverable Resource Estimates provides the mean oil production for the Project, and by field, as well as the P90 and P10 oil production total for the Project. Project and field specific recovery volumes may vary as subsurface evaluations and field development activities progress. The volumes and profiles presented may differ slightly from those in other documents due to variations in timing of the assessments.

Detailed subsurface descriptions for each field are located in Section 2 Geology, Section 3 Petrophysics, Section 4 Geophysics, and Section 6 Reservoir and Production Engineering. Integration of the subsurface data into detailed models for each field is described in Section 5 Reservoir Models.

The reservoir exploitation strategy is located in Section 7 Reservoir Exploitation, deferred development in Section 8 Deferred Developments, and the resource estimates are located in Section 9 Reserves and Resource Estimates.

A high-level summary of the fields within the Project are outlined in Table 1.6.

Table 1.6 Project Field Overview

Field	Exploratory and Appraisal Wells	Development Reservoirs	Estimated Recovery (e^6m^3)	Estimated Recovery (MBO)
Bay du Nord	6	Mizzen Bay du Nord	37.7	237
Cambriol	1	Mizzen	30.5	192
Project	-	-	**68.2**	**429**

1.3 Development Drilling and Completions

The Project will drill wells using one or more drilling installation, and some wells may be drilled before the FPSO arrives at the operations site. The objective of the wells will be to produce oil or to support oil production by WI or WAG.

Drilling and completion operations are planned to be conducted from subsea templates installed on the seabed. The drilling process includes measures to reduce the impact of potential drilling hazards such as hard seabed, shallow gas pockets, and/or unstable rock. Drilling fluids and equipment will be used to keep the wells stable and prevent unintended discharge. Each well will have multiple safety barriers to prevent uncontrolled flow, such as, but not limited to, the use of a Blowout Preventer (BOP).

Once drilled, wells will be completed with equipment that allows produced oil to flow to the FPSO, or equipment that enables water or WAG to be injected into the reservoir to help maintain and improve recovery.

Wells will be designed to minimize the need for maintenance or repairs. If needed, drilling installations or intervention-capable vessels will be used to perform the work.

1.4 Design Criteria and Production Installation

Design Criteria

The production installation, including the FPSO, turret and mooring system, and SPS, will be designed according to applicable regulatory requirements, international standards and codes, and when required, Equinor and/or contractor requirements. In addition, the FPSO will be designed to applicable Class notations.

The Project's design will consider the physical and environmental conditions of the Flemish Pass Area, and data collected from geotechnical investigations.

Refer to Table 11.15 for an overview of the current design basis [5] for the Project, which is subject to change during FEED and detailed design phases.

Hull

The FPSO hull will be designed to operate in harsh offshore conditions. It will be designed for continuous operation at the production site without dry docking, subject to relevant regulatory approvals, and it includes the ability to disconnect if necessary. Marine systems will be integrated within the hull, and will support essential functions such as, but not limited to, propulsion, power distribution, cooling, and sewage treatment.

The accommodations area will be located at the rear of the vessel, away from the oil processing areas, and designed to support both daily operation and for typical hook-up and commissioning, maintenance, and turnaround work scopes. However, if activities require higher, sustained peak Personnel on Board (POB) levels, a temporary accommodations installation(s) may be considered. The helicopter deck will be positioned to ensure safe landings and takeoffs, with minimal movement from wind and waves, and will include a nearby control centre and a designated area for unserviceable helicopters.

Seawater will have a vital role in FPSO operations, serving multiple purposes including, firefighting, cooling, water injection into the reservoir, and generation of fresh water. Firewater pumps will be strategically located in the hull, away from processing areas.

To support safe and efficient handling of heavy equipment, the FPSO will includes crane, elevators, and transport routes designed to reduce manual lifting. Equipment can be moved horizontally and vertically using forklifts, trolleys, and monorails, with designated laydown areas accessible by crane.

The FPSO will also feature around 18 cargo oil tanks, one off-spec tank and two slop tanks, with a total storage capacity of approximately 1.2 MBO. Oil will be pumped through a metering system and transferred to shuttle tankers via a specialized offloading system.

Turret and Mooring System

The Submerged Turret Production (STP) system will enable:

- Position keeping and weather-vanning;
- Transfer of fluids, power, and signals; and
- Disconnection/reconnection.

The mooring system will provide position keeping to keep the FPSO stable and secure in open sea conditions. It will consist of 15 lines arranged in clusters, each connected to the seabed and the FPSO through a combination of chains, ropes, and buoyancy elements. The system will be equipped with a mooring line monitoring system.

Topsides Production and Utility Systems

The topsides production and utility systems are where the main oil and gas processing will take place. Oil, gas, and water from the subsea wells will be brought up through the turret and separated on the topsides. The oil will be treated, stabilized, and stored, while the gas will either be reused in the process or reinjected into the reservoir. Produced water will be treated and discharged in accordance with C-NLOER guidelines. Treated seawater may be injected to help maintain pressure in the reservoir.

The topsides will be built in modules and mounted above the hull. The systems will include oil separation, gas compression, water treatment, power generation, and safety systems. It will be designed to operate efficiently and reliably, with built-in flexibility to adapt to future needs.

A flare tower will be provided to ensure the safe release of hydrocarbons, as required. There will be no routine flaring from the production process. Some low-pressure sources will be routed upstream of the Volatile Organic Compounds (VOC) compressor together with gas from the cargo tanks. Gas from the VOC compressor will be routed to the closed flare system for recovery together with flare gas during normal operations.

Chemicals that may be discharged overboard will be screened in accordance with Equinor's chemical screening and management processes and in consideration of C-NLOER guidelines.

A central control system will monitor all topsides operations, including safety systems for fire, gas, and emergency shutdowns.

Power will be generated using Gas Turbine Generators (GTGs) with backup diesel generators.

All fluids (i.e., oil, gas, water) will be measured in consideration of C-NLOER guidelines.

Additional systems will be required for cooling, fuel storage, air and nitrogen supply, heating, drainage, and waste management.

Subsea Production System

The SPS is a network of equipment on the seafloor that connects the reservoirs to the FPSO. It will include wellheads, umbilicals, flowlines, risers, and control systems that allow oil and gas to be extracted and processed. The system will also support the injection of water, gas, and chemicals to help maintain reservoir pressure and flow.

The SPS will utilize several subsea structures called templates and manifolds, which control the flow from multiple wells. These will be connected to the FPSO by flexible and rigid flowlines and risers. The system will be designed for deepwater conditions and includes features that allow for remote operation, inspection, and maintenance using underwater vehicles. The system will include advanced monitoring and control technologies, including sensors, valves, and communication lines. Some components, like the subsea coolers and flow control modules, will be designed to be retrieved and serviced if needed. A subsea cooler will be used to reduce the temperature of fluids from the Cambriol Field before they reach the FPSO.

Power and communication will be delivered through specialized cables and umbilicals, and technical solutions will be implemented for detection of subsea leakages.

1.5 Construction, Installation, and Commissioning

FPSO, Subsea and Marine Operations

The Project will begin with the construction, installation, and commissioning of an FPSO facility, which includes an ice-strengthened hull, topsides processing modules, and a disconnectable turret. These components will be constructed, installed, and commissioned at an international yard prior to transit to the operations site in the Canada-NL offshore area.

Before offshore installation begins, pre-clearance surveys will be conducted. This will be followed by the installation of subsea infrastructure, including templates, manifolds, riser bases, flowlines, umbilicals, and mooring systems. These components will be laid on the seafloor; protection measures may include rock installation, concrete mattresses, and/or trenching, where applicable.

The FPSO will then transit to the operations site. Upon arrival, offshore installation, hook-up, and commissioning will take place. This includes connecting the riser buoy, connecting the turret and mooring system, and commissioning subsea systems and wells. If activities require higher, sustained peak POB levels, a temporary accommodations installation(s) may be considered.

Drilling Services

Wells will be drilled and completed using one or more drilling installation suitable for year-round operations in deepwater. These installations will primarily use Dynamic Positioning (DP) to stay on location, with the option to use anchors if needed. To support drilling operations, a wide range of goods and services will be required. These include drilling installation, technical services, logistics support services, among others.

Environmental Considerations

The EIS [4] addressed the environmental effects of all Project activities in marine waters, including offshore construction, installation, hook-up and commissioning, drilling, and operations, among others. Mitigations identified in the EIS and EA conditions [3] will be implemented during construction, installation and commissioning, as applicable. An Environmental Protection Plan (EPP) will be submitted with the Operations Authorization (OA) application.

1.6 Management System

Equinor ASA has a structured management system (EMS) to ensure its operations are safe, reliable, and compliant with regulations, while also being efficient and aligned with the company's values. This system is designed to work across different countries, industries, and business models.

The EMS is built on three main levels:

1. The Equinor Book: Outlines who Equinor ASA is and how it operates, including values, leadership, and performance expectations;
2. Directives: Mandatory requirements and policies that guide risk management and corporate governance; and
3. Governing Documents and Work Processes: Provide detailed procedures and standards for both global and local operations.

The proposed approach to the Project's management system is as follows, and illustrated in Figure 1.6, the Equinor Book and Directives will set the foundation; applicable and appropriate global governing documents and work processes will be incorporated; work closely with contractors to incorporate and bridge management systems; local governing documents and work processes will be developed to reflect specific risks, conditions, operating model, and regulatory requirements; and comply with the applicable regulatory requirements.

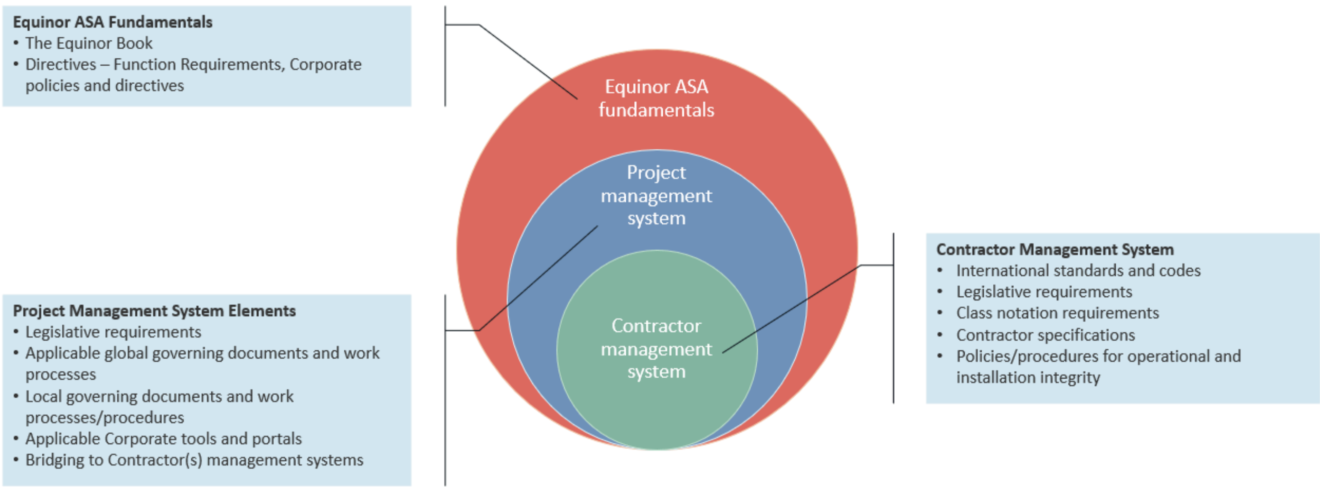


Figure 1.6 Proposed Project Management System Structure

The Project will use applicable tools and systems from Equinor ASA to build a fit for purpose management system for the Project. The Project will conduct assurance activities to ensure compliance with the management system and drive continuous improvement.

1.7 Asset Operating Model

Operating Philosophy

The Asset, which includes the FPSO, SPS, and wells, will be operated in alignment with a structured safety and environmental management approach (Section 1.8 Safety, Security, and Environmental Management). Operations will utilize the proposed management system strategy described in Section 1.6 Management System and will draw on the extensive experience of Equinor, its partners, and contractors. All phases, from design to decommissioning, will comply with applicable regulatory requirements.

The main objectives of the Asset Operating Model (AOM) are as follows:

- Always safe - vision is zero harm for people, the environment and our assets;
- Reliability, availability, and maintainability of equipment and systems; and
- Collaborative optimization and continuous improvement in operations.

The FPSO will be delivered under a lease and operate model, with the contractor responsible for its full lifecycle, including design, construction, operation, and eventual removal. Equinor will be responsible for the subsea systems and wells and will serve as the field operator throughout.

Staffing

Equinor and contractors will establish both onshore and offshore teams to support safe and efficient operations. The offshore organization will follow a traditional staffing model, with approximately +/- 80 personnel during regular operations and capacity for up to 120 personnel to support activities such as installation, commissioning, maintenance, and turnarounds. Offshore staffing will be optimized through cross-training, reliability-centred maintenance, and remote monitoring from onshore.

Onshore operations support staffing levels are expected to range between 50 and 100 people. The onshore team will be tailored to the operating model and will maintain sufficient local capacity to meet emergency response requirements and regulatory obligations.

The Equinor Drilling & Well Operations Team may include up to 15 people; with organization structures adjusted as the Project evolves. Offshore staffing will depend on the drilling installation but is expected to range between 120 and 160 POB, with contractor selection occurring in later phases.

Crew rotations for the FPSO and drilling installations will likely follow the standard schedule in Canada-NL offshore area, typically three weeks on and three weeks off. Shorter seasonal campaigns may adopt alternate rotation schedules, subject to approval by relevant authorities.

Training and Competency

Equinor will ensure all Equinor personnel are properly trained and competent through a structured Training and Competence Management Plan. This plan will align with applicable regulatory, industry, and internal standards, and will include role-specific requirements, training tracking, and regular assessments. Contractor training will be reviewed during selection and verified throughout operations. All required offshore and onshore training will be documented and verified to maintain a safe and capable workforce.

Integrated Operations

Equinor will operate the Asset using an Integrated Operations (IO) model, aiming for seamless coordination between offshore and onshore teams. The Integrated Operations Centre (IOC) in the St. John's, NL area will have representation from both Equinor and the FPSO contractor teams, enabling collaborative planning and support across functions such as, but not limited to, production, maintenance, safety and environment, logistics, and engineering. The IOC will provide operational support, field monitoring, and scalable assistance across all functions. It will also serve as the incident command post and a hub for regulatory engagement, digital systems, and technical integrity oversight. Global support networks will be leveraged as needed to enhance performance and drive continuous improvement.

Operations Manual

Equinor will develop an Operations Manual in accordance with applicable regulatory requirements and industry best practices. The manual will be reviewed and accepted by the Certifying Authority (CA).

Automation and Control

Asset operations will be managed through the FPSO's Integrated Control and Safety System (ICSS), operated from the offshore Central Control Room (CCR). Direct control from onshore is not contemplated, however, remote monitoring and testing of systems will be available from the IOC. Advanced tools and simulations will enhance efficiency and reliability across the Asset lifecycle.

Reliability and Maintenance

The FPSO contractor will manage maintenance and integrity of the FPSO throughout all phases of operation, using tailored strategies and digital systems to ensure reliability and efficiency. Maintenance will be planned and executed based on equipment condition and performance, supported by a scalable Computerized Maintenance Management System (CMMS). Long-term planning will align with the FPSO's lifecycle, including periodic planned turnarounds. Spare parts and tooling will be managed to support uptime and operational continuity.

Equinor will lead the engineering, planning, and execution of subsea maintenance through an Inspection, Maintenance, and Repair (IMR) program. Subsea systems will be designed for reliability and ease of recovery using ROVs. Maintenance will be planned around seasonal campaigns, with contingency options available year-round. A dedicated IMR vessel may be used to support multiple offshore functions. Spare parts and tooling will be available, and technical integrity will be monitored to guide maintenance decisions.

Equinor will implement an Asset Integrity Management (AIM) program to ensure the safety and reliability of all systems throughout the Asset's lifecycle. The program will follow applicable regulatory requirements and use risk-based assessments, standardized processes, and digital tools to monitor and maintain integrity. Equinor and the FPSO contractor will manage integrated AIM plans for their respective areas. Continuous monitoring and periodic assessments will drive performance and ensure compliance of the AIM program.

Logistics

Equinor will implement a logistics strategy to support offshore operations, leveraging existing infrastructure and collaborating with other operators in the region, when feasible. Logistics will include marine vessels and helicopters, with operations fully compliant with regulatory requirements. Digital tools will be used for tracking and coordination, and logistics will integrate ice management, weather forecasting, and emergency response. The Logistics Team will manage personnel movements, cargo transport, and shore base activities, enabling efficient support across drilling, production, and subsea operations. Close coordination with FPSO and drilling contractors will optimize schedules and resource use.

Equinor will use a fleet of marine vessels to support offshore operations. These vessels may handle cargo, fuel, personnel transfers, and emergency response, with capabilities tailored to harsh offshore conditions. Logistics will be coordinated to ensure efficient and reliable marine support throughout the Asset's lifecycle.

Equinor will likely use twin-engine helicopters for offshore transport and Search and Rescue (SAR). All flights will meet strict regulatory and safety standards. In addition to the traditional FROG transfer device used in the Canada-NL offshore area, the Project is evaluating a Walk-to-Work (W2W) solution to be installed on one of the supply vessels for mobilization and demobilization of personnel for high offshore activity, routine passenger transfers, and demobilization, as required, and a decision will be made during the next phase of the Project.

Process Design Characteristics

The process characteristics in the operation phase will be aligned with the parameters and specifications described in Section 1.4 Design Criteria and Production Installation.

Ice Management

The FPSO will be ice-strengthened and designed to disconnect. Equinor and its contractors will implement an Ice Management System to monitor, assess, and respond to sea ice and icebergs. This system may include surveillance, physical iceberg deflection, and coordinated response procedures. The Ice Management Plan will build on extensive offshore experience and use proven techniques and technologies. The plan will evolve with new innovations and be tailored to the specific needs of each offshore activity.

Physical and Environmental Condition Monitoring

Equinor and its contractors will establish a monitoring program to track weather, ocean, and ice conditions. Observational data will be shared with federal agencies to enhance national forecasting and situational awareness. A forecasting program will also be developed.

Disconnection

The FPSO disconnection system is designed to safely disconnect the vessel from the STP buoy and moorings. There are two modes of disconnection that the FPSO is designed for: planned and emergency. Table 15.4 outlines the preliminary measures to be implemented in preparation of a disconnection.

Contingency Planning

Equinor's emergency management approach will focus on prevention, with clear plans in place to protect people, the environment, and assets if an incident occurs. A suite of contingency plans, covering scenarios such as oil spills, well control, ice management, and vessel collisions, will be developed.

Equinor will also develop an Emergency Response Plan that will outline clear roles, procedures, and communication protocols across tactical, operational, and strategic response levels. Emergency preparedness will be supported by training, performance standards, and coordination between Equinor, contractors, and authorities.

1.8 Safety, Security, and Environmental Management

Equinor is committed to a "zero harm" vision for the Project. Safety, security, risk management, and environment are fully integrated into the EMS, guiding all Project phases. Risks will be assessed and managed to protect people, the environment, and assets.

A Concept Safety Analysis (CSA) [9] was completed for the Project to assess potential risks during all phases of development. The analysis focuses on major safety and environmental hazards related to key offshore systems, such as the FPSO, SPS, offloading facilities, and personnel transport to the FPSO, and helps guide safe Project design and operations.

The Project underwent a federal EA that was led by the Impact Assessment Agency of Canada in collaboration with the C-NLOER. It included engagement with Indigenous groups, stakeholders, and the public. In April 2022, the Minister of Environment and Climate Change concluded that the Project is not likely to cause significant adverse environmental effects, provided over 150 conditions are met. These mitigations and conditions will be integrated into the design and operations of the Project.

The Project will develop and implement activity-specific follow-up and Environmental Effects Monitoring (EEM) programs, and wildlife observational programs. These programs will be designed with flexibility in mind - they will incorporate adaptive management principles, allowing monitoring parameters to be adjusted or phased out over time based on results and evolving conditions. Equinor will adhere to applicable financial security regulatory requirements, and will develop a Compensation Plan.

A Project Safety Plan and EPP will be developed in accordance with the applicable regulatory requirements and in consideration of C-NLOER guidance. A Security Plan, including cybersecurity, will also be developed for the FPSO.

1.9 Decommissioning and Abandonment

At the end of field life, the Project will be decommissioned in accordance with applicable regulatory requirements at the time of decommissioning. A Decommissioning and Abandonment Plan will be developed and updated, as necessary, throughout the life of the Project. It is anticipated that decommissioning will be carried out over multiple seasons and may require resources such as drilling installations(s), Riserless Light Well Intervention (RLWI) vessel (s), construction vessels, heavy lift vessels, among others.

2 Geology

2.1 Database and Methods

A detailed and integrated geological study of the Bay du Nord and Cambriol fields was evaluated for reservoir characterization (Section 2.3 Bay du Nord Field and Section 2.4 Cambriol Field). The integrated evaluation considers regional and field-scale data and interpretations from the Flemish Pass Basin, consisting of core descriptions, biostratigraphic, petrological, and petrophysical data, following [10]. Depositional analogues are also used to guide the reservoir characterization for each field (Figure 2.1). All datatypes were used to construct a sequence stratigraphic model for Tithonian to Berriasian stratigraphy, which help develop depositional environment maps.

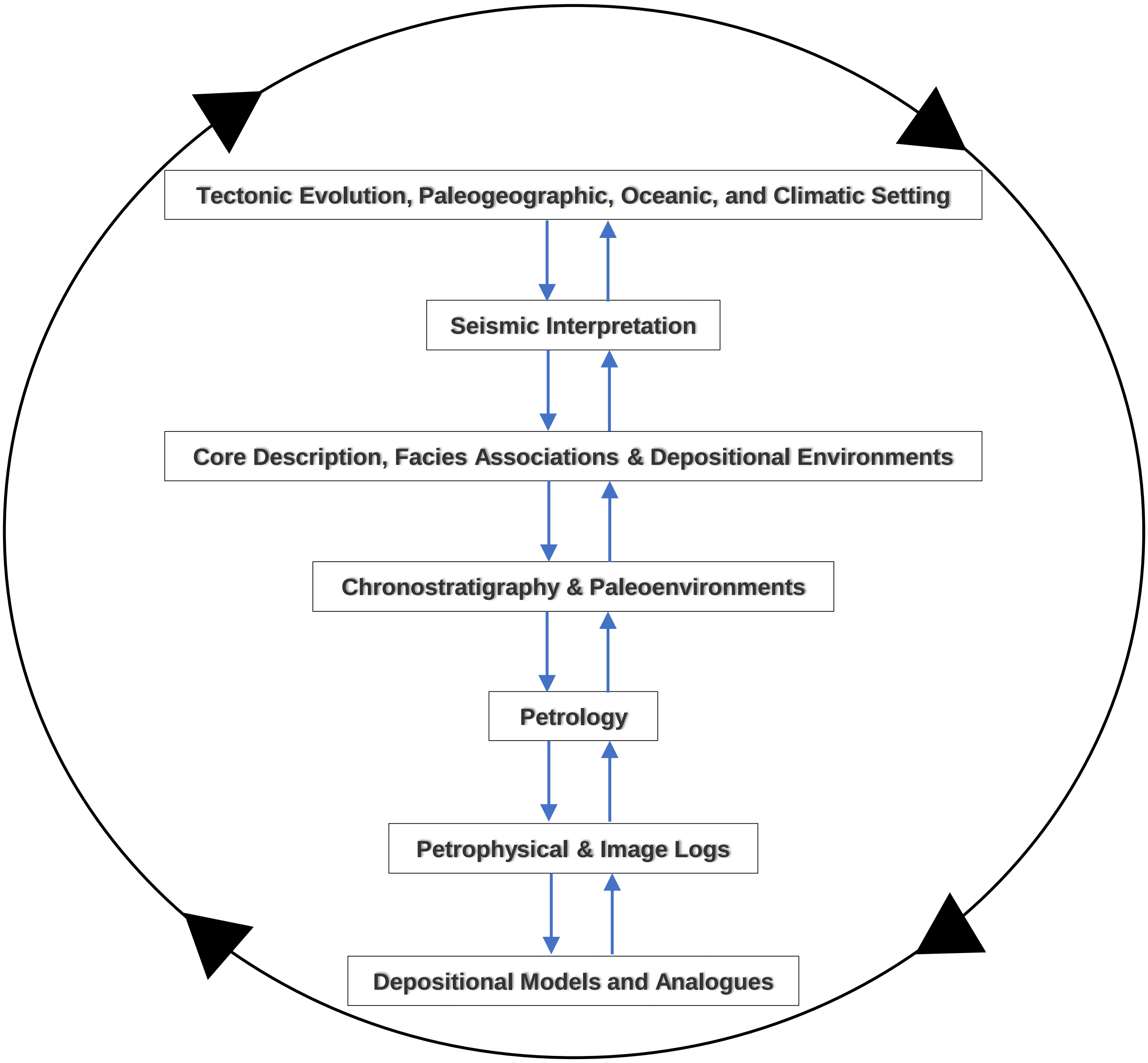


Figure 2.1 Data Types and Workflow for Reservoir Characterization.

Tectonic Evolution, Paleogeographic, Oceanic, and Climatic Setting

The regional geological setting was used to set the context for detailed field-scale interpretations, and is described in detail in Section 2.2 Regional Geology. The regional geologic setting established the tectonic regime(s), and the associated climatic and paleogeographic settings during the time of deposition for both source and reservoir intervals (spanning approximately from the Oxfordian to Early Berriasian, respectively). In addition, a Petroleum Systems Model (PSM) was utilized to understand and de-risk the working petroleum system in the Flemish Pass Basin.

Seismic Interpretation

Regional and field-scale seismic interpretations, using traditional and inversion volumes, provided the basis for regional to local reservoir mapping and fault interpretations. Seismic interpretation was fundamental for constructing depositional environment maps beyond the localities of cored stratigraphy.

Core Descriptions, Architectural Elements, and Depositional Environments

Cored stratigraphy provided the basis for interpreting depositional environments with relatively higher certainty, and are essential to fully integrate with all other datatypes. Cored stratigraphy across most discovery areas were collective utilized to build a geological understanding from field- to regional-scale. Key cored wells include Bay du Nord L-76Z (Section 2.3 Bay du Nord Field), Baccalieu F-89, Cappahayden K-67Z, and Cambriol G-92 (Section 2.4 Cambriol Field). The cored stratigraphy is essential for defining hierarchical elements within the depositional system. Depositional hierarchies, from smallest to largest scale, are defined as: lithofacies, architectural elements (i. e. facies associations), depositional sub-environments, and depositional environments (Figure 2.27).

Biostratigraphy (Chronostratigraphy and Paleoenvironments)

Biostratigraphic samples are taken from Rotary Sidewall Core (RSWC), ditch cuttings, and conventional core and predominantly rely on palynological analysis to resolve chronostratigraphy and general paleoenvironments. Chronostratigraphy was also used to help constrain lithostratigraphic and sequence stratigraphic nomenclature (Section 2.2.1 Stratigraphy), and improve regional stratigraphic and seismic correlations.

Petrology

Petrological studies are taken from cuttings, RSWC, and cored intervals. They were used to understand primary depositional sandstone quartz-feldspar-lithic constituents (i.e. Quartz-Feldspar-Lithic [QFL]), and authigenic components via point counting.

Petrophysical and Image Logs

A full suite of petrophysical logs, including Wireline (WL) and computer processed interpretations, were used to understand reservoir trends and parameters for all discovery areas. A detailed description of these logs is given in Section 3 Petrophysics. Gamma Ray (GR) and Shale Volume (VSh) were particularly useful for calibration from cored to non-cored stratigraphic intervals. Image log data has been acquired in several wells across the Project Area. These logs are primarily used, both in the presence or absence of core, to further constrain depositional (i.e. image log facies) and structural interpretations.

Depositional Models and Analogues

Depositional models and analogues are selected based on data observations and interpretations (Figure 2.1), which is used to further illustrate the geological conceptual model.

2.2 Regional Geology

2.2.1 Stratigraphy

A regional stratigraphic chart summarizing the general lithostratigraphy, chronostratigraphy, seismic stratigraphy, paleoenvironments, and tectonic evolution for the Flemish Pass Basin is shown in Figure 2.2 [11]. The Flemish Pass Basin has predominantly adopted informal (i.e. not recognized within the North American Commission on Stratigraphic Nomenclature) 'equivalent' Jeanne d'Arc Basin lithostratigraphic names for the purpose of familiarity. Reservoir-bearing Tithonian-Berriasian stratigraphy includes additional informal stratigraphy not identified in the Jeanne d'Arc Basin (Figure 2.3), but can be considered similar to the Tithonian reservoir stratigraphy at the Terra Nova field [12][13]. Collectively, this framework is the basis for the regional geologic understanding, and the current field-scale reservoir stratigraphic framework, which has expanded and evolved with continued exploratory drilling. As a result of subsurface maturation, there have been many versions of the reservoir stratigraphic nomenclature throughout the years. Figure 2.3 summarize the current stratigraphic nomenclature used for the Flemish Pass Basin, in relation to historical names for reference. Certain figures in this application may reference the historical nomenclature; use Figure 2.3 to relate the historical naming convention to the current reservoir stratigraphy.

Lithostratigraphy

The regional tectono-stratigraphic framework provides the basis for the general lithostratigraphy in the Bay du Nord Project (the Project). Figure 2.2 [11] illustrates the seabed to Lower Jurassic stratigraphy, consisting of approximate lithostratigraphic equivalents described in the Jeanne d'Arc Basin [14]. The overburden is represented from seabed to Base Cretaceous, while the reservoir and source-rich intervals, reside within Kimmeridgian-Oxfordian to Tithonian-Berriasian stratigraphy. Tithonian stratigraphy is uniquely denoted by re-occurring sandstones, overlying heterolithics, and mudstones (Figure 2.3 and Figure 2.4), similar to Tithonian reservoir-bearing stratigraphy in the Jeanne d'Arc Basin [15][16][17]. Lithostratigraphic Members and Units are herein defined by sandstone-mudstone divisions, largely differentiated by sharp bases and gradational or sharp-based tops (cf. Figure 2.29). Therefore, member and Unit bases typically represent the most confident lithostratigraphic correlable surfaces, particularly with seismic control (cf. Section 4 Geophysics), however, a lack of confident reoccurring palynological markers makes any further resolution (i.e. unit to bed-scale) correlations uncertain.

Chronostratigraphy

The Late Jurassic to Early Cretaceous chronostratigraphic framework is shown in Figure 2.3. Highest confidence ages identified are represented by the Tithonian base and Base Cretaceous. Ages are consistent with the International Chronostratigraphic Chart [18]. This stratigraphy is lithostratigraphically and chronostratigraphically correlated in several discovery areas, demonstrated in Figure 2.4.

Sequence Stratigraphy

A sequence stratigraphic framework (Figure 2.5) is constrained by the chronostratigraphic framework, defined in Figure 2.3. Depositional sequences, systems tracts, and surfaces follow stratigraphic nomenclature defined by [19]. As a result, eight Tithonian depositional sequences are identified from the base Gallants member to the Mizzen member Top (Base Cretaceous). Given the total chronostratigraphy, and without any further relative confident sub-zones, each depositional cycle most likely represents higher frequency events. A sequence stratigraphic southwest to east-north-east correlation panel of type wells is shown in Figure 2.6.

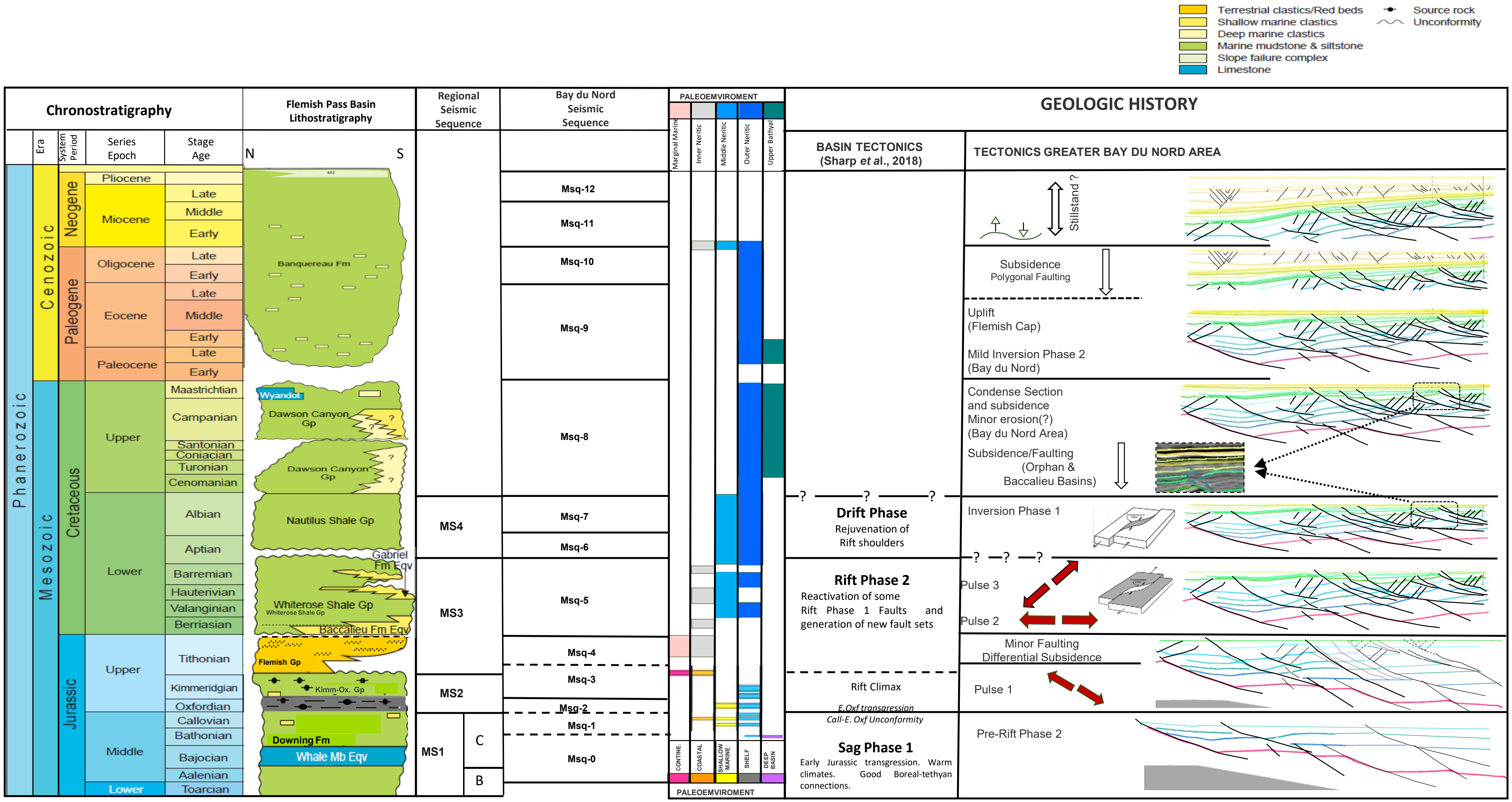


Figure 2.2 Regional Flemish Pass Basin Tectonostratigraphy Regional Flemish Pass Basin Tectonostratigraphy including seismic sequences, paleoenvironments and basin tectonics of Bay du Nord and area. Modified from Bernal (2023).

Ma	Period	Age	Group	Fm	Mbr	Unit	Alternative/Historical Names	
	Early Cretaceous	Berriasian	HIBERNIA GP.	Hibernia Fm.	Baccalieu Mbr.	BAC_3	Baccalieu Sandstone	Upper Baccalieu
						BAC_2		
143.1						BAC_1		Lower Baccalieu
	Late Jurassic	Tithonian	FLEMISH GP.	Bodhran Fm.	Mizzen Mbr.	MIZ_3	Bodhran Fm. 4.1	Ti marine
						MIZ_2		Ti4 sandstone
						MIZ_1		Ti3 sandstone and shale
					Bay du Nord Mbr.	BDN_1	Bodhran Fm. 3.1	Ti2 sandstone and shale
					Bonaventure Mbr.	BVT_4	Bodhran Fm. 2.2	Ti1a sandstone and shale
						BVT_3	Bodhran Fm. 2.1	Ti1 sandstone and shale
						BVT_2	Bodhran Fm. 1.2	Ti0a sandstone and shale
						BVT_1	Bodhran Fm. 1.1	
					Gallants Member	GAL_1		Ti0 sandstone and shale
					Base Middle Bodhran Shales Mbr.	BMB_2		Grey shales
						BMB_1		
					Lower Bodhran SR Mbr.	LSR_1		Organic Shales
						LBO_2		
						LBO_1		
149.2		Kimm	KIMM.-PLIENS. GP.	Rankin Fm	Tempest Sst Mbr.			Lower Tempest
					Egret Shales Mbr			
		OX			Egret SR Mbr.			
					Port au Port Mbr.			

Figure 2.3 Late Jurassic to Early Cretaceous Stratigraphy Flemish Pass Basin Late Jurassic to Early Cretaceous Stratigraphy Flemish Pass Basin, including chronostratigraphy, lithostratigraphy, and historical names. BAC = Baccalieu; MIZ = Mizzen; BDN = Bay du Nord; BVT = Bonaventure; GAL = Gallants, BMB = Base Middle Bodhran Shales; LSR = Lower Bodhran Source Rock (SR); Lower Bodhran Organics.

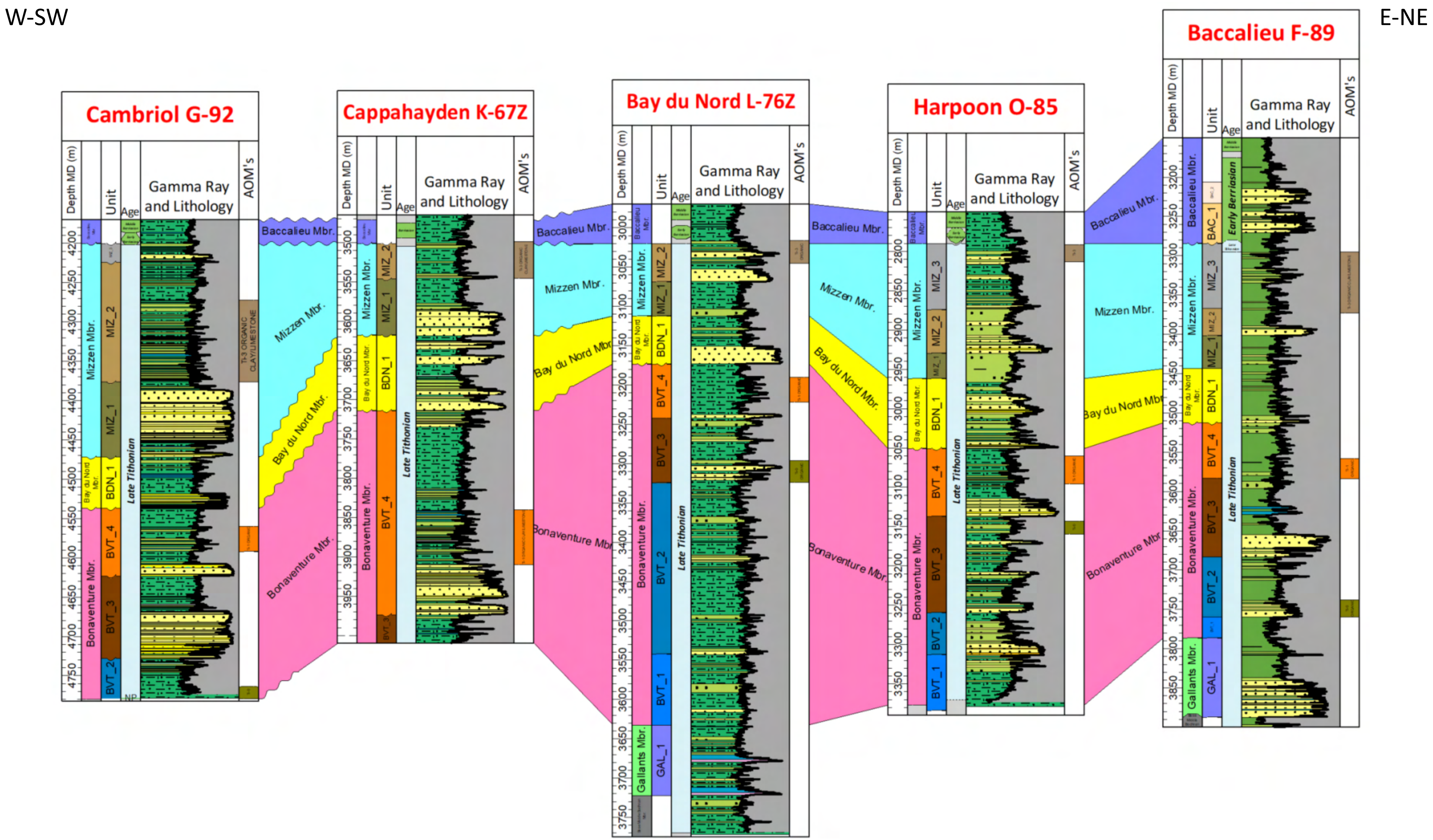


Figure 2.4 Chrono- and Lithostratigraphic Correlation of Type Wells in the Bay du Nord Project Area Chrono- and lithostratigraphic correlation of type wells in the Bay du Nord Project Area. Correlation panel is 1:2500 and is flattened on Base Cretaceous.

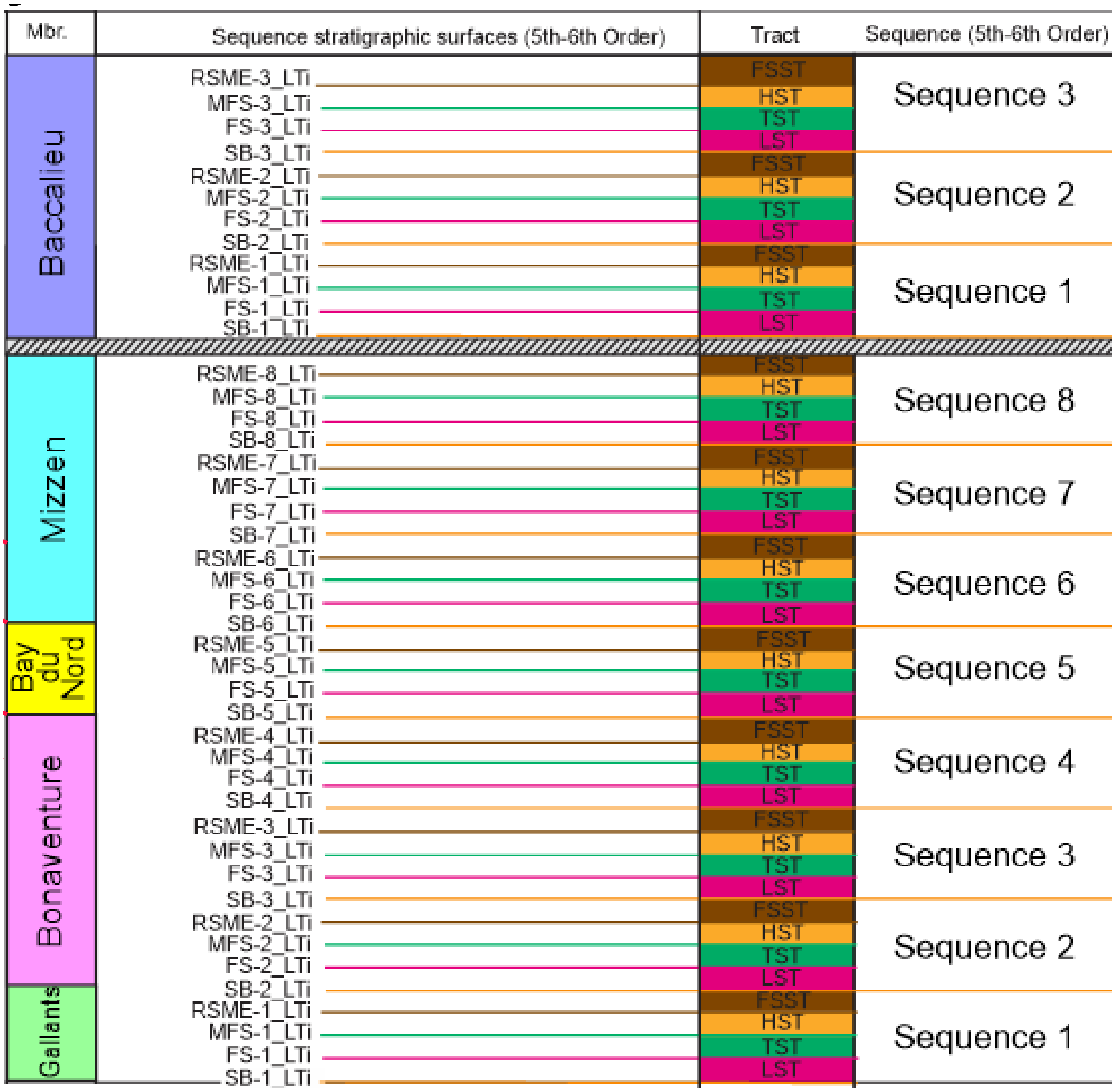


Figure 2.5 Sequence Stratigraphy 2022 Sequence stratigraphy for the discovery areas in the Flemish Pass Basin. A. Older nomenclature (pre-2020) and B. Updated sequence stratigraphic nomenclature. Sequence Boundary (SB), Flooding Surface (FS), Maximum Flooding Surface (MFS), and Regressive Surface of Marine Erosion (RSME), following Cantuneau, 2002.

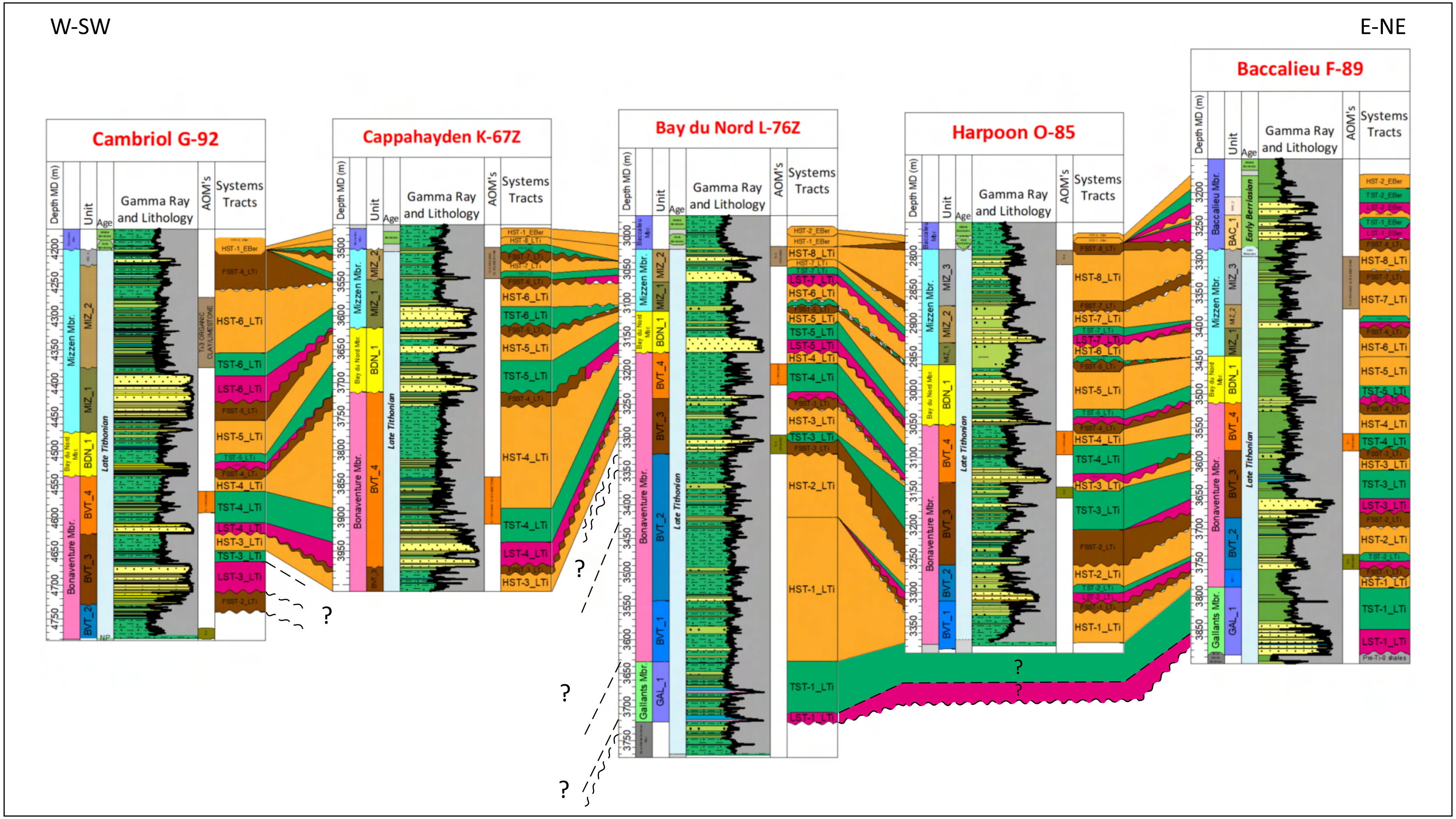


Figure 2.6 Sequence Stratigraphic Correlation, Bay du Nord Project Area Sequence stratigraphic correlation of Bay du Nord project area type wells. Sequence stratigraphic nomenclature follows Cantuneau (2002).

2.2.2 Tectonics and Structure

The Flemish Pass Basin

The Flemish Pass Basin is west of the Flemish Cap, north of the Jeanne d'Arc Basin and Central Ridge, and East of the Bonavista Platform. It corresponds to one of the NE-SW oriented Tithonian depocentres, interpreted as a rift arm of the North Atlantic rift system, and encompasses an area in excess of 10,000 km² with Mesozoic and Cenozoic sedimentary packages up to 10 km in thickness. The Flemish Pass and Orphan basins represent the younger, northerly extent of the Grand Banks province, which is a northeast-trending assemblage of Mesozoic cratonic basins and intervening basement ridges that originated in the latest Triassic and Middle Jurassic. The Flemish Pass is found at the eastern flank of the East Orphan Basin, which represents the southern continuation of the Rockall Trough Figure 2.7.

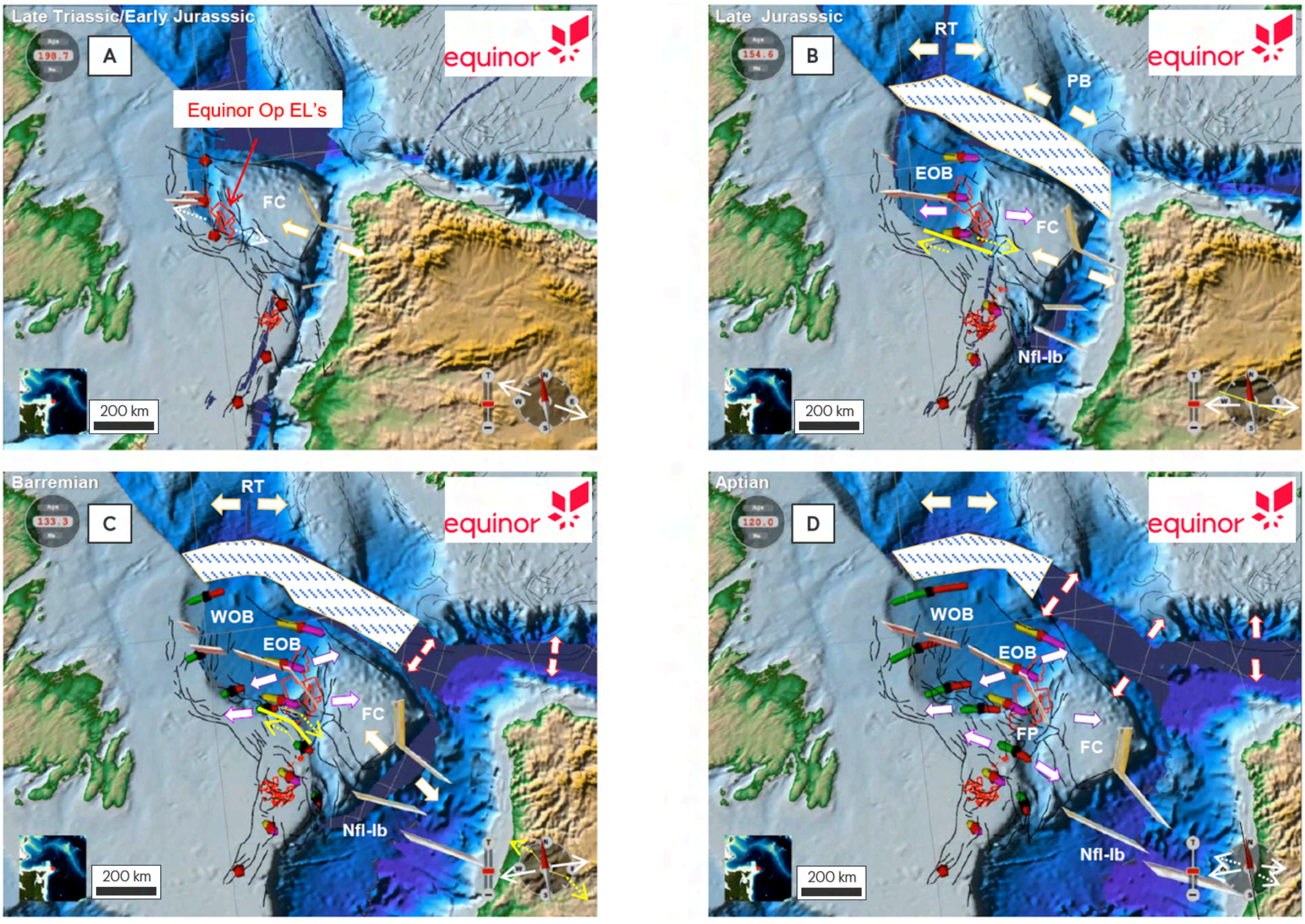


Figure 2.7 Summary Plate Tectonics and Proposed Evolution of the Stress Field in the Flemish Pass Basin (A) Late Triassic/Early Jurassic Rifting Phase 1. (B) Late Jurassic Rifting Phase 2 Climax and opening of the East Orphan Basin. (C) Barremian Rifting Phase 2 and opening of the Western Orphan Basin. (D) Aptian Rift/Drift Transition, final opening of the West Orphan Basin, and propagation of the Labrador Rift (modified from Skogseid 2017, personal communication). Newfoundland-Iberia (Nfl-Ib); Flemish Cap (FC); East Orphan Basin (EOB); West Orphan Basin (WOB); Porcupine Basin (PB) and Rockall Trough (RT).

<u>*Tectonic events.*</u> An overall agreement exists on the identification and timing of major tectonic events during the rifting-drifting process on the North Atlantic (e.g. [20], [21], [22], [23], [24], [25], [26], [27], [28], [11]). The consensus is on the interpretation of a series of rifting events migrating northward, extending from Late Triassic to Lower Cretaceous, followed by continental drifting, which becomes younger from south to north (e.g. [27]). Rifting in Late Triassic has been documented offshore USA (e.g. [27]) and in the Jeanne d'Arc Basin (e.g. [20]). Late Triassic Rifting into the Flemish Pass has been proposed ([29], [30], [27]) but no stratigraphic controls exist to support this interpretation. Most of these authors proposed that the location and configuration of these Late Triassic rift systems are partially controlled by the outline of Paleozoic fold belts (e.g. Appalachian according to [27]) and crustal lineaments (Variscan meta-sediments fold trends and Caledonian Terrane Boundaries according to [28]). More stratigraphic control exists for the Jurassic and Cretaceous rifting events and their transition toward

continental drifting. Withjack *et al*. (2012) [27] proposed the onset of the rift/post-rift transition ranges from 142 Ma in the southern portion of the Jeanne d'Arc Basin to 118 Ma in the northern portion of the Jeanne d'Arc Basin, while Driscoll *et al*. (1995) [22] proposes that this transition occurred by late Aptian in the Jeanne d'Arc Basin. In the Flemish Pass Basin, Foster & Robinson (1993) [29] proposes that the beginning of the rift/post-rift transition occurs at Mid-Aptian time (120 Ma) while Sinclair (1998) [31] suggest that this transition occurs near the end of Albian time. The Jeanne d'Arc and Flemish Pass Basins were abandoned as 'failed' rifts when seafloor spreading started between Newfoundland and Iberia, propagating northward and eventually linked to the Labrador system (Skogseid, personal communication). Sharp *et al*. (2018) [28] propose that the Drift Phase in the North Atlantic begins in Aptian/Albian time from an integrated study that includes the Jeanne d'Arc, Flemish Pass and Orphan Basins.

Evolution of the Stress Field

Two rift phases have been proposed offshore Newfoundland (East Coast Canada) by Bernal (2024) and Sharp *et al*. (2018): Phase 1 in Triassic characterised by wide distributed basins, and Phase 2 in Mid-Late Jurassic to Cretaceous displaying different degrees of faulting and subsidence (Figure 2.8). A summary of the plate evolution model and changes of the stress field in the Orphan and Flemish Pass Basins associated with the rifting is described below and depicted in Figure 2.7:

A. The presumed pre-rift configuration suggests little rift development at Late Triassic-Early Jurassic (20 to 26 km based on structural restorations in the Greater Bay du Nord Area from Galperin & Novoa, 2015 [32]; with higher uncertainty on the degree of closure between Iberia and Newfoundland. A Late Triassic-Early Jurassic rift initiation has been proposed for the Jeanne d'Arc Basin (e.g. [20], [27]) and suggested in the Flemish Pass Basin (e.g. [29], [28]). If Late Triassic-Early Jurassic rifting responds to the opening of Iberia and Newfoundland, a maximum horizontal stress direction of ca. EES-WWN is expected in the Flemish Pass.

B. The Late Jurassic reconstruction suggests that the rift zone of the Rockall Trough-East Orphan Basin-Jeanne d'Arc sets a maximum horizontal stress field with an orientation of ca. E-W in the Flemish Pass Basin. Note the development of a crustal-scale, right lateral, strike-slip fault to the south of the Flemish Pass and Flemish Cap (ca. 180 to 140 ma) associated with the opening of the East Orphan Basin (e.g. [25], [33]).

C. By the Barremian-Hauterivian time, the West Orphan Basin is established by a westward, rift axis jump and southward rift propagation, which cut across the East Orphan and Jeanne d'Arc basins, and continues through the Flemish Pass. This evolution of the West Orphan Basin set a maximum horizontal stress field with an orientation of ca. E-W in the greater Bay du Nord Area; oblique to the orientation of the stress field developed during Late Jurassic time. An ENE-SSW maximum stress field orientation might also be present in the Flemish Pass Basin. The southward and eastward translation of the Flemish Cap (e.g. [25]) imposed a strike-slip displacement along a convex-to-the-north right lateral fault located in the southern section of the Flemish Pass Basin and Flemish Cap (ca. 140 to 135 ma). The far stress field created by the Newfoundland-Iberia rift (NW-SE) is superimposed to the stress field created by the growth of the West Orphan and Flemish Pass Basins.

D. A final major phase of rifting developed during Albian-Aptian time ([29], Labrador Rift according to [20]). The growth of the West Orphan Basin imposes a maximum horizontal stress field with an orientation of ca. WWS-EES whereas the clockwise rotation and southward propagation of the Flemish Cap (e.g. [25]) sets up a maximum horizontal stress field which orientation changes from the south (NNW-SSE) to north (NE-SW). Note that the stress field orientation associated with the movement of the Flemish Cap is oblique to the orientation of the stress field associated with the growth of the East Orphan Basin in Late Jurassic time. Faults reactivated by Albian-Aptian time may be pure dip-slip or have a strike-slip component (right-lateral most likely) depending on their original orientation (ca. 135 to 120 ma). The stress field created by the Labrador Rift (maximum horizontal stress field with an orientation of ca. NE-SW) is superimposed to the stress field created by the growth of the West Orphan and Flemish Pass Basins.

The structural style observed in the greater Bay du Nord Area is controlled by 1) diachronous opening of the Orphan Basin, 2) west to East displacement and clockwise rotation of the Flemish Cap, and 3) diachronous opening of the North Atlantic Rift.

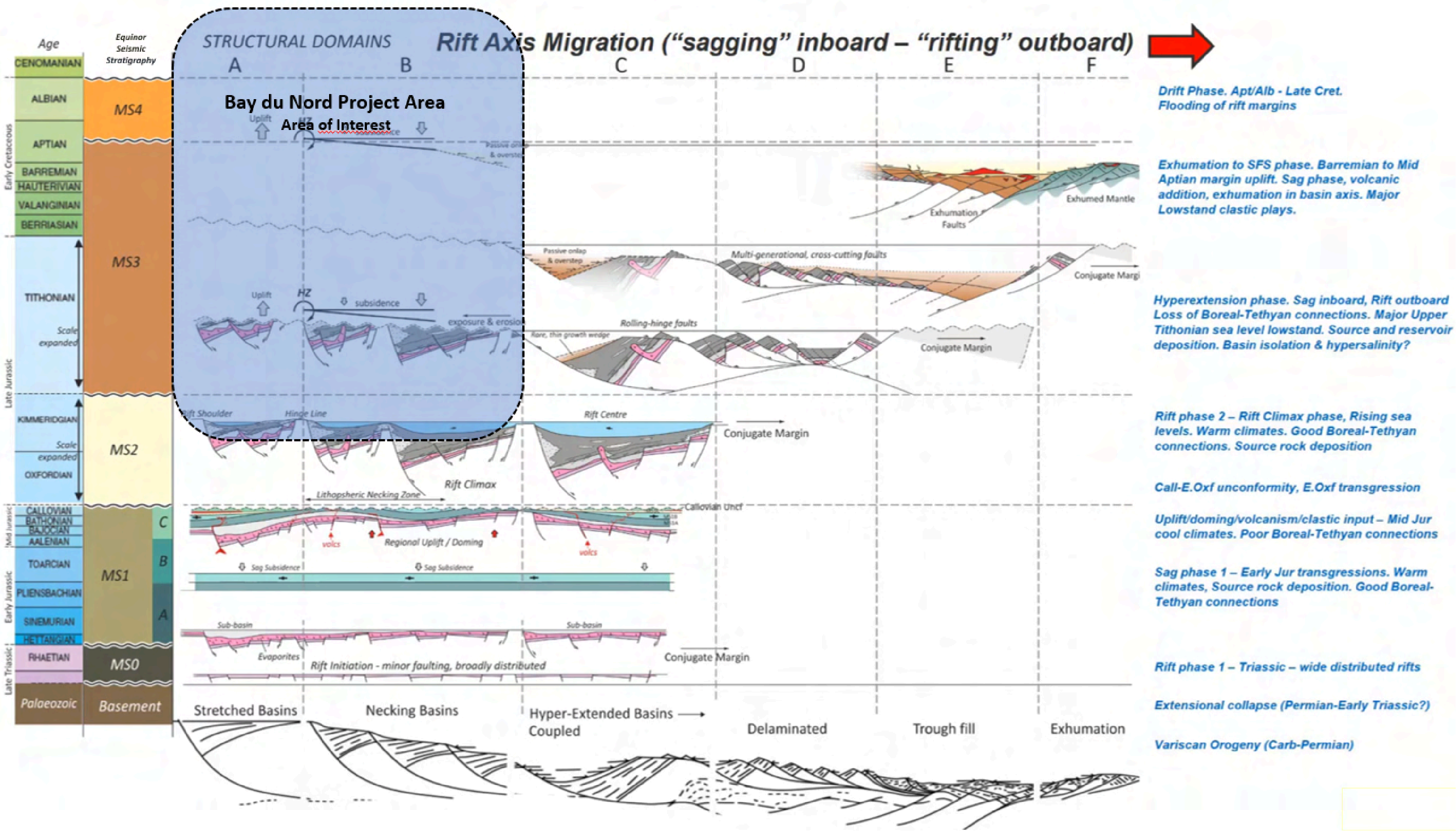


Figure 2.8 Summary Geological Chart of Offshore Newfoundland, East Coast Canada Geological chart from the super-regional study of Sharp et al. (2018). Details of the tectonic evolution of the Flemish Pass and the Greater Bay du Nord Area are not fully captured in this summary chart. Note the interpreted major relative sea-level lowstand in the Upper Tithonian.

Structural Style

There are distinct changes in structural style and crustal evolution from proximal to distal regions in the eastern Newfoundland Continental Margin (e.g. [33]). The structural style interpreted in the greater Bay du Nord Area displays characteristics observed in the stretched and necking domains of the present-day, lithospheric-scale structural model presented in Sharp *et al*. (2018) [28]. To the north of the Bay du Nord Project Area, seismic data shows the onlap of Jurassic and Cretaceous strata against upper-crust rocks (basement and pre-rift sediments). Seismic onlap of Jurassic and Cretaceous strata is also evident west of the Flemish Cap (East of Harpoon O-85 and Baccalieu I-78 wells), and to the East onto basement highs between the East Orphan and Flemish Pass Basins. These suggest that the basement highs were exposed during Jurassic and Early Cretaceous times (Figure 2.9). In addition, Upper Tithonian reservoirs (Bay du Nord and Mizzen members) contain reworked Palaeozoic (Late Ordovician, Devonian, Carboniferous, and Permian sediments) and Triassic miospores.

The magnetic highs observed in the Grand Banks have been correlated to the Caledonian Terrane Boundaries interpreted onshore (e.g. [28]). Note that these magnetic highs intersect the pre-Tithonian Mesozoic Basins, Tithonian depocentres, and Flemish Cap sub-perpendicularly. Seismic reflections imaged under the northern part of the unrifted Flemish Cap extend southwards into the Flemish Pass rift and relate directly to basement penetrations in wells (Mizzen O-16). These facies are interpreted as Palaeozoic (Devonian/Carboniferous) metasediments structures formed during the Caledonian orogeny by Sharp *et al*. (2018) [28]. The orientation of these lineaments is sub-parallel to the orientation of the Tithonian and pre-Tithonian depocenters, suggesting that the Paleozoic lineaments have some control on the location of the Mesozoic depocenters.

2-D restoration. A structural restoration of an Orphan Basin - Flemish Cap cross section was performed and results are shown in Figure 2.9. It included decompaction, flexural isostasy, un-faulting and unfolding of the different stratigraphic units. The results show that the main tectonic events for the greater Bay du Nord Project area from Jurassic to present day can be summarized as follows: Rift phase 2 from Mid Jurassic to Berriasian, followed by a drift phase in which the main faults were reactivated as transtensional or transpressional features during the Lower Cretaceous. These results are consistent with the plate tectonic model discussed earlier.

The restoration shows that a total of ~15 km of extension is accommodated during the Mid Jurassic-Berriasian Rift Phase 2 for this section only, which excludes most of the Orphan Basin. As a result, newly formed grabens and horsts control, in part, the local Tithonian reservoir and source rock fairways in the Greater Bay du Nord Project Area sits in a graben located in between the Renews High-and the Flemish Cap.

During the Early Cretaceous, the Rift Phase 2 faults were reactivated as transtensional or transpressional features. An example of this reactivation is the Baccalieu structure, which seems to be related to transpression accommodated by the fault to the East thus causing local inversion of the graben and significant erosion of the crest. A similar event of the same age has been documented in the Jeanne d'Arc Basin (located to the south of the Project area) which has been related to an NW-SE to E-W rotation of the stress field. Finally, the Tertiary deformation is dominated by subsidence mainly caused by sediment loading.

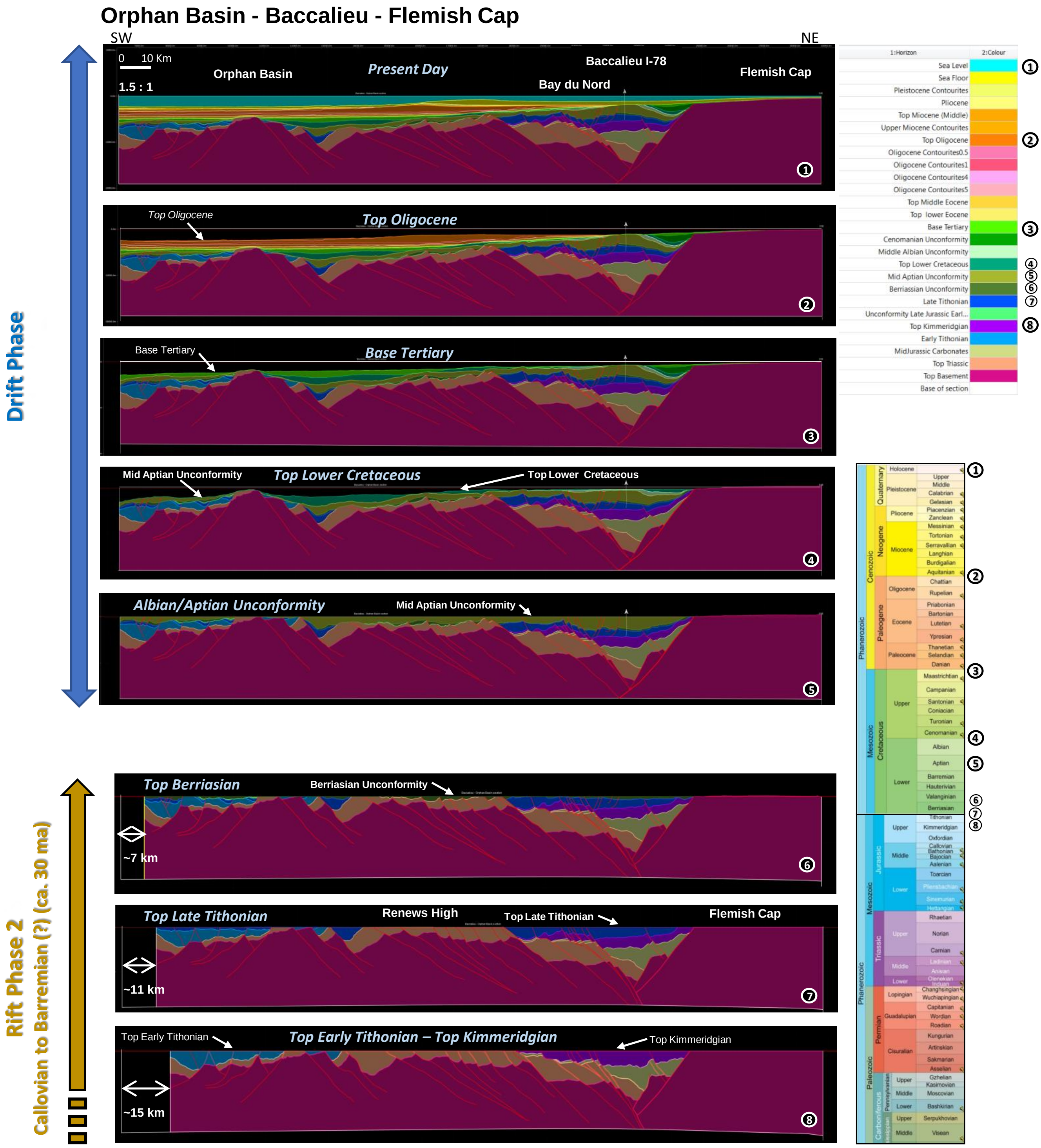


Figure 2.9 2D Structural Restoration of a Regional Geological Section from the Flemish Cap to the Orphan Basin (Galperin and Novoa, 2015) The Drift Phase is associated with the Crustal separation between Europe, Greenland and North America while the Rift Phase 2 is characterised by reactivation of some fault trends developed during Rift Phase 1 (Late Triassic-Early Jurassic).

2.2.3 Paleogeography

Triassic to Mid-Jurassic Rift Propagation

The Late Permian to Middle Jurassic breakup of super-continent Pangea resulted in a multi-directional rift system and the development of divergent margins between Gondwana and Laurasia (Figure 2.10A, B), with the southward propagation of the Norwegian-Greenland Sea rift and the westward propagation of the Tethys rift system. In the north-central and north Atlantic the two rift systems met and interfered with each other. Tensional reactivation of Permo-Carboniferous fracture systems played an important role in localizing many of the Triassic grabens (e.g., Iberia, northwest Africa).

During the mid-Triassic, southward propagation of the rift system is recorded by crustal extension and subsidence in the Porcupine and Celtic Sea, on the east Newfoundland Shelf, and between the Grand Banks and Iberia. The Triassic rifts on the Atlantic shelves of Morocco and Nova Scotia came into evidence during the late-Middle to early-Late Triassic (Landinian to Carnian). During the Late Triassic (Carnian), rifting propagated southward through the central Atlantic into the Gulf of Mexico. During the Late Triassic to Early Jurassic (Carnian to Hettangian), marine transgressions advanced westward through the Bay of Biscay, the Gibraltar, and northwest African rift zones, giving rise to accumulation of the Argo salts. A continued rise in sea level and differential subsidence of Tethys and Arctic-North Atlantic rift systems gave rise to the development of open marine conditions in the North and Central Atlantic rift systems during the Early Jurassic (Late Sinemurian). Communication between the rift systems was disrupted during the Bajocian and Bathonian due a thermal doming in the North Sea [34].

Late Jurassic-Early Cretaceous Sea-Floor Spreading

The Late Jurassic to Early Cretaceous was governed by the step-wise northward propagation of the Central Atlantic seafloor-spreading axis (Figure 2.10C, D, E). In the North Atlantic rift zone, crustal extension persisted until separation was achieved in its different segments during the Cretaceous. During the Jurassic to earliest Cretaceous, the central Atlantic seafloor-spreading system terminated at the Azores fracture zone (southeast Newfoundland); however, crustal extension propagated into the southern Labrador Sea as evidenced by volcanic activity in southwest Greenland and on the southeast coast of Labrador ([35], [36]). Tectonic activity accelerated at the transition to the Early Cretaceous [37]. During the Early Cretaceous (Aptian), crustal separation between Portugal and the Grand Banks induced a first phase of counter clockwise rotation of Iberia. The Iberian micro-continent became isolated from Laurasia due to crustal separation between the Flemish Cap and Galicia Bank and counter-clockwise rotation away from Europe ([38], [39]). The Labrador Sea rift apparently propagated rapidly northward through Baffin Bay into the southern parts of the Canadian Arctic Archipelago. This was accompanied by intense volcanic activity in the Labrador Sea area ([40], [41], [42], [43])

Recent Late Jurassic paleogeographic reconstructions [44] for the Grand Banks show major palaeo-oceanic bodies connected to seaways in the East Orphan, Flemish, and Jeanne d' Arc basins (Figure 2.11A). The inlet from Tethys is likely to have been located at present-day Gibraltar strait, joining the northern tip of Central Atlantic and entering between Newfoundland and Iberia. Large-scale transgressive-regressive cycles are identified. Following a transgression in the Callovian and a regression in the early Oxfordian, sea level continued to rise in the Late Oxfordian and reached a highstand in the Kimmeridgian. The area then experienced a period of regression during the Tithonian. The Kimmeridgian-Tithonian transgressive-regressive cycle resulted in the deposition of Kimmeridgian marine source rock and Tithonian marginal marine source rocks. The Kimmeridgian transgressive sediments are the main source rock in the Jeanne d'Arc basin and the Tithonian regressive sediments are the main source rock in the Flemish Pass basin. In the Late Tithonian, the southern Grand Banks and southern Jeanne d'Arc basins were affected by Avalon uplift, resulting in the development of large-scale fluvio-deltaic sequences. The paleoclimate and oceanography of the Late Jurassic was semi-arid to arid, with warm to hot temperatures in the winter (24-30 °C) and hot to very hot values in the summer (30-38 °C), and seasonal variations in rainfall (Figure 2.12B), with low winter values (0.0-0.7 mm/d) and high summer values (5.0-7 mm/d).

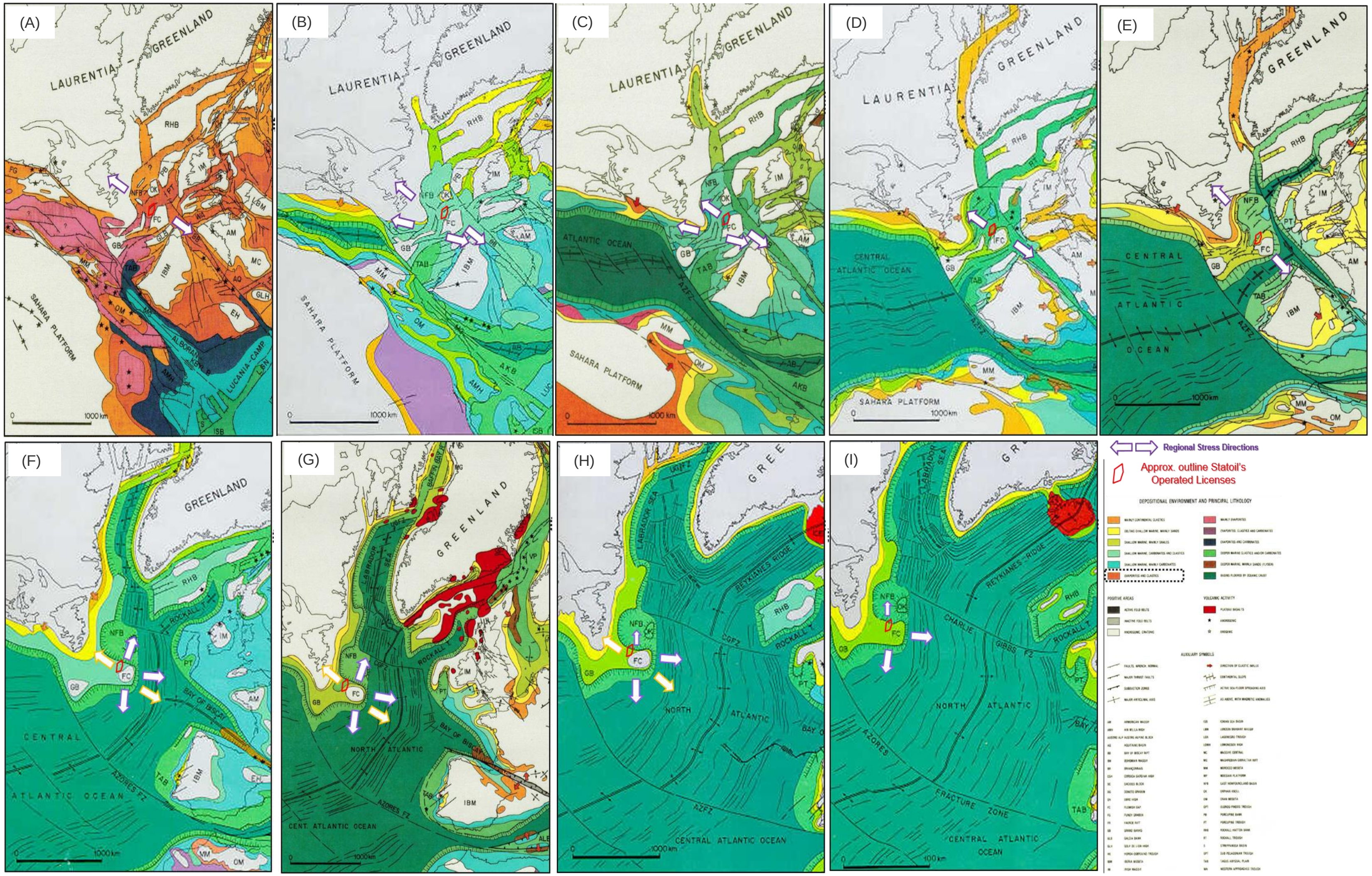


Figure 2.10 Paleogeographic Maps according to Ziegler (1999) (A) Late Triassic (Carnian-Norian). (B) Middle Jurassic (Bajocian-Bathonian). (C) Late Jurassic (Oxfordian-Tithonian). (D) Early Cretaceous (Berriasian-Barremian). (E) Early Cretaceous (Aptian-Albian). (F) Late Cretaceous (Turonian-Campanian). (G) Early Cenozoic (Paleocene). (H) Mid-Cenozoic (Late Oligocene). (I) Late Cenozoic (Middle Miocene). The red polygon outlines the approximate location of Statoil's Operated Licenses in the Flemish Pass. The dotted rectangle indicated the expected depositional environment in the Greater Bay du Nord area. In most cases, the predicted depositional environments agree with drilling results in the Flemish Pass and Jeanne d'Arc Basin.

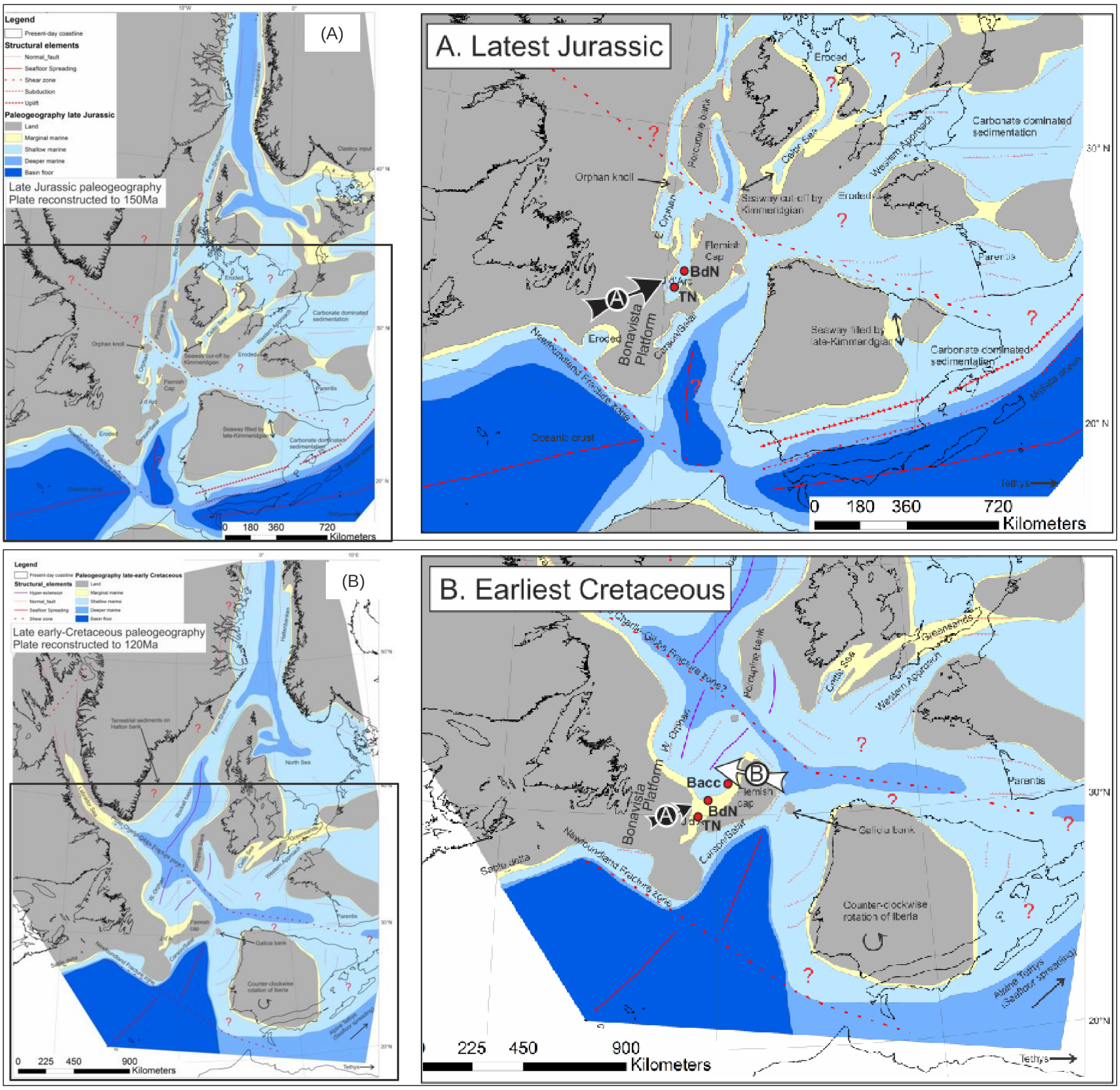


Figure 2.11 Paleogeographic Maps of the North Atlantic and Conjugate Iberian to UK Margins during the (A) Latest Jurassic (150 Ma; Tithonian) and (B) Earliest Cretaceous (120 Ma; Aptian) Major provenance directions are indicated (arrows). Red dots indicated the approximate relative positions of Terra Nova (TN; Jeanne d'Arc Basin), Bay du Nord (BdN; Flemish Pass Basin), and Baccalieu (Bacc; Flemish Pass Basin). Paleogeographic maps modified from the North Atlantic Conjugate Margin (NACM) Project (2015).

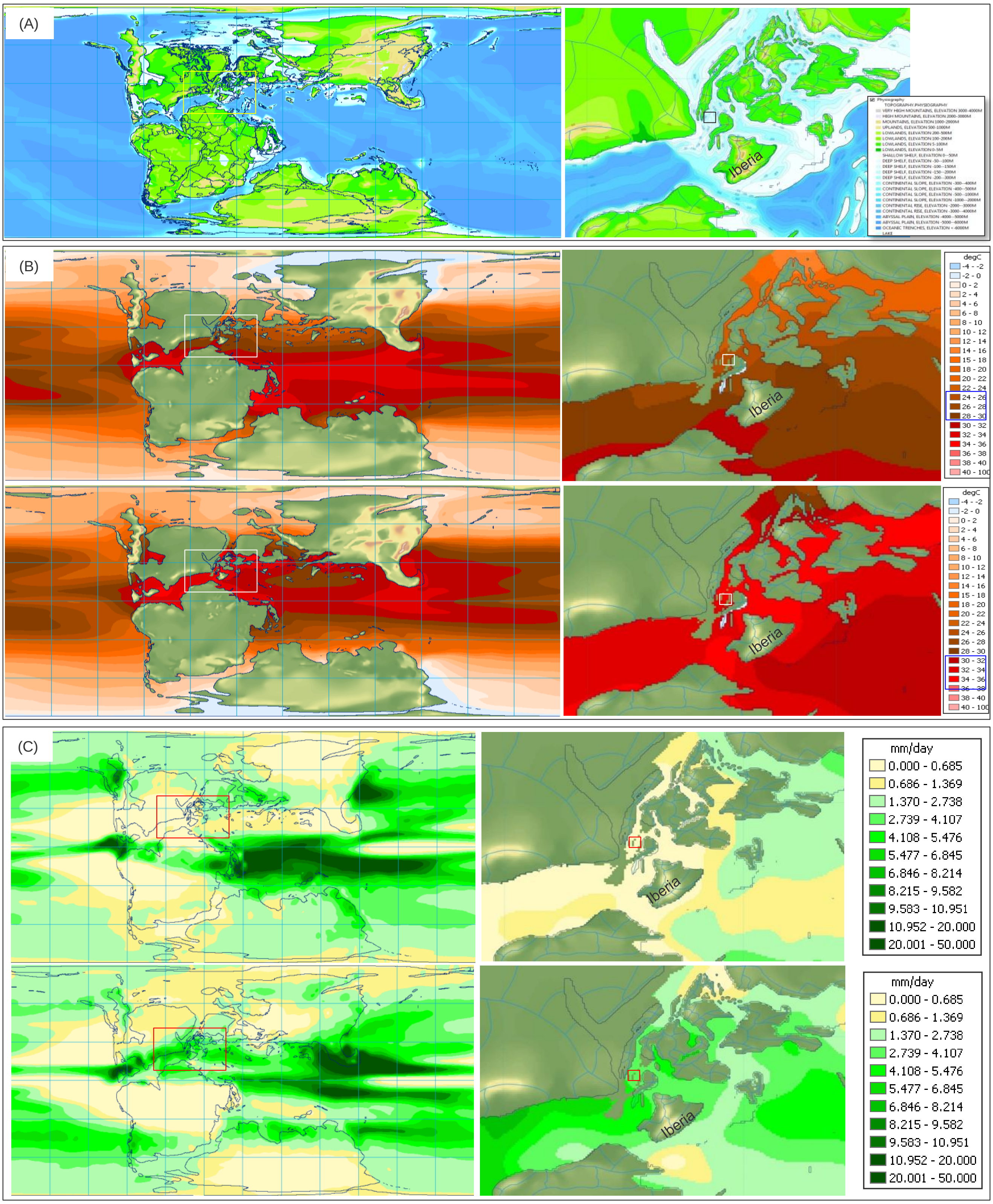


Figure 2.12 Palaeoclimate and Palaeoceanogeography of the Late Jurassic (153 Ma) at Global and Basinal Scales (A) Sea surface temperatures (SST's) (deg C) during the winter and summer. (B) Seasonal precipitation during the winter and summer. Source: Statoil Paleo-climate Atlas / MERLIN & GANDOLPH.

Figure 2.11B shows the paleogeography just before the break-up along the transform margin between Porcupine basin and the Newfoundland basins. Marine shale and carbonates dominated the Iberia-Newfoundland margin and the Grand Banks basins. The main extension axis in the East Orphan basin shifted to the West Orphan basin in early Cretaceous, following a clockwise rotation of the Flemish Cap. The extension was kinematically linked to the Rockall basin. This NE-SE extension axis ceased by the late-early Cretaceous and is marked by an Aptian unconformity in these basins. The extension was then overtaken by the Labrador Sea.

Late Cretaceous-Early Tertiary Crustal Separation

In the North Atlantic sea-floor spreading continued during the Cenomanian to early Campanian. During the early Campanian, crustal separation was achieved between the Labrador Shelf and Greenland (Figure 2.10F). The North Atlantic spreading axis then rapidly propagated into the Labrador Sea, causing rotation of Greenland relative to the North American craton. At the same time, seafloor- spreading axes in the southern Rockall Trough, the Bay of Biscay [39], and possibly in the Canada basin became extinct [45]. Following this reorganization of seafloor-spreading axes, activity along the North Atlantic-Labrador Sea axes dominated the late Senonian to Paleocene evolution of the North Atlantic area.

Seafloor spreading started in the Iberia-Newfoundland margin, Bay of Biscay and propagating into the Labrador Sea. Paleogeographic reconstructions [44] show that in the early-late Cretaceous the main extension took place along the Labrador Sea and marine conditions developed in the basin. The development caused a transition from marginal marine sediments of Aptian-Albian age to shelfal marine sediments of Cenomanian-Turonian age. Seafloor spreading commenced in the Labrador Sea post-Turonian until the late Paleogene (~35 Ma). The Statoil plate model places the age of break-up in the Labrador Sea at 90 Ma.

During the Cenozoic, Europe and North America continued to drift away from each other along the North Atlantic ridge (Figure 2.10G-I). By late-Paleocene seafloor spreading began along the Greenland (west of the Hatton Bank) - Norway margin. The seafloor spreading arm along the Labrador Sea ceased by Eocene-Oligocene. At this time, the Grand Banks was a passive margin, dominated by deepwater sediments. Pelagic chalk deposition began in late Cretaceous and lasted until the earliest Paleocene (Danian). Post-Danian deepwater sedimentation was then replaced by fine grained clastics. Although multiphase uplift began to affect Europe from the late Paleocene due to a combination of mantle processes and the Alpine orogeny, the Canadian margin was mainly passive except for recent phases of uplift linked to de-glaciation during the Quaternary.

2.2.4 Source, Generation and Migration

Source

Source rocks of varied thicknesses responsible for generation of hydrocarbons in the Flemish Pass Basin are encountered in wells from the Late Tithonian to Kimmeridgian (Figure 2.13). Richness of source rocks from the Project Area and regional wells are illustrated in Figure 2.14, which demonstrates that Tithonian source rocks are relatively enriched in total organic carbon and S2 (i.e. kerogen yield from rock evaluation analysis) in comparison to Kimmeridgian equivalents. Comparison of Flemish Pass sterane-types indicates that open marine depositional environments are generally linked to the bulk of the hydrocarbons analysed (Figure 2.15). Therefore, the base case kerogen used for modelling source rock is type II, which is derived from a marine environment.

Figure 2.16 shows the areal extent of type II kerogen across the Project Area during peak migration. Most of the hydrocarbons generated are believed to be linked to early-mature Tithonian source rocks. Oil generated from these early mature Tithonian marine source rocks are also undersaturated with respect to gas (i.e. low gas-oil ratios).

Generation and Migration

For the relatively smaller amount of gas generated during the Lower Tithonian (Figure 2.16), and the observed present day low gas-oil ratios, it is possible that gas generation slightly pre-dates complete structural closure and/ or gas may have leaked from the structure after migration and emplacement.

Present day expulsion maps are shown in Figure 2.17 and illustrate a consistent area of increased expulsion in the Bay du Nord Project area amongst all ages of source rock. Timing of peak hydrocarbon expulsion occurred mainly during the Cretaceous (Figure 2.18) and structures are believe to be filled via vertical or relatively short distance migration from the expulsion areas in Figure 2.17.

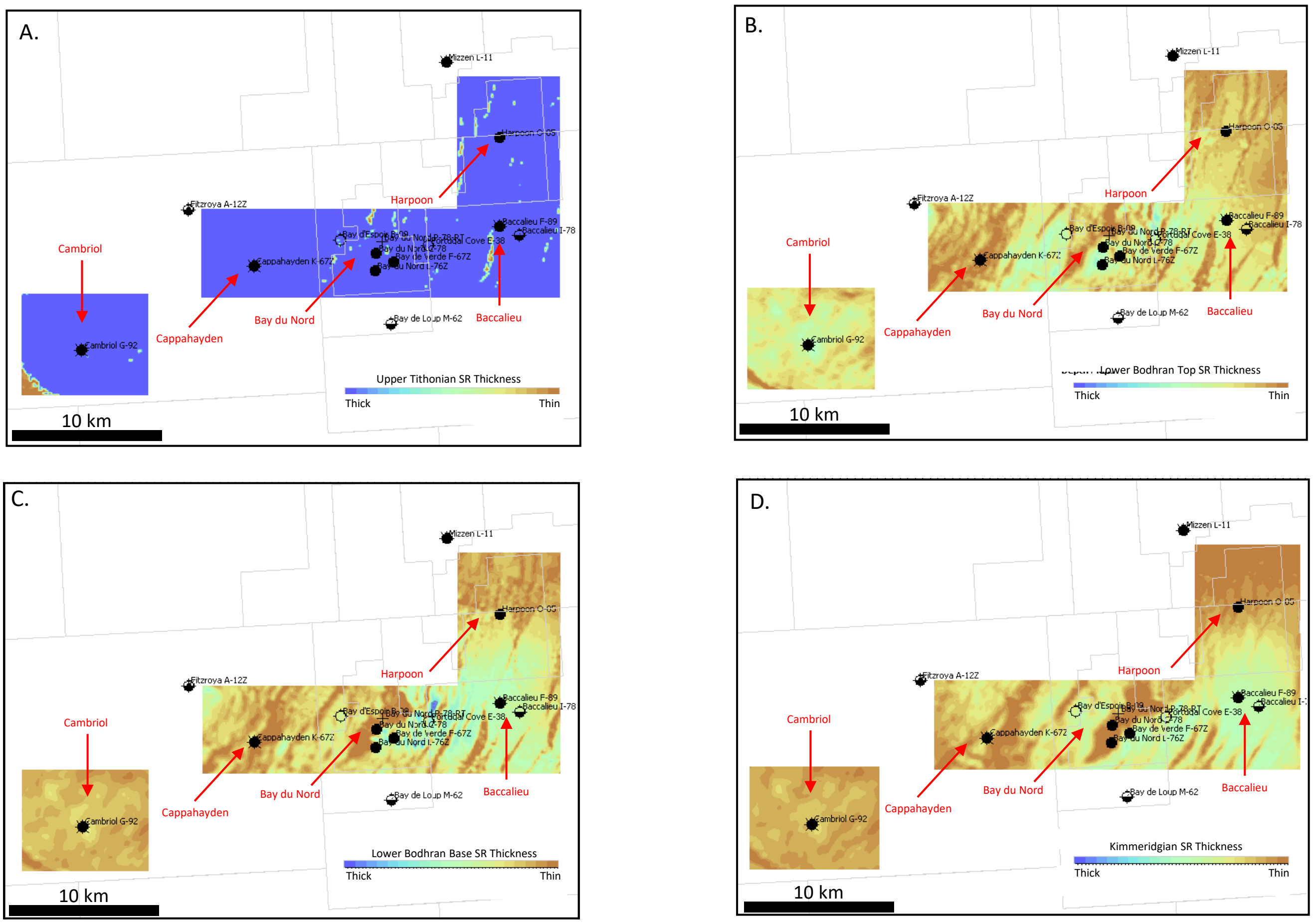


Figure 2.13 Source Rock Thickness Maps Source rock isochores. A. Upper Tithonian (average thickness <20 m). B. Lower Bodhran SR Top (average thickness <300 m). C. Lower Bodhran SR Base (average thickness <400 m) and D. Top Egret SR (average thickness <400 m). Maps B and C collectively represent the gross Lower Tithonian source rock, but are separated by seismically mapped surfaces, Base Upper Tithonian Marker and Oolitic Marker (cf. 3.2.1 Stratigraphy).

Relatively smaller expulsed volumes from the Cambriol area was still significant enough to fill the Cambriol (G-92) structure with early mature-generated hydrocarbons (Figure 2.16).

Discovered hydrocarbons in the Flemish are typically in combination, structural-stratigraphic traps, which are generalized in Figure 2.19.

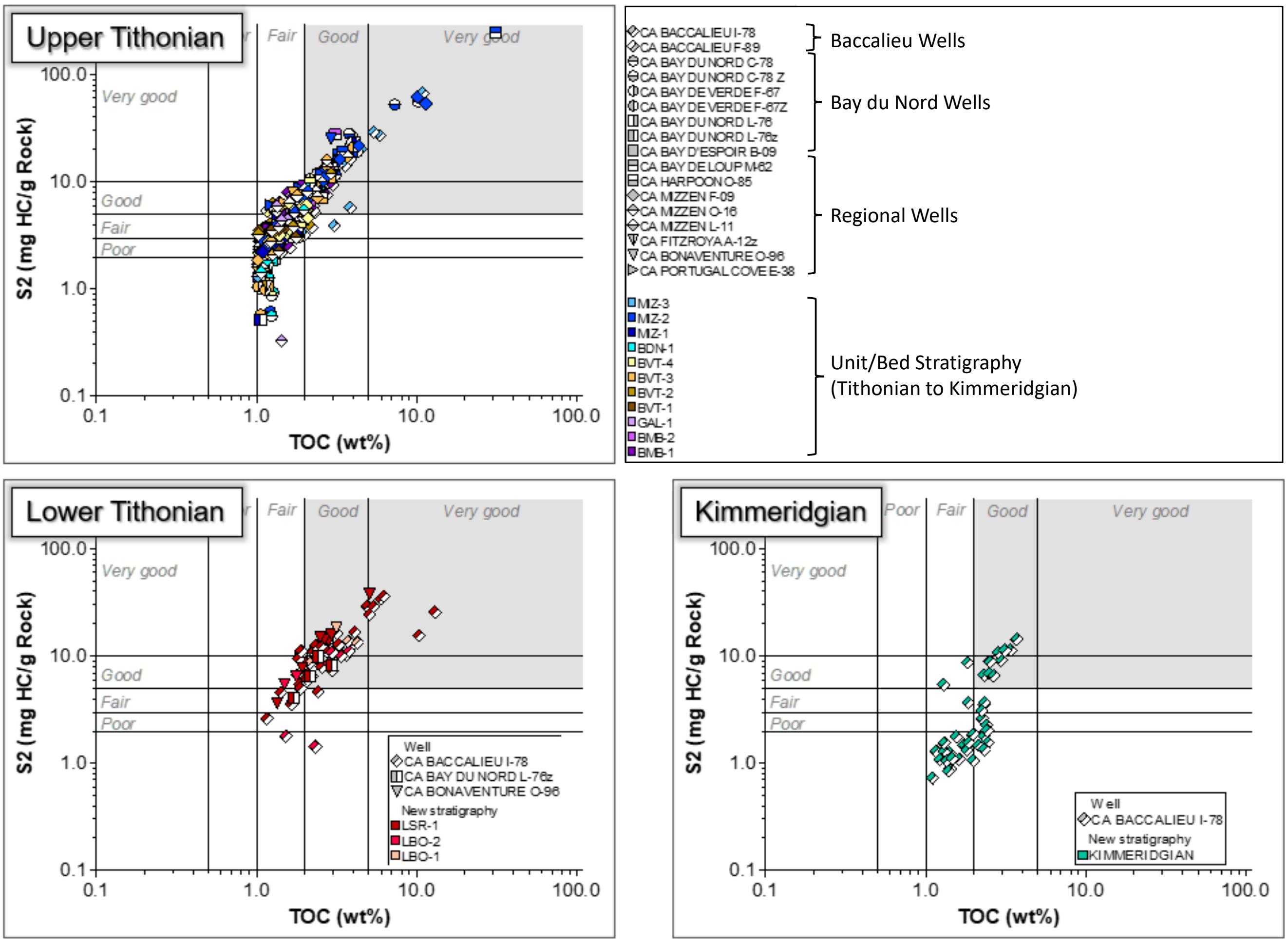


Figure 2.14 Source Rock Richness Source rock richness from Flemish Pass Basin wells, showing the relative TOC and S2 proportions by stratigraphy.

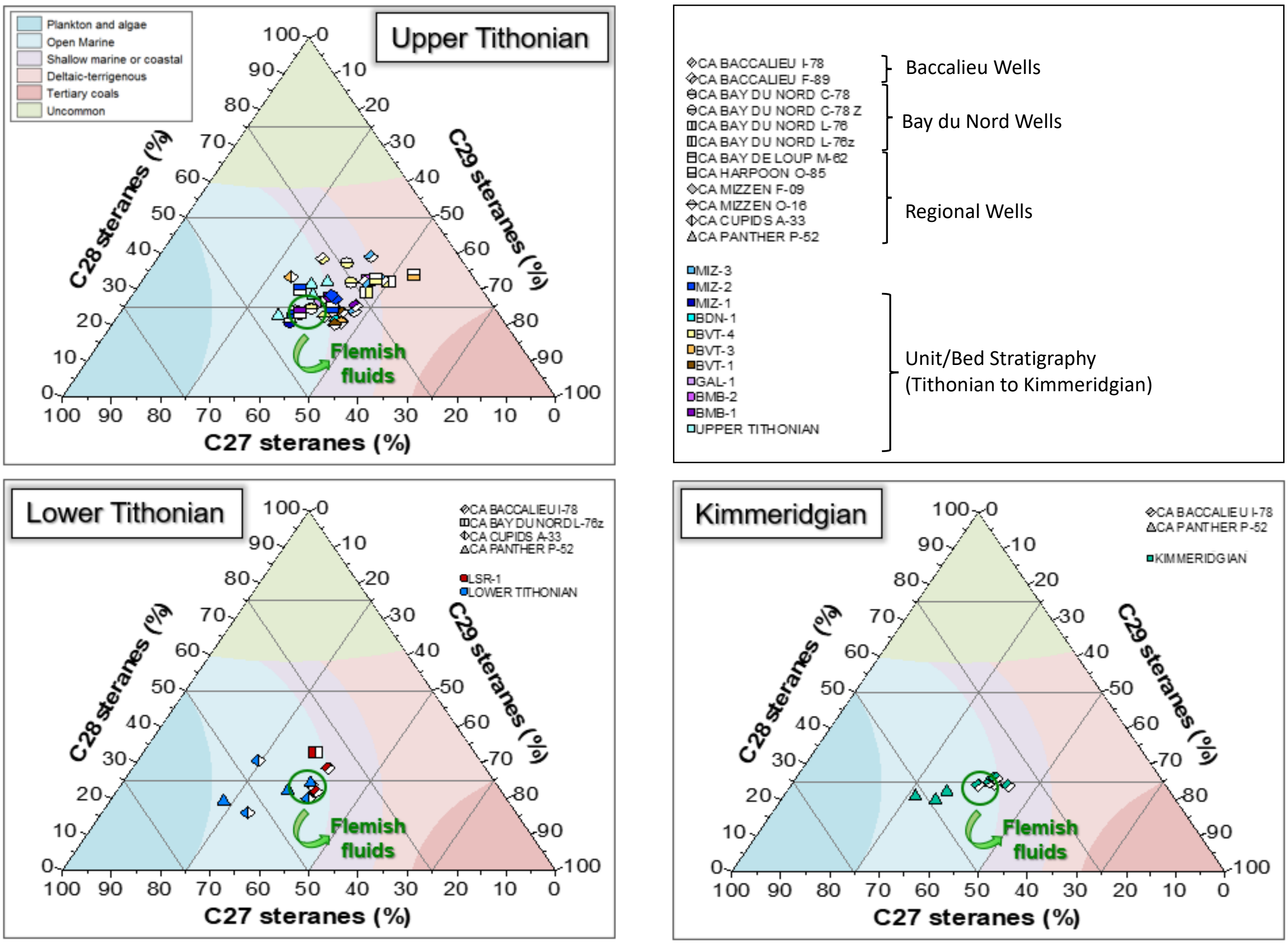


Figure 2.15 Source Rocks and Depositional Environments Ternary plots of sterane types of Flemish wells showing the differences in inferred source rock types derived by depositional setting.

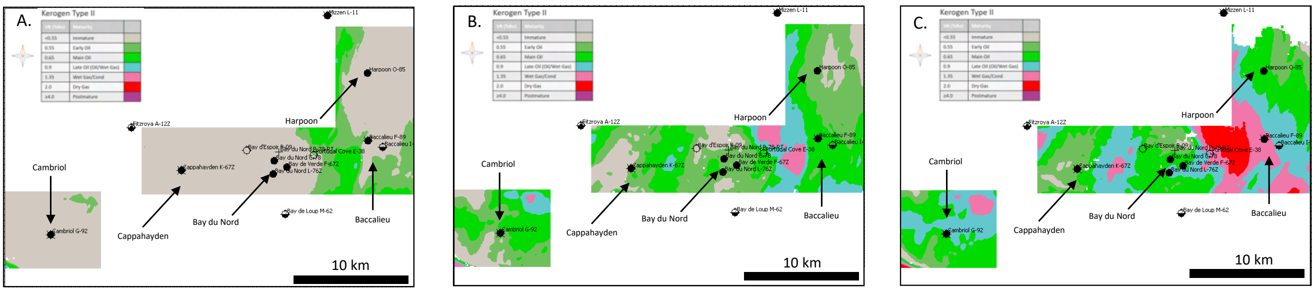


Figure 2.16 Kerogen Maturity Maps Kerogen maturity maps of the Bay du Nord Project area during peak generation. A. Upper Tithonian B. Lower Tithonian and C. Kimmeridgian.

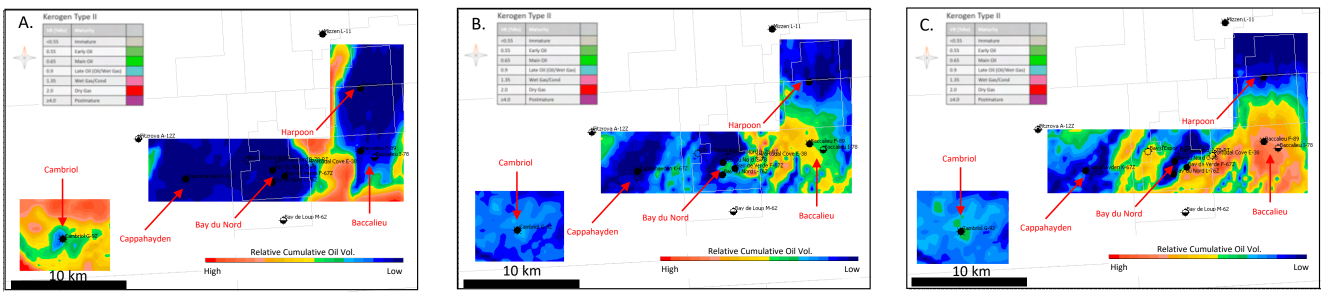


Figure 2.17 Oil Expulsion Present day oil expulsion maps of the Bay du Nord Project area. A. Upper Tithonian. B. Lower Tithonian. and C. Kimmeridgian.

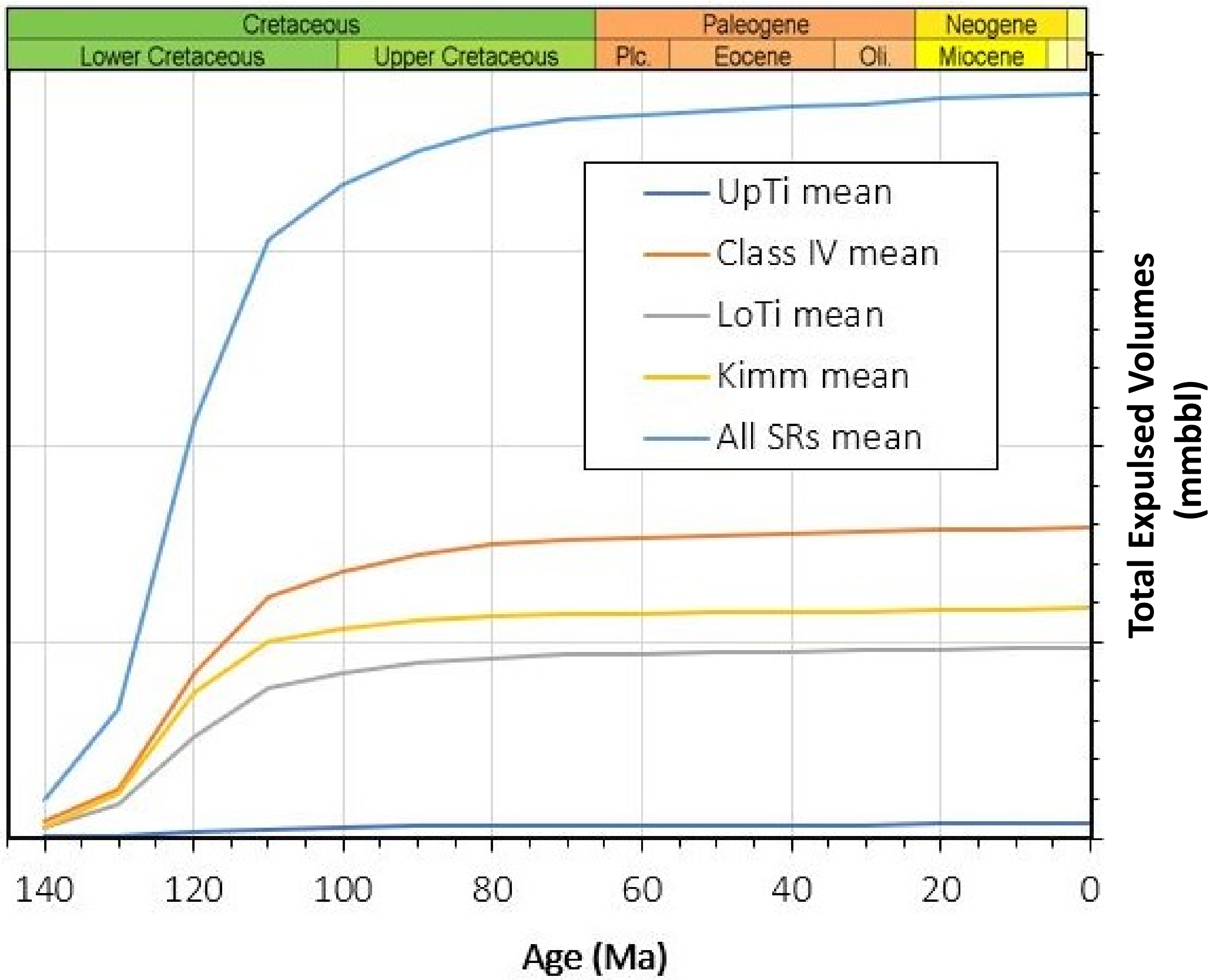


Figure 2.18 Bay du Nord Expulsion Expulsion timing plot for source rocks in the Flemish Pass Basin. Plot also includes mappable seismic (Class IV) horizon for comparison to source rock-derived curves. Mean peak charge occurs during the Cretaceous.

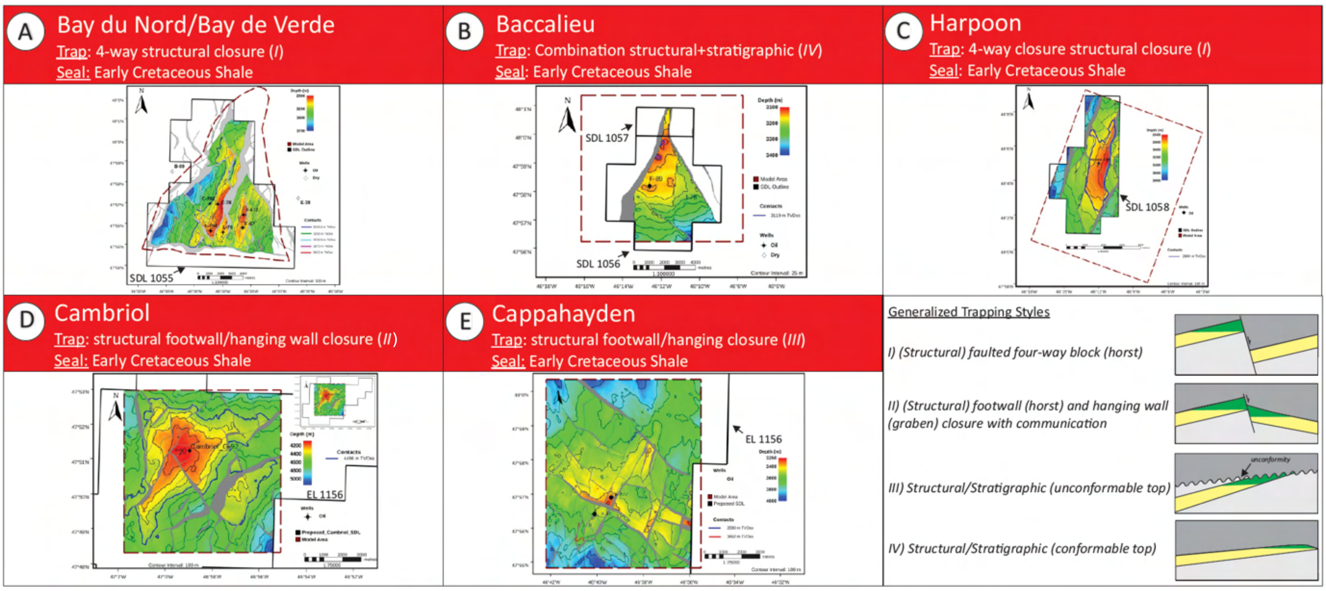


Figure 2.19 Trapping Styles for Flemish Discoveries Simplified cross-sections illustrating trapping styles for discoveries in the Bay du Nord Project.

2.3 Bay du Nord Field

Introduction

Bay du Nord L-76Z (Figure 2.20) is the type-well for Bay du Nord Field with 165 m of continuous core spanning Bonaventure to Mizzen member stratigraphy. Therefore, it was fundamental for building a geological understanding for the Bay du Nord Field using core and seismic to calibrate with other cored- and non-cored local and regional wells.

Field-Scale Structure

The Bay du Nord Field is structurally complex, with more than 150 faults interpreted seismically in the reservoir model area (Figure 5.6). Multiple episodes of rifting have affected the greater area (Section 2.2.2 Tectonics and Structure), which resulted in the complex faulting and highly compartmentalized structures evident at Bay du Nord (Figure 2.21). There are three main rifting episodes, identified as being part of the regional rift phase 2, that affect the structure and stratigraphy within the field. A typical seismic section across Bay du Nord is depicted in Figure 2.22 and a detailed overview of the fault timing of the individual faults in Bay du Nord is summarized in Figure 2.23.

(1) Rift episode 1 occurred in Late Jurassic, and gradually waned into the latest Tithonian. At the time of deposition of the Mizzen and Bay du Nord members, there was mostly tectonic quiescence and only localized fault movements are observed on the seismic data. As a result of the tectonic quiescence, the Bay du Nord and Mizzen members have a fairly uniform thickness. Regional mapping also indicates a uniform thickness is consistent outside of the Bay du Nord field. However, there are localized indications of initiation of rift episode 2 in the latest Tithonian, and consequently, growth strata is sometimes evident within the upper part of Mizzen member.

(2) Rift episode 2 occurred during the Early Berriasian to Hauterivian-Barremian, and is characterized by reactivation of NNE-SSW and N-S striking Jurassic faults, and generation of cross-cutting NE-SW Cretaceous faults. Formation of thick Cretaceous depocentres is also evident during this episode. For example, the NNW-SSE trending faults that separate the Bay de Verde East fault blocks from Bay de Verde and Bay du Nord fault blocks were active at this time. The NNE-SSW and NE-SW striking fault sets display a segmented geometry, with fault bifurcations, relays and lenses. Different kinds of fault intersections are observed: (i) cross-cutting intersection without major changes of fault strike, (ii) cross-cutting intersections with changes in fault strike, and (iii) abrupt change of fault strike at fault tip (L-shaped faults). Similar geometries of fault intersections have been observed in analogue experiments, both in non-coaxial (e.g. [46], [47]) and conjugate (e.g. [48]) faulting configurations. The majority of the faults with higher displacements show curvilinear geometry, with changes in strike. Faults with NNE-SSW to NE-SW orientation show the higher displacements (this is also observed in the Cambriol area). There are also high displacement (high heave) concentrates on few faults with strike direction ranging from NE-SW to NW-SE. The anomalous distribution of fault heave and the configuration of fault bifurcation and displacement transfer resemble the models presented in Henza et al. (2010) [46] of non-coaxial deformation.

(3) Rift episode 3, which is the last extensional rifting in the area, was ongoing in Aptian time and characterized by a major change of the orientation of the maximum horizontal stress field, which is rotated ~90° counter-clockwise with reference to the orientation in Late Jurassic (Figure 2.7). As a consequence of the rotation of the stress field, most of the faulting in the Aptian was accommodated on NW-SE striking normal faults. This accommodation is also supported by evidence of growth strata in the seismic data. The Aptian NW-SE fault population usually offsets the older faults, but intersecting geometries are also observed. An overview of the fault population data in Bay du Nord / Bay de Verde field is compiled in Figure 2.24.

As a result of the complex faulting outlined above, a high degree of structural compartmentalization is evident in Bay du Nord, and the field is sub-divided into eight structural segments (Figure 2.21). The communication between these segments will ultimately be controlled by the fault juxtapositions in combination with the stratigraphic configuration of the reservoir zones.

Core

Lithofacies ('LF'; Figure 2.25) were used to develop subsequent depositional elements (Figure 2.26, Figure 2.20, and Figure 2.27). These lithofacies are also observed in cored stratigraphy (i.e. Bay du Nord and Mizzen members) at Bay du Nord C-78, Bay de Verde F-67Z, which also result in the same depositional processes and elements.

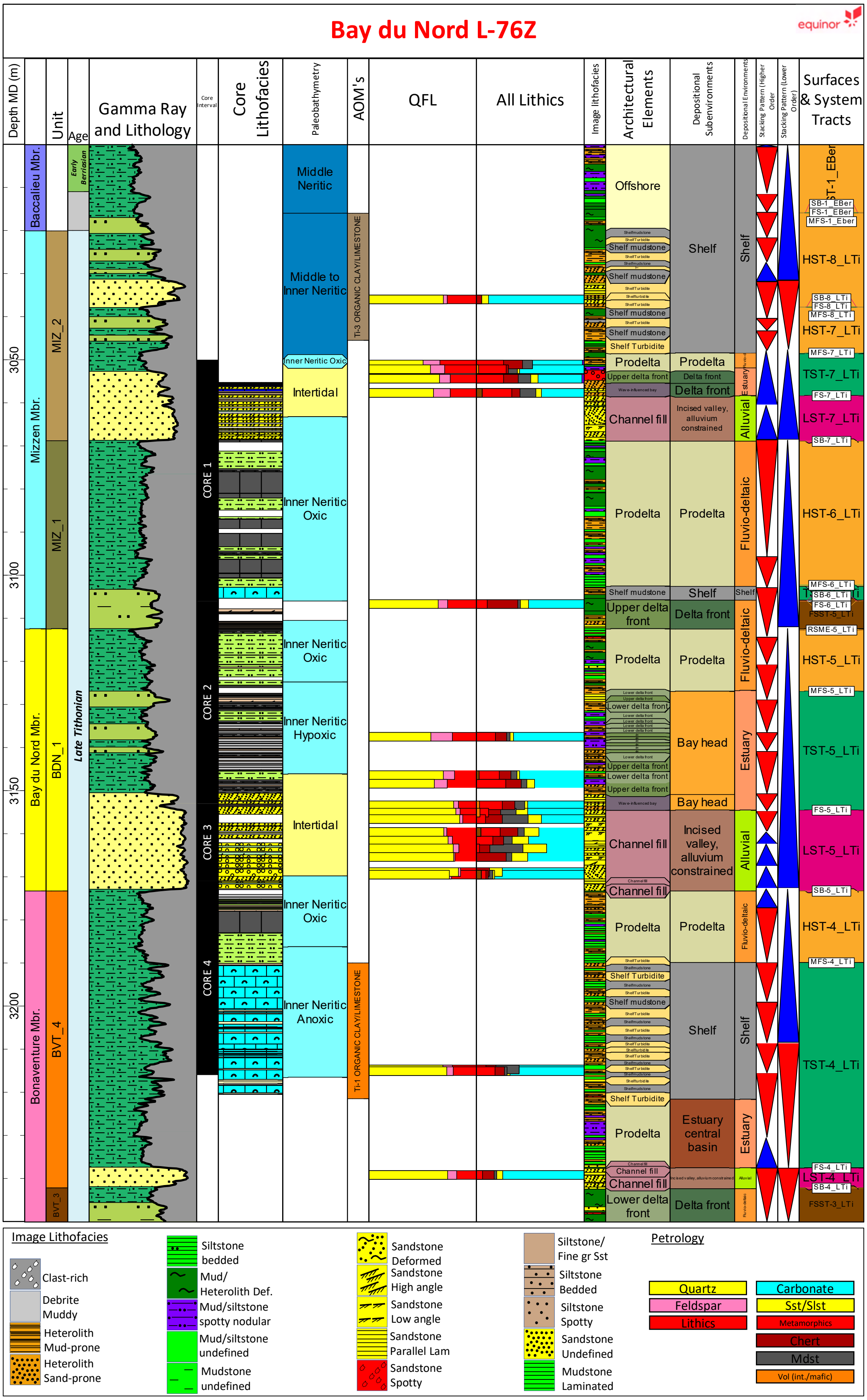


Figure 2.20 Bay du Nord L-76Z Well Panel Bay du Nord L-76Z well panel, which includes the main data types used for reservoir characterization in the Bay du Nord/Bay du Verde discovery area. Also included are key paleoenvironmental, depositional, and sequence stratigraphic interpretations, which are largely derived from core.

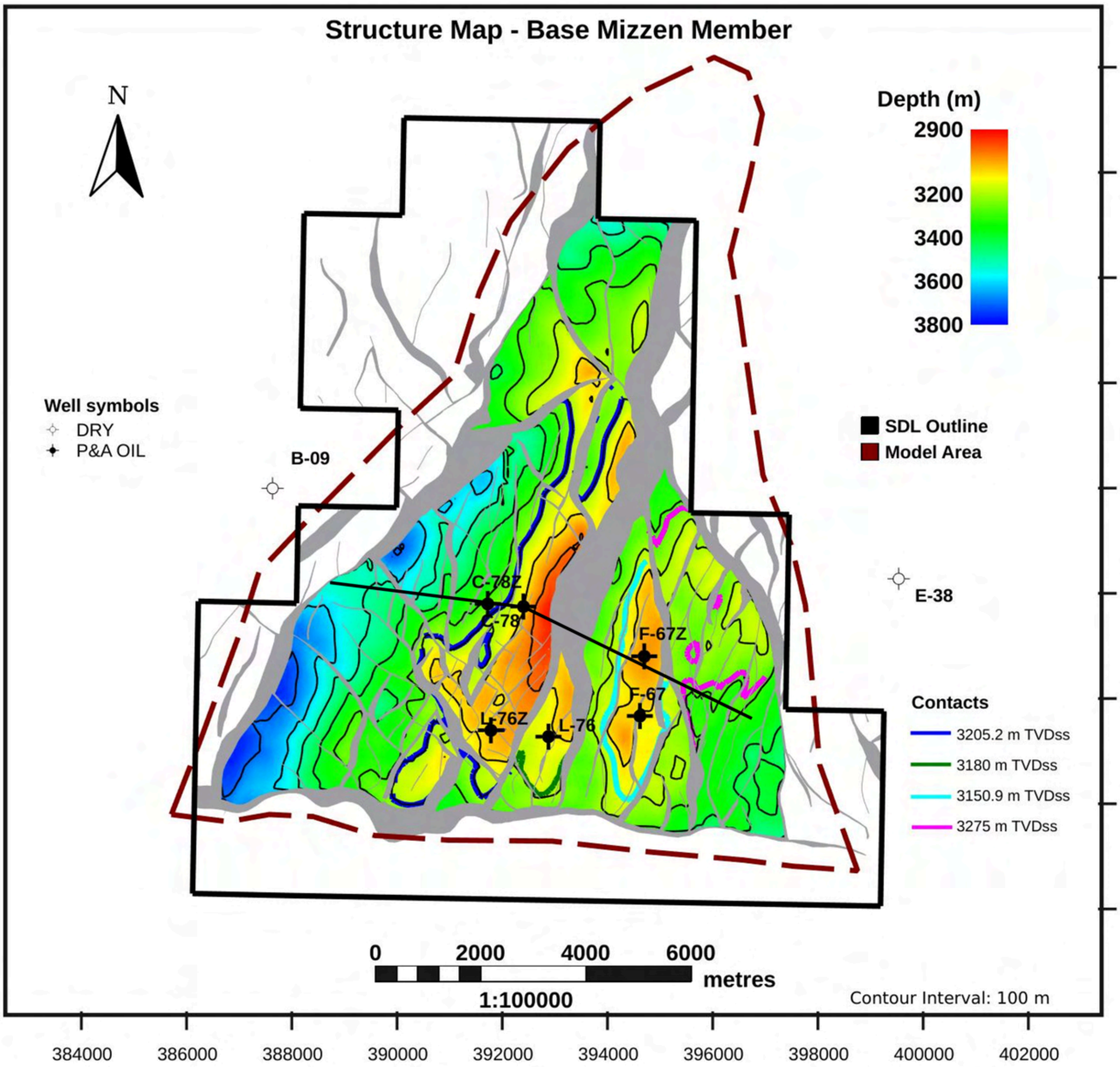


Figure 2.21 Bay du Nord Field Structural Map Base of Mizzen member Structure map at Base Mizzen level. The location of the seismic cross-section in Figure 2.22 is indicated with the black line.

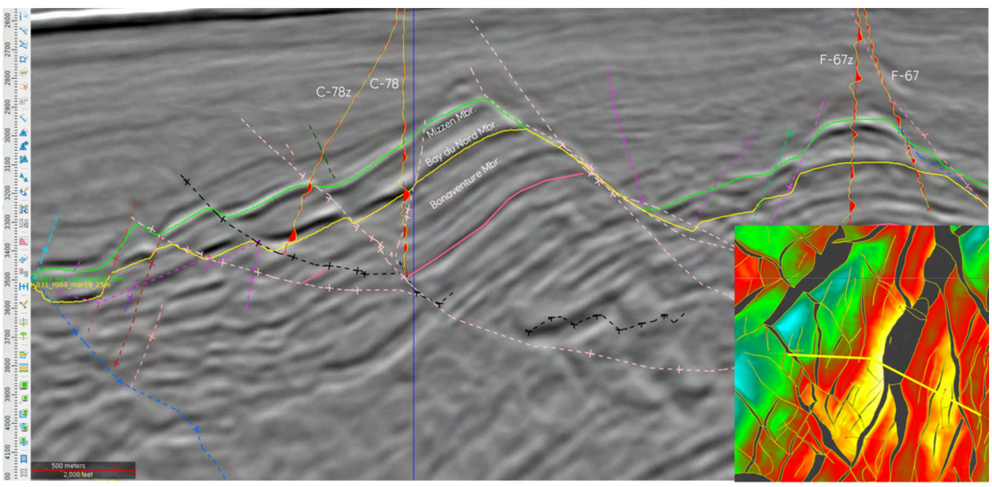


Figure 2.22 Seismic Cross-Section across Bay du Nord Field Seismic cross-section across Bay du Nord field, from Bay du Nord main across to Bay de Verde / Bay de Verde East. The line location is also indicated in Figure 2.21.

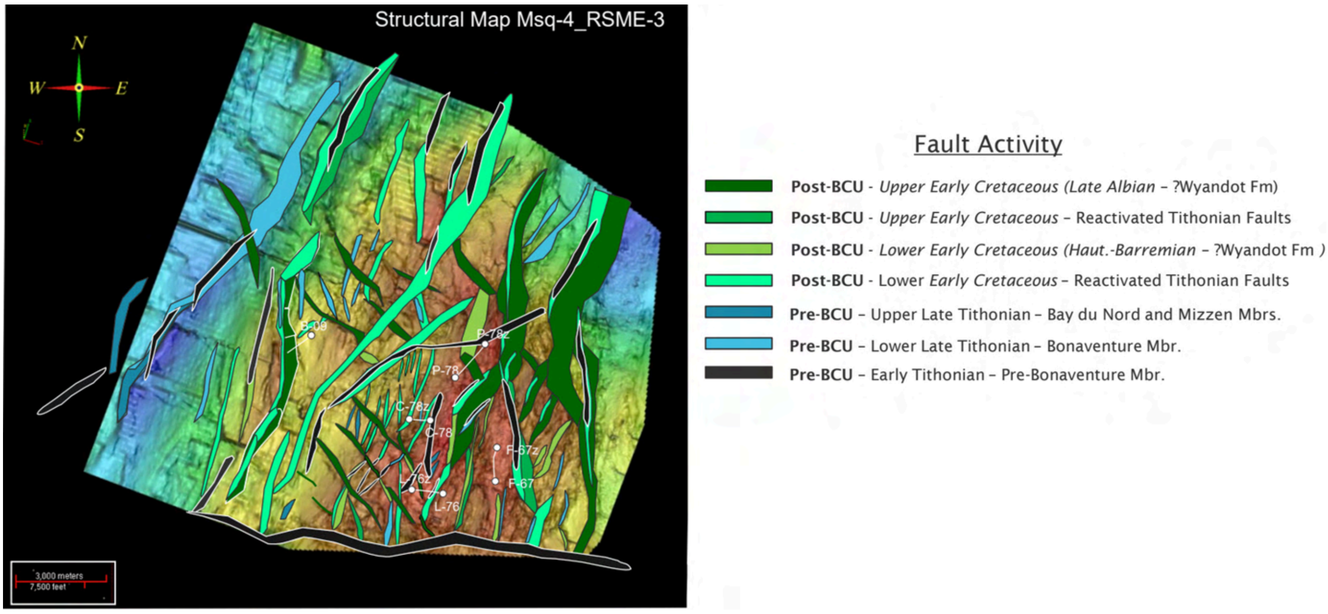


Figure 2.23 Bay du Nord Field Fault Timing Overview Fault timing for the individual faults are indicated with colors.

The cored stratigraphy in the Bay du Nord and Mizzen members, at L-76Z, consist of upper medium to very coarse-grained sandstones (LF1-LF3) sharply overlying shales (LF9-LF11) from the Bonaventure member (approximately 3169.7 m MD). The underlying shales contain occasional very-grained laminated sandstones that sometimes exhibit convolute laminations, and rare wave-rippled laminations, but can also be structureless. The lowermost shales, below 3187.5 m MD, consist of regularly occurring inter-laminated white calcareous fossils and dark brown to black organics (LF12-LF20).

Coarse-grained sandstones of the Bay du Nord member overly a basal sharp contact, which is evident in the L-76Z core and is characterized by an abrupt transition on the GR log (Figure 2.20, Figure 2.26). The sandstones contain mm-to-cm scale floating granules to pebbles (approximately 3168 m to 3167 m MD; Figure 2.26) that vary in roundness and sphericity (LF1, LF2). These sandstones gradationally fine upwards to medium-grained sandstones that are characterized by planar laminations and trough cross stratifications.

Sandstones abruptly transition into overlying fine-grained sandstone, inter-laminated with shales, which contain wave and combined flow ripples, and parallel to wavy laminations. This succession eventually transitions, with decreasing sandstone content, into an overlying succession dominated by shale, which is almost identical to shale successions underlying the sharp basal contact (LF6-LF10).

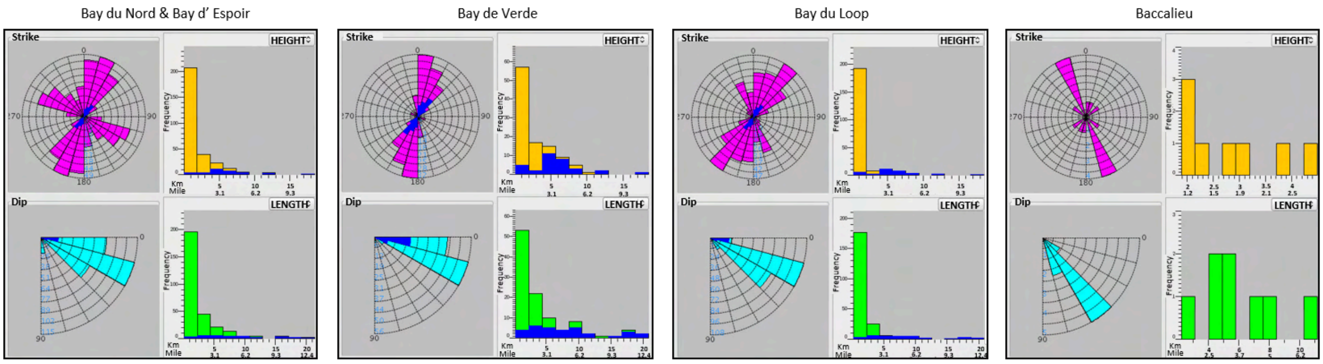


Figure 2.24 Fault Orientations in the Greater Bay du Nord Area Strike, dip, height, and length for the faults in each structure in the greater Bay du Nord area. The blue color indicates the dimensions of the faults that extend down to the Economical Basement. From left to right, Bay du Nord & Bay d'Espoir, Bay de Verde, Bay du Loup, and Baccalieu.

Chronostratigraphy and Paleoenvironments

Figure 2.26 Bay du Nord (Bay du Nord member) L-76Z Core with DSE Selected core images, amongst cores 3 and 4, from Bay du Nord L-76Z. Colours represent depositional sub-environments; shelf (grey), incised valley (light brown), bay head delta (orange). Note the sharp basal Bay du Nord member contact denoted in a dashed red line.

LF1	Very coarse-to coarse-grained sandstone with abundant granules and pebbles up to 2cm in diameter. Clasts consist of quartz and feldspar. Clasts rounded to angular and sorting from moderate to very poor.	LF11	Interbedded calcareous silty mudstone, very fine-grained sand (well-sorted) and upper silt beds and lamina sets, with abundant calcareous material.
LF2	Very coarse to medium grained sandstone with isolated clasts comparable to those of Facies 1 floating in moderately to poorly sorted sandstone.	LF12	Very fine grained calcareous grainstone /mudstone that is grey, beige to white locally.
LF3	Medium grained sandstone (well sorted). Typically, transitional from Facies 1 and 2 into Facies 4. Rare gravel and mudstone rip up clasts dispersed in the sandstone.	LF13	Limy grainstone.
LF4	Lower fine-grained sandstone (well sorted).	LF14	Shale, dark grey to black.
LF5	Upper fine to fine grained sandstone moderately sorted). Base is transitional from Facies 2 to Facies 4 T op sharply overlain by Facies 2 .	LF15	Fine to very fine-grained calcareous sandstone.
LF6	Upper fine-grained sandstone (well sorted).	LF16	Silt and sand layers with fining upward lamina sets; grey.
LF7	Fine grained sandstone (well sorted) with subordinate mudstone drapes.	LF17	Very fine grained, calcareous silty to sandy mudstone, grey to beige in colour
LF8	Heterolithic unit consisting of subequal proportions of mudstone, siltstone and very fine grained well sorted sandstone. Sand and silt as laminae or in lamina sets. Bed scale sand and silt layers uncommon.	LF18	Light grey marl.
LF9	Heterolithic mudstone dominated intervals. Silt layers comprise approximately 30% and sandstones constitute < 10%.	LF19	Medium to coarse-grained sandstones, beige in colour.
LF10	Mudstone (>90%), with rare silt and sand lamina sets.	LF20	Glauconitic silty mudstone.

Figure 2.25 Lithofacies in the Flemish Pass Basin Flemish Pass Basin Lithofacies (LF). Colours are represented in subsequent well panels for each discovery area.

Facies Association/Architectural Element	Unconfined		Confined	
	Depositional Subenvironment	*Depositional Environment*	*Depositional Subenvironment*	*Depositional Environment*
Channel Fill	Incised Valley	Alluvial	Incised Valley	Alluvial
Channel Abandonment	Incised Valley/Delta Top	Fluvio-deltaic or Delta	Incised Valley/Delta Top	Estuary
Wave Influenced Restricted Bayfil/Bayfilll	Delta Top		Bayhead Delta	
Distributary Channel Fill				
Distributary Mouthbar/River Mouth Deposits	Delta Front			
Upper Delta Front				
Lower Delta Front				
Slump (Good Quality)				
Shelf Turbidite	Shelf	Shelf	Shelf	Shelf
Shelf Mudstone				

Figure 2.27 Flemish Pass Facies The main facies in discovery areas interpreted from type wells. Facies associations are illustrated with approximate correlating depositional nomenclatures and by confinement.

Core samples and cuttings taken from L-76Z, in addition to other cored and non-cored wells in the Flemish Pass Basin, indicate that the Bonaventure, Bay du Nord, and Mizzen members represent Tithonian stratigraphy between 147.7 and 145 Ma (Figure 2.3 and Figure 2.20).

Paleoenvironmental analysis of L-76Z concludes that the encountered Tithonian sediments generally represent inner neritic water depths with varied levels of oxygenation ([49], [50], [51], and [52]), with the exception of the sandstone-rich intervals (intra Bay du Nord and Mizzen members), which are interpreted to represent relatively shallower water conditions with improved oxygenation.

The uppermost Tithonian paleoenvironments (approximately <3050 m MD) indicate a slight deepening of the water column with varied oxygenation.

Petrology

An example of petrological results are illustrated in Figure 2.28. Most samples analysed from L-76Z illustrate sandstones that classify as sublitharenites to feldspathic litharenites using a QFL ternary plot after Folk (1980) [53]. This classification is typical of most Tithonian sandstones observed in project wells, as most tend to be less enriched in feldspathic components.

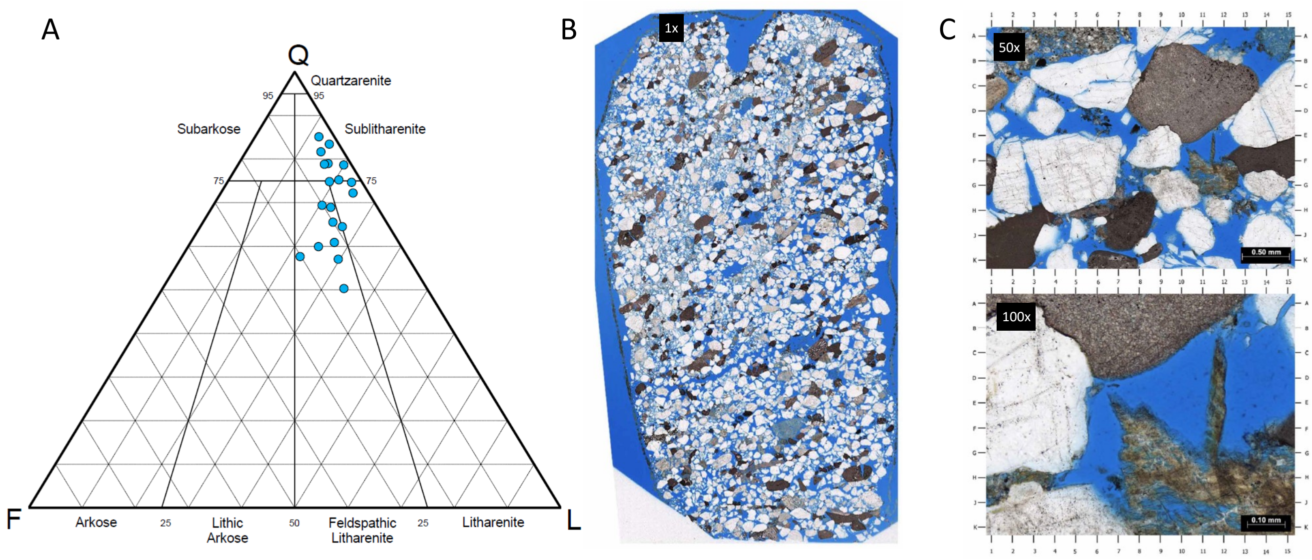


Figure 2.28 Bay du Nord L-76Z Petrology Example A. QFL plot (after Folk, 1980); B. 3169.5 m MD sample from the Bay du Nord member at 1x and; C. 3169.5 m MD at 50x (upper image) and 3169.5 m MD at 200x (lower image). Images illustrate poor sorting, medium-grained sublitharenite sandstone, with moderate compaction. Grains are dominantly (monocrystalline) quartz with rock fragments mainly comprised of limestone and metamorphics.

The photomicrographs illustrate massive to poor grain alignment with poor sorting. Grains are predominantly consist of monocrystalline quartz (25.3% to 54.7% by volume) and lithics ranging 3.3% to 13.3% by volume, consisting predominantly of limestone with some metamorphic grains (phyllite and slate).

Cements are present but in lower proportions (i.e., 2.0% to 26.7% by volume) and are commonly calcite and ferroan dolomite cements. In addition, there are quartz overgrowths (some of which could be inherited), and authigenic clays (e.g. illite and/or mica).

The over-porosity and permeability is considered good to excellent (cf. Section 3.2 Bay du Nord Field) and appears to be preserved due to limited compaction and cementation with preservation of the original lithological textures.

Log Data

The full suite of petrophysical logs are described in detail for the Bay du Nord Field in Section 3.2 Bay du Nord Field. GR log motifs (following Cant, 1992 [54]) were used across cored intervals and calibrated against uncored stratigraphy to aid in developing the depositional elements within the L-76Z type well and the Bay du Nord Field.

Figure 2.29 illustrates the types of log motifs interpreted from Bay du Nord L-76Z. The main sandstones of the Bay du Nord and Mizzen members (i.e., BDN_1 and lowermost MIZ_2) have cylindrical- to bell-shaped motifs, while thinner sandstones throughout the well panel display funnel-shaped motifs. Shales can display all five motifs; however, serrated and funnel motifs are the most common.

Stacking Patterns

The stacking patterns are also illustrated in Figure 2.20, which depicts two different hierarchies for stacking. The higher order stacking patterns represent cycles of coarsening- and fining-up grain size trends that are largely constructed from core observations, whereas the lower order stacking patterns represent larger-scale depositional trends linked to sequence stratigraphy (i.e., larger transgressive-regressive cycles).

Higher order cycles largely consist of coarsening or regressive cycles (i.e. red triangles), ranging from 2-30 m. Occasional fining-up or transgressive cycles are interpreted across the Bay du Nord reservoir (stacked 2-5 m cycles) and similar-sized intervals that occasional overly the regressive cycles (e.g. Bonaventure and Mizzen member sandstones).

Lower order cycles are largely comprised of 20-60 m transgressive cycles, which dominate the cored stratigraphy. Regressive cycles are also (partially) observed at the core base and top, but are interpreted to represent relatively smaller cycles (10-30 m).

Depositional Environments and Analogues

The sequence stratigraphic framework built and defined in Figure 2.5 was used to create depositional models and subsequent Depositional Sub-Environment (DSE) maps for the Bay du Nord and Mizzen members across SDL 1055 (Figure 2.30). These maps represent maximum regression to Lowstand Systems Tract (LST) Bay du Nord and Mizzen members for the Bay du Nord and Mizzen member reservoirs encountered (i.e., Sequence 5, LST and Sequence 7, LST). SDL 1055 mainly consists of terraced incised valley's (approximately 2-5 km in width and 50 m thick) trending E-NE/S-SW comprised of fluvial channels.

Transgressive systems tract maps are shown in Figure 2.31 and represent flooding or partial flooding of the previous LST fluvial channels within incised valleys and on the alluvium. The main depositional systems are deltaic at this time, with N-S and transverse systems contributing to the overall paleodrainage. These delta systems are envisioned to have some or full confinement in the valley systems; however, it is unknown how facies change from confined to unconfined during each sea level rise within each depositional sequence.

All types of depositional analogues address varying degrees of confinement, depositional environments, and sedimentological processes. The Terra Nova Field is considered a depositional subsurface analogue for the Bay du Nord Field. Possible modern depositional analogues that may be applicable to Bay du Nord and Cambriol include the Trinity Valley system, Pensacola (and associated) Bay(s), and the Wax Lake Delta, Atchafalaya. Outcrop analogues include Willow Creek, Little Park Wash and Coal Canyon, which are located in Utah and Colorado.

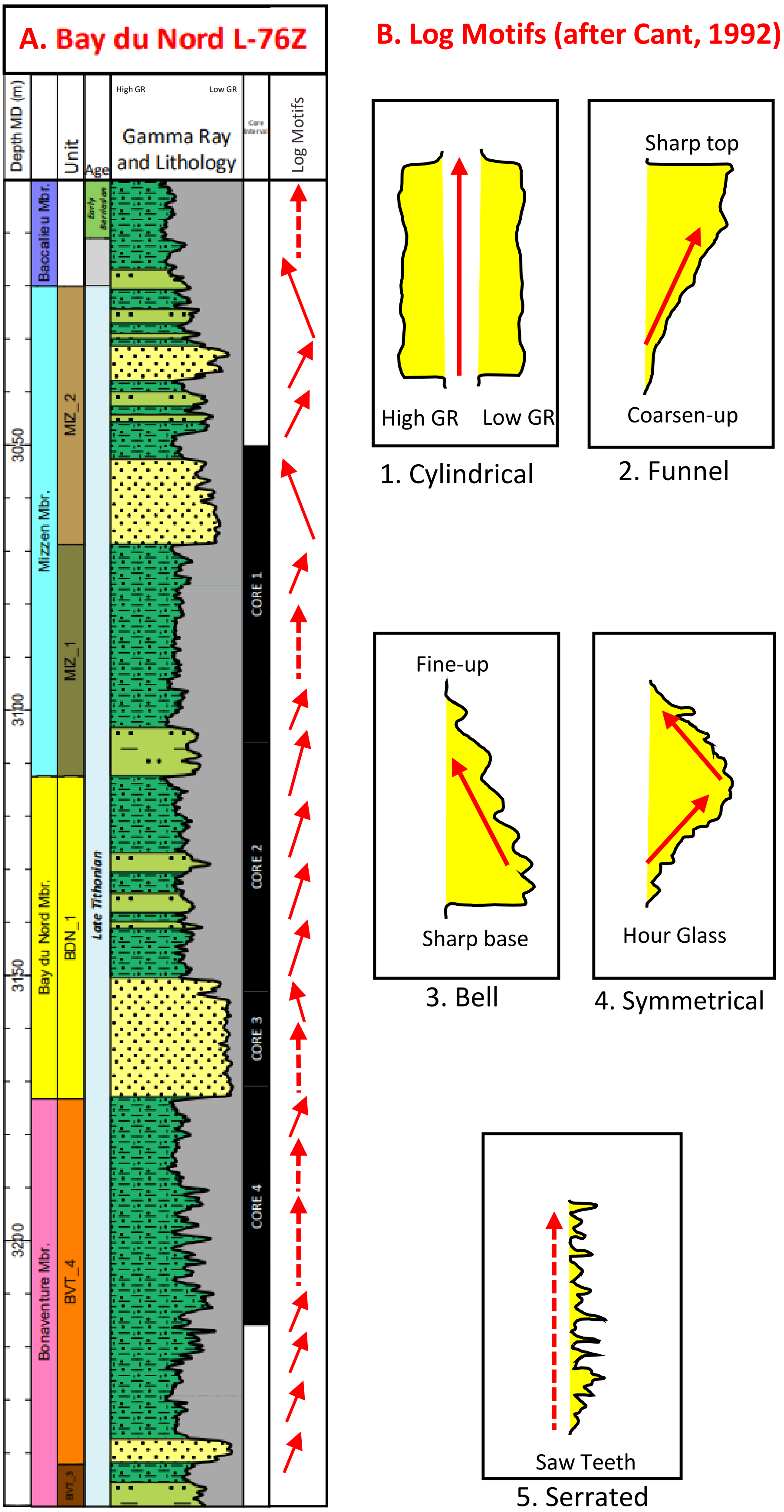


Figure 2.29 Bay du Nord L-76Z Well Panel with Log Motifs (A) with lithostratigraphy, chronostratigraphy, lithology, gamma ray, and core locations. An additional column illustrates how the log motifs were interpreted across the cored and uncored stratigraphy. The gamma ray log motifs (B) are referenced to five types defined by Cant (1992), which suggest probable environments of deposition for each.

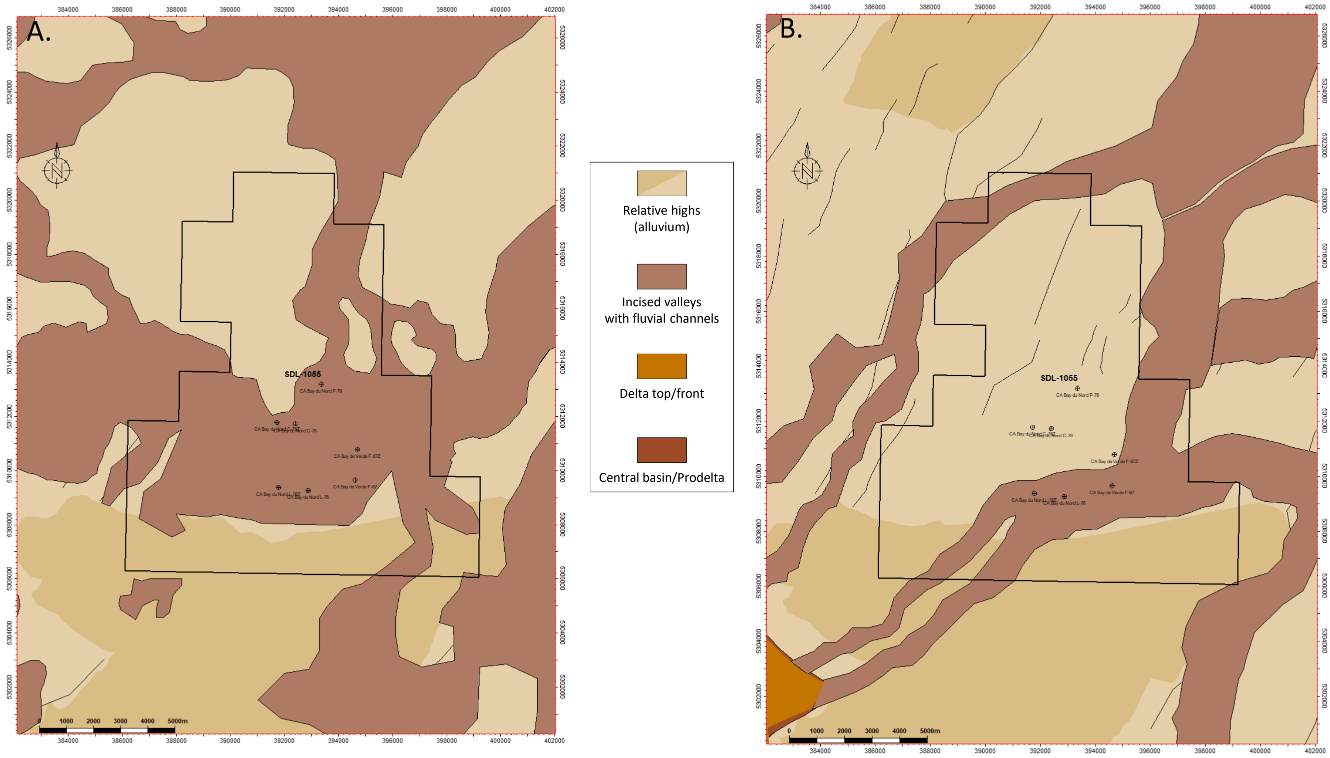


Figure 2.30 SDL 1055 Bay du Nord and Mizzen Members LST Depositional sub-environment maps for A. Bay du Nord and B. Mizzen Members (Sequences 5 and 7, respectively) at SDL 1055.

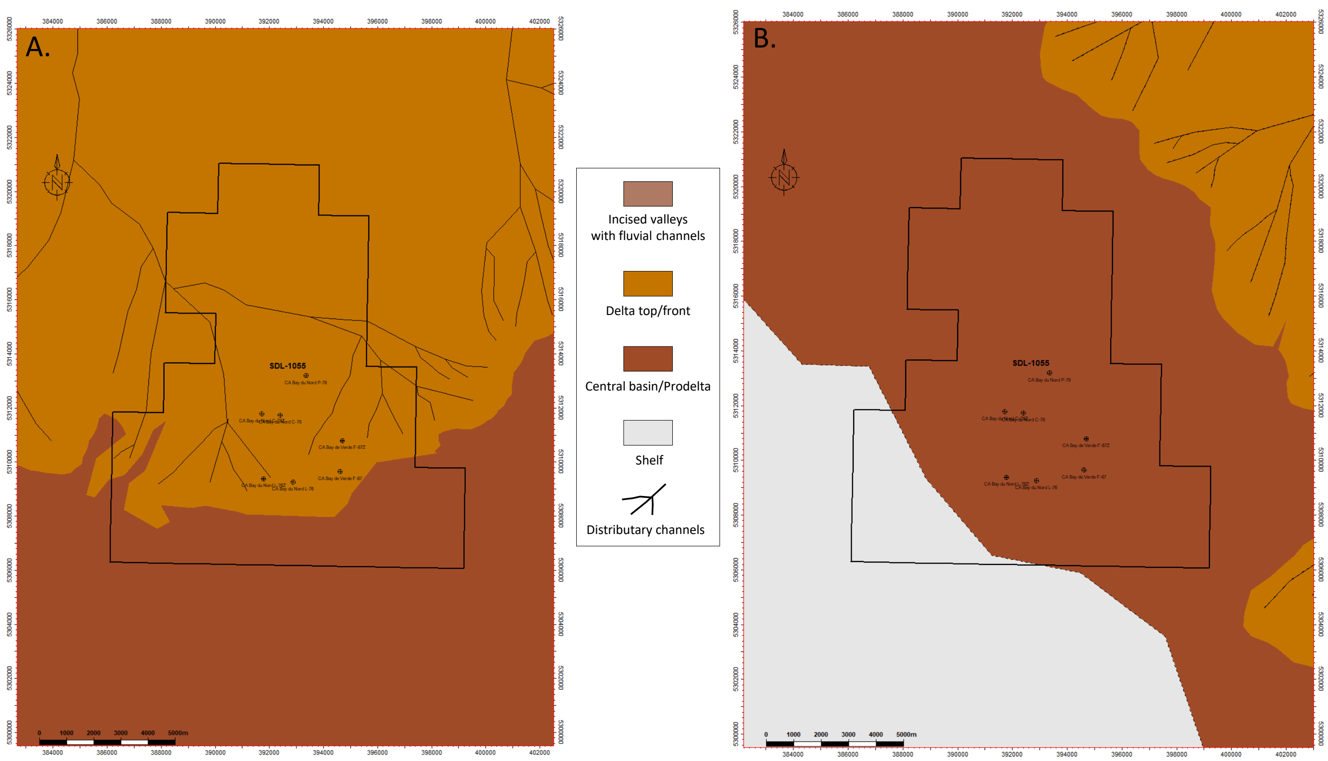


Figure 2.31 SDL1055 Bay du Nord and Mizzen Members TST Depositional sub-environment maps during transgression for A. Bay du Nord and B. Mizzen members (Sequences 5 and 7, respectively) at SDL 1055.

2.4 Cambriol Field

Introduction

Cambriol G-92 is the discovery well for the Cambriol structure, which contains 27 m of core from the Mizzen member (Figure 2.34). This core was calibrated to wireline logs and used to define depositional facies and sequences throughout the well.

Field-Scale Structure

The Cambriol structure is significantly deformed by multiple phases of faulting similar to the other discovery areas in the Flemish Pass Basin (Figure 2.32, Figure 2.33, Figure 5.18). However, at Cambriol the structural uncertainty is higher as the seismic resolution and data quality is low (Section 4.3.5 Horizon Uncertainty Modelling). The structural setting and tectonic development is similar and consistent with what is seen in other areas in the Flemish Pass and can be sub-divided into three post-Kimmeridgian deformation phases. There is also pre-Kimmeridgian tectonic activity that occurred during deposition of the Bonaventure member, but this interval is not mapped extensively as it is not hydrocarbon-bearing at Cambriol. This tectonic activity is not discussed locally at Cambriol, but is described regionally in Section 2.2 Regional Geology. A summary of the most important field-scale observations is given below:

(1) Late Tithonian faulting (Figure 2.32). This is a period of dispersed and subtle faulting, in accordance with a typical rift initiation phase as described by Gawthorpe and Leader (2000) [55]. Most SW-NE faults seem to be active at this time, but with very subtle movements (estimated to a maximum of a few 10s of metres displacement). As is discussed in Section 4.3.3 Structural Seismic Interpretation, it is possible there is some minor growth of the

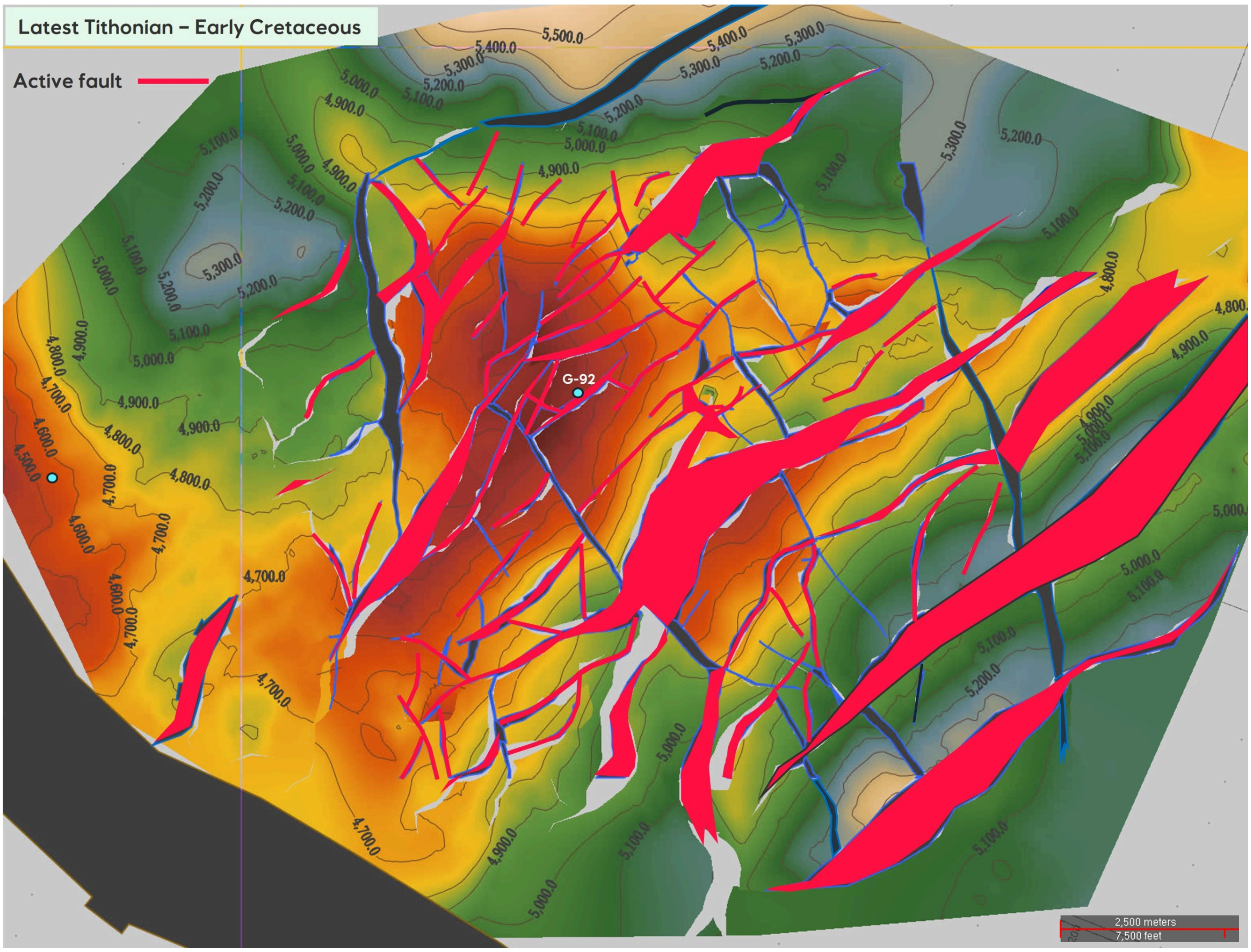


Figure 2.32 Fault Timing Late Tithonian to Berriasian All red faults have been identified as active in Late Tithonian to Early Cretaceous (Berriasian). All other faults were not present at this time.

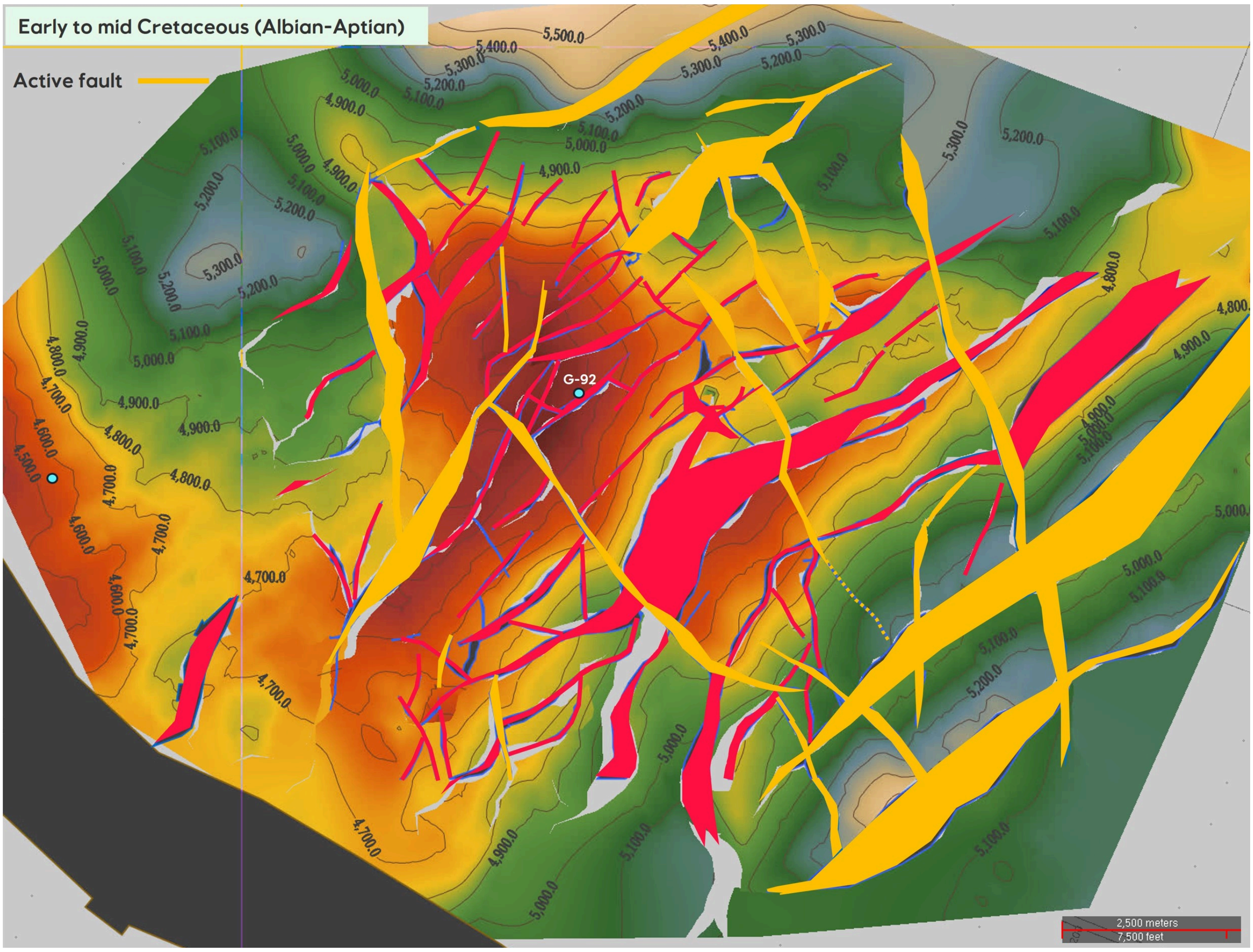


Figure 2.33 Fault Timing Aptian All orange faults have been identified as active in Aptian time. All other faults were inactive (but present) at this time.

Mizzen reservoir during this time, but this growth is uncertain. There is no evidence of any growth during deposition of the Bay du Nord member, but this is also uncertain as this stratigraphic level was not a priority for mapping, and a detailed interpretation has not been completed.

(2) In the Early Cretaceous, rifting picks up and by the Early Berriasian faults are linking up to form longer fault segments with larger displacements (100s of metres). Most of the extension at this time is taken up on a few of the larger faults (with larger fault heaves) in SW-W, while some of the previously active faults from Jurassic became inactive. Fault throws vary from 10s to 100s metres of displacement (look at the fault heaves to distinguish the smaller from the larger ones).

(3) In the Aptian, there is a large-scale shift in the stress-field, which can be linked to the regional tectonic evolution (Section 2.2.2 Tectonics and Structure). A new set of predominantly NW-SE faults (Figure 2.33) is formed at this time, and these cross-cut many of the already existing faults at a high angle (~90°). Some of the older structures are also reactivated (for example the two large faults in SE), but mostly the Aptian faults are newly formed. Fault throws typically vary from 10 to 100 metres in some cases, but in general smaller displacements are seen in Aptian than in Berriasian-Valanginian. It seems that most of the erosion in Cambriol is related to these later fault movements (Valanginian to Aptian).

Overall, the structures in Cambriol may have a significant implication on the compartmentalization of the reservoir, but less influence on the reservoir deposition and reservoir quality. Based on fault geometries and truncations, six structural segments have been defined in the Cambriol field (Figure 5.3) and the base case interpretation is illustrated in Figure 5.18. Region F is interpreted to be isolated from the main field (i.e., different contact than regions B, C and D) and may or may not be filled with hydrocarbons.

Data Panel

Figure 2.34 displays an integrated panel of key subsurface data types that were used to construct depositional models and maps.

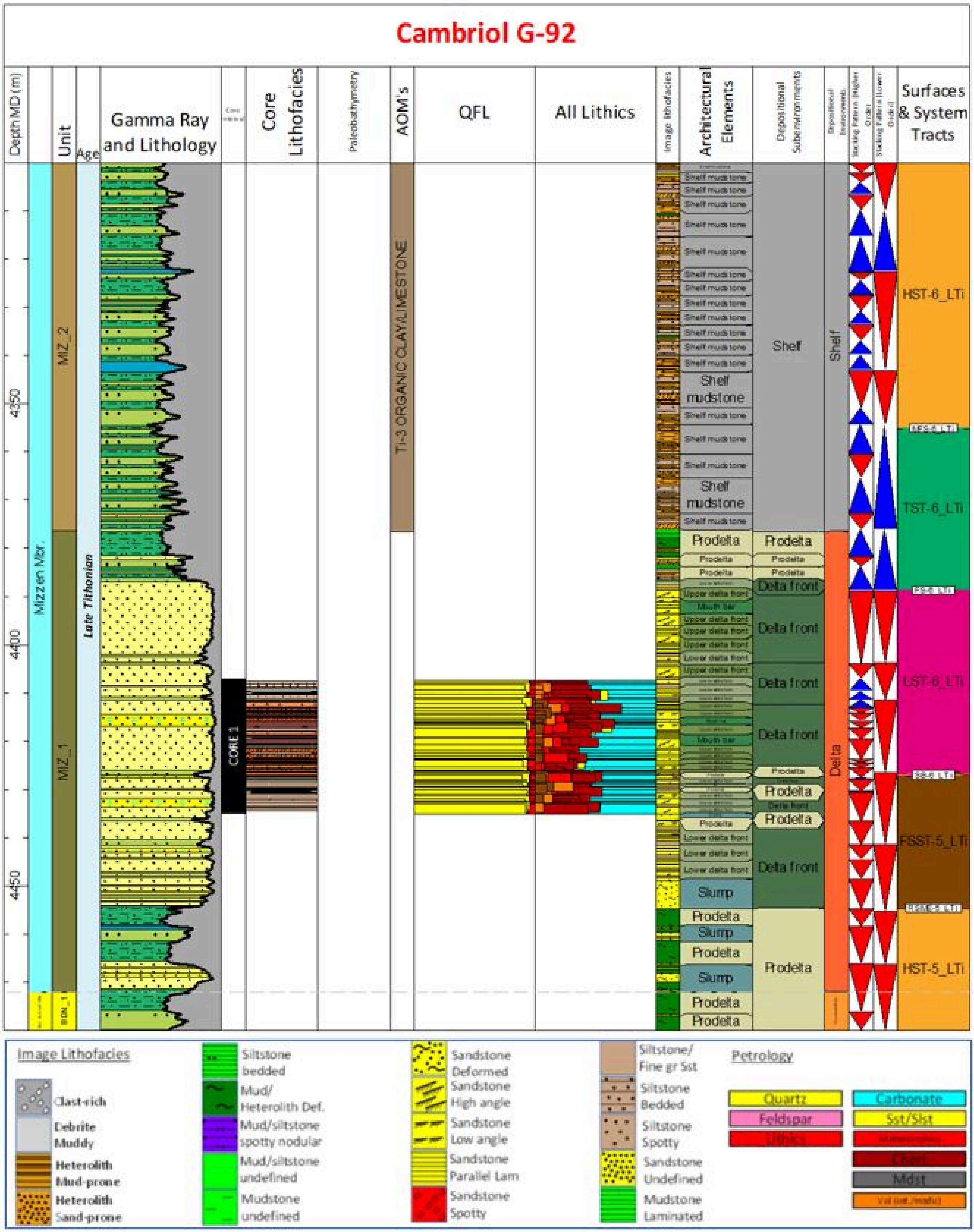


Figure 2.34 Cambriol G-92 Data and Interpretations

Core

The cored stratigraphy in the Mizzen member at G-92 consists of fine to very coarse-grained sandstones (LF2-LF5), with minor mudstones (LF8/LF9) (Figure 2.35). The underlying and overlying mudstones are uncored. The lowermost cored section comprises fine-grained sandstones, with mm-scale sand- and organic-rich parallel or very low-angle laminae (LF1-LF3) (Figure 2.35A). They are occasionally intercalated with muddy heteroliths with soft-sediment deformation and local hummocky cross-stratifications (LF8-LF9) (Figure 2.35B). These sandstones gradationally coarsen upwards to medium-grained sands displaying m-thick coarsening packages, tangential or tabular cross beds, and bedsets with opposing directions and reactivation surfaces (LF4) (Figure 2.35C). Further up-section these sediments pass into very coarse-grained sandstones, with floating granules, poor sorting, and crudely developed cross-beds (LF5) (Figure 2.35D). Coarse-grained sandstones abruptly transition into overlying fine-grained sandstone (LF1-LF3), intercalated with siltstones, which contain current ripples, low-angle laminae, and wavy laminae.

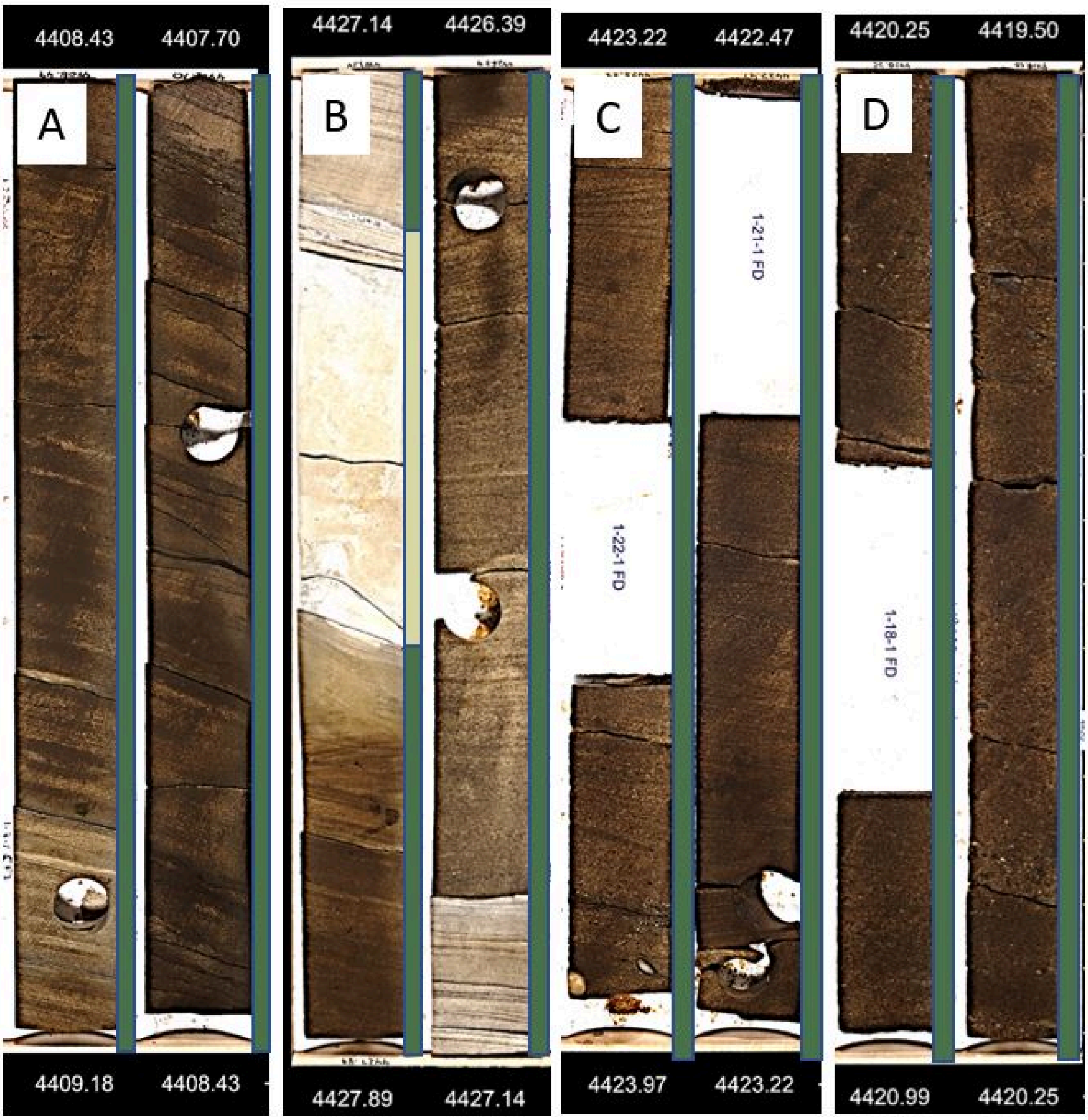


Figure 2.35 Cambriol G-92 Core Examples DSE A) 4407.70-4409.18 m displaying fine-grained sandstones with low-angle to horizontal cross-stratification in a distal delta front environment (dark green). B) 4426.39-4427.89 m. Muddy heteroliths with soft-sediment deformation and local hummocky cross-stratification in a prodelta environment (pale olive green) overlain and underlain by fine-grained sandstones in a distal delta front environment (dark green). C) 4422.47-4423.97 m. Fine- to medium-grained sandstones with high-angle tabular cross-stratification in a proximal delta front environment (dark green). D) 4419.50-4420.99 m. Coarse-grained sandstone with granules, poor sorting, coarsening-upward trends, and crudely developed cross-beds in a proximal delta front environment (dark green).

Chronostratigraphy and Paleoenvironments

Core samples and cuttings from G-92 indicate that the Mizzen member represents Late Tithonian stratigraphy (Figure 2.34). Paleoenvironmental analysis concludes that the cored sandstone interval represents a proximal marine embayment (intertidal), with a very shallow water depth (0-20 m), an oxic water column, variable water salinities, and a sparsely vegetated coastal plain. The encasing mudstones found above and below the Mizzen member sandstones were deposited in a slightly deeper water setting (inner neritic environment) with anoxic to dysoxic conditions.

Petrology

An example of petrological results are illustrated in Figure 2.36. Most sandstone samples from G-92 are classified as quartzarenite to sublitharenite using a QFL ternary plot after Folk (1980) [53]. This classification is typical of most sandstones observed in project wells in the Late Tithonian; however, many of the samples in G-92 are enriched in monocrystalline quartz relative to other wells in the Flemish Pass. The photomicrographs illustrate a range of textures from massive and poorly sorted to laminated with grain alignment. Monocrystalline quartz forms a major detrital constituent (40-74%). Minor detrital constituents include metaquartzite, carbonate fragments and chert. Cements are present in variable proportions (2-44.7% by volume) and are commonly calcite and dolomite (up to 40%), in addition to inherited quartz overgrowths (1-10%) and authigenic clays (predominantly illite and/or mica).

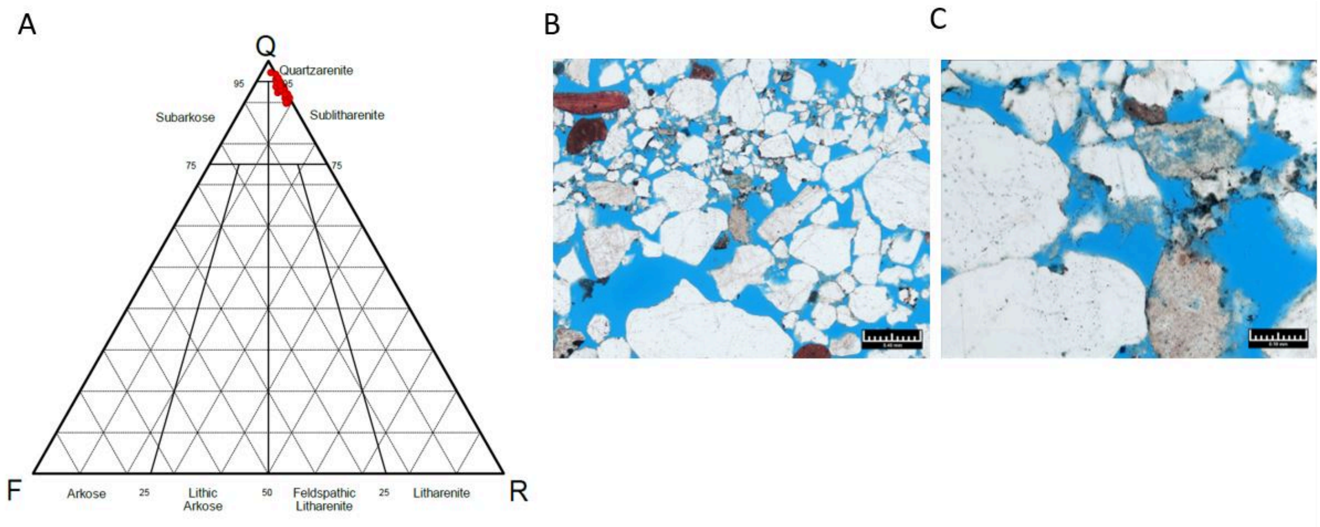


Figure 2.36 G-92 Petrology A) Sandstone classification (after Folk, 1974). B) 50x view of 4424.79 m showing a massive fabric. C) 200x image illustrating varied grain size and a pore network reduced by quartz overgrowth, dolomite cement, and calcite/ ferroan calcite cement.

Log Data

GR and VSh log motifs were calibrated against cored intervals and extrapolated into uncored sections (after Cant, 1992 [54]; Figure 2.37). The main sandstones of the Mizzen member (i.e. MIZ_1) have predominantly funnel-shaped motifs (ranging from 5-10 m thick), corroborating with the coarsening-up observations made from core (Figure 2.34).

Stacking Patterns

Two hierarchies of stacking pattern have been identified in Cambriol G-92 (Figure 2.34). In the Bay du Nord and Mizzen members, lower order cycles are largely comprised of 10-30-m-thick regressive trends until top MIZ_1. Higher order cycles display a similar trend, with coarsening upward / regressive trends, but at a finer scale (1-10-m thick). Above MIZ_1, there is a change in stacking pattern (at both higher and lower orders) to predominantly transgressive cycles, which continue up-section towards the base Cretaceous.

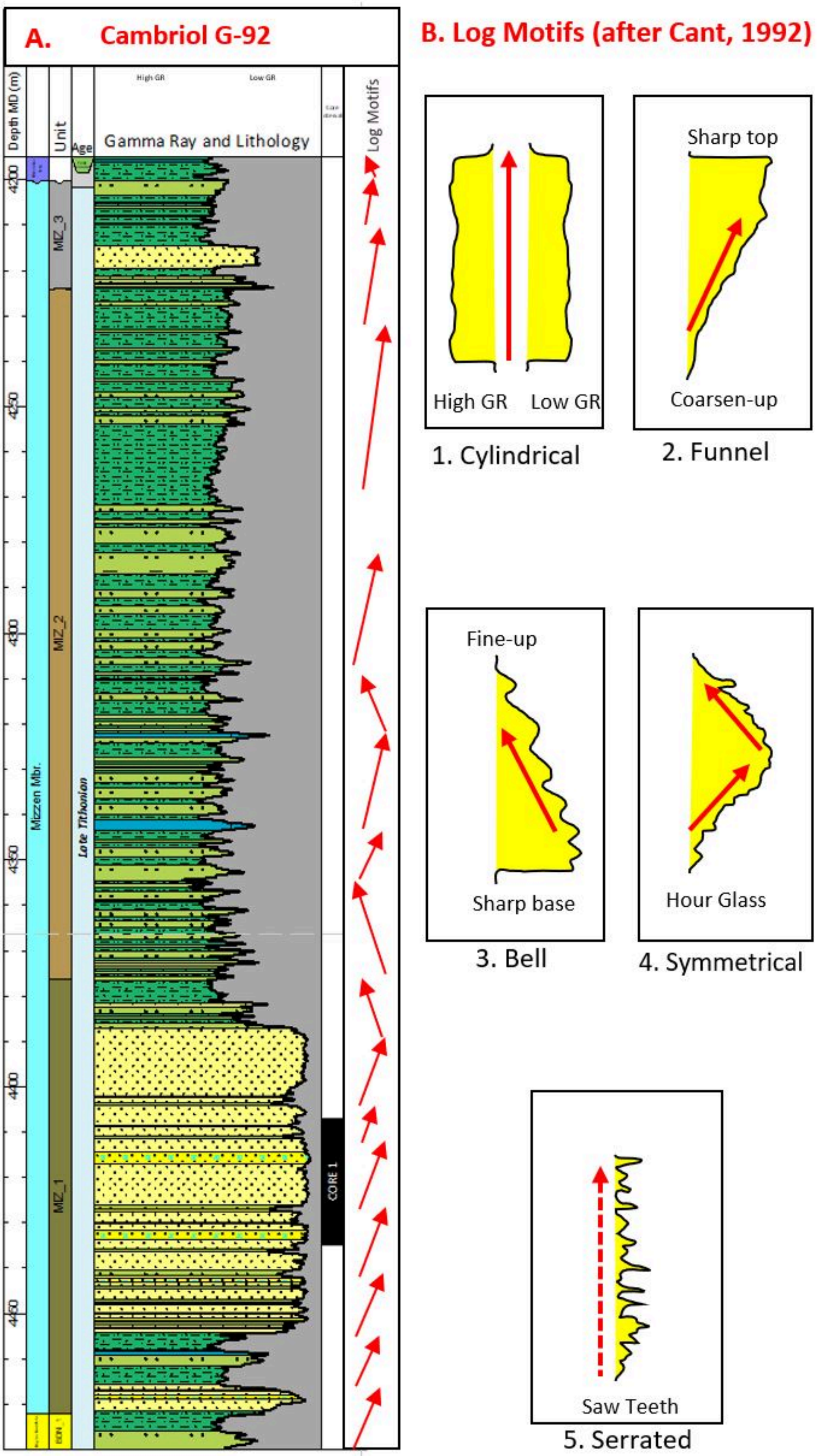


Figure 2.37 Cambriol G-92 Well Panel with Log Motifs (A) with lithostratigraphy, chronostratigraphy, lithology, gamma ray, and core locations. An additional column illustrates how the log motifs were interpreted across the cored and uncored stratigraphy. The gamma ray log motifs (B) are referenced to five types defined by Cant (1992), which suggest probable environments of deposition for each.

Depositional Maps

The regional sequence stratigraphic framework defined in the Bay du Nord and Cappahayden fields (see Section 2.3 Bay du Nord Field) was consistent with data obtained from Cambriol G-92. This was used to map depositional sub-environments for the Mizzen member across Exploration Licence (EL) 1156 (Figure 2.38). Maximum regression (i.e., lowstand systems tract 'LST') during MIZ_1 resulted in unconfined fan deltas (approximately 5-10 km wide and up to 60 m thick) trending northeast to southwest along with axis of the Flemish Pass Basin (Figure 2.38A). Transgressive systems tract maps (Figure 2.38B) represent flooding or partial flooding of the previous lowstand deltas, with backstepping of the paleo-coastline towards the northeast, and the onset of prodelta and shelf sedimentation.

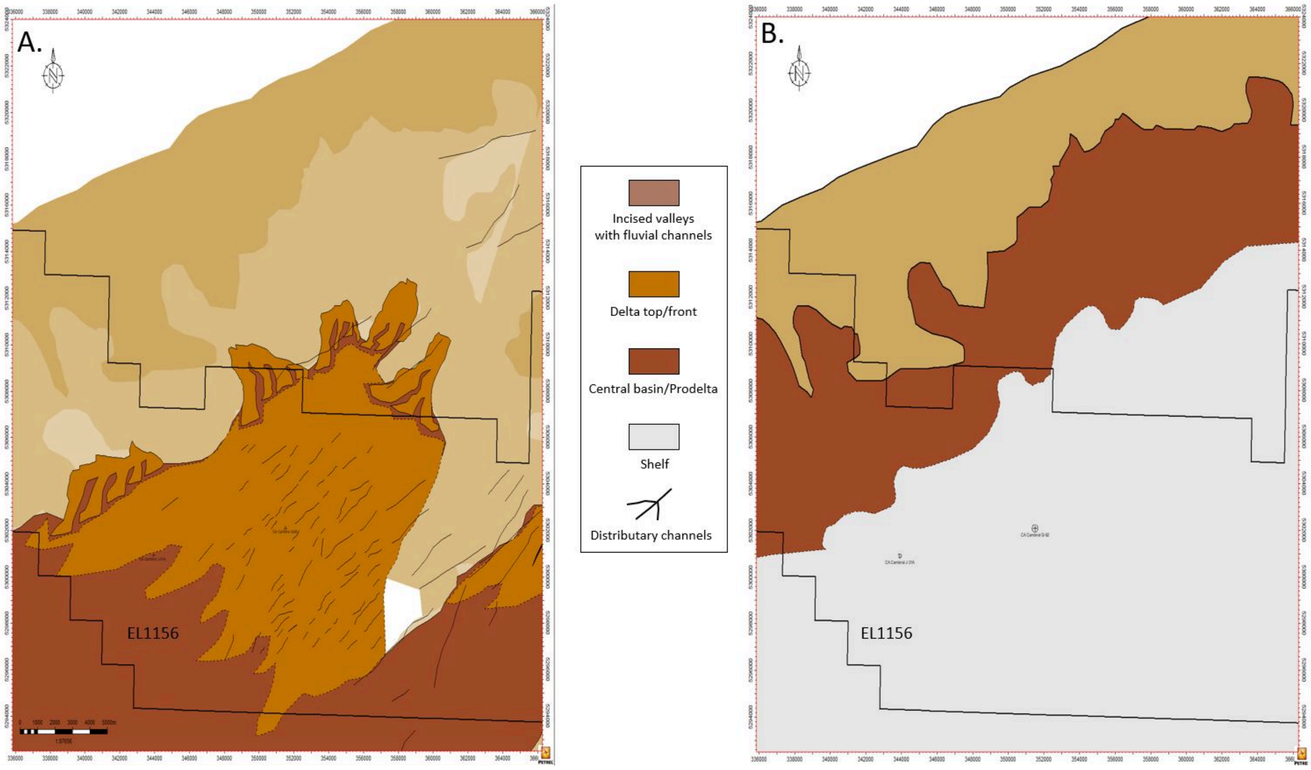


Figure 2.38 EL1156 Mizzen member Depositional Subenvironment Maps A) Lowstand Systems Tract. B) Transgressive Systems Tract.

3 Petrophysics

3.1 Database and Methods

All available data was utilized in the petrophysical evaluation and results used as inputs into the reservoir models. The modelled reservoirs include the Mizzen and Bay du Nord members. Log evaluation was consistent with core measurements and well test data. The deliverables from the petrophysical evaluation are representative estimates of reservoir properties (porosity, permeability, water saturation) and fluid contacts used as input into volumetric assessments.

The reservoir sections in the Project Area have full wireline logging suites. The Bay du Nord P-78 well was Logged While Drilling (LWD) in the overburden, however the reservoir section was not penetrated. Cambriol J-31/J-31A was an exploratory well drilled in 2022 to test the hydrocarbon extent of the Cambriol oil discovery. Results showed that J-31/J-31A was wet with poor reservoir development and is disconnected from the G-92 hydrocarbon accumulation. While results from J-31/J-31A were disappointing, they were incorporated into the Cambriol modelling as part of the uncertainty study and could potentially be an example showing the geological scenario of drilling cemented reservoir. Cambriol J-31/J-31A was also important for the collection of additional overburden log data in the 17.5" and 12.25" hole sections used for overburden management studies.

All wells were logged with modern tools complimented with conventional core from the main reservoirs. Conventional coring was supplemented with Rotary Sidewall Cores (RSWC) providing additional information used in the evaluation. All wells were drilled with synthetic Oil-Based Mud (OBM) over reservoir sections providing good hole conditions for logging. A summary of data acquisition is provided in Table 3.1.

Table 3.1 Data Acquisition Summary

Well	Contractor	Mud type	Hole size (inch)	LWD Logs	Wireline Logs	Sampling
C-78	SLB	Seawater	8.5 (pilot)	GR-Res		
		Seawater	26	GR-Res		
		Paradrill SBM	12.25	GR-Res	AIT-MSIP-PEX, MDT (pressures only)	Cuttings
		Paradrill SBM	8.5	GR-Res	AIT-MSIP-PEX, MDT, OBMI, UBI, Litho-CMR, MSCT, VSP, USIT	Cuttings, core, SWC
C-78Z	SLB	Paradrill SBM	8.5	GR-Res	AIT-MSIP-PEX-OBMI, MDT, MSCT, VSP	Cuttings, SWC
F-67	SLB	Seawater	8.5 (pilot)	GR-Res-Den-Neu		
		Seawater	17.5	GR-Res		
		Paradrill SBM	12.25	GR-Res	PEX-AIT-HNGS, CMR-ECS, MSIP-OBMI, MDT, MSCT	Cuttings, SWC
F-67Z	SLB	Paradrill SBM	12.25	GR-Res	PEX-AIT-HNGS, CMR, MDT, MSIP-NGI, FTWT, MSCT	Cuttings, core, SWC
L-76	SLB	Seawater	17.5	GR-Res		
		Paradrill SBM	12.25	GR-Res	AIT-PEX-HNGS, MSIP-NGI, MDT, MSCT	Cuttings, SWC
L-76Z	SLB	Paradrill SBM	12.25	GR-Res	PEX-HNGS-NGI-MSIP-ZAIT, VSI4, MDT-CMR, FTWT, MSCT	Cuttings, core, SWC
P-78	SLB	Seawater	9.875 (pilot)	GR-Res_Den-Neu-Son		
G-92	SLB	Seawater	26	GR-Res		
		Paradrill SBM	17.5	GR-Res-Son		Cuttings
		Paradrill SBM	12.25	GR-Res-Son		Cuttings
		Paradrill SBM	8.5	GR-Res-FPWD	AIT-MSIP-PEX-DOBMI, MDT-CMR, MSCT, VSP, ORA-FDTT	Cuttings, core, SWC
J-31/J-31A	SLB	Seawater	8.5 (pilot)	GR-Res-Den-Neu-Son		
		Seawater	26	GR-Res		
		Paradrill SBM	17.5	GR-RES-SON		Cuttings
		Paradrill SBM	12.25	GR-Res-Den-Neu-Son		Cuttings
		Paradrill SBM	8.5	GR-Res-FPWD	AIT-HLDS-CNT-HNGS-NGI-MSIP-XPT, VSI4, MSCT	Cuttings, SWC

The petrophysical evaluation was completed using the same methodology for all wells:

- Total porosity was derived from the density log;
- Permeability estimated from correlations of core porosity to core permeability;
- Shale volume was calculated from Gamma Ray (GR);
- Net reservoir was defined using cut-off values to shale volume and porosity;
- Total water saturation was calculated using Archie;
- Log-based J-functions were derived for water saturation modeling;
- Core water saturation functions were derived from Special Core Analysis (SCAL) data for uncertainty evaluation; and
- Fluid contacts were based on pressure gradient analysis in combination with other data observations.

Approximately 352.9 m of conventional core was recovered from three Bay du Nord wells and one Cambriol well, providing sufficient coverage for reservoir characterization (Table 3.2). Sidewall Coring (SWC) programs were conducted to supplement well logs in uncored intervals. A summary coring and sidewall coring analyses is provided in Table 3.3. Core and SWC data was used to derive porosity and permeability, and also provided confidence in water saturation models. The inputs used in the petrophysical evaluation is summarized in Table 3.4. The general methodology is further described in sections Section 3.2 Bay du Nord Field and Section 3.3 Cambriol Field.

Table 3.2 Conventional Coring Summary

Field	Well	Core	Zone	Top (mMD)	Base (mMD)	Cut (m)	Recovered (m)	Recovery (%)	Remarks
Bay du Nord	C-78	1	BDN_Mbr	3180.0	3216.0	36.0	36.0	100.0%	
Bay du Nord	F-67Z	1	BAC_Mbr	2985.0	3039.0	54.0	52.0	96.3%	
Bay du Nord	F-67Z	2	MIZ_Mbr	3039.0	3061.4	22.4	16.9	75.6%	Core jammed
Bay du Nord	F-67Z	3	MIZ_Mbr	3061.4	3062.6	1.2	1.2	100.0%	Cut 1.2m in 3 hours, aborted
Bay du Nord	F-67Z	4	BDN_Mbr	3134.0	3196.0	63.0	58.1	92.2%	
Bay du Nord	L-76Z	1	MIZ_Mbr	3050.0	3106.0	56.0	53.4	95.4%	Core jammed
Bay du Nord	L-76Z	2	BDN_Mbr	3160.0	3153.0	47.0	44.4	94.6%	Core jammed
Bay du Nord	L-76Z	3	BDN_Mbr	3153.0	3171.0	18.0	17.1	95.0%	Core jammed
Bay du Nord	L-76Z	4	BVT_Mbr	3171.0	3216.0	45.0	46.8	103.9%	
Cambriol	G-92	1	MIZ_Mbr	4407.7	4434.7	27.0	27.0	100.0%	
Total						369.6	352.9	95.5%	

Table 3.3 Plug Analyses from Conventional Core and Rotary Sidewall Core

Well	Zone	Routine Analysis		Special Core Analysis					
		CCA	RSWC	FF, OB	PcRI	Wettability	Rel. Perm	XRD	MCIP
C-78	BDN_1	123		6	6	3	4		
	Cret-Jur		45					42	14
C-78Z	Cret-Jur		17					27	11
F-67	Cret-Jur		42					16	10
F-67Z	BDN_1	157						8	
	Cret-Jur		19					22	19
L-76	Cret-Jur		55					19	15
L-76Z	MIZ_MBR	113		6	6	4	4	6	16
	BDN_1	137				2	4	7	
	BVT_4	16						2	
	Cret-Jur		20					30	29
G-92	MIZ_MBR	91	12	6	6	4	4	82	21
	BDN_1		3					7	3
	BVT_4		4					5	1
	BVT_3		7					8	
J-31A	MIZ_MBR		12					5	1
	BDN_1		1						
	Cret-Jur							4	2
Totals		637	237	18	18	13	16	290	142

Table 3.4 Petrophysical Inputs

Field	Interval	VSH_GR		Porosity - Saturation								
		GR_{min} *GAPI*	GR_{max} *GAPI*	RHOG *Kg/m3*	$RHOB_{sh}$ *Kg/m3*	$RHOFL_a$ *Kg/m3*	$NPHI_{sh}$ *v/v*	FTEMP *DegC*	Salinity *ppm*	a	m	n
Bay du Nord	Miz_Mbr			2668	2505			70	34778	1	1.67	2.05
	BDN_Mbr	5	130	2665	2500	820	0.46	75	34348	1	1.73	1.86
	BVT_Mbr			2688	2545			80	33515	1	2	2
Cambriol	Miz_Mbr	5	100	2645	2590	780	0.40	130	51700	1	1.8	2

3.1.1 Comparison of Petrophysical Results to Well Tests

Interpreted well test results were compared to the petrophysical evaluation and core plug data. The petrophysical evaluation is limited to the wellbore data, whereas well test data extends out from the wellbore into the reservoir. Differences in the petrophysical analysis compared to the well test interpretation could be related to any or all of these factors:

- Estimated reservoir thickness contributing to productivity may not be equal;
- Uncertainty in reservoir properties away from the wellbore; and
- Differences in static versus dynamic reservoir properties.

However, there is generally a good match when comparing the interpretation results, as shown in Table 3.5.

Table 3.5 Comparison of the Petrophysical Evaluation to Well Test Results

Field	Well	Test	Zone	Test/Sensor	Interval	Core analysis	Log analysis		Well test			Comment
						K_CORE (OBC)	KLOGH-h	KLOGH	Kh_TEST	h	K_TEST	
				mMD	mMD	mD	mD-m	mD	mD-m	m	mD	
Bay du Nord	L-76Z	DST 2	Mizzen Mbr.		3053.0 - 3069.0	4510	46270	4627	48000	9 - 11	4400 - 5400	
		DST 1	Bay du Nord Mbr.		3151.0 - 3171.0	6585	81360	5085	135000	18	7400	
		FTWT	Mizzen Mbr.		3033.8 - 3036.5		197	48	690	3.5	200	
			Mizzen Mbr.		3064.3 - 3067.0	5228	42975	4775	47000	9 - 11	4300 - 5200	
			Bay du Nord Mbr.		3156.8 - 3159.5	6585	81360	5085	125000	18	6800	
			Bay du Nord Mbr.		3165.5 - 3168.2	6585	81360	5085	120000	18	6300	
	F-67Z	FTWT	Mizzen Mbr.		3115.3 - 3116.4		1260	350	5200	4	1300	sample interval
	C-78	mini-DST 1	Mizzen Mbr.	3087.3	3086 - 3098	634	5358	893	3570	6	595	3 SWC samples over test interval
		mini-DST 2	Mizzen Mbr.	3122.1			143	25	78	5.7	13.7	
		mini-DST 3	Bay du Nord Mbr.	3181.5		875	1960	338	612	3.2 - 10.2	60 - 190	Height uncertain; probes placed in poor location
		mini-DST 4	Bay du Nord Mbr.	3219.2		5500	174405	5775	43000	30.2	1420	
	C-78Z	mini-DST 1	Mizzen Mbr.	3394.6			34	21	120	1.6	75	
Cambriol	G-92	FTWT	Mizzen Mbr.		4394.1 - 4396.7	1765	22140	1476	15750	15	1050	Kv/Kh = 0.7 was assumed, yielding max contributing net pay of 15m.

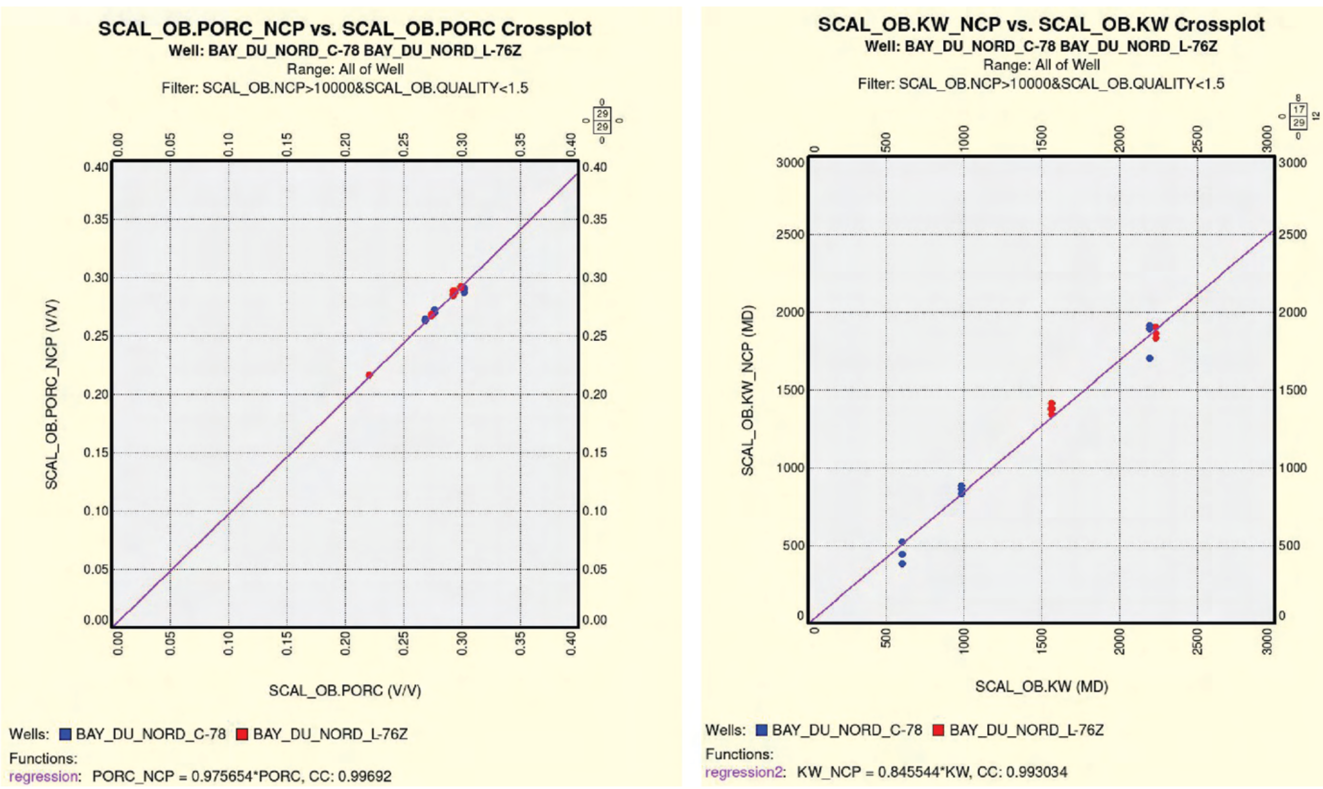


Figure 3.1 Estimated Overburden Core Corrections for Bay du Nord Porosity 0.97, Permeability 0.85.

3.2 Bay du Nord Field

Overburden Corrections

Porosity and permeability are influenced by the overburden stress of the formation. Core plug samples were selected from both the Mizzen and Bay du Nord members to conduct experiments to assess the effect of increasing hydrostatic overburden pressure, and allow for comparison of porosity and permeability at lab conditions to measurements of porosity and permeability at reservoir conditions (net confining pressure). Relationships between standard lab conditions and reservoir conditions for porosity and permeability measurements are illustrated in Figure 3.1.

Porosity

Log porosity was derived from the density log calibrated to overburden corrected core data. There is generally good agreement between density log porosity and overburden core porosity. However, there are some thin interbeds of sand, silt, and shale affecting the density log (vertical resolution), as well as some minor amounts of organic material causing some anomalous density porosity calculations. The organic material is typically located above or between the main reservoirs in shaly/silty sections. Combinable Magnetic Resonance (CMR) logging was acquired in multiple wells (Table 3.1). The CMR log utilizes nuclear magnetic resonance to provide lithology-independent measurements of formation porosity, fluid volumes, and pore size distribution. Where necessary, total porosity from the CMR log was substituted in place of erroneous density porosity calculations caused by the organic material. The inputs used for the log-derived porosity calculation are summarized in Table 3.4. A porosity difference histogram with a mean value near zero shows a good match between log porosity to overburden corrected core porosity (Figure 3.2).

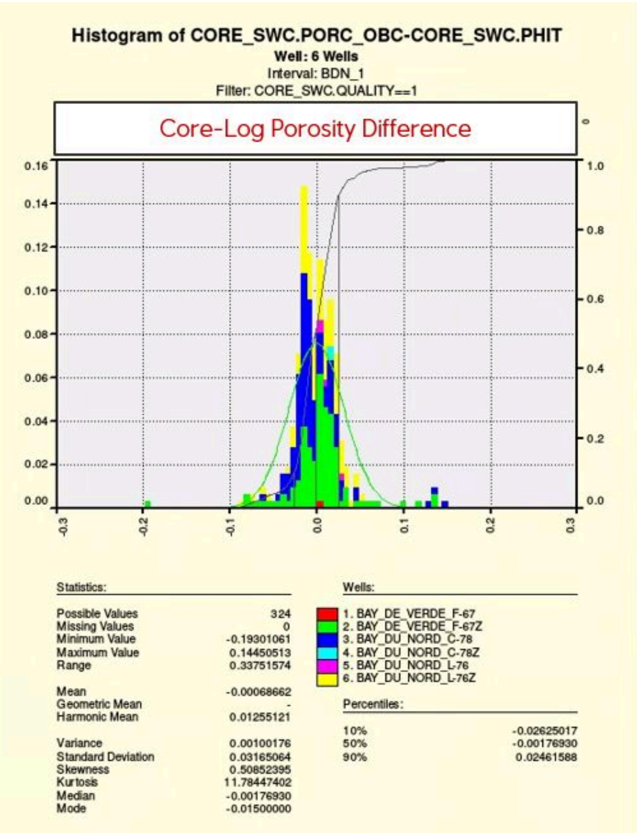


Figure 3.2 Bay du Nord Log-Core Porosity Difference Histogram

Permeability

Core plug permeability measurements were the primary data input for quantitative permeability estimates along the wellbore. Core plugs were evaluated for fractures and assigned a quality flag based on the fracture assessment. Permeability estimates from wireline formation testers (Modular Formation Dynamic Test [MDT]) and

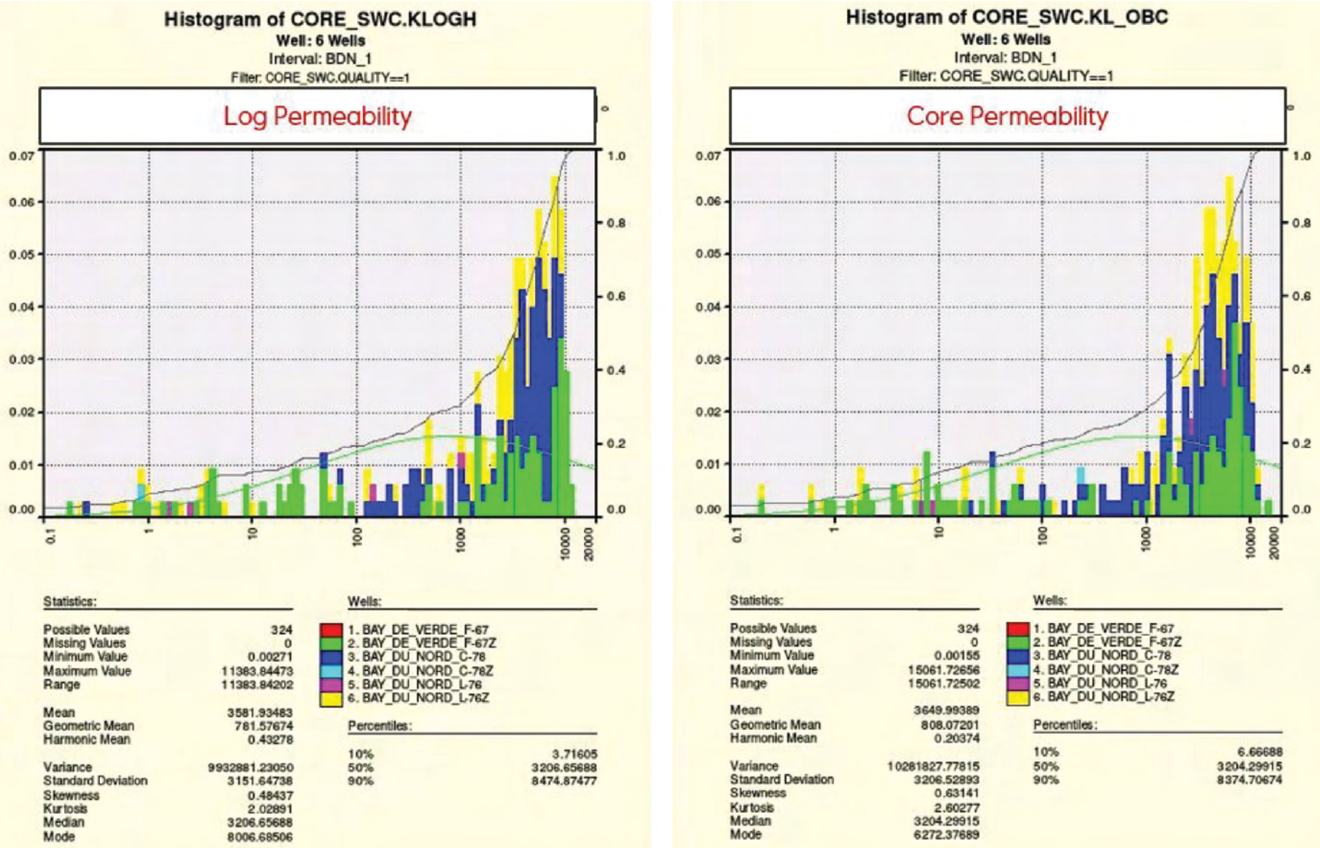


Figure 3.3 Bay du Nord Log and Core Permeability Comparison

well test interpretations (Drilling Stem Test [DST], Formation Testing While Tripping [FTWT], mini-DST) were reviewed but not used directly to derive permeability along the wellbores. A comparison of permeability results is displayed in Figure 3.3.

Volume of Shale

Multiple volume of shale methods were calculated for each well, however shale volume estimated from GR was used as the reference case. Values used in the shale volume estimation are summarized in Table 3.4.

Formation Resistivity

Formation resistivity is based on deliverables by the logging company. All wells were drilled with OBM. Therefore, the resistivity logs are an array induction type. Generally, the AT90 measurements from wireline and P40H measurements from LWD were used to represent the deep resistivity log.

Formation Water Resistivity

Formation water resistivity is based on lab measurements from downhole water samples collected by wireline formation testing tools. The average water salinity from 10 samples collected at Bay du Nord is 33,675 ppm.

Water Saturation

The Archie method was used for water saturation calculations at Bay du Nord. The Archie saturation inputs for both the Mizzen member and Bay du Nord member reservoirs were determined from special core analysis data and are summarized in Table 3.4. The Archie inputs for the Bonaventure member sands were assumed to be standard values.

Net Reservoir

Net reservoir can be defined as intervals which contain hydrocarbons, or potentially could have contained hydrocarbons if they had been located sufficiently high above the Free Water Level (FWL). An interval is deemed as having net reservoir properties regardless of vertical position (above/below FWL), if there is reason to believe that this interval could contain hydrocarbons. This is a static definition related to modelling in-place volumes, there is no reference to economically producible and/or to technically producible hydrocarbons. The cut-offs used in the Bay du Nord evaluation were 15% porosity combined with a shale volume cut-off of 50%. The average reservoir properties based on the net reservoir definition a provided in Table 3.6.

Table 3.6 Average Reservoir Properties for Net Reservoir Criteria

WELL	INTERVAL	TOP mTVDss	BASE mTVDss	TOP mMD	BASE mMD	GROSS METRES	NET METRES	N/G M/M	PHIT_AV V/V	SWT_AV V/V	PERM_AM MD	PERM_GM MD	VSH_AM V/V
BAY_DE_VERDE_F-67	MIZ	3029.78	3099.83	3263.09	3368.70	70.05	24.46	0.349	0.188	0.397	15	5	0.347
BAY_DE_VERDE_F-67	BDN_1	3099.83	3145.66	3368.70	3437.74	45.84	2.23	0.049	0.171	0.402	3	2	0.384
BAY_DE_VERDE_F-67	BVT_4	3145.66	3229.65	3437.74	3564.11	83.99	6.84	0.081	0.197	0.857	435	83	0.183
BAY_DE_VERDE_F-67	BVT_3	3229.65	3249.53	3564.11	3594.00	15.14	1.22	0.080	0.181	0.898	23	22	0.456
BAY_DE_VERDE_F-67	TOTAL	3029.78	3249.53	3263.09	3594.00	215.01	34.75	0.162					
BAY_DE_VERDE_F-67Z	MIZ	2966.21	3036.64	3043.14	3122.07	70.43	13.87	0.197	0.198	0.389	84	9	0.346
BAY_DE_VERDE_F-67Z	BDN_1	3036.64	3112.15	3122.07	3206.19	75.51	38.81	0.514	0.239	0.190	3000	276	0.218
BAY_DE_VERDE_F-67Z	BVT_4	3112.15	3177.23	3206.19	3277.93	65.08	19.83	0.305	0.209	0.949	349	86	0.221
BAY_DE_VERDE_F-67Z	BVT_3	3177.23	3254.05	3277.93	3361.65	76.83	3.51	0.046	0.196	0.370	193	40	0.196
BAY_DE_VERDE_F-67Z	BVT_2	3254.05	3300.80	3361.65	3412.00	32.86	0.00	0.000	-	-	-	-	-
BAY_DE_VERDE_F-67Z	TOTAL	2966.21	3300.80	3043.14	3412.00	320.70	76.02	0.237					
BAY_DU_NORD_C-78	MIZ	3013.49	3109.80	3044.55	3140.86	96.31	37.95	0.394	0.216	0.292	667	31	0.326
BAY_DU_NORD_C-78	BDN_1	3109.80	3194.99	3140.86	3226.05	85.19	44.80	0.526	0.276	0.099	3440	1316	0.144
BAY_DU_NORD_C-78	BVT_4	3194.99	3266.50	3226.05	3297.59	71.52	0.00	0.000	-	-	-	-	-
BAY_DU_NORD_C-78	BVT_3	3266.50	3369.77	3297.59	3400.97	103.26	1.83	0.018	0.195	0.907	238	146	0.157
BAY_DU_NORD_C-78	BVT_2	3369.77	3460.36	3400.97	3491.84	90.59	1.97	0.022	0.171	-	59	16	0.283
BAY_DU_NORD_C-78	BVT_1	3460.36	3478.45	3491.84	3510.00	16.63	0.00	0.000	-	-	-	-	-
BAY_DU_NORD_C-78	TOTAL	3013.49	3478.45	3044.55	3510.00	463.49	86.55	0.187					
BAY_DU_NORD_C-78Z	MIZ	3148.39	3230.43	3364.38	3460.39	82.04	3.13	0.038	0.189	0.311	8	5	0.308
BAY_DU_NORD_C-78Z	BDN_1	3230.43	3369.96	3460.39	3623.92	139.53	48.23	0.346	0.211	0.947	493	136	0.226
BAY_DU_NORD_C-78Z	BVT_4	3369.96	3404.22	3623.92	3664.00	34.10	0.00	0.000	-	-	-	-	-
BAY_DU_NORD_C-78Z	TOTAL	3148.39	3404.22	3364.38	3664.00	255.67	51.36	0.201					
BAY_DU_NORD_L-76	MIZ	3059.67	3150.17	3295.04	3433.42	90.50	23.61	0.261	0.223	0.193	1581	81	0.297
BAY_DU_NORD_L-76	BDN_1	3150.17	3219.85	3433.42	3539.79	69.68	24.01	0.345	0.232	0.170	1938	182	0.178
BAY_DU_NORD_L-76	BVT_4	3219.85	3274.85	3539.79	3623.86	55.00	4.30	0.078	0.203	0.386	149	28	0.197
BAY_DU_NORD_L-76	BVT_3	3274.85	3330.89	3623.86	3709.00	53.86	0.40	0.007	0.188	0.799	9	8	0.330
BAY_DU_NORD_L-76	TOTAL	3059.67	3330.89	3295.04	3709.00	269.04	52.31	0.194					
BAY_DU_NORD_L-76Z	MIZ	2973.77	3063.03	3020.11	3112.47	92.36	36.42	0.394	0.218	0.351	1223	37	0.315
BAY_DU_NORD_L-76Z	BDN_1	3063.03	3121.88	3112.47	3173.27	60.80	33.30	0.548	0.238	0.247	2492	190	0.237
BAY_DU_NORD_L-76Z	BVT_4	3121.88	3188.72	3173.27	3242.20	68.93	4.72	0.069	0.201	0.380	143	15	0.233
BAY_DU_NORD_L-76Z	BVT_3	3188.72	3268.72	3242.20	3324.37	82.17	4.72	0.057	0.212	0.964	589	145	0.185
BAY_DU_NORD_L-76Z	BVT_2	3268.72	3482.26	3324.37	3542.46	218.09	1.98	0.009	0.161	0.632	2	2	0.329
BAY_DU_NORD_L-76Z	BVT_1	3482.26	3571.48	3542.46	3632.54	90.08	0.00	0.000	-	-	-	-	-
BAY_DU_NORD_L-76Z	TOTAL	2973.77	3571.48	3020.11	3632.54	612.43	81.15	0.133					

3.3 Cambriol Field

Overburden Corrections

Porosity and permeability are influenced by the overburden stress of the formation. Core plug samples were selected from the Mizzen member sandstone to conduct experiments to assess the effect of increasing hydrostatic overburden pressure, and allow for comparison of porosity and permeability at lab conditions to measurements of porosity and permeability at reservoir conditions (net confining pressure). Relationships between lab conditions and reservoir conditions for porosity and permeability measurements are illustrated in Figure 3.4.

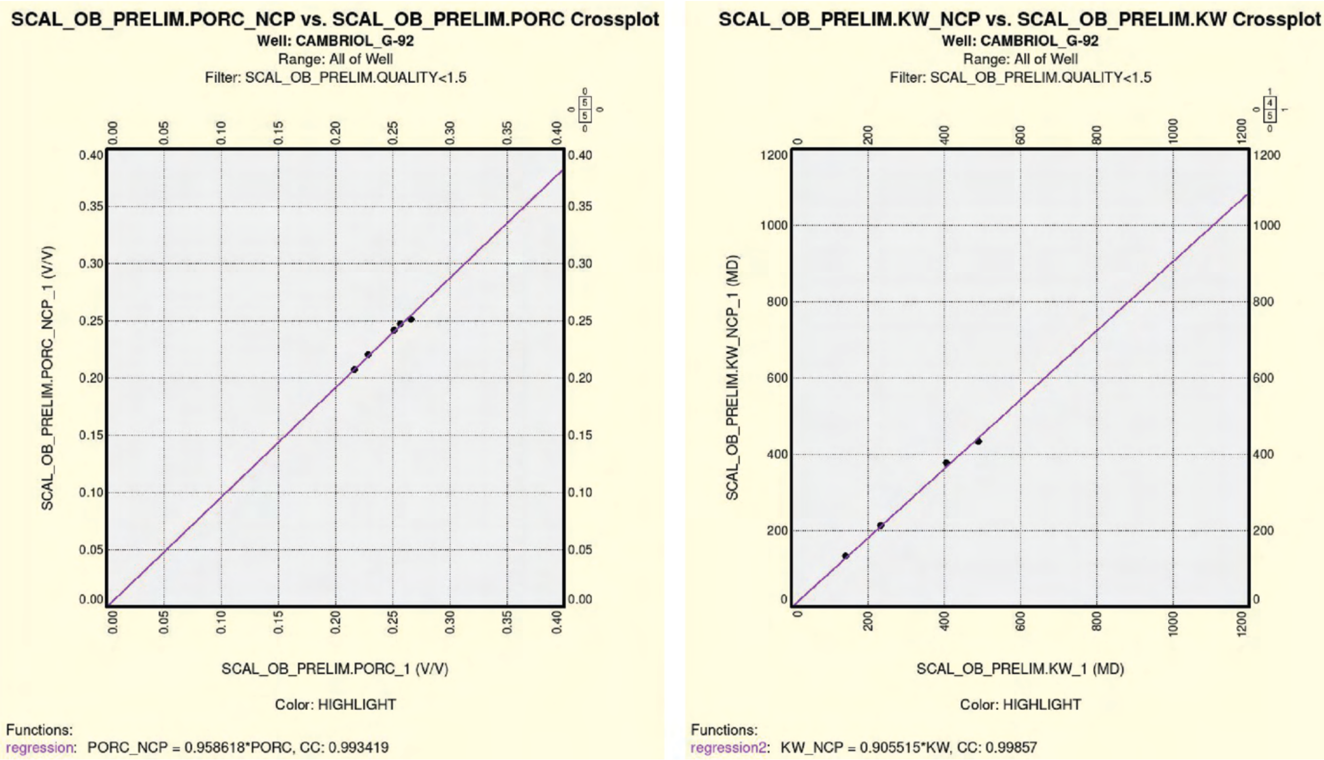


Figure 3.4 Estimated Overburden Core Correction Factors for Cambriol Porosity 0.96, Permeability 0.91.

Porosity

Log porosity was derived from the density log calibrated to overburden corrected core data. There is generally good agreement between density log and core porosity. This is illustrated in a porosity difference histogram by subtracting log porosity from core porosity. In Figure 3.5, the porosity difference histogram of Cambriol G-92 plug data shows a mean average near zero. The inputs used for the log-derived porosity calculation are summarized in Table 3.4.

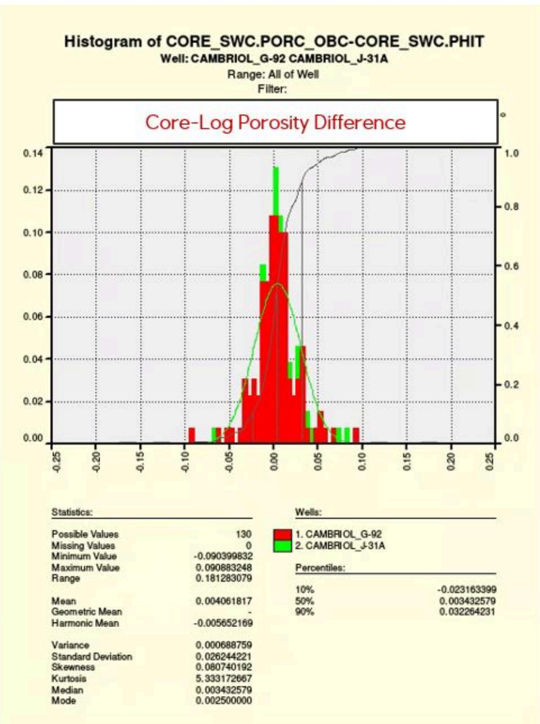


Figure 3.5 Cambriol G-92 Comparison of Density Porosity Calculation to Overburden Corrected Core Porosity

Permeability

Core plug permeability measurements were the primary data input for quantitative permeability estimates along the wellbore. Core plugs were evaluated for fractures and assigned a quality flag based on the fracture assessment. Permeability estimates from wireline formation testers (MDT) and well test interpretations (DST, FTWT, mini-DST) were reviewed but not used directly to derive permeability along the wellbores. A comparison showing log and core permeability is displayed in Figure 3.6.

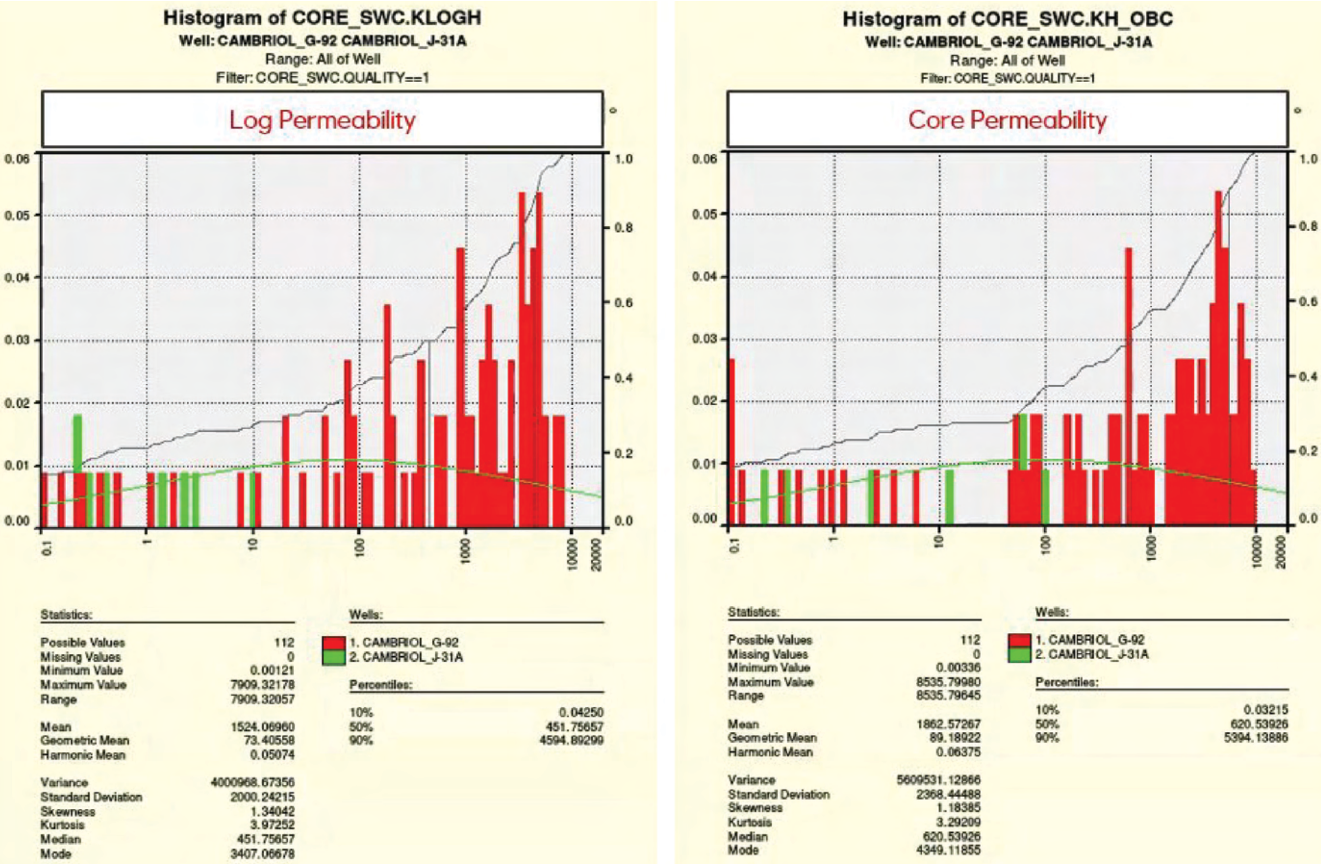


Figure 3.6 Cambriol Log-Core Permeability Comparison

Volume of Shale

Multiple volume of shale methods were calculated for each well, however shale volume estimated from GR was used as the reference case. Values used in the shale volume estimation are summarized in Table 3.4.

Formation Resistivity

Cambriol G-92 was drilled using synthetic OBM and resistivity was measured using induction tools. The wireline resistivity tool failed prior to exiting casing on downlog. The tool did not work for the entire main log. It did come on again when entering casing and an attempt was made to run back to bottom and log again, but the tool failed once exiting casing as it did originally. Therefore the LWD data was depth shifted to the wireline logs and the LWD induction data was used as the resistivity in the evaluation.

Formation Water Resistivity

Formation water resistivity was determined using the water sample analysis which was collected from the Bonaventure member sandstone. Water salinity used in the evaluation was 51,700 ppm.

Water Saturation

Archie water saturation inputs are summarized in Table 3.4. The Pickett plot in the Bonaventure member reservoir suggests that the Archie cementation exponent is approximately m=1.8 and assumed valid in the evaluation for the Mizzen member reservoir (Figure 3.7). Preliminary results from SCAL suggest the cementation exponent for the

Mizzen member could be approximately 1.75. Capillary pressure and resistivity index is currently not available as testing is ongoing. The Archie saturation exponent was assumed to be n=2. Water saturation will be re-evaluated after final SCAL results become available.

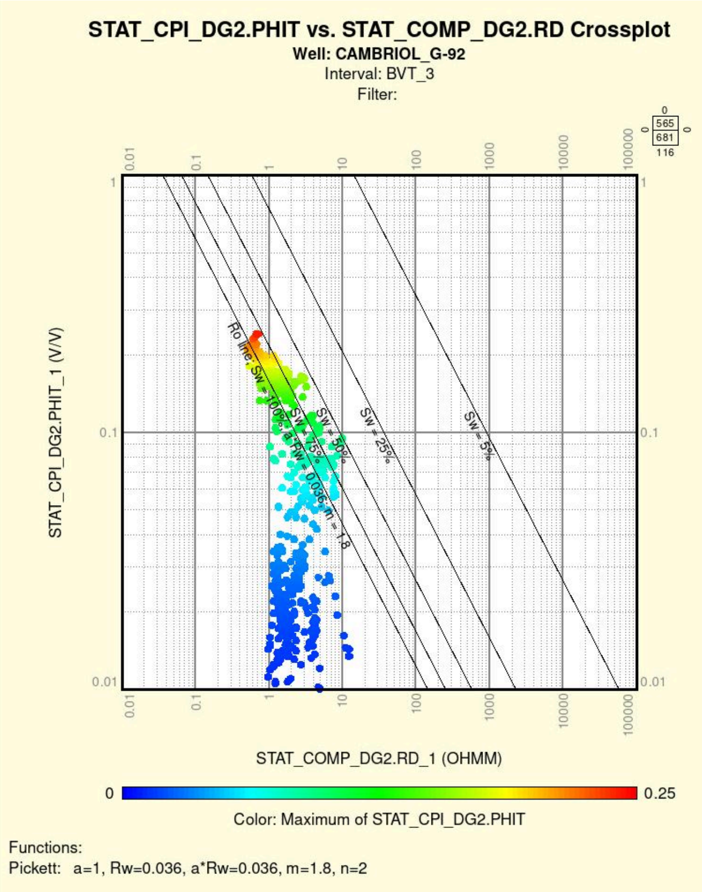


Figure 3.7 Cambriol G-92 Pickett Plot

Net Reservoir

Net Reservoir is defined as intervals which contain hydrocarbons or potentially could have contained hydrocarbons if they had been located sufficiently high above the FWL. An interval is deemed as having net reservoir properties, regardless of vertical position (above/below FWL), if there is reason to believe that this interval could contain hydrocarbons if positioned at high enough above a FWL. This is a static definition related to modeling in-place volumes, there is no reference to economically producible and or to technically producible hydrocarbons. The cut-offs used in the Cambriol evaluation were 10% porosity combined with a shale volume cut-off of 40%. The average reservoir properties based on the net reservoir definition are provided in Table 3.7.

Table 3.7 Cambriol G-92 Net Reservoir Summary

WELL	INTERVAL	TOP mTVDSS	BASE mTVDSS	TOP mMD	BASE mMD	GROSS METRES	NET METRES	NTG M/M	PHIT_AV V/V	SWT_AV V/V	PERM_AM MD	PERM_GM MD	VSH_AM V/V
CAMBRIOL_G-92	MIZ_MBR	4159.66	4430.75	4200.29	4471.54	271.09	67.27	0.248	0.213	0.105	1537	457	0.113
CAMBRIOL_G-92	BDN_1	4430.75	4496.37	4471.54	4537.25	65.62	3.80	0.058	0.120	0.869	1	1	0.207
CAMBRIOL_G-92	BVT_4	4496.37	4582.22	4537.25	4623.30	85.85	12.91	0.150	0.163	0.659	245	27	0.074
CAMBRIOL_G-92	BVT_3	4582.22	4686.73	4623.30	4728.23	104.51	38.54	0.369	0.168	0.911	254	92	0.119
CAMBRIOL_G-92	TOTAL	4159.66	4686.73	4200.29	4728.23	527.08	122.53	0.232					

4 Geophysics

4.1 Database and Methods

Seismic Database: Bay du Nord Field

The Bay du Nord Field is covered by two separate seismic surveys that were acquired by Western Geco in 2000 (BdN2000) and 2014 (ST14001) (Figure 4.1).

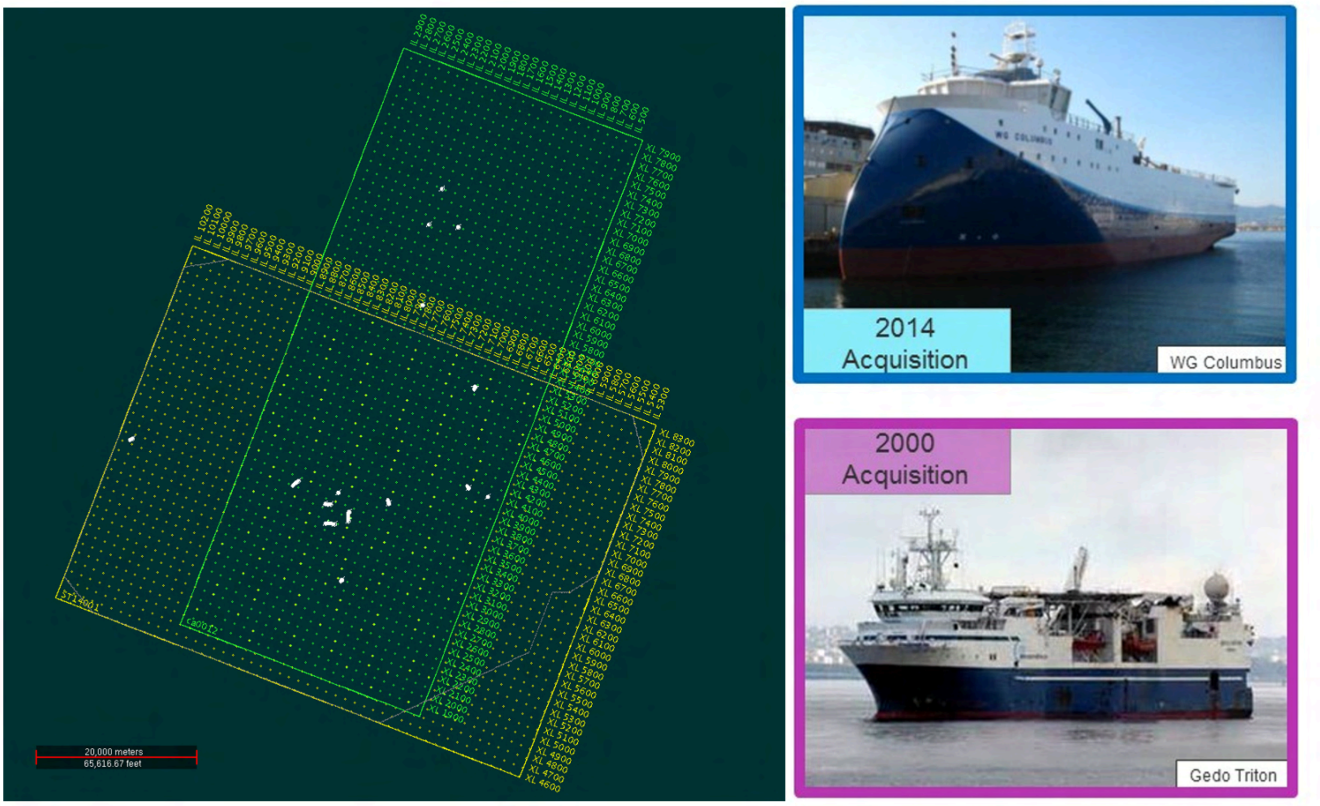


Figure 4.1 Relevant Seismic Surveys in the Bay du Nord Area Seismic surveys for Bay du Nord were acquired by Western Geco in 2000 and 2014. The 2000 data was acquired in the strike direction, with the survey outline shown in green. The 2014 data was acquired in the dip direction, with the survey outline shown in yellow.

The main differences between the 2000 and 2014 acquisitions are outlined below:

2000:

- 10 Streamers - 5000 m length - 100 m separation;
- Acquisition in strike direction; and
- Dual source at 7 m depth.

2014:

- 12 Streamers - 7500 m length - 75 m separation;
- Acquisition in dip direction;
- ObliQ broadband (10-20 m slant); and
- Delta-3 broadband source.

The 2000 data set has numerous reprocessing vintages. The latest one was a Pre-Stack Depth Migration (PSDM) reprocessing by CGG which was finished in July 2015.

The 2014 data set was processed for Anisotropic Pre-Stack Time Migration (APSTM) and Tilted Transverse Isotropic (TTI) Anisotropic Pre-Stack Depth Migration (APSDM). In addition to the Raw TTI APSDM Stack and Raw APSTM Stack, four additional stack products were delivered:

- TTI APSDM Final 1 Stack - Q-wave applied;
- TTI APSDM Final 2 Stack - Q-wave, and amplitude only Q-compensation applied;
- APSTM Final 1 Stack - Q-wave applied; and
- APSTM Final 2 Stack - Q-wave, and amplitude only Q-compensation applied.

A line comparison between the 2000 (2015 reprocessing) and the 2014 (APSDM final stack) is shown in Figure 4.2 and the spectrum in Figure 4.3.

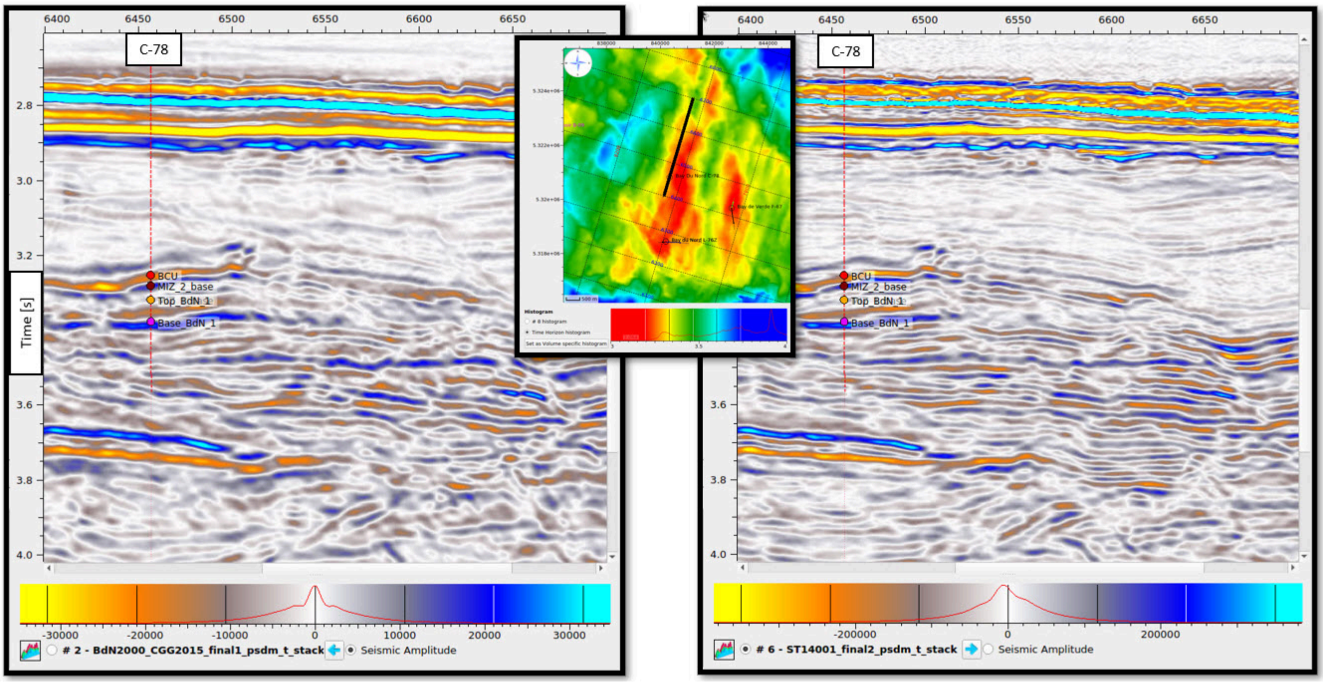


Figure 4.2 Seismic Vintage Comparison Left: 2000 survey, 2015 reprocessing; Right: 2014 survey, CGG original processing (seismic data courtesy of Viridien).

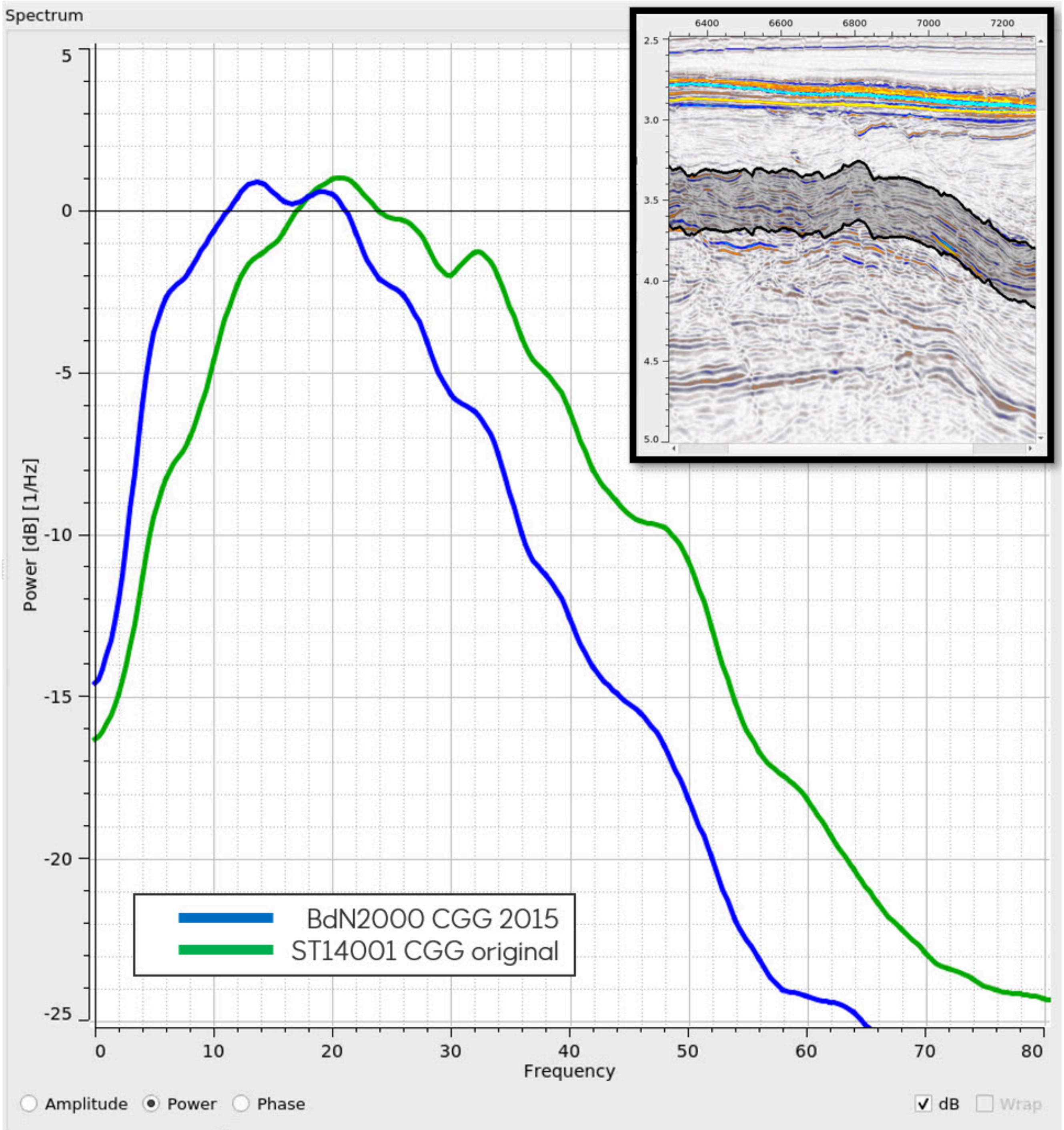


Figure 4.3 Spectrums - Vintage Comparison Spectrums are computed in a 400 ms time window below the Base Cretaceous (see insert) in an IL 7800-8200 and XL 6150-6800 area (seismic data courtesy of Viridien).

Seismic Database: Cambriol
Survey Acquisition:

1. Renews 3D seismic survey acquired by Fugro in 2012 (ST12002, Figure 4.5). The Renews 3D exploration survey covers an area of 4747 km^2 and was processed in 2013, including both time and depth imaging. The 2013 depth velocity model and anisotropy values were obtained without well control.

2. MC3D seismic 3D survey acquired by PGS. The MC3D survey covers 1570 km^2 of 3D Geostreamer seismic data (Figure 4.5). The data was processed by July 2022, including both time and depth imaging. The 2021 depth velocity model and anisotropy values were obtained with well control from the Cambriol G-92 well.

The acquisition parameters are summarized in Table 4.1.

Table 4.1 Seismic Acquisition Parameters

Acquisition information		
Suevey name	**Renews 3D (ST12001)**	**MC3D**
Vessel(s)	Fugro Geoteam AS M/V Geo Caribbean	Ramform Atlas (seismic), Aqviq (escort), Thor Magni (supply)
Location	Offshore East Coast Canada	Offshore East Coast Canada
Type of survey (2D or 3D)	3D marine streamer	3D marine streamer
Area (km3)	5270	1570.43
Number of lines acquired	114 (including 3 NTBP	59
Heading	16.7o / 196.7o	111.188° / 291.188°
Processing grid	25.0m (inline) x 12.5m (crossline)	6.25 (inline), 12.5 (crossline)
Streamer Parameters		
Cable type	Sercel Sentinel solid streamer	GeoStreamer
Number of streamers	12	14
Group length (m)	12.5	12.5
Streamer length (m)	7050	9000
Streamer depth (m)	10.0 ± 1.0	20
Streamer separation (m)	100 front; 150 tail	75
Number of groups by streamer	564	2x720
CMP-line separation	25	
Recording Parameters		
Recording system	Sercel Seal Acq. System Ver 5.2, 24 bit digital	gAS GeoStreamer
Recording format	SEG-D 8058	Internal TD format
Record length (s)	9.1	11.072
Sample rate (ms)	2	2
Recording filter (Hi-cut, slope)	200 Hz, 370 dB/Oct	214 Hz @ 341 dB/octave
Recording filter (Low-cut, slope)	3Hz, 6 dB/oct	3.04Hz @ 7.5 dB/octave
Recording media	3592	3592 in E07 mode
Source Parameters		
Source	Sodera G-Gun	Bolt 1900 LLXT
Number of sources	2	3
Source separation (m)	50	50 (adjacent), 100 (outer)
Shotpoint interval (m)	25	12.5
Shotpoint interval per source (m	50	
Volume (per source) (cu in)	4700	3280

Seismic Reprocessing:

In 2015, the southern part of the Renews 3D survey (covering 1600 km^2) was reprocessed, focusing on an improved demultiple over Cambriol. The 2015 reprocessing did not include depth velocity model building, and the 2013 model was used for depth imaging. In 2016, a regional seismic and velocity merge was performed that encompassed the Renews and Cupids seismic surveys, totalling to 6600 km^2. The depth migrated data from 2013 and 2015 were utilized in the post-migration merge, and the 2013 depth- velocity model was scaled to tie the seismic to both Fitzroya and Cupids wells. The scaled velocity model from 2016 was an input for the 2019 Equinor in-house depth imaging of the 2013 and 2015 data. The resulting volumes were the 2019 PSDM reprocessing of the 2013 data, and the 2019 PSDM reprocessing of the 2015 data. The 2019 reprocessing covers a depth section from 0 m to 6000 m. A short overview of the 2019 re-imaging workflow is given in Figure 4.4. The 2019 reprocessing was used for the drilling of the Cambriol G-92 well.

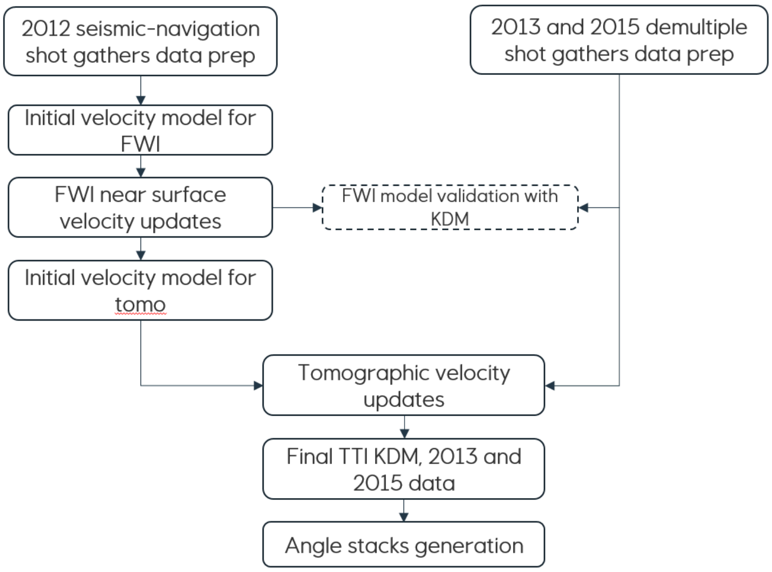


Figure 4.4 Processing Flow

The 2013 data was also reprocessed in 2017. The 2017 reprocessing was a result of a mega-merge of several surveys, including the Cupids, Renews and Cambriol surveys. It was done in two phases:

1. Phase 1 (2016) – merge the original Cupids and Renews velocity models and scale velocities to tie the seismic to the Cupids and Fitzroya wells. The existing Renews and Cupids angle stacks were then repositioned with the scaled velocity model.
2. Phase 2 (2017) – utilized the velocity model obtained in Phase 1. It started from the existing migrated gathers (2012, 2013, 2015) and involved recreating angle stacks by using the new velocity model for offset to angle mapping. The new angle stacks have been repositioned to depth using the merged and scaled velocity model.

The geographical extent of the original Renews-Cambriol survey and the 2019 reprocessed survey is illustrated in Figure 4.5.

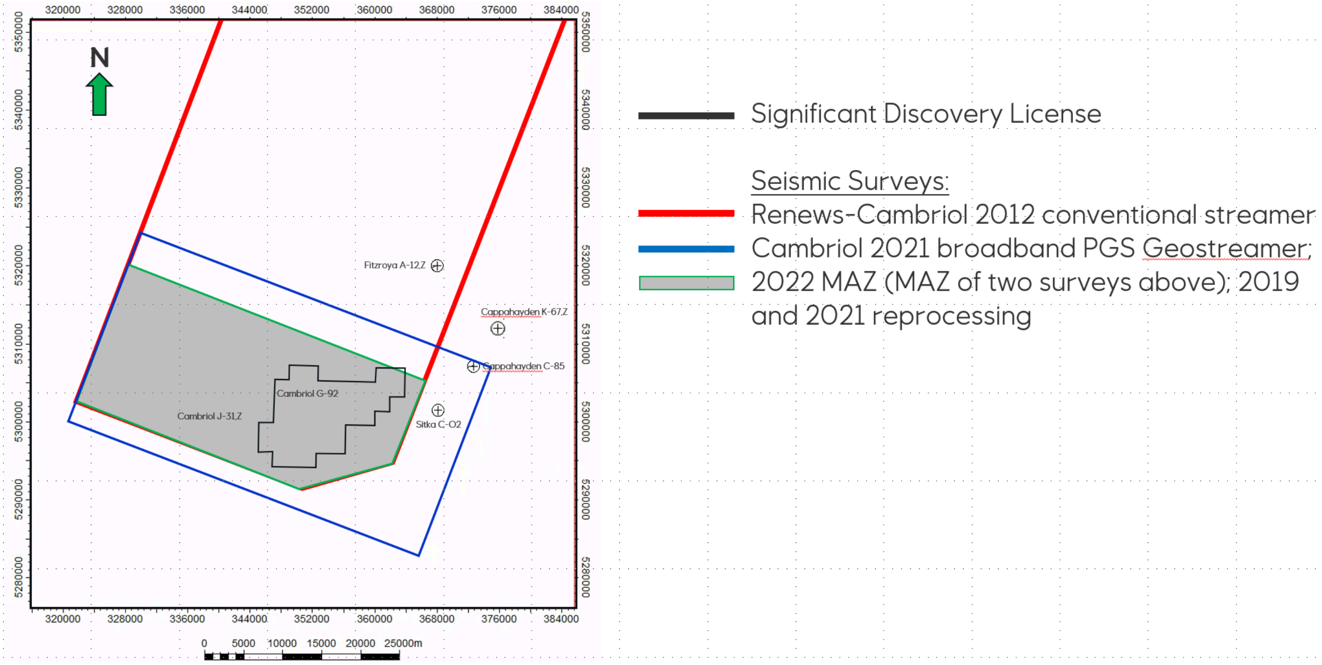


Figure 4.5 Cambriol - Seismic Database Red: Renews-Cambriol 2012 3D survey; Black: Extent of 2019 reprocessing; Blue: Cambriol 2021 broadband PGS Geostreamer; Green with grey fill: 2022 MAZ (Multi Azimuth) of two surveys above plus area for 2019 and 2021 reprocessing of Renews-Cambriol 2012 3D survey.

In 2021 an input area of 1079 km^2 of the Renews 3D survey was reprocessed by PGS (ST12002R21Z). The focus of the reprocessing was on wavelet processing and deghosting for broadband frequencies, multiple attenuation and preservation of primaries and to preserve the true amplitudes for AVO interpretation. A noise attenuation flow was designed that was able to attenuate the noise, explicitly swell noise, present in the survey. The optimal denoise flow allowed the application of a deghosting technique to remove the effects of the source and receiver ghost and broaden the frequency content of the data. A 3D demultiple flow was employed to tackle the heavily contaminated data. The demultiple was driven fairly aggressively to clean up multiple energy from the target region. Subsequently 3D PSDM processing was performed, using the velocity model updated in 2019. The deliverables were gathers, time and depth angle and full stacks. This survey was used as the basis for the drilling of the Cambriol J-31A well.

In 2022 the Renews 3D (ST12002) survey was reprocessed for multi azimuth (MAZ) stacking with the MC3D. The difference in acquisition directions between the two surveys is 90 degrees. The reprocessed ST12002 for MAZ stacking has survey number ST12002R22Z and MAZ stacks of ST12002 and Cambriol MC3D Full Integrity are named EQ22M06. The major part of the processing sequence was designed and applied to ST12002 dataset during 2021 reprocessing done by PGS under survey name ST12002R21Z.

Figure 4.6 compares inline 2844 of the most recent reprocessing of the Renews 3D (ST12002R21Z) survey, the MC3D original processing and the Multi Azimuth survey combining the first two. Figure 4.7 illustrates a comparison of the spectra extracted in a 500 ms window below Base Cretaceous and 25 inlines around G-92. The MAZ dataset has a wider frequency spectra than the Renews 3D 2015 reprocessing.

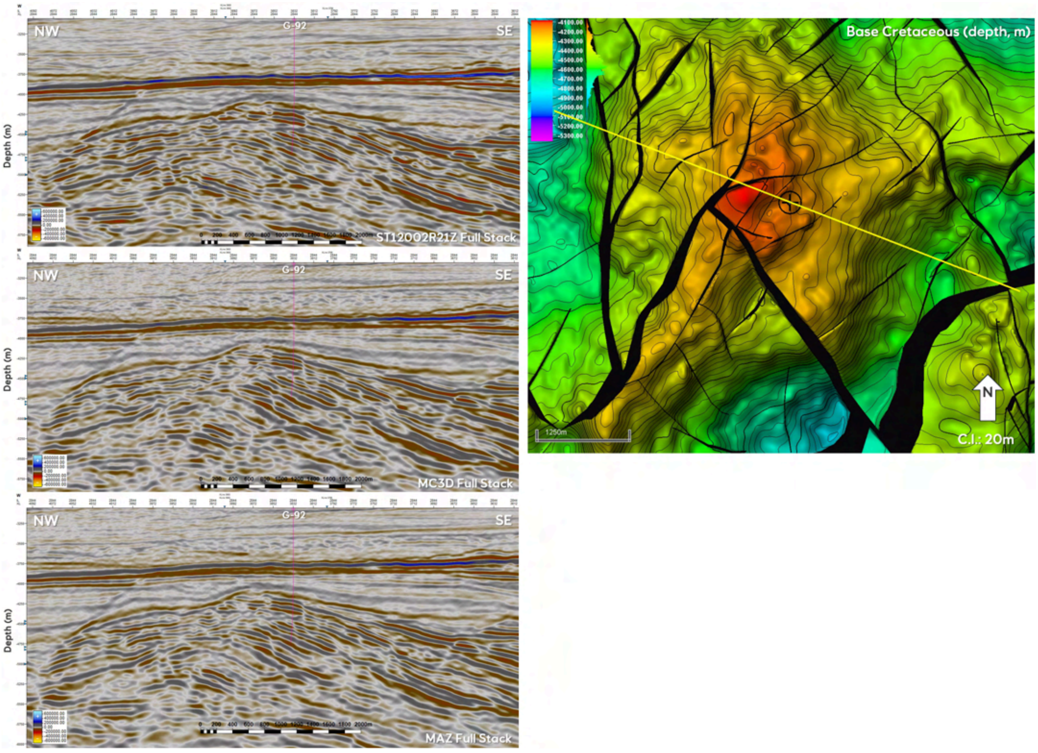


Figure 4.6 Seismic Vintage Comparison Comparison of inline 2844 of the most recent reprocessing of the Renews 3D (ST12002R21Z, top) survey, the MC3D original processing (middle) and the Multi Azimuth survey combining the first two (bottom) (seismic data courtesy of Fugro and TGS)

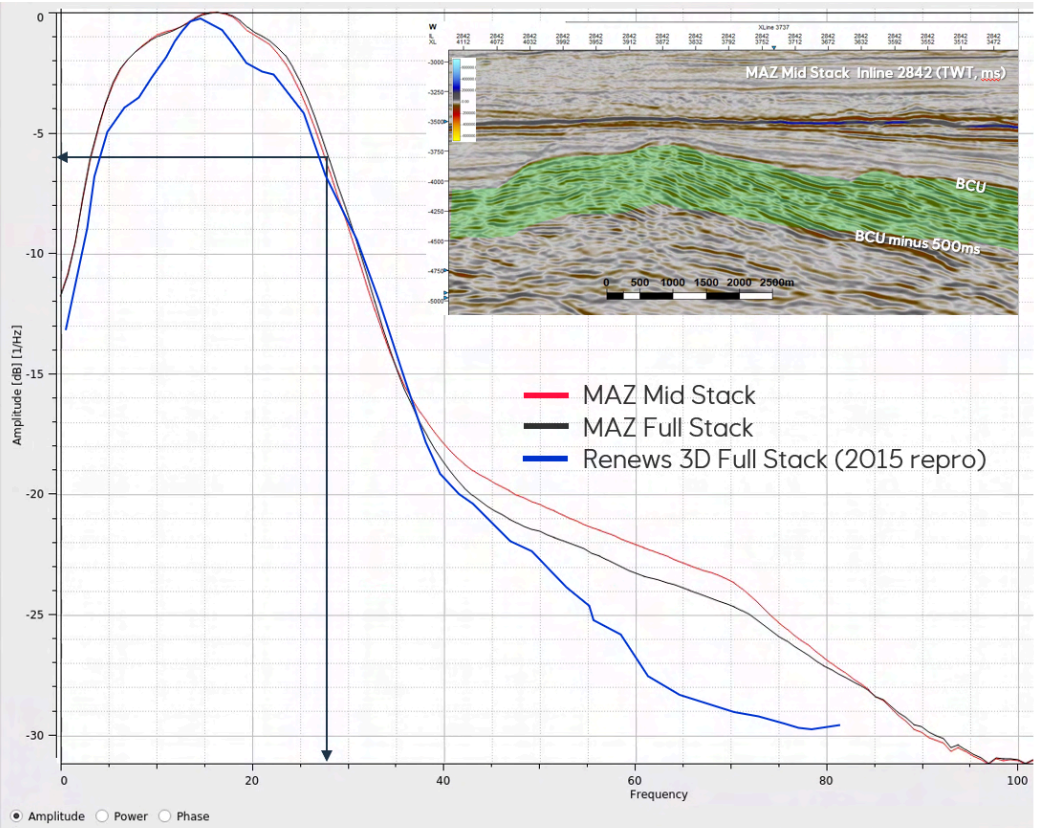


Figure 4.7 Cambriol Spectrums - Vintage Comparison Blue: Renews 3D 2015 reprocessing Red and black: MAZ Mid and Full stacks respectively.
Green shaded area illustrated interval for frequency spectrum extraction (seismic data courtesy of Fugro)

Geophysical Well Database

Twenty-one wells exist within the ST14001 seismic survey (Figure 4.8). The oldest well, Baccalieu I-78, was drilled in 1985 and penetrated strata down to 5135 m TVD. Statoil (Equinor) with partner Husky (Cenovus) drilled the Bay du Nord discovery C-78 and subsequently C-78Z, Bay de Verde F-67 and F-67Z, Bay du Nord L-76 and L-76Z, Bay d'Espoir B-09, Bay de Loup M-62, Portugal Cove E-38, Baccalieu F-89, and Harpoon O-85. The Bay du Nord P-78 well was spudded, but was abandoned prior to encountering the reservoir due to technical problems with sea ice. In 2015 Statoil (Equinor) with partner BP drilled Fitzroya A-12,Z and in 2020 the partnership drilled Cappahayden K-67 and K-67Z oil discovery wells. The Sitka O-02 was spudded in 2020 and temporarily abandoned. The well was re-entered in 2022, but had to be abandoned due to technical reasons. Subsequently the Sitka O-02A was spudded, but was TD'ed before reaching the target. In 2024 the partnership successfully drilled Sitka C-02 and Cappahayden C-85 (Figure 4.8).

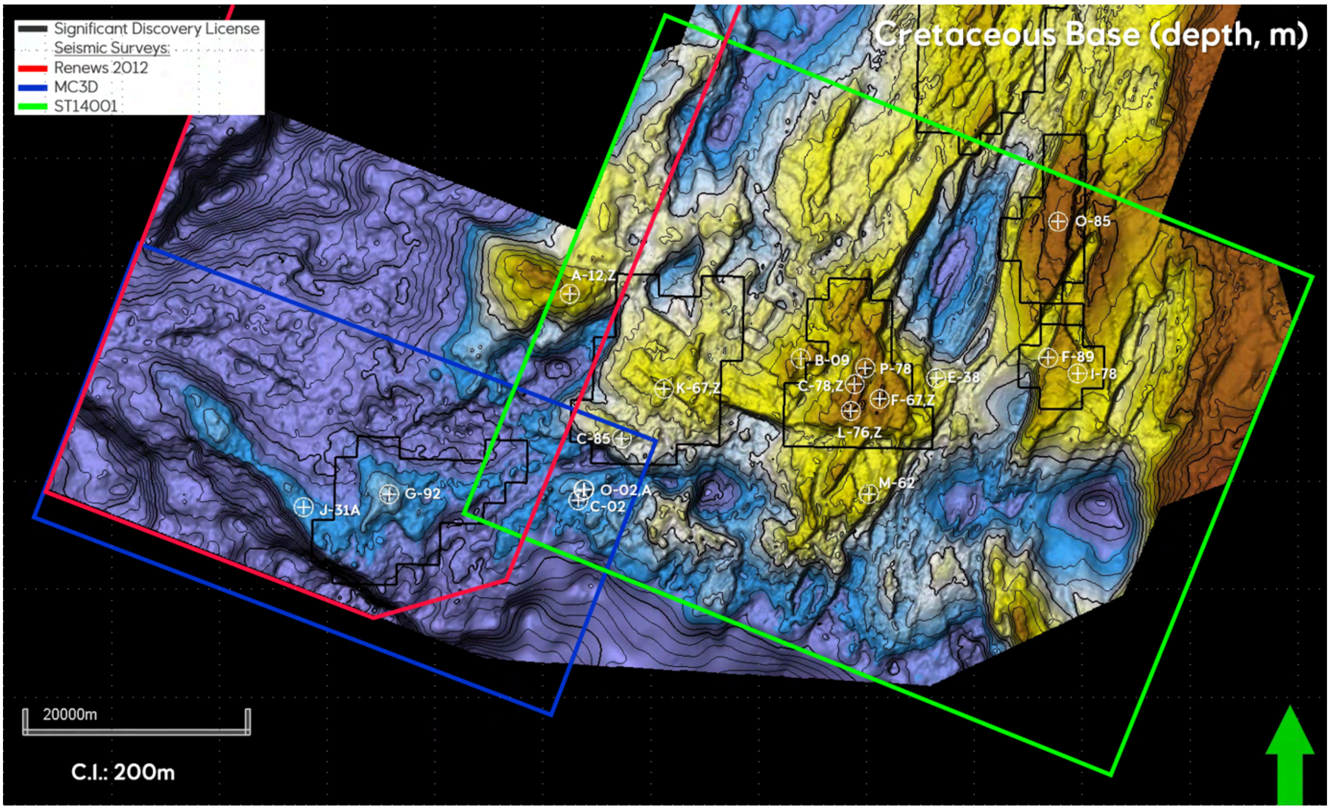


Figure 4.8 Well Database Wells in the vicinity of Bay du Nord and Cambriol displayed on the Cretaceous Base structural depth map.

In 2020 and in 2022 Equinor with partner BP drilled the Cambriol G-92 oil discovery and Cambriol J-31 and J-31A respectively, which are located on the Renews 3D 2012 and MC3D surveys. The Sitka wells and Cappahayden C-85 are also on the MC3D survey (Figure 4.8).

All wells have a full suite of wireline and computed petrophysical logs. Details of the log data base are discussed in Section 3 Petrophysics. To facilitate seismic pre-stack well-ties and analysis, shear sonic logs were acquired in all wells but Baccalieu I-78. Furthermore, a zero-offset VSP was acquired in Bay d'Espoir B-09; Bay du Nord C-78, C-78Z, and L-76Z; Bay de Verde F-67Z; Baccalieu F-89 and I-78; Cappahayden K-67, Cambriol G-92, Cambriol J-31A. A walk away VSP was also acquired in Bay de Verde F-67Z.

4.2 Bay du Nord Field

4.2.1 Seismic Data Quality

After careful evaluation of the ST14001 and the BdN2000 survey, the ST14001 PSDM seismic volume was selected as the input for the Bay du Nord Field seismic interpretation. Except for the faulted zones, the signal-to-noise ratio is generally high. Figure 4.9 shows a map view of the signal-to-noise estimation for a time window of -70 ms to + 20 ms around the Base Bay du Nord member seismic horizon, and a seismic line through the greater Bay du Nord Field. The seismic line (location shown in yellow on the map) illustrates that the areas of higher signal-to-noise content correlate with the reservoir structures. Figure 4.10 shows the same map view with the fault polygons overlain, identifying that the fault locations correspond to lower signal-to-noise ratios.

The original CGG processed ST14001 seismic volume is still impacted by multiples. Figure 4.11 demonstrates the influence of the seabed multiple in a gather display. The raw fast-track gathers (after de-ghosting) have no multiple attenuation and show the strong reflections of the multiples. At this particular Common Depth Point (CDP), the first multiple interferes with the near offset at 2.9 s. The same multiple interferes at reservoir level (3.4 s) with the medium offsets and below reservoir (3.8 s) with the far offsets. The raw PSDM gather, shown on the right, still shows a significant impact of the multiples even though a full de-multiple process was executed.

A subsequent Equinor internal Amplitude Versus Offset (AVO) conditioning processing mitigated the impact of the multiples. The processing flow finished with and without trim statics (semblance optimization). A comparison of the original CGG PSDM gathers and the AVO conditioned gathers is shown in Figure 4.12. The comparison of the flatness of the CGG original gathers, the AVO conditioned gather without trim statics, and the AVO conditioned gather with trim statics is illustrated in Figure 4.13. The AVO conditioning improved the flatness of the gathers significantly. Please note, the colour scale is -12 ms to +12 ms for all map displays and the colour scale is exceeded most of the time for the original processing.

Based on the seismic quality analysis, the ST14001 survey with the internal Equinor AVO conditioning process was selected for the Bay du Nord Field seismic interpretation.

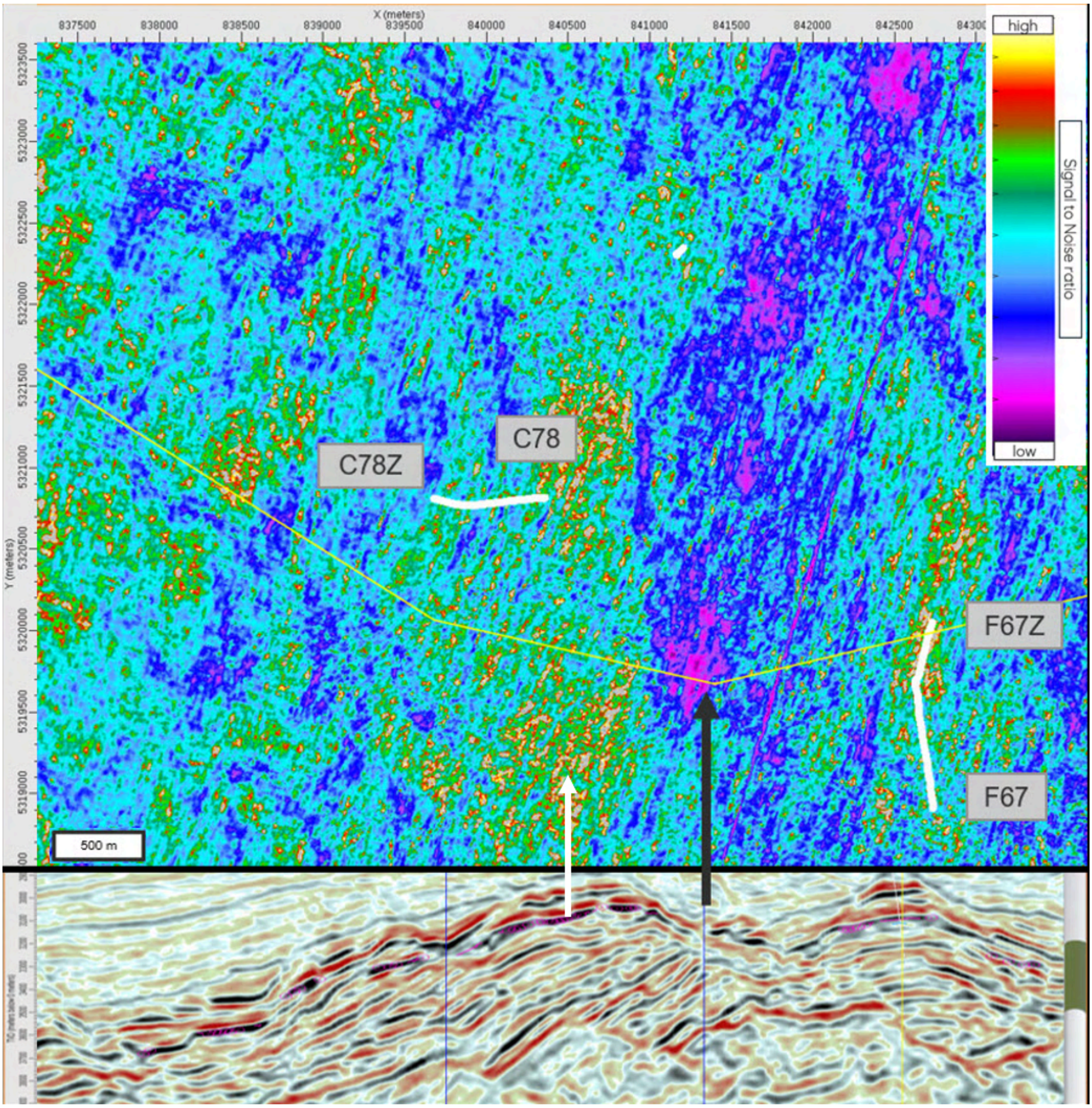


Figure 4.9 Signal-to-Noise Ratio The colors refer to a normalized RMS value with hot colors indicate high S/N and cold colors low S/N. The black arrows show example of low S/N on the map and the corresponding section location. The white arrow are corresponding to high S/N. The extraction time window is around the main reservoir.

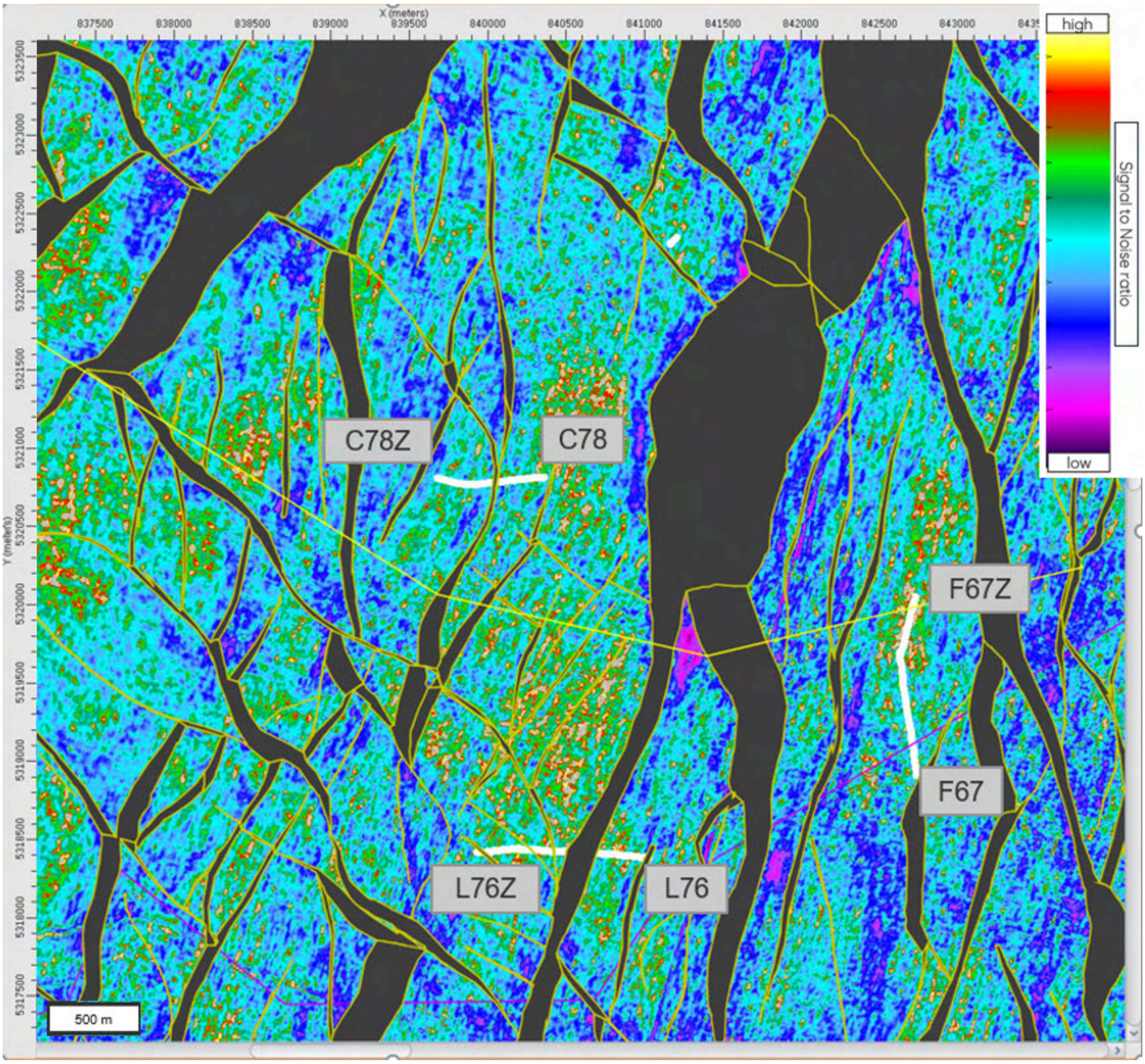


Figure 4.10 Signal-to-Noise Ratio with Main Faults Depicted

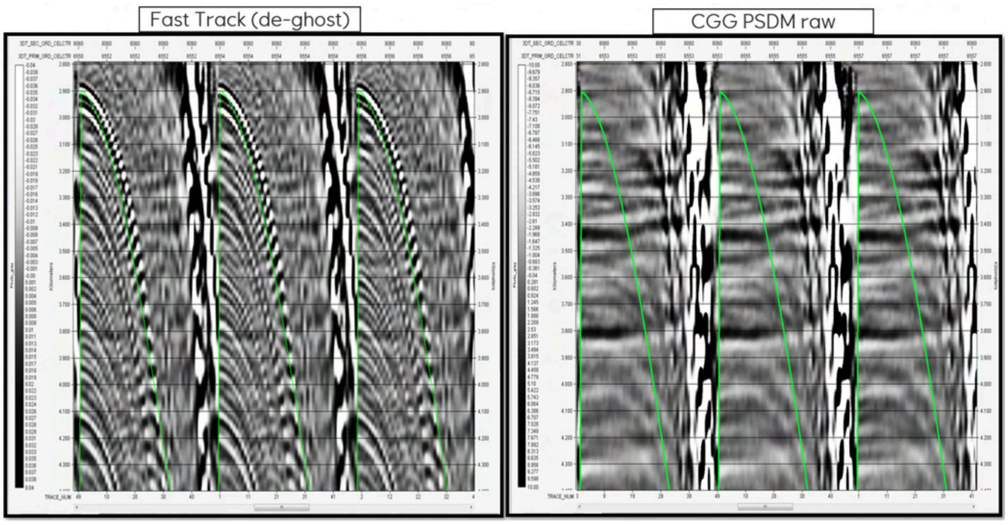


Figure 4.11 Example of Seabed Multiples in a Seismic Gather IL 8060.

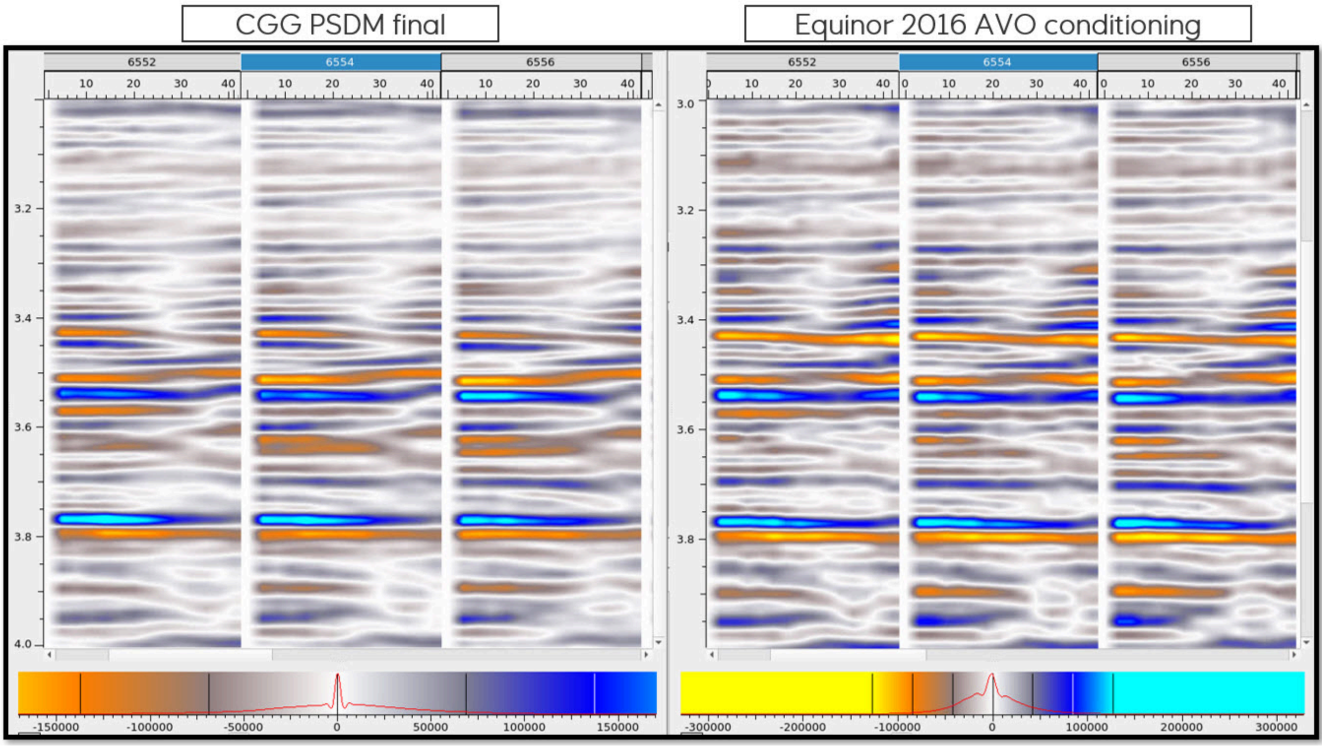


Figure 4.12 Gather Comparison

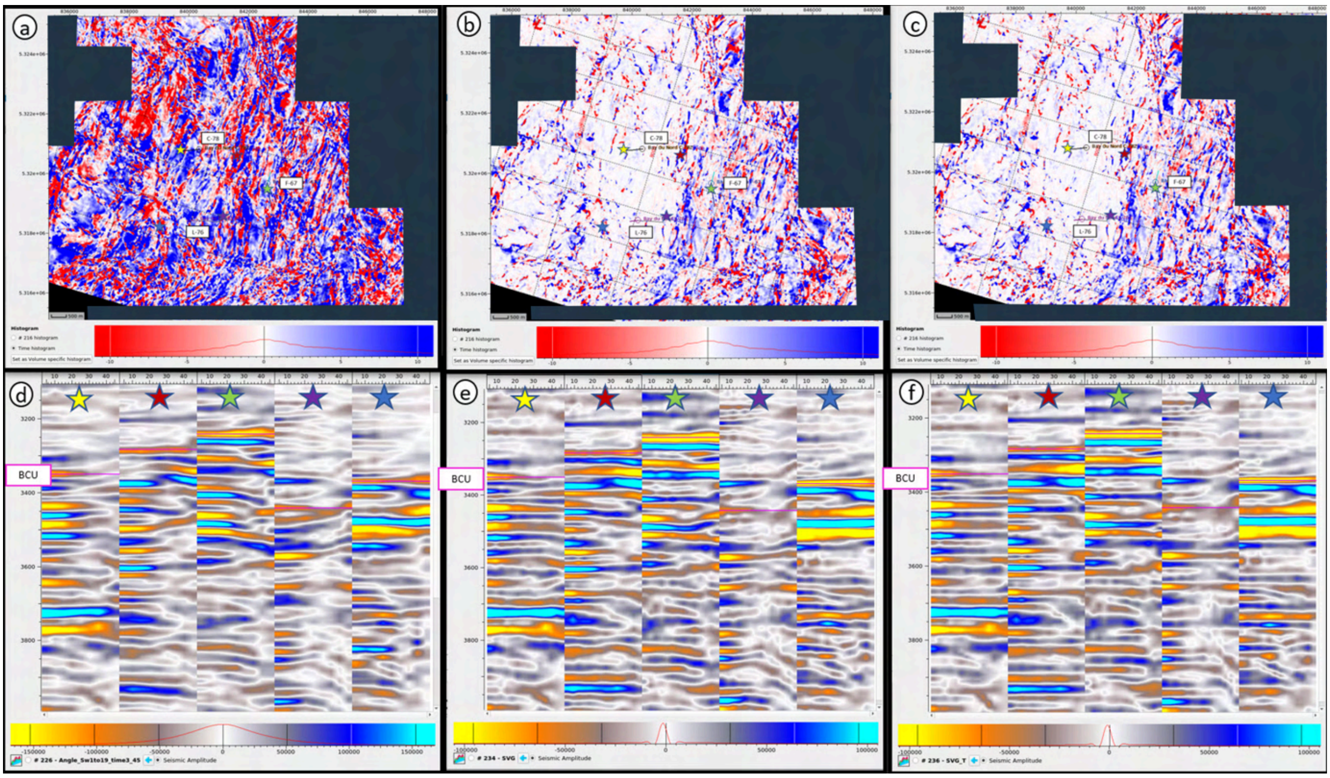


Figure 4.13 AVO Conditioning - Flatness of Gathers a to c: Cross-correlation Near and Ufar; time difference; d to e: Gather comparison at specific locations; a+d: Original processing; b+e: AVO conditioning; c+f: AVO conditioning plus trim statics.

4.2.2 Seismic Well Correlation

Post-Stack Well Correlations

All of the the wells within the Bay du Nord Field recorded sonic and density data, which were used as input for the synthetic seismogram computation. However, the recordings have limited length and do not start immediately at the seafloor. Within the Bay du Nord area, the Bay de Verde F-67 and F-67Z wells have sonic and density recordings with the shallowest starting point. Both wells share the same top-hole, and the logs start just above the Base Pleistocene seismic marker. The deepest sonic and density recordings in the Bay du Nord area were recorded in the Bay d'Espoir B-09 well, which penetrated the lower part of the Tithonian, and recorded data to approximately 4200 m MD.

For the well-ties, a wavelet was extracted from the near stack around the F-67Z well in the time interval from 2328 ms to 3562 ms. The wavelet was subsequently simplified to a trapezoid wavelet, with corner frequencies of 4-10-11-37 Hz. The comparison of the extracted and simplified wavelets is shown in Figure 4.14. The purpose of the simplification is to create a wavelet that is valid for all the Bay du Nord wells, without the specifics of the frequency spectrum around F-67Z where the wavelet was extracted. While this generalized wavelet provides a good overall tie, it is recognized that the shallower section of the surface seismic includes higher frequency components. Therefore, the well-ties for the shallower section were improved by choosing a time variable wavelet and merging the frequency bands between 3000 ms and 3100 ms. The wavelet for the deeper and shallow sections are compared in Figure 4.15. In general, the near stack extracted wavelets have a lower frequency content than the frequency-enhanced and Q-compensated final stacks shown in Figure 4.3.

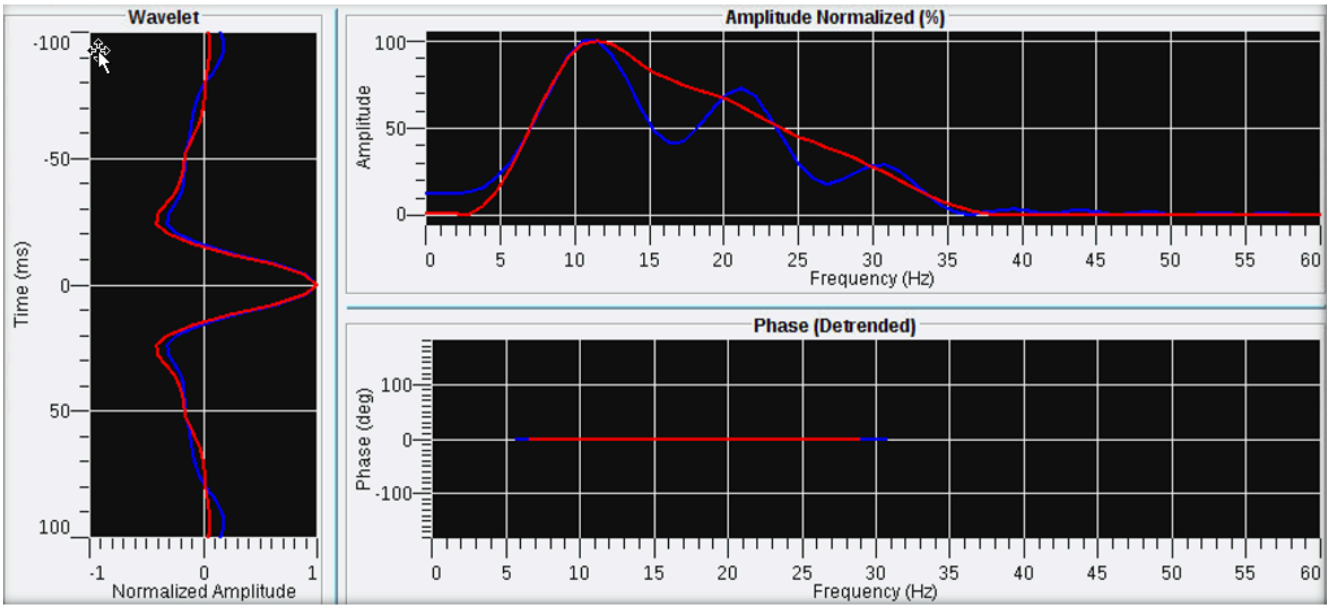


Figure 4.14 Wavelet Definition for Well Tie Blue: Statistical wavelet extracted in the near vicinity of F-67Z and a time interval from 2328 ms to 3562 ms. Red: Simplified trapezoid wavelet adapted to the statistical wavelet.

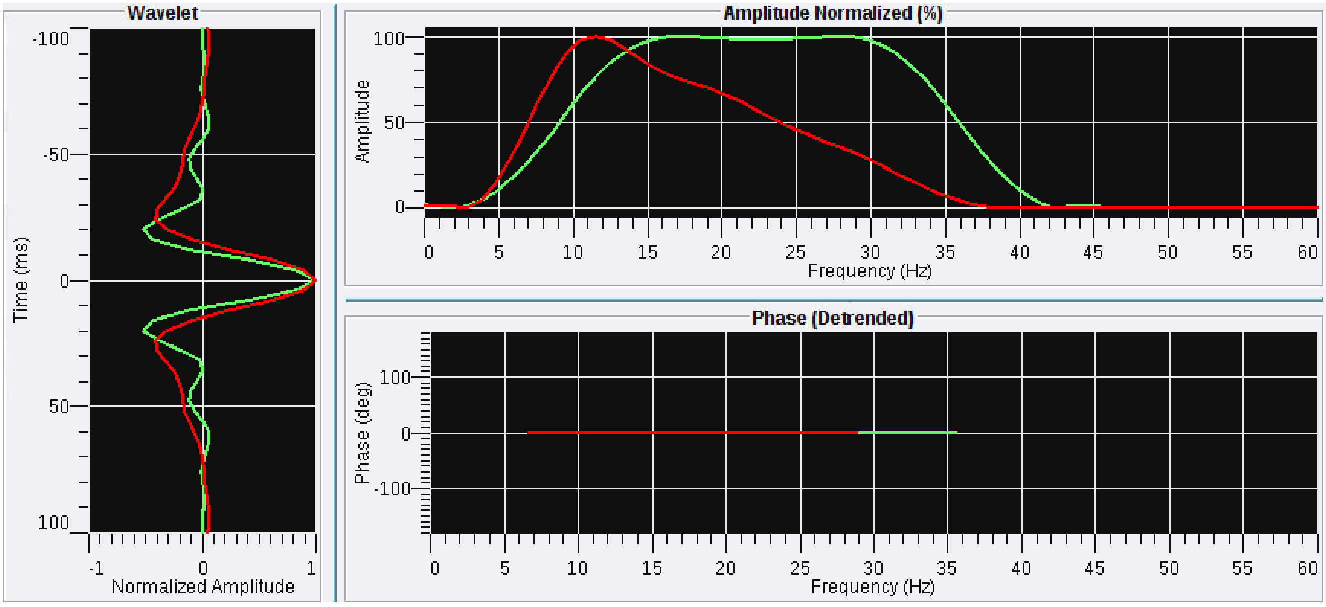


Figure 4.15 Time Variant Wavelets Green: Trapezoid wavelet for shallow well section, i.e. depth less than 3000 ms. Red: Trapezoid wavelet for deeper well section, i.e. depth more than 3100 ms. Frequencies are merged in the interval 3000 ms to 3100 ms.

The initial time-depth curves used in the well-tie process are from the Vertical Seismic Profile (VSP) time-depth tables, which were available for the Bay du Nord C-78/C-78Z, Bay du Nord L-76Z, Bay de Verde F-67Z, and Bay d'Espoir B-09 wells. The VSP time-depth tables take care of the initial drift curve correction. However, all the wells except C-78 are highly deviated. Even with a deviation correction applied to the VSP time-depth tables, a perfect match to the seismic data cannot be expected. The wellbore deviation results in an imperfect alignment of the VSP, so the drift curve is not correctly captured and additional stretching is necessary to achieve a well-tie from the top to the bottom of the well. In general, this stretching is kept to a minimum, which results in small misties in the upper well section. It was determined that these small misties, which do not impede the overall well-tie, are less of a concern than the resulting negative effects of stretching.

The full section well-tie (i.e. start of sonic and density log to Total Depth [TD]) includes the overburden section, and is not constructed for the detailed evaluation of the reservoir interval. However, the full section well-ties deliver a good understanding of the overall geological concepts and chronostratigraphic framework within the Bay du Nord area. Detailed well-ties specific to the reservoir section are discussed later in Section 19.5.1.3 Seismic Reservoir Characterization: Lithology and Fluids.

The full section well-tie correlations are illustrated in Figure 4.16, Figure 4.17, Figure 4.18, Figure 4.19, Figure 4.20, Figure 4.21, and Figure 4.22. While most well-ties are straightforward, the C-78Z well shows a significant mistie at the base of the Bay du Nord member due to cement. Additionally, there are some discrepancies between well-picks and the corresponding interpreted horizons in the F-67Z well. These discrepancies can be attributed to the complexity of the fluvial reservoirs. Seismic inversion (discussed in Section 19.5.1.1 Seismic Inversion) provides a better resolution of the reservoir interval. Inversion assists in the mapping of the Mizzen member sandstone and discriminates between clean and cemented sandstone within the Bay du Nord member. Consequently, the inversion data is the basis for the Bay du Nord member reservoir mapping.

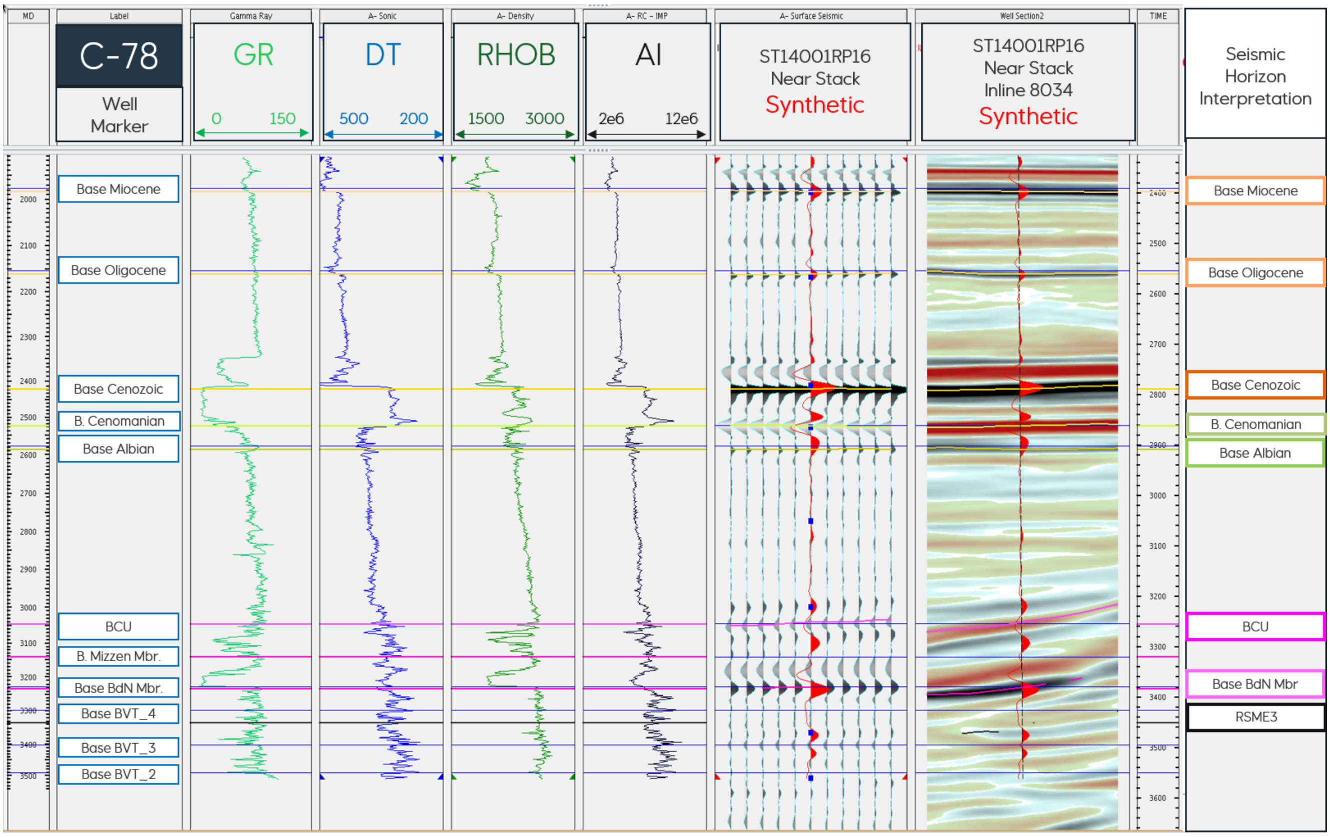


Figure 4.16 Bay du Nord C-78 Well Correlation

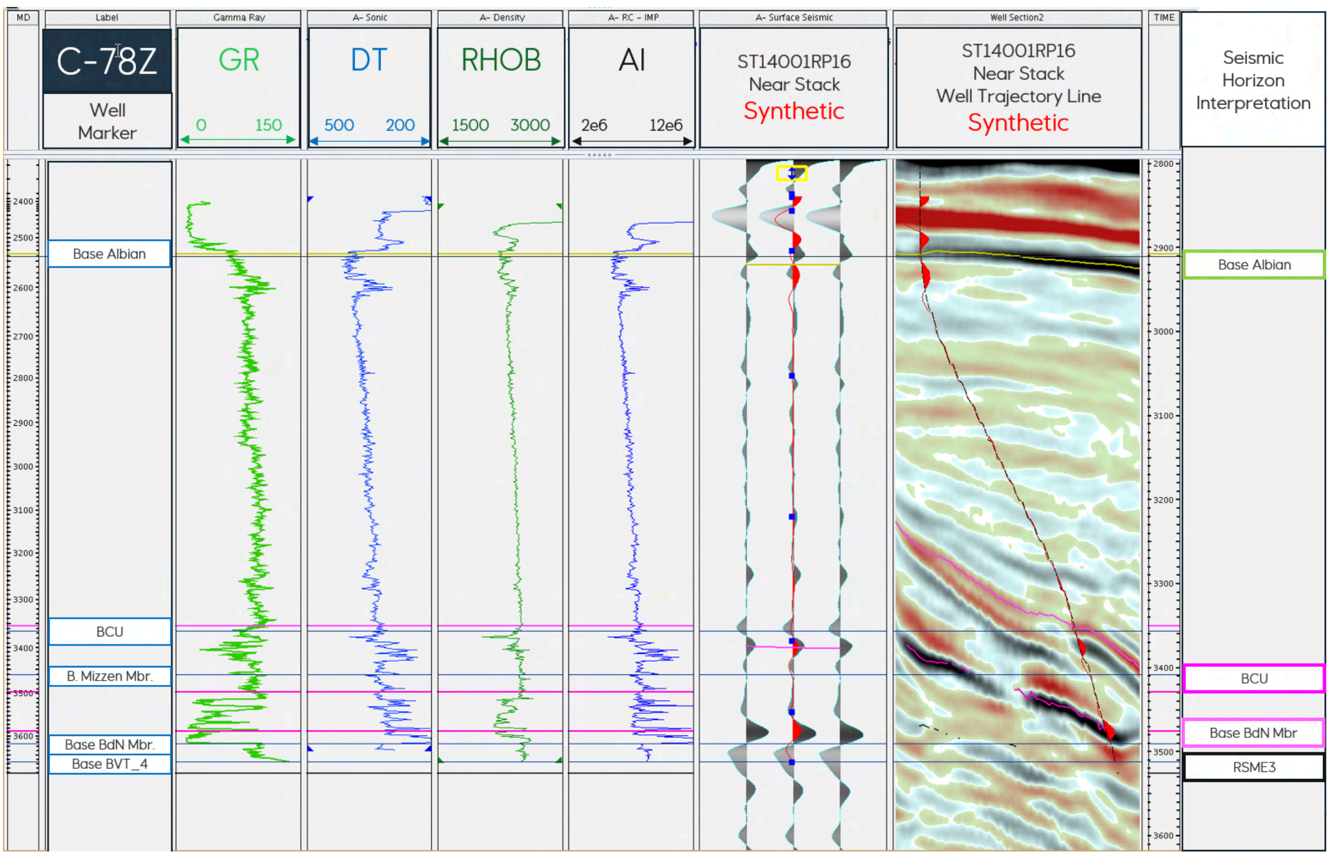


Figure 4.17 Bay du Nord C-78Z Well Correlation The Base Bay du Nord member shows a significant mis-tie due to the cementation at the base of the reservoir. The pick identifies the base of uncemented sand. Seismic inversion enables a discrimination between clean and cemented sand.

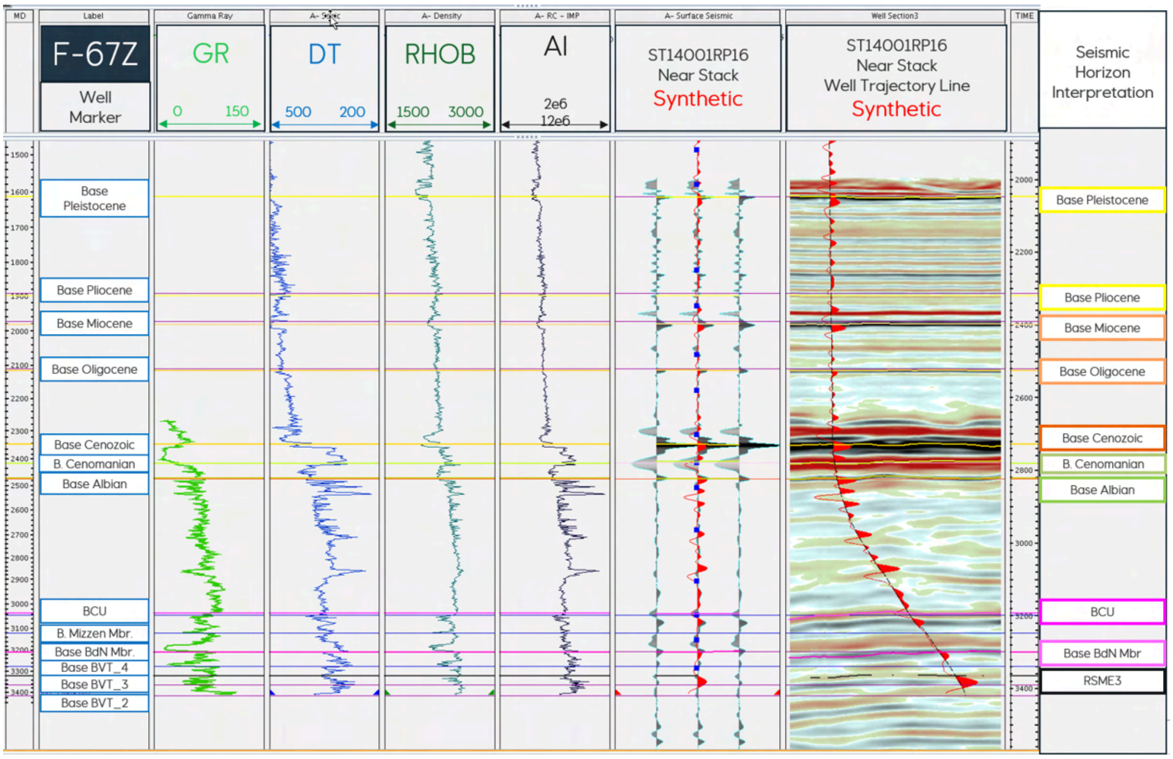


Figure 4.18 Bay de Verde F-67Z Well Correlation

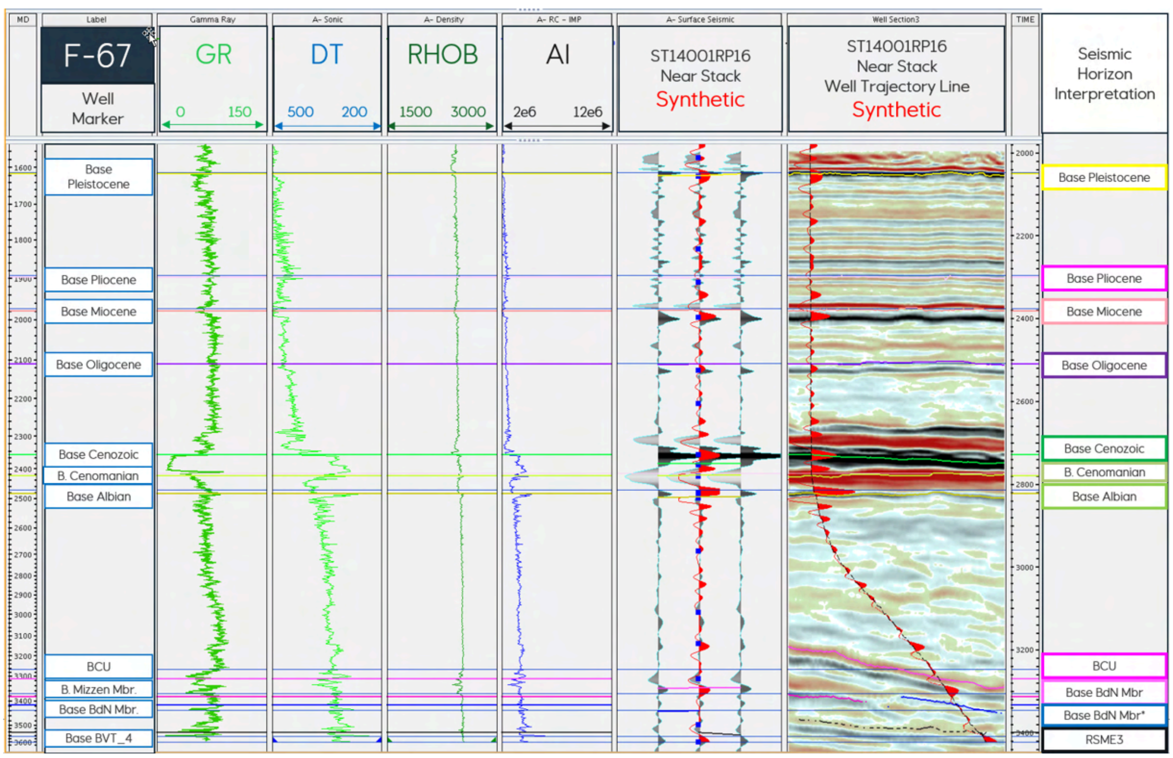


Figure 4.19 Bay de Verde F-67 Well Correlation The Base Cretaceous well marker is significantly higher than the interpreted seismic horizon. For consistency with the rest of the wells, the Base Cretaceous was picked in the trough. The magenta horizon for Base Bay du Nord member is the consistent pick within the high-quality sand environment associated with the valley depositional system. Outside of the valley system, the seismic interpretation is continued on a peak (blue horizon). The differentiation between the two seismic picks is based on the seismic inversion attributes, which are discussed later in the Application.

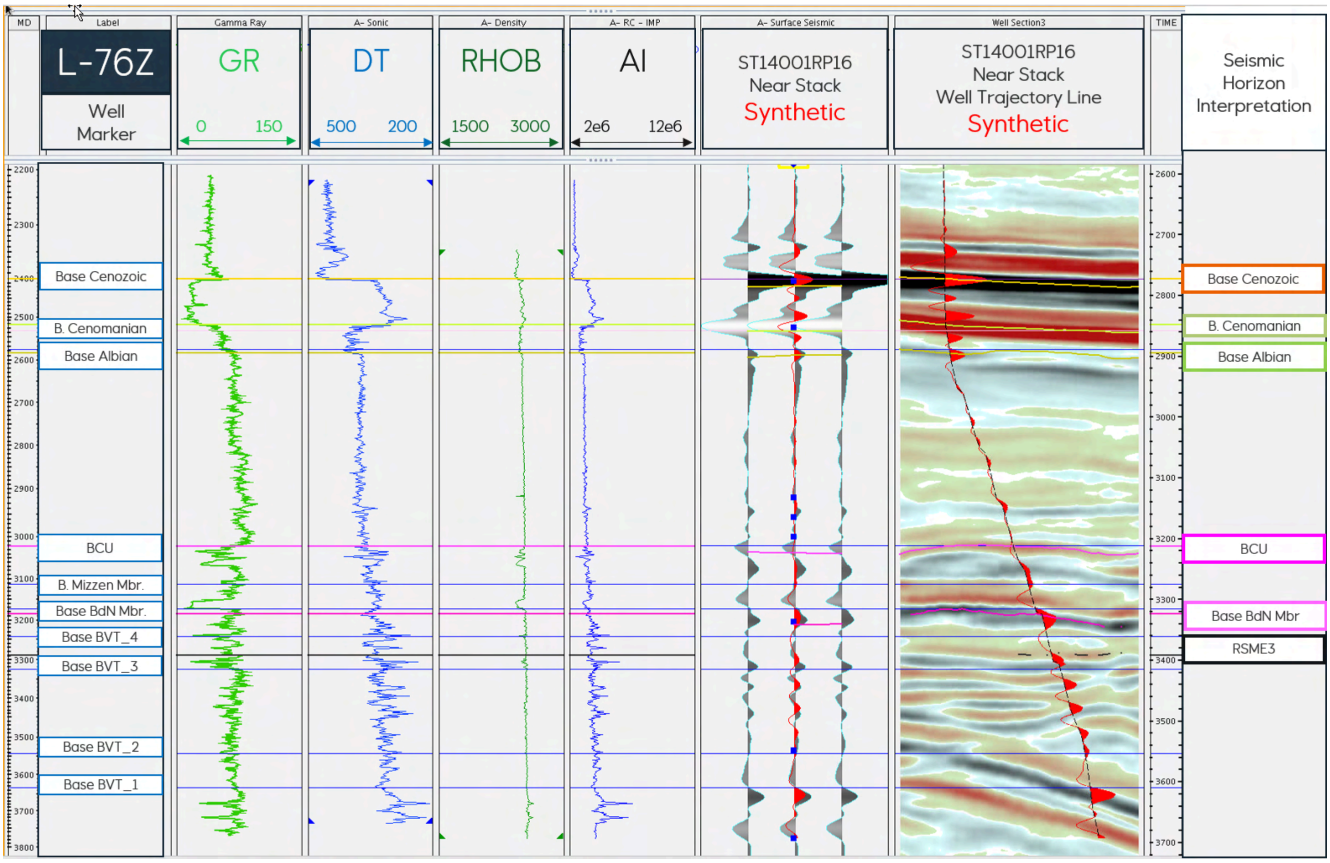


Figure 4.20 Bay du Nord L-76Z Well Correlation

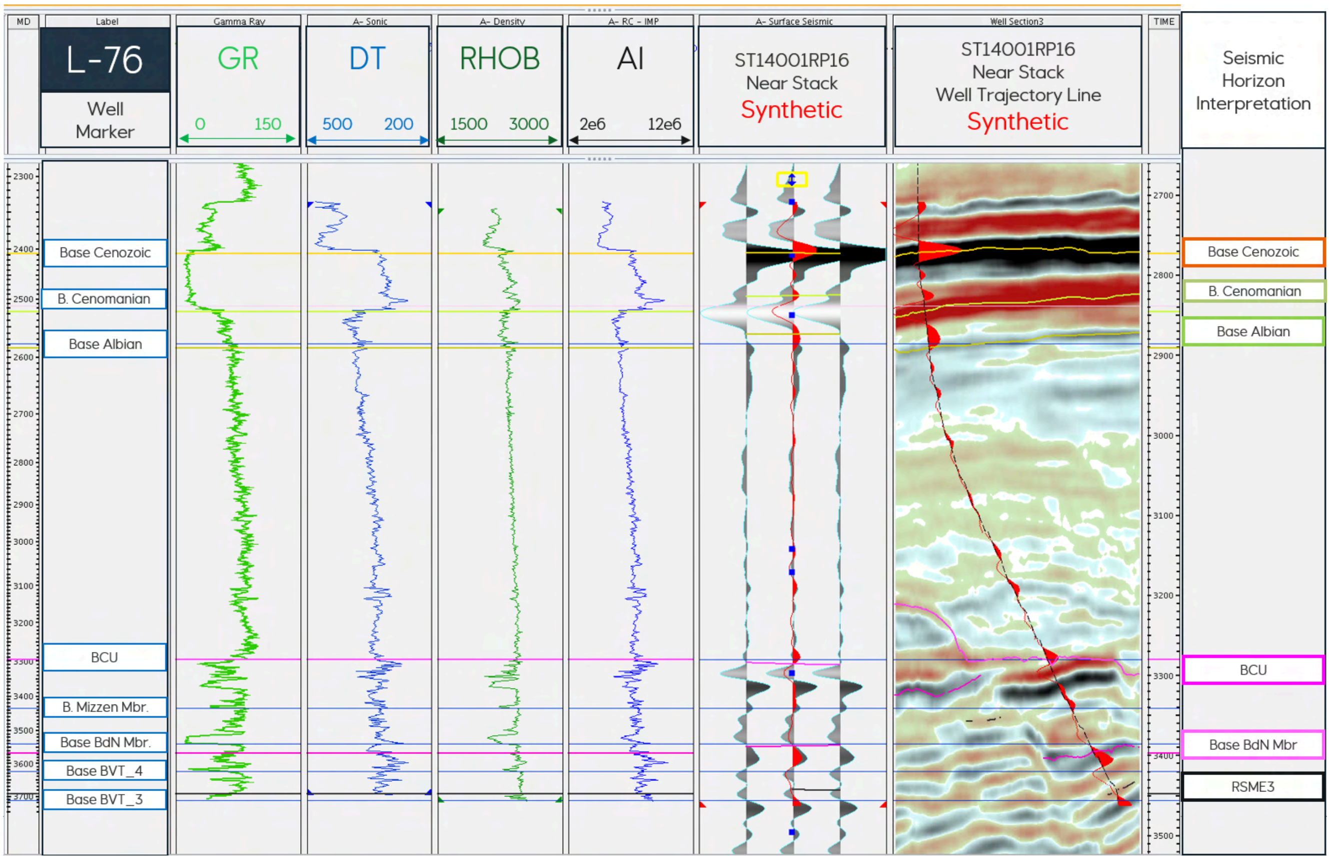


Figure 4.21 Bay du Nord L-76 Well Correlation

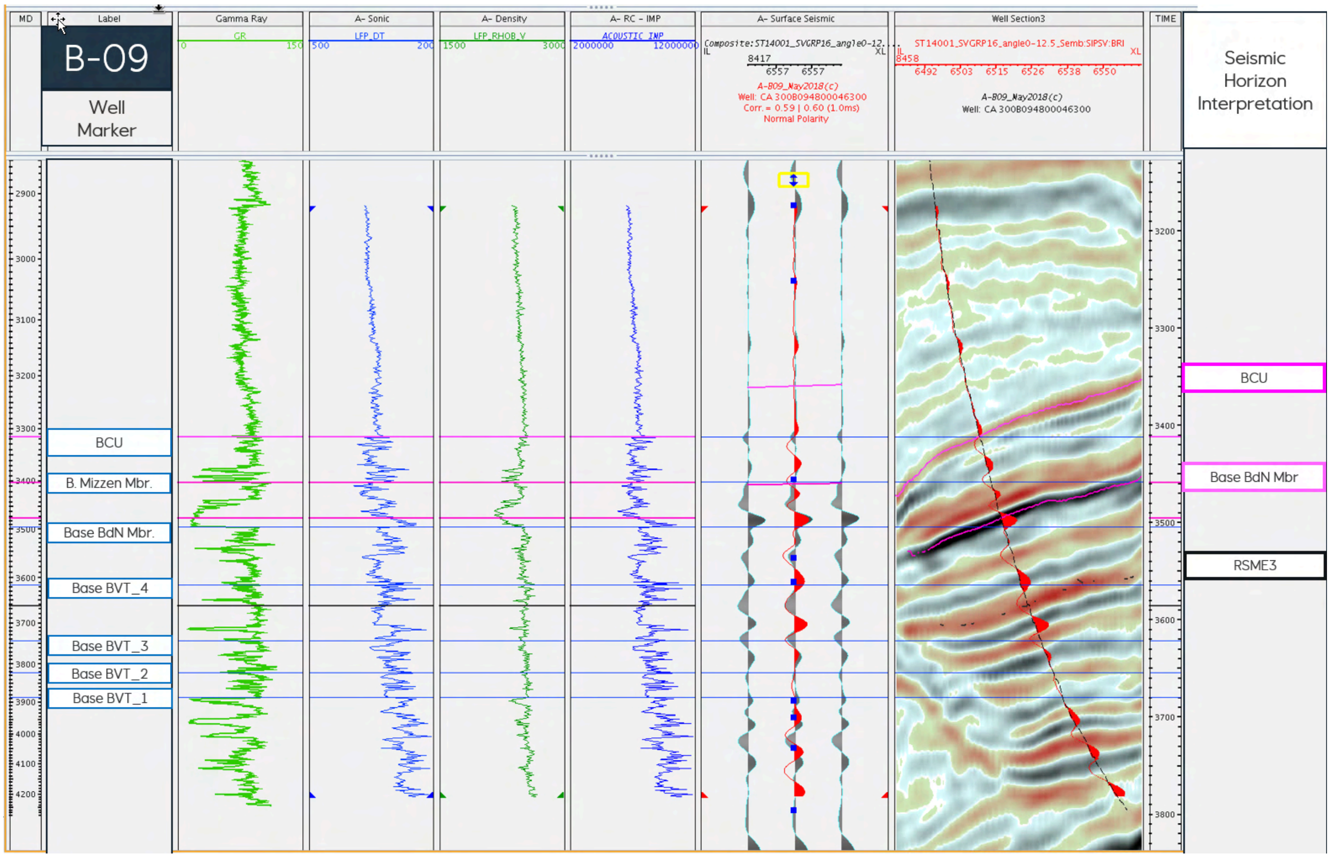


Figure 4.22 Bay d' Espoir B-09 Well Correlation

The well-tie illustrations include a few deeper Tithonian markers within the Bonaventure member. In most cases, these markers are not tied to the surface seismic as no consistent horizon interpretation was possible. However, the RSME3 marker, which is close to the Base Bonaventure member (BVT_4) has a more consistent seismic signature.

Pre-Stack Well Correlations

The basic AVO response of the top main Bay du Nord member reservoir is a class III response, i.e. trough at the top with negative gradient. This basic response is only valid for a blocked model and is shown in Figure 4.23.

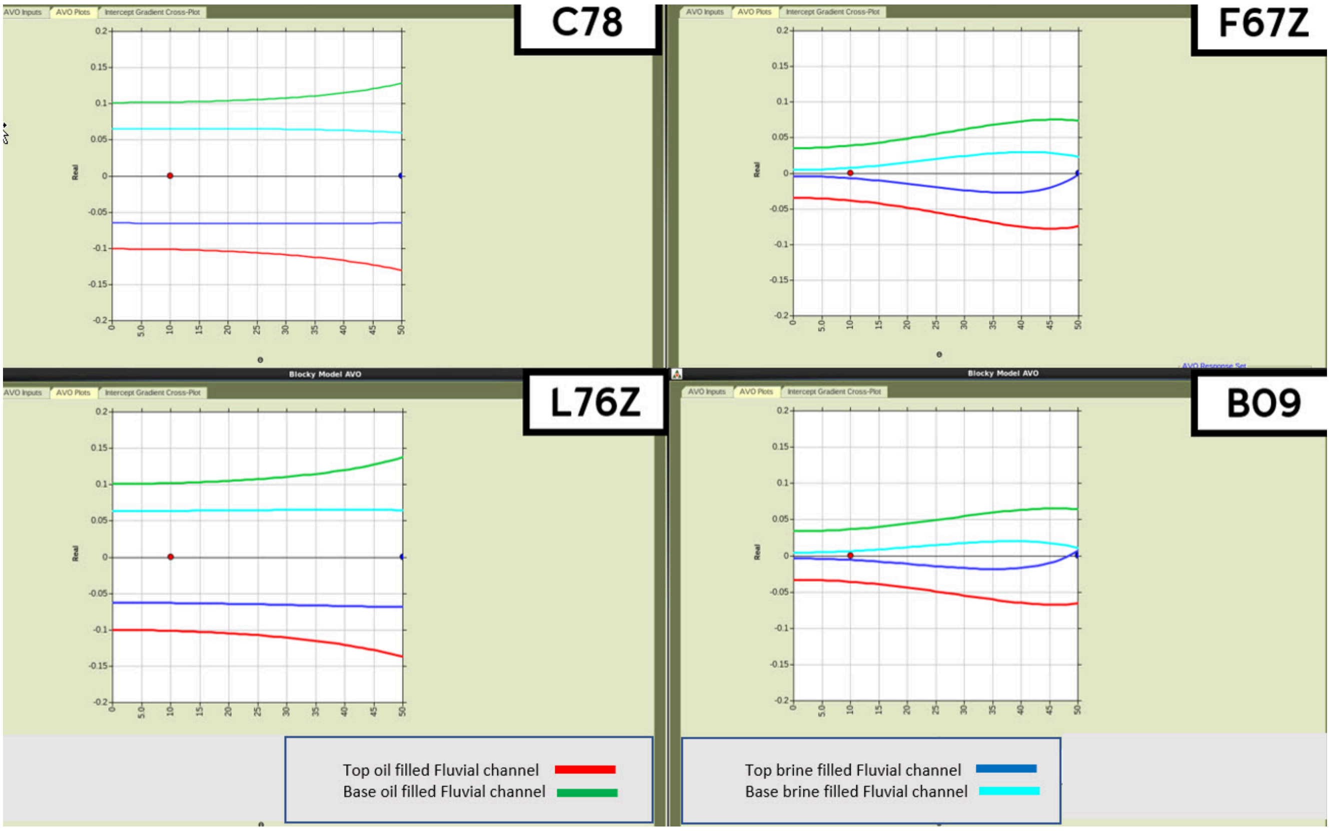


Figure 4.23 Basic AVO Response - Bay du Nord Reservoir

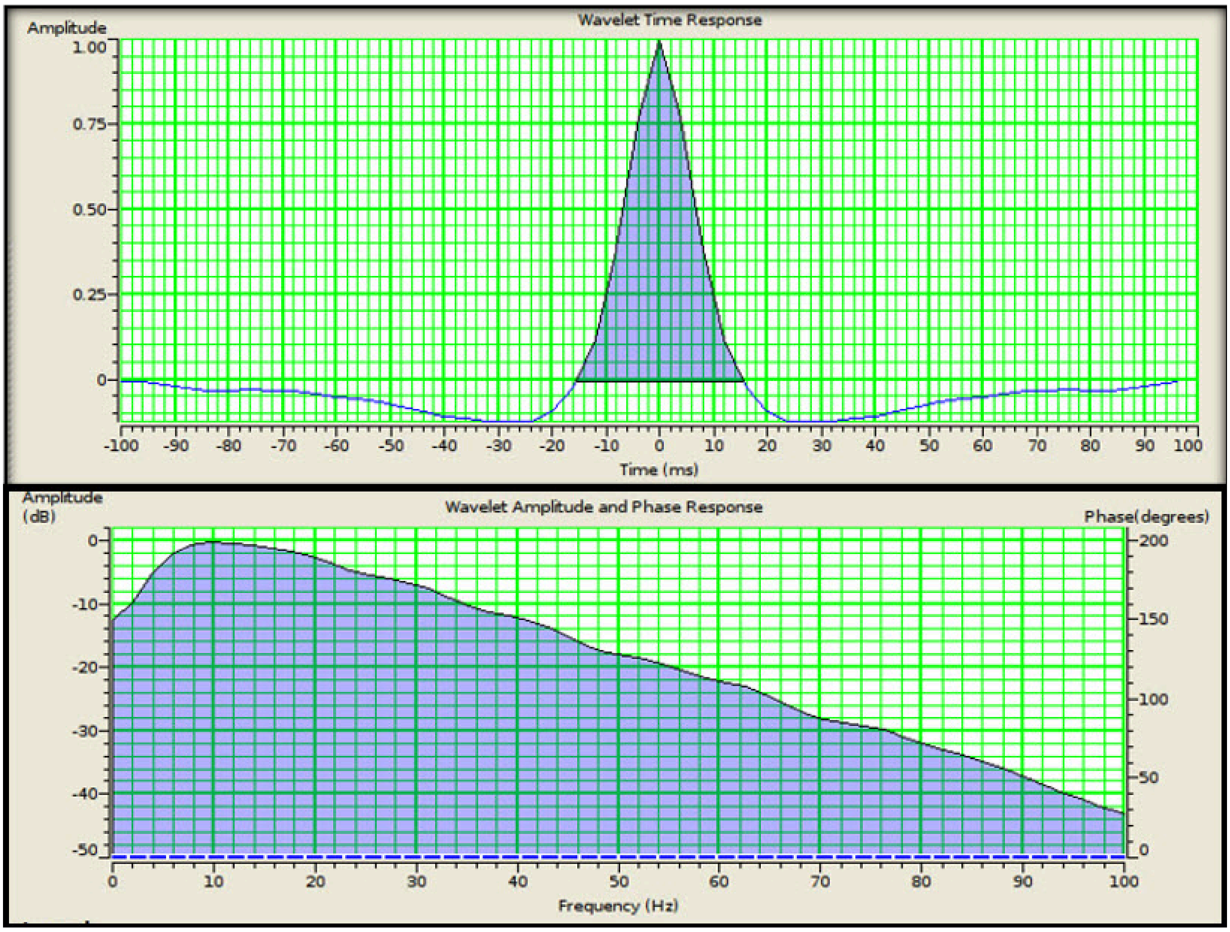


Figure 4.24 Extracted Wavelet Input for Synthetic Seismograms

The synthetics were generated with a statistical wavelet extracted in a time window 2800 ms to 3700 ms between IL 7400 to 8600 and XL 6000 to 7400 (Figure 4.24).

The set-up of the pre-stack well-tie figures is composed in the following pattern:

- The middle top shows the zero-offset synthetic (blue trace) tied to the near-stack section;
- The plots to the right illustrate the synthetic gather, which was computed with a 3 m Backus average of the logs, and the corresponding extracted gather at the reservoir zone from the surface seismic;
- The bottom panel shows the extracted gather at the reservoir zone, and the corresponding synthetic gather. The coloured lines indicated the events where the AVO amplitudes were extracted. The AVO amplitudes are displayed in the lower right display. An Aki Richard 2 term gradient solution is fitted through the extracted amplitude point. Light and dark blue show the amplitudes extracted from the surface seismic and red and orange the amplitudes from the synthetic.

Figure 4.25, Figure 4.26, Figure 4.27, Figure 4.28, Figure 4.29, Figure 4.30, and Figure 4.31 demonstrate the following:

- The real gathers follow the synthetic AVO trend very closely for the L-76Z, F-67Z, and F-67 wells;
- For the F-67 well, only the trough of the real gather responds like the model gather;
- The C-78, C-78Z, and B-09 wells have a poor correspondence between the real and modelled gathers;
- In general, it is important to be aware of the limitation of the pre-stack well ties, as they are only valid/correct at a specific CDP because the software does not allow for the extraction of gathers along the trajectory of the wellbore;
- The AVO tie is displayed at fixed CDPs, so consequently only vertical wells allow for a good comparison. Deviated wells tie only at one fixed inline (IL) / crossline (XL) location, which was chosen close to the target and is illustrated with a red indicator in the figures; and
- AVO ties are more sensitive to noise than acoustic ties. Illustrating the tie only at one trace is a limitation, so many CDPs around each well have been included in the analysis.

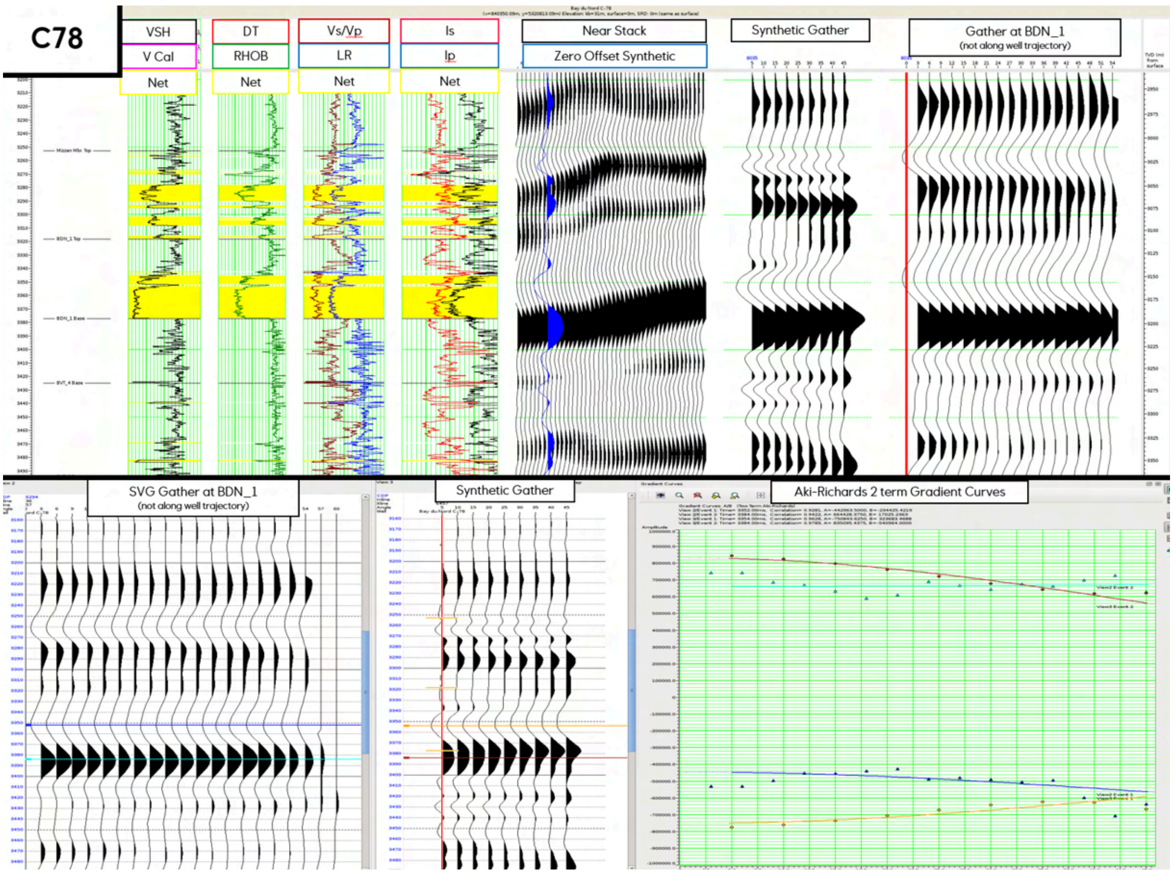


Figure 4.25 Bay du Nord C-78 AVO Well Tie

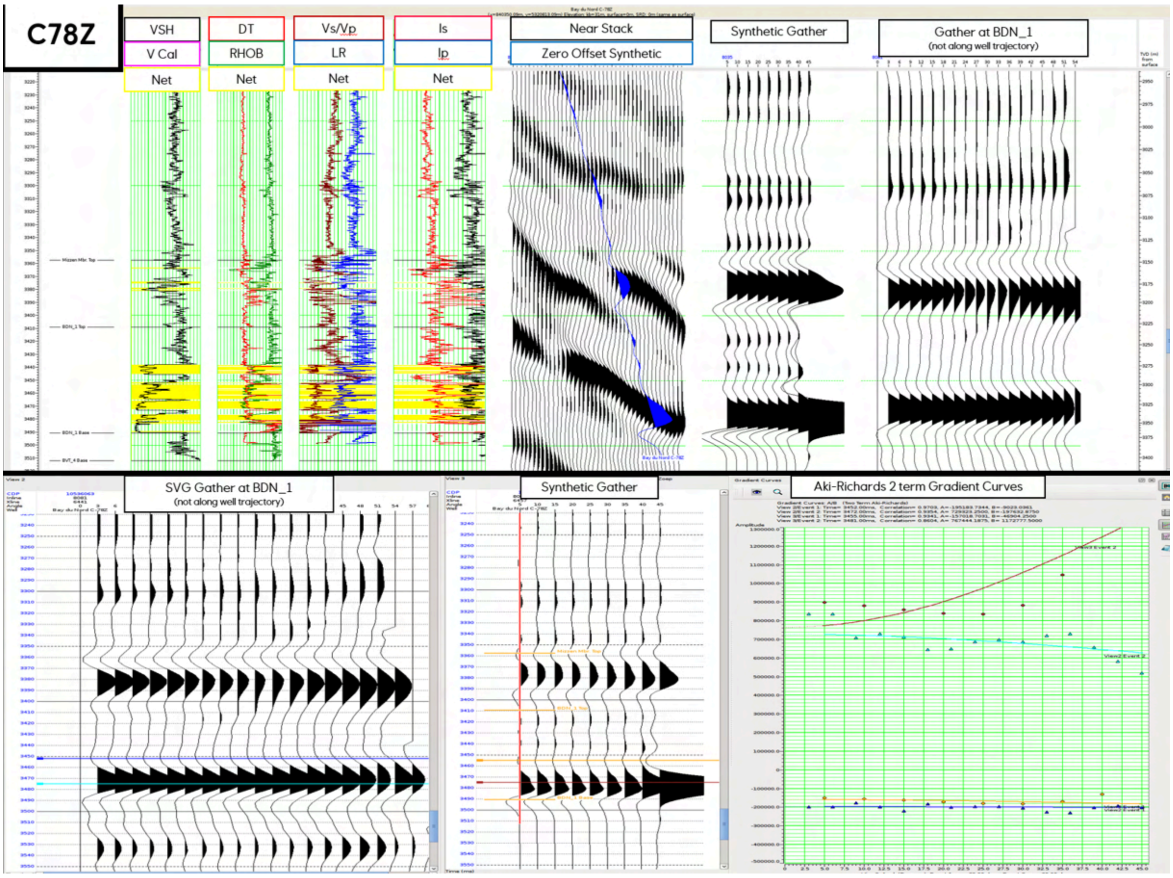


Figure 4.26 Bay du Nord C-78Z AVO Well Tie

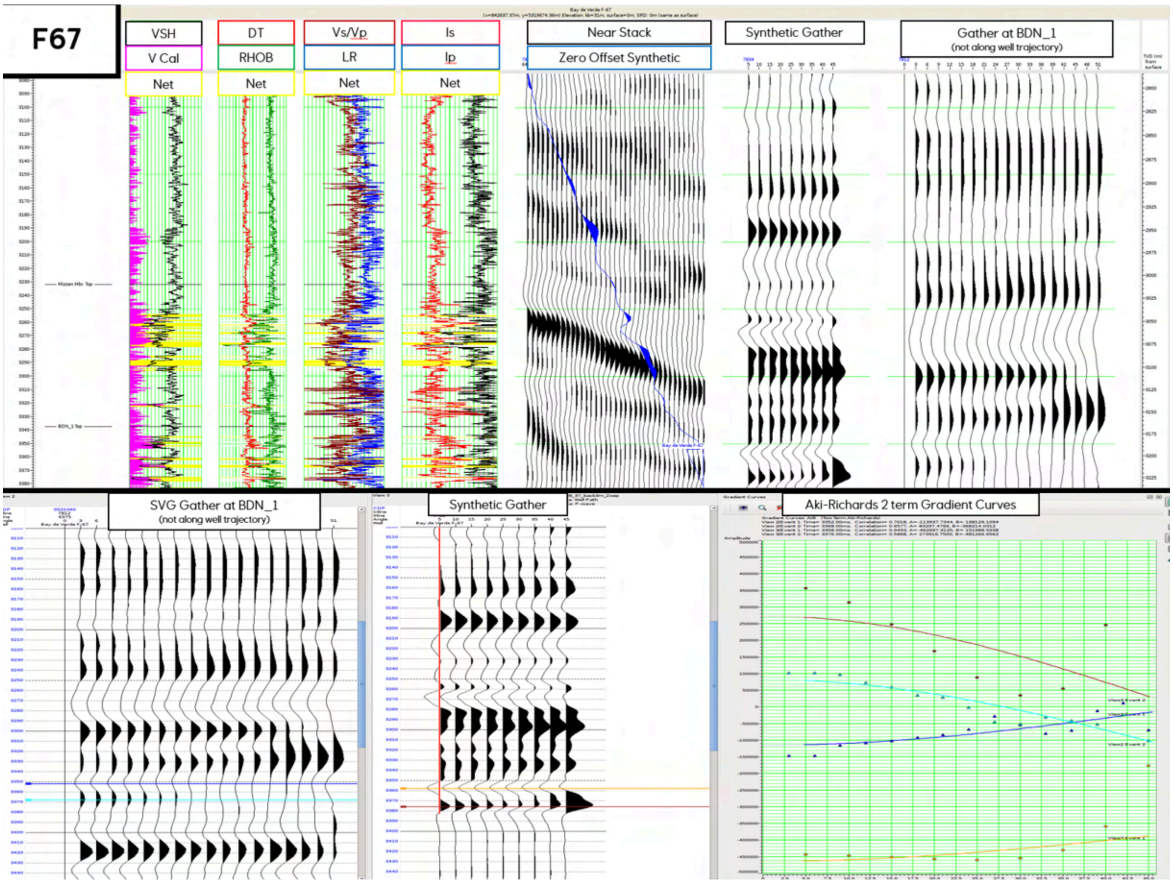


Figure 4.27 Bay de Verde F-67 AVO Well Tie

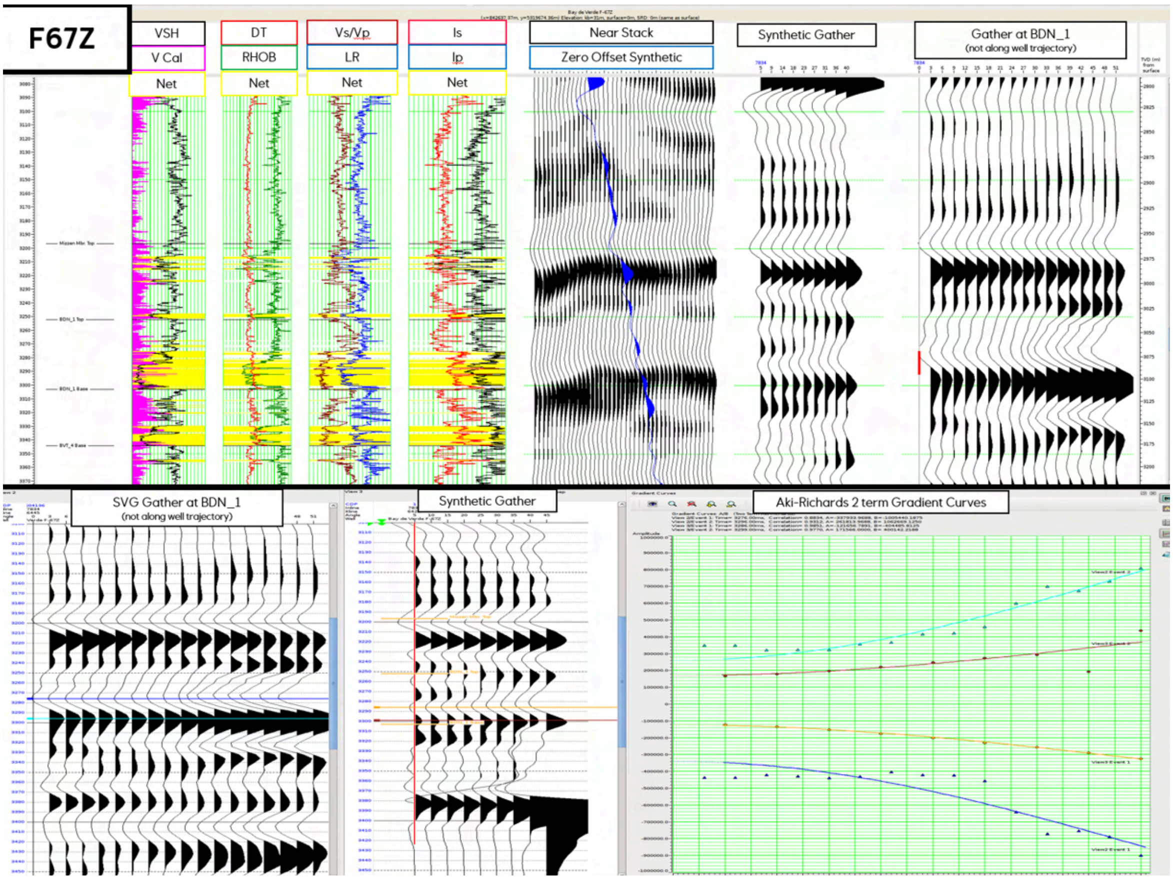


Figure 4.28 Bay de Verde F-67Z AVO Well Tie

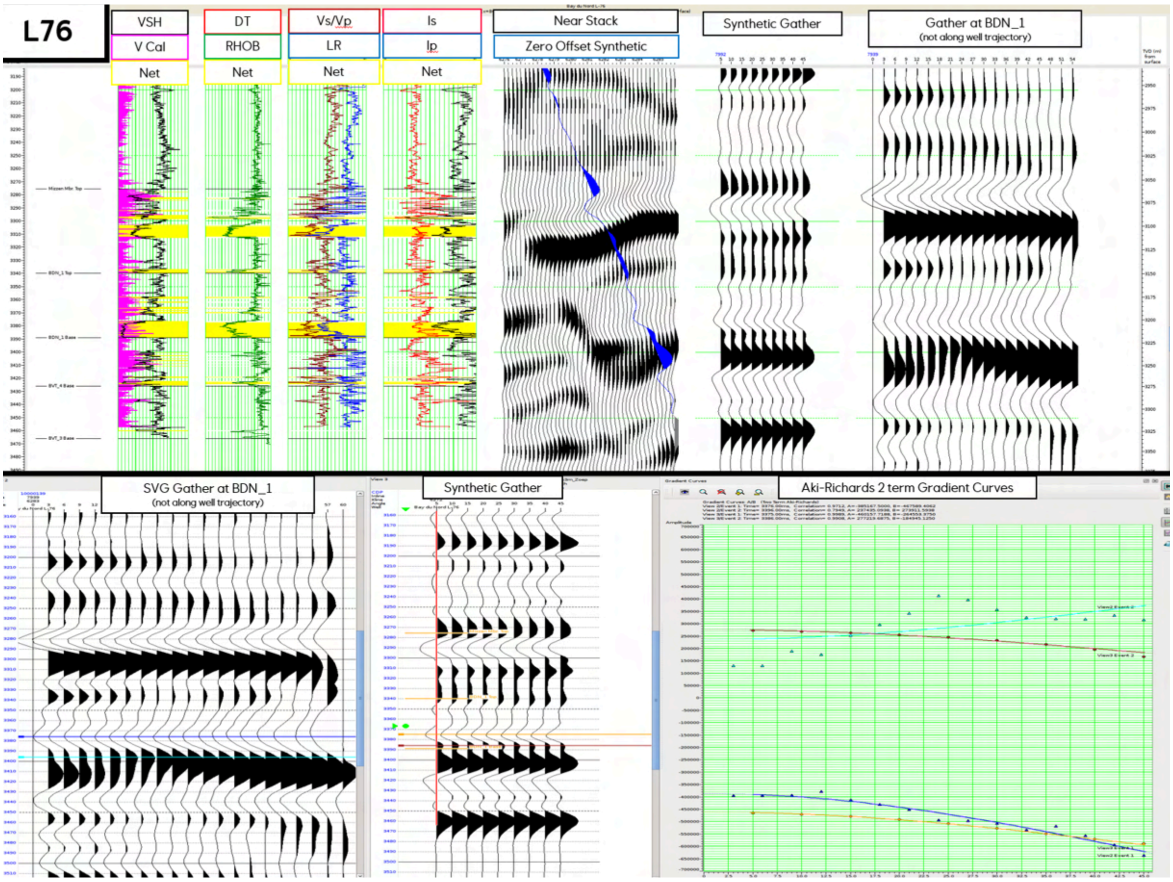


Figure 4.29 Bay du Nord L-76 AVO Well Tie

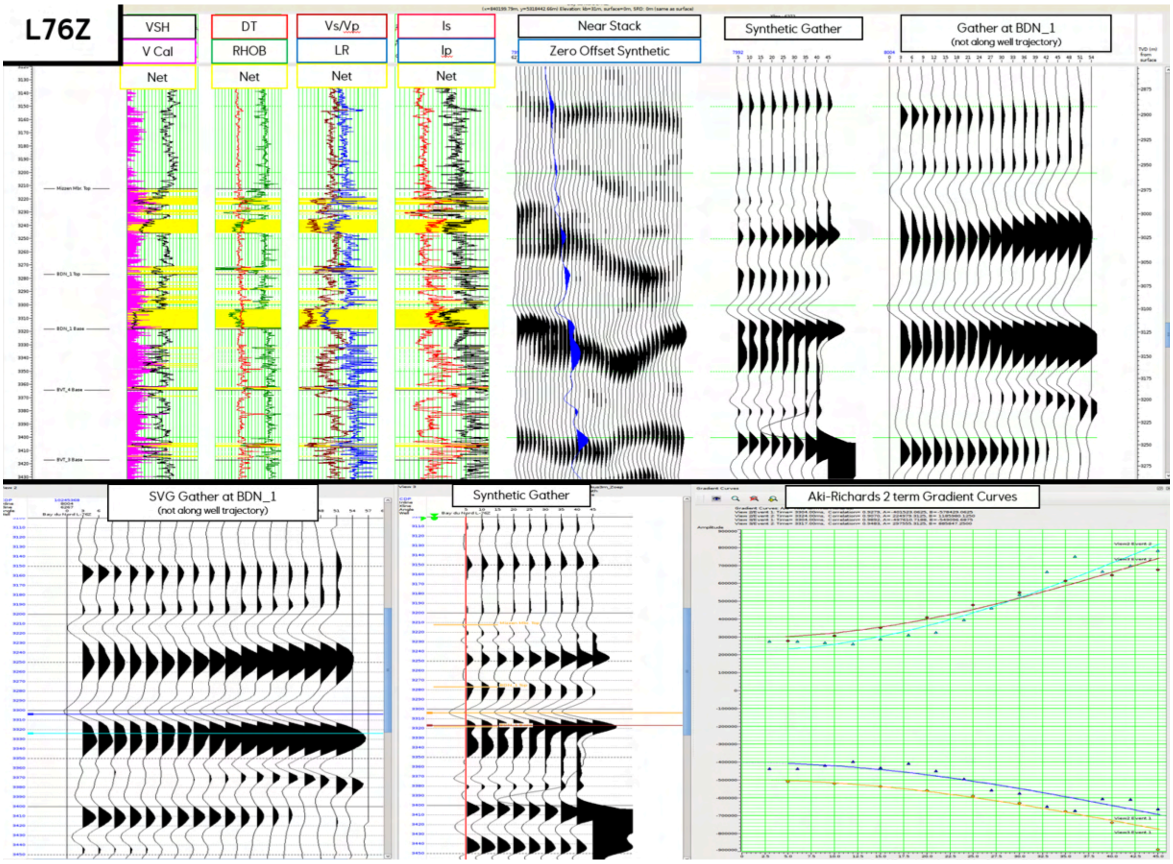


Figure 4.30 Bay du Nord L-76Z AVO Well Tie

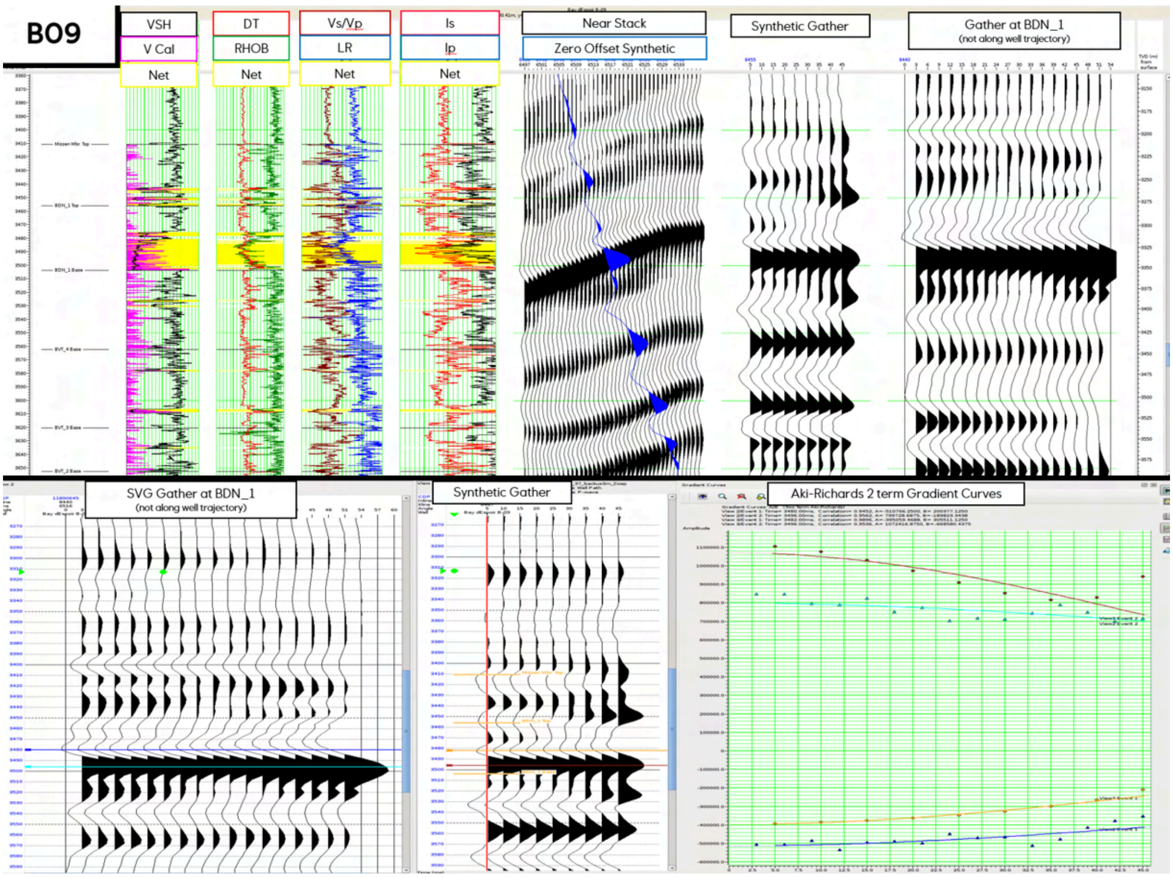


Figure 4.31 Bay d'Espoir B-09 AVO Well Tie

4.2.3 Structural Seismic Interpretation

A) Horizon Interpretation

Overburden Section

Based on the well correlation, the overburden section was interpreted according to the well marker - horizon correlation shown in Table 4.2. The horizon interpretation was mainly based of a number of seed lines followed by autotracking. The resulting overburden depth surfaces are shown in Figure 4.32, Figure 4.33, Figure 4.34, Figure 4.35, Figure 4.36, Figure 4.37, Figure 4.38 and the Base Cretaceous time structure map is given in Figure 4.39. A representative set of seismic time sections are given in Figure 4.40, Figure 4.41, Figure 4.42, and Figure 4.43.

Table 4.2 Well Marker - Seismic Horizon Correlation

Well Marker	Seismic Horizon Interpretation Onset
Base Pleistocene	Peak
Base Pliocene	Trough
Base Miocene	Peak
Base Oligocene	Peak
Base Cenezoioc	Peak
Base Cenomanian	Trough
Base Albian	Peak
BCU	Trough

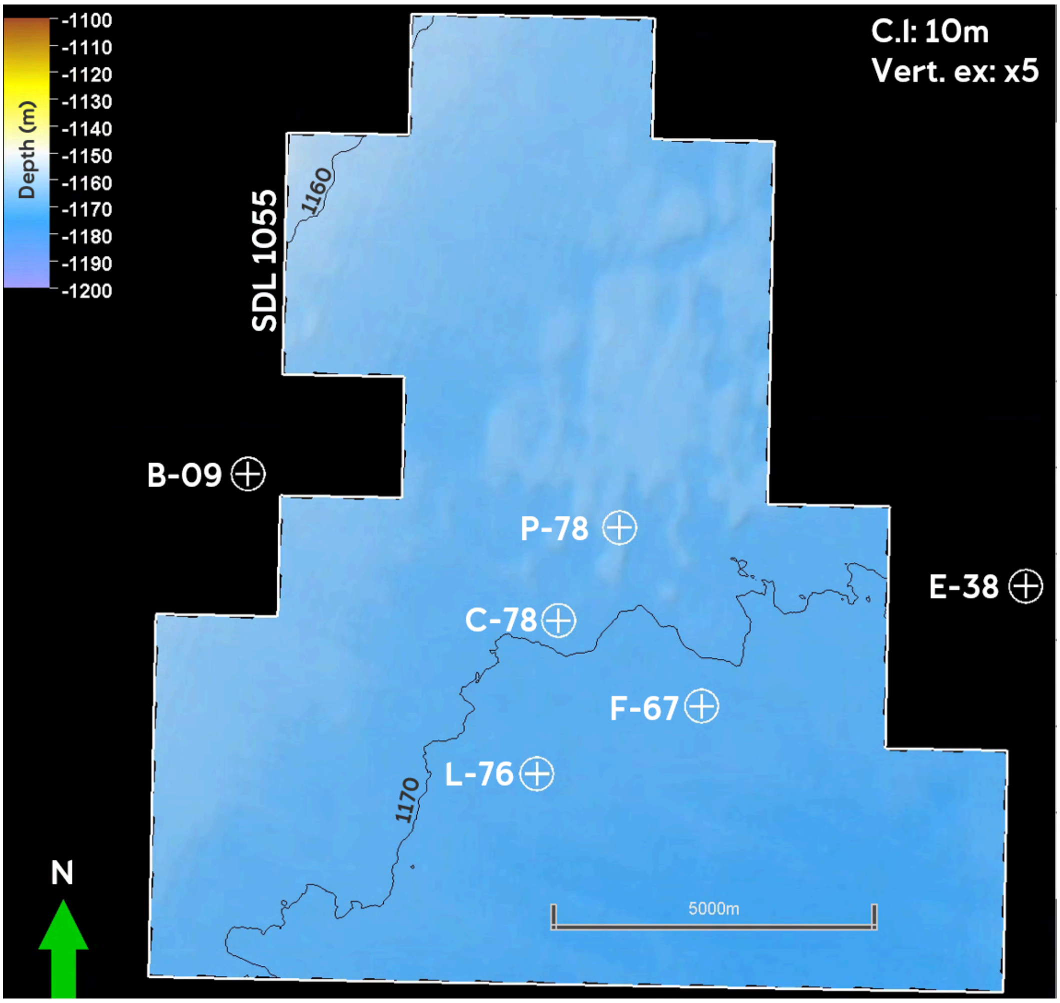


Figure 4.32 Seabed Surface Depth (m)

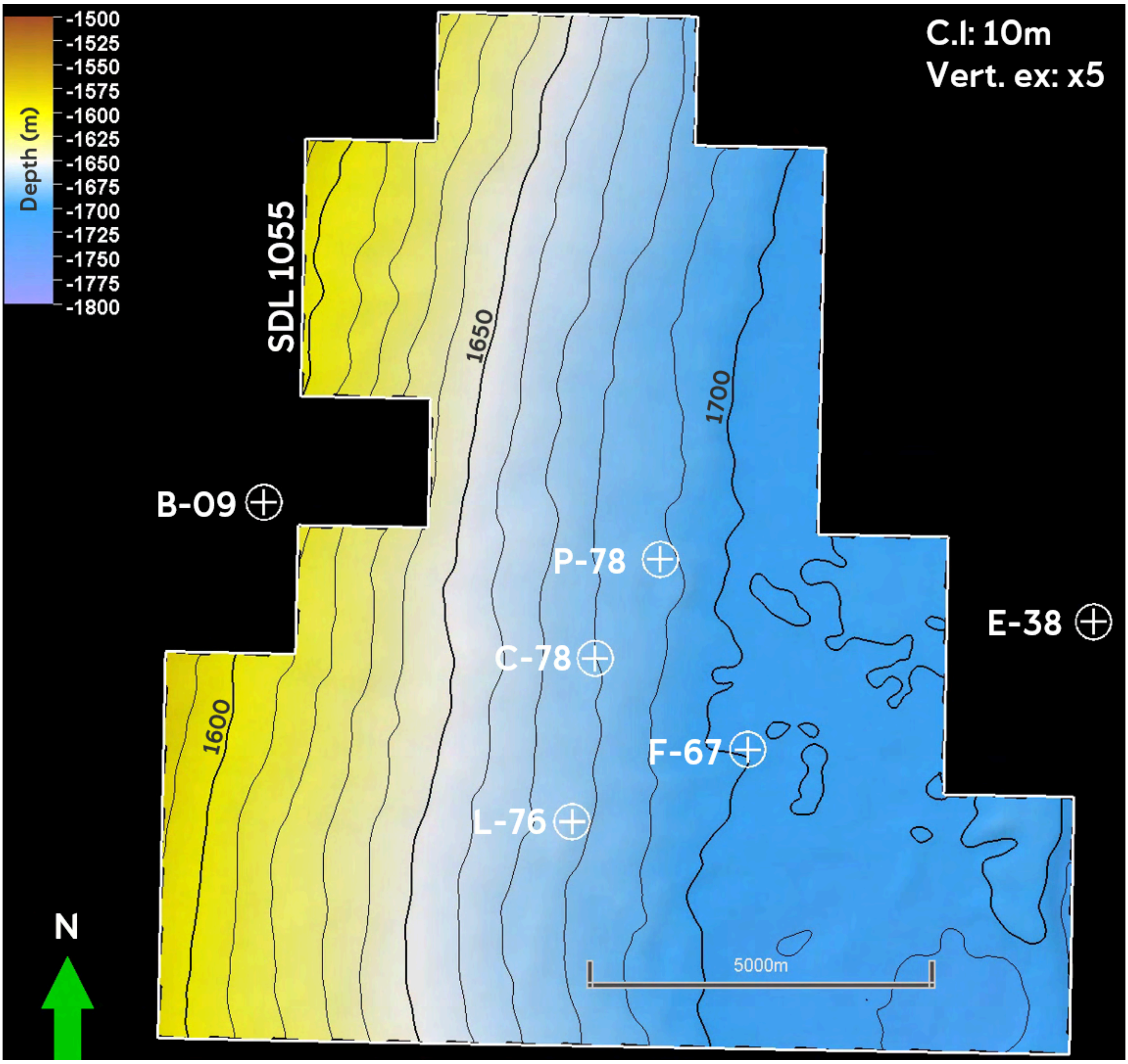


Figure 4.33 Pleistocene Base (base MTZ) Surface Depth (m)

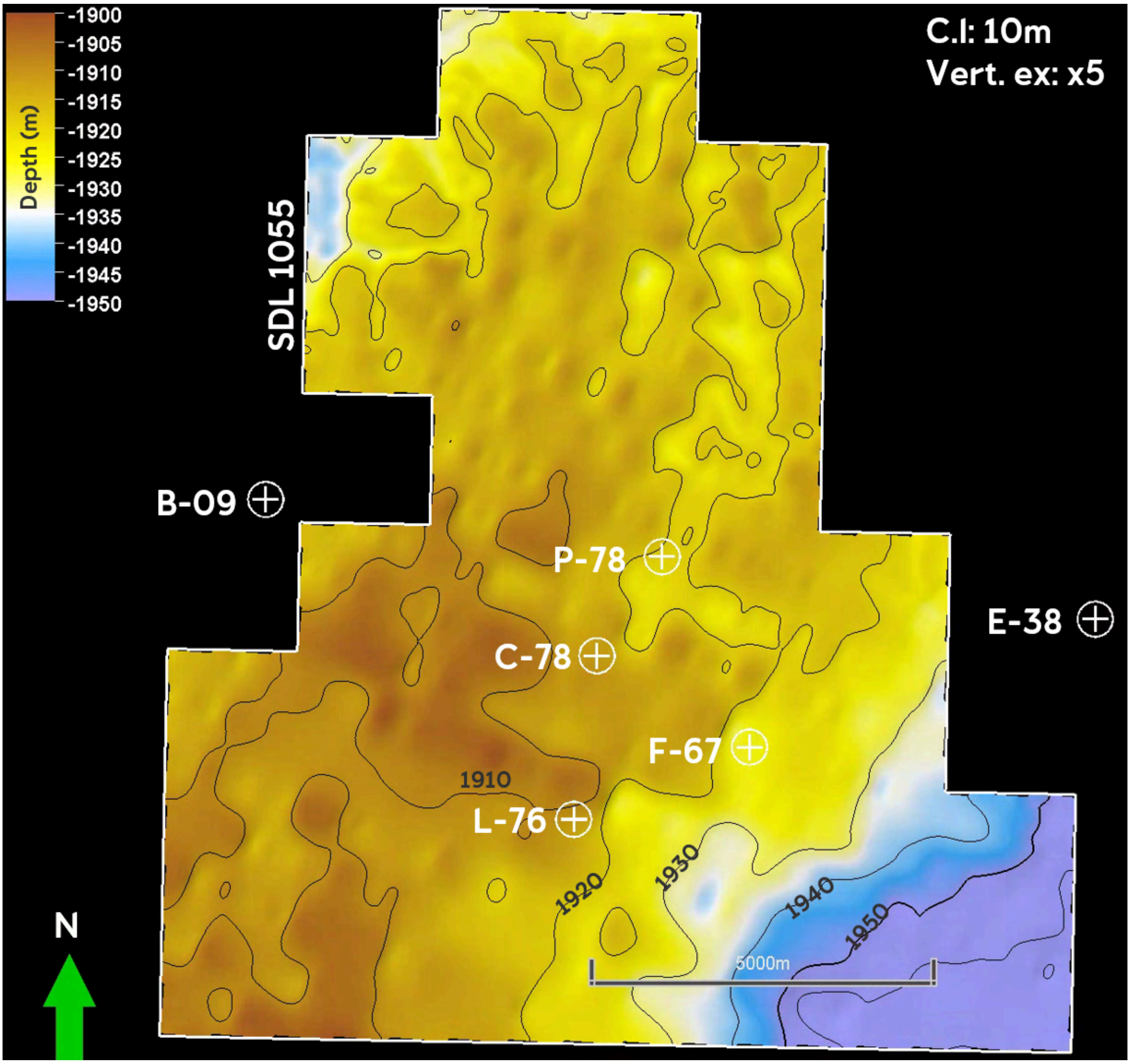


Figure 4.34 Miocene Base Surface Depth (m)

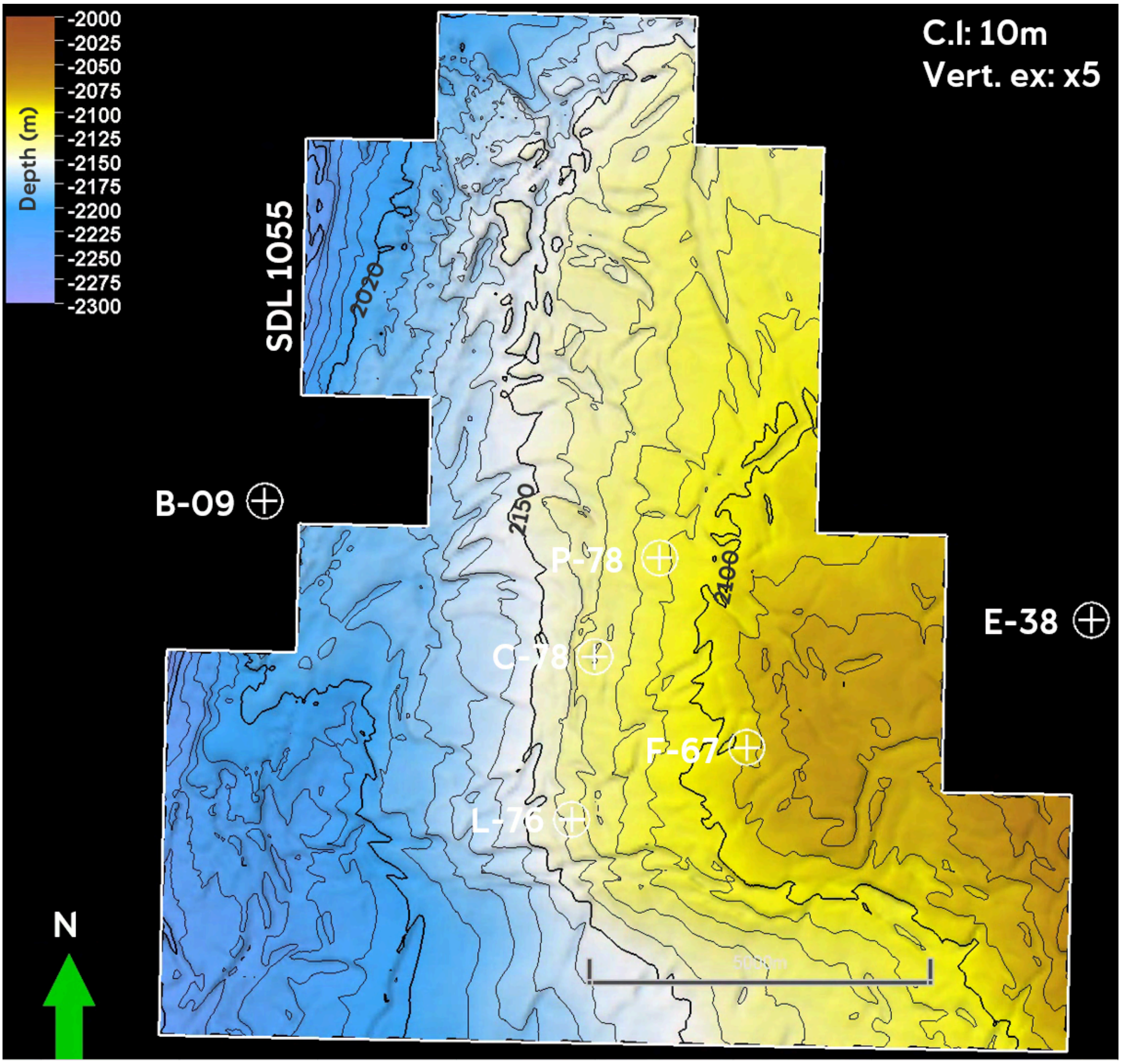


Figure 4.35 Oligocene Base Surface Depth (m)

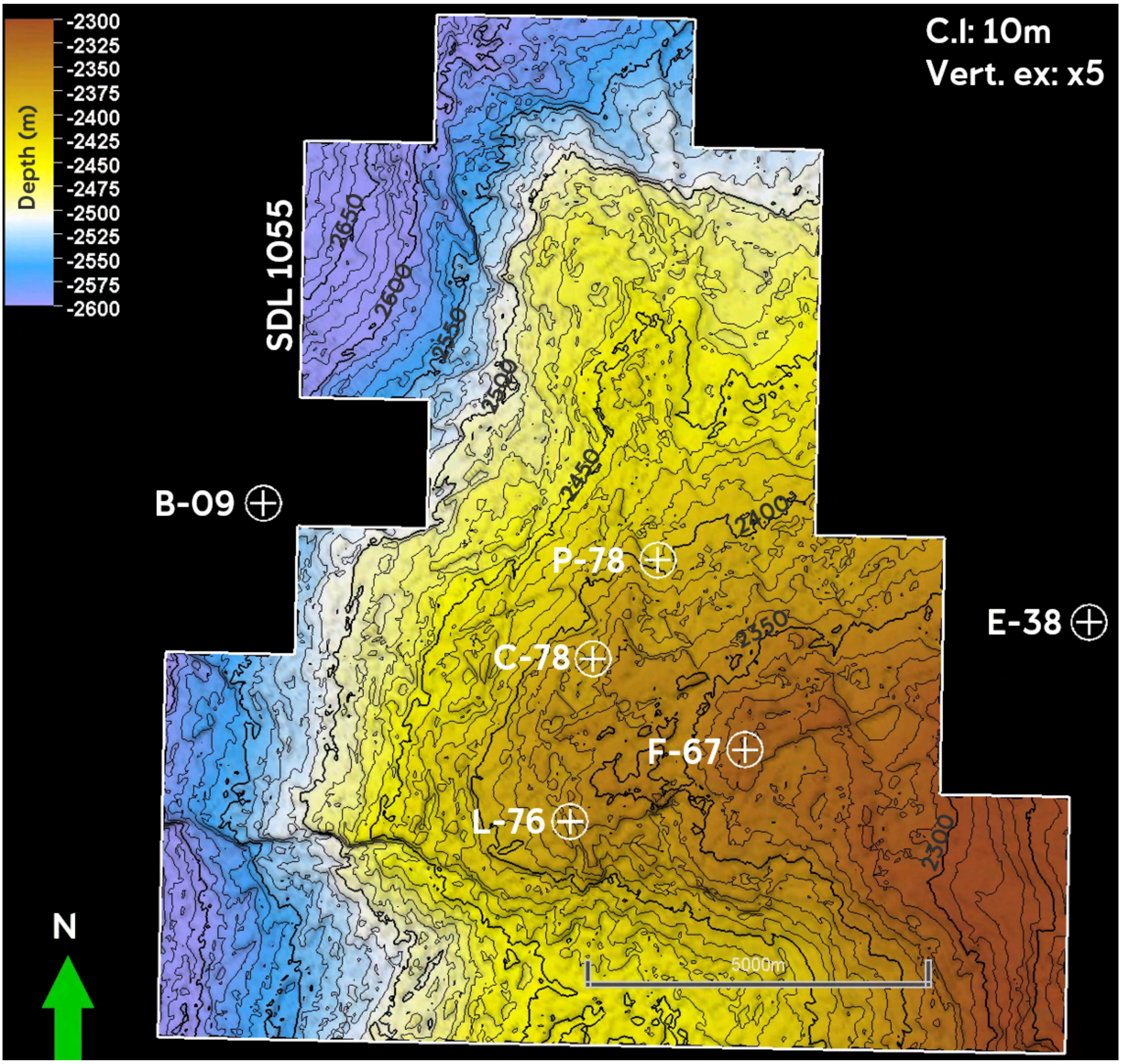


Figure 4.36 Cenozoic Base Surface Depth (m)

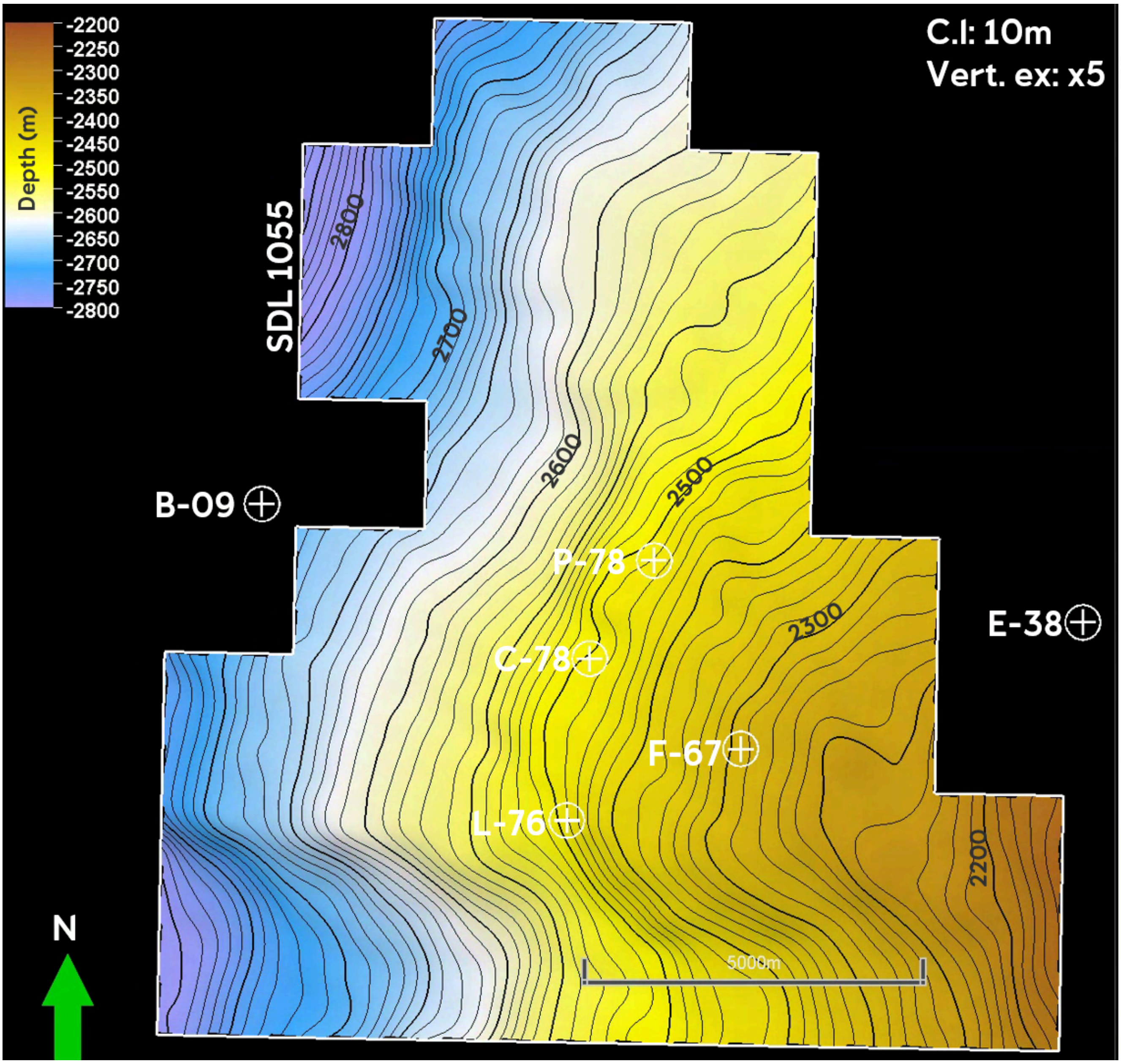


Figure 4.37 Cenomanian Base Surface Depth (m)

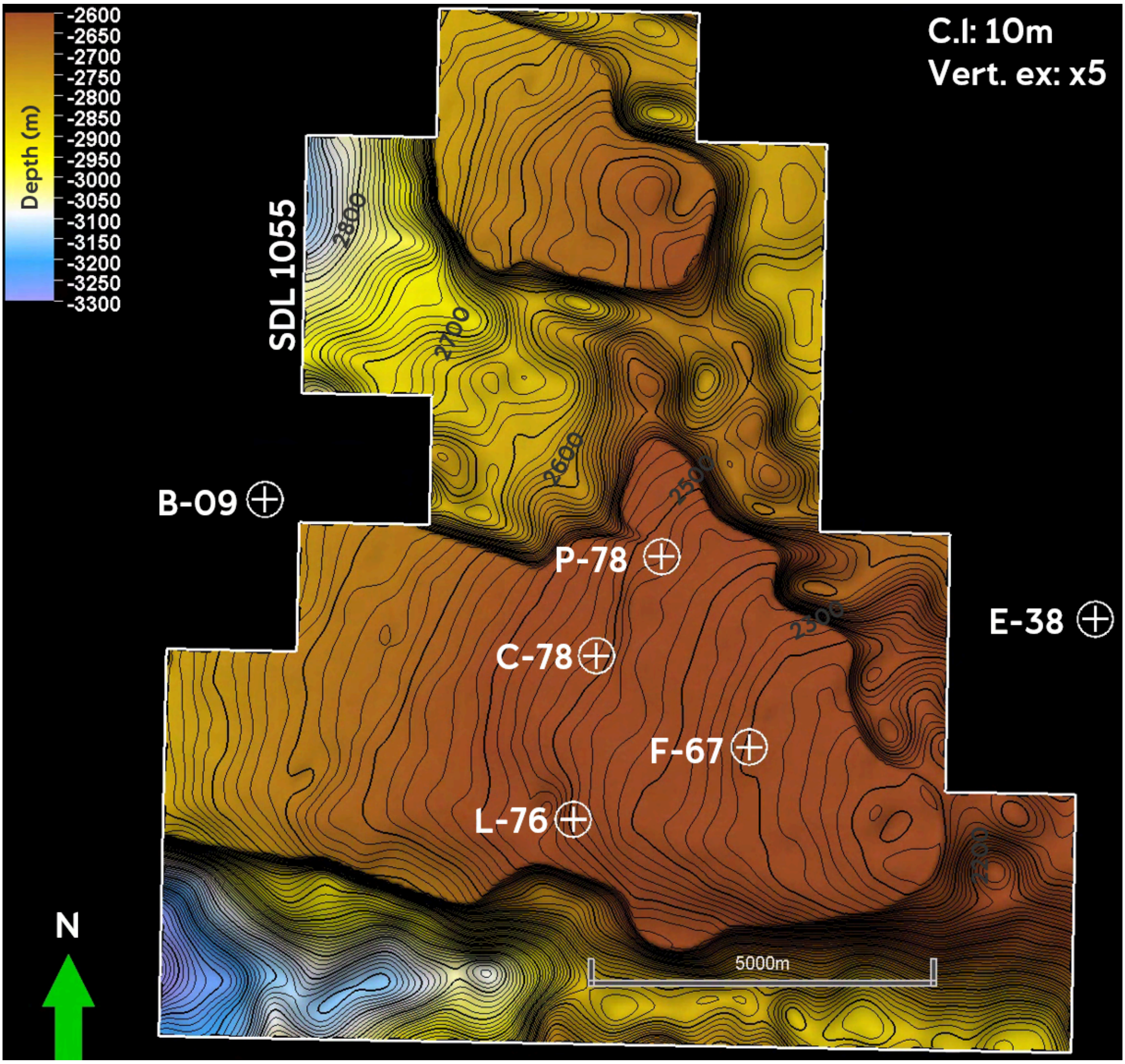


Figure 4.38 Barremian Base (Barremian SB) Surface Depth (m)

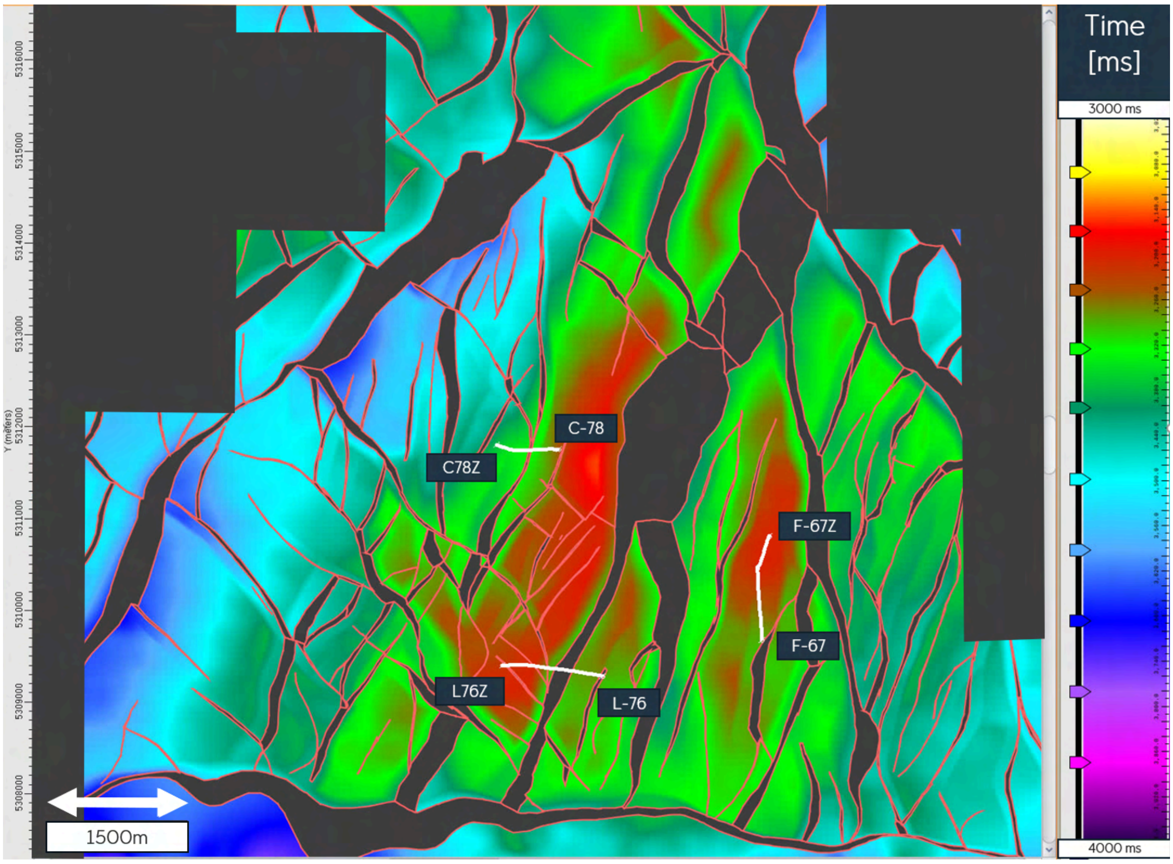


Figure 4.39 Base Cretaceous Time Structure Map

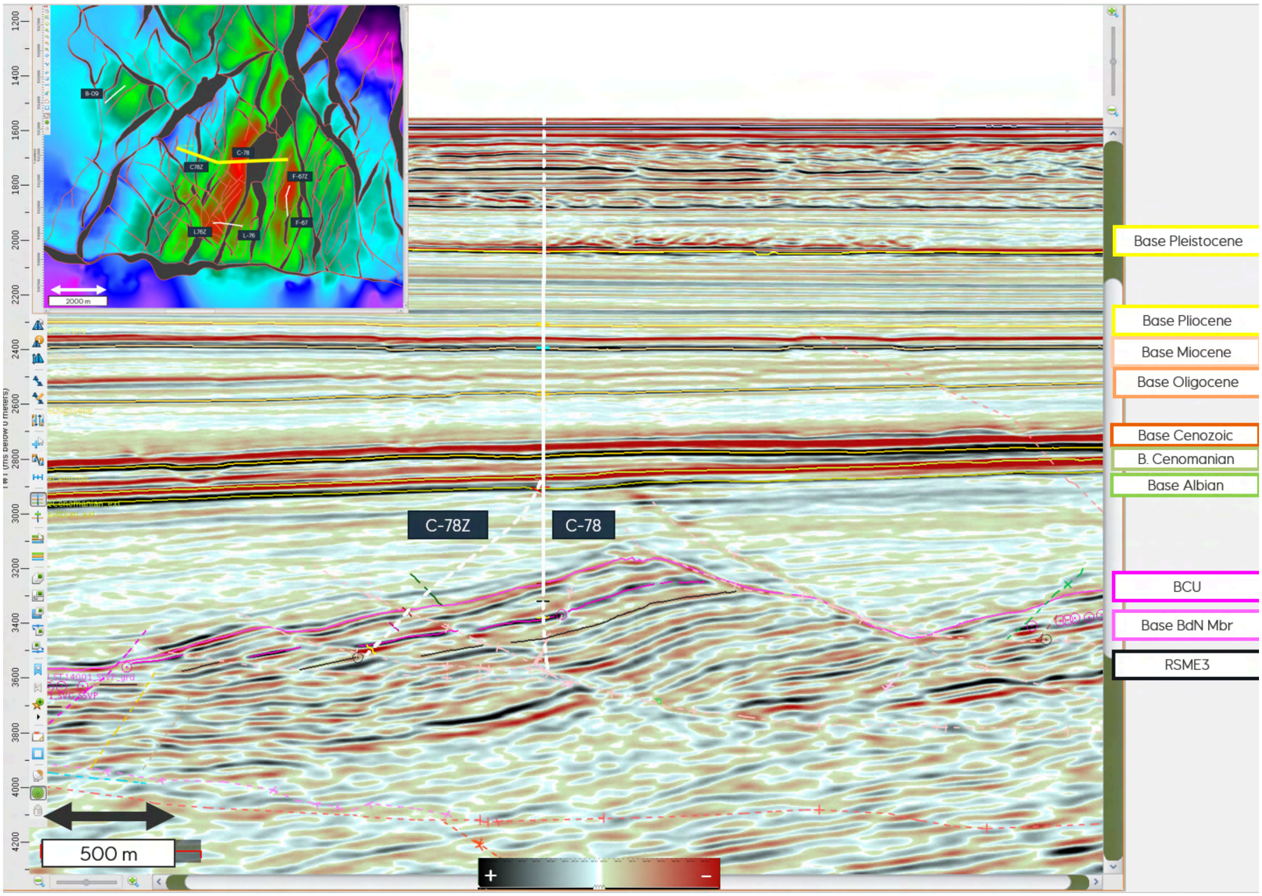


Figure 4.40 Example Seismic Line A through the Bay du Nord C-78/C-78Z Wells

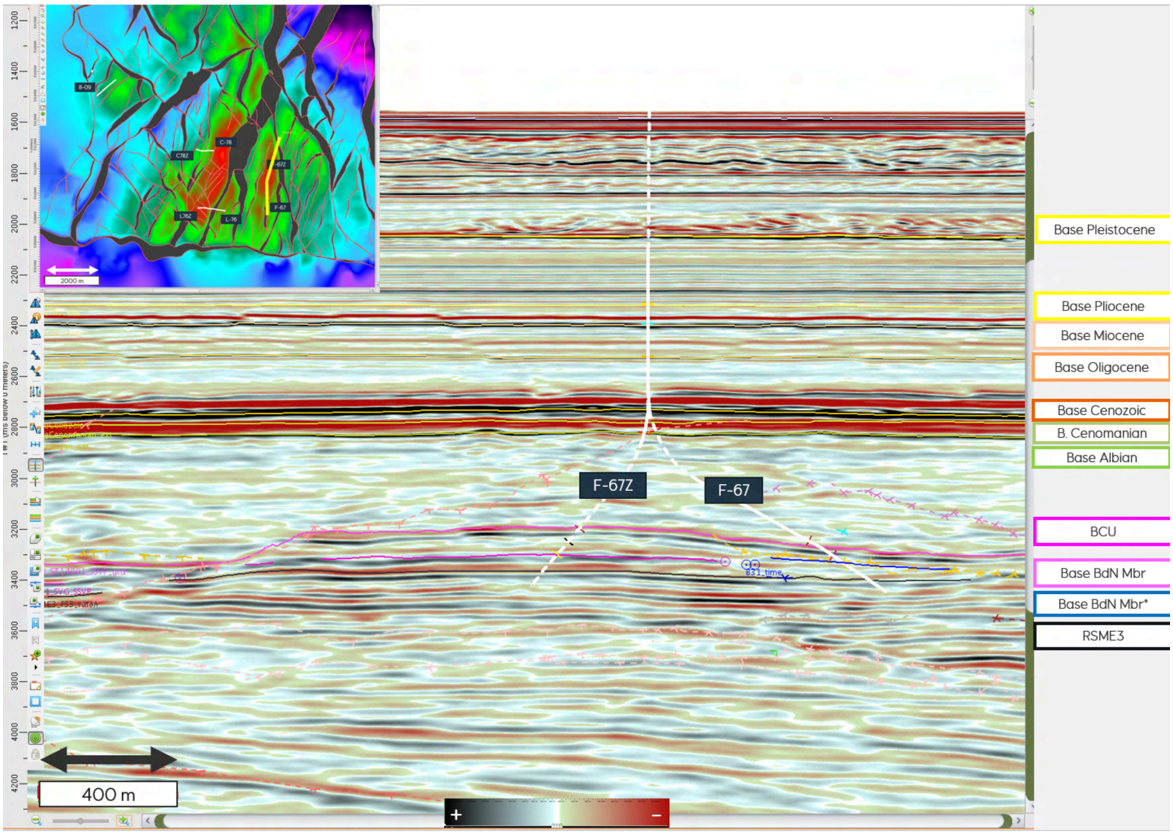


Figure 4.41 Example Seismic Line B through the Bay de Verde F-67/F-67Z Wells

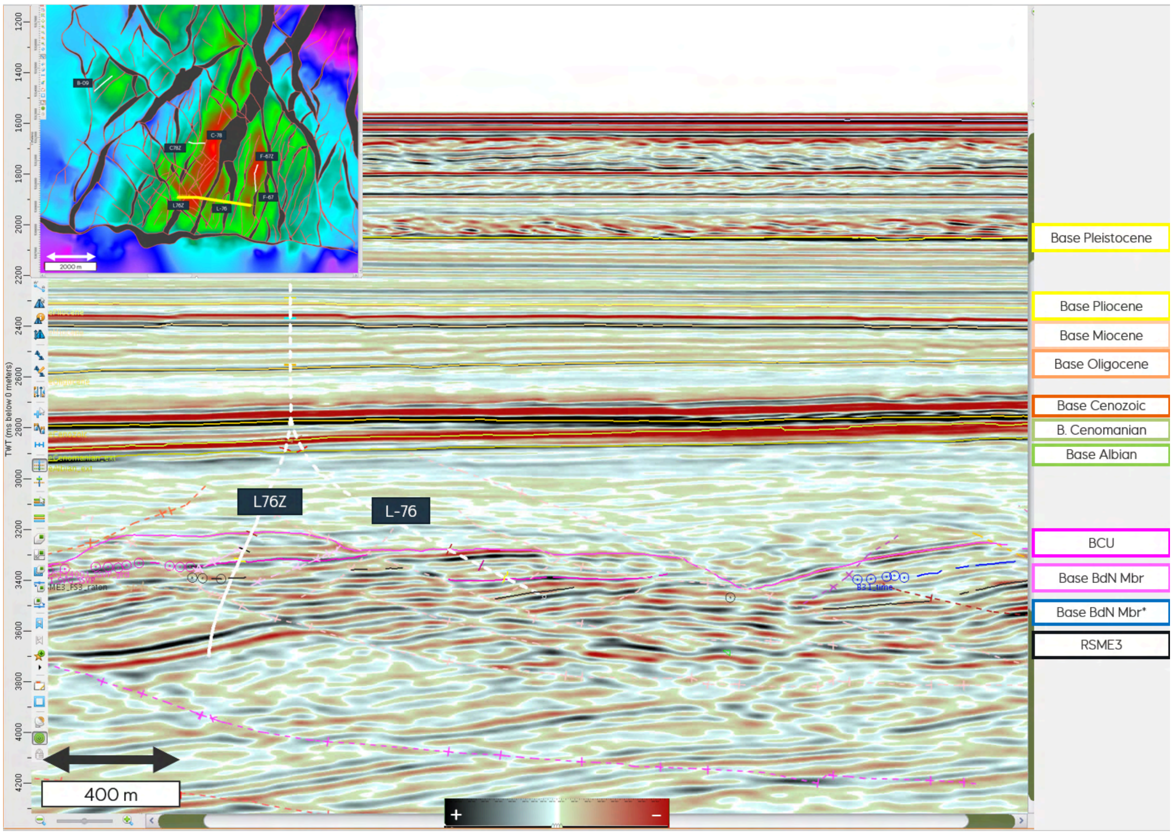


Figure 4.42 Example Seismic Line C through the Bay du Nord L-76/L-76Z Wells

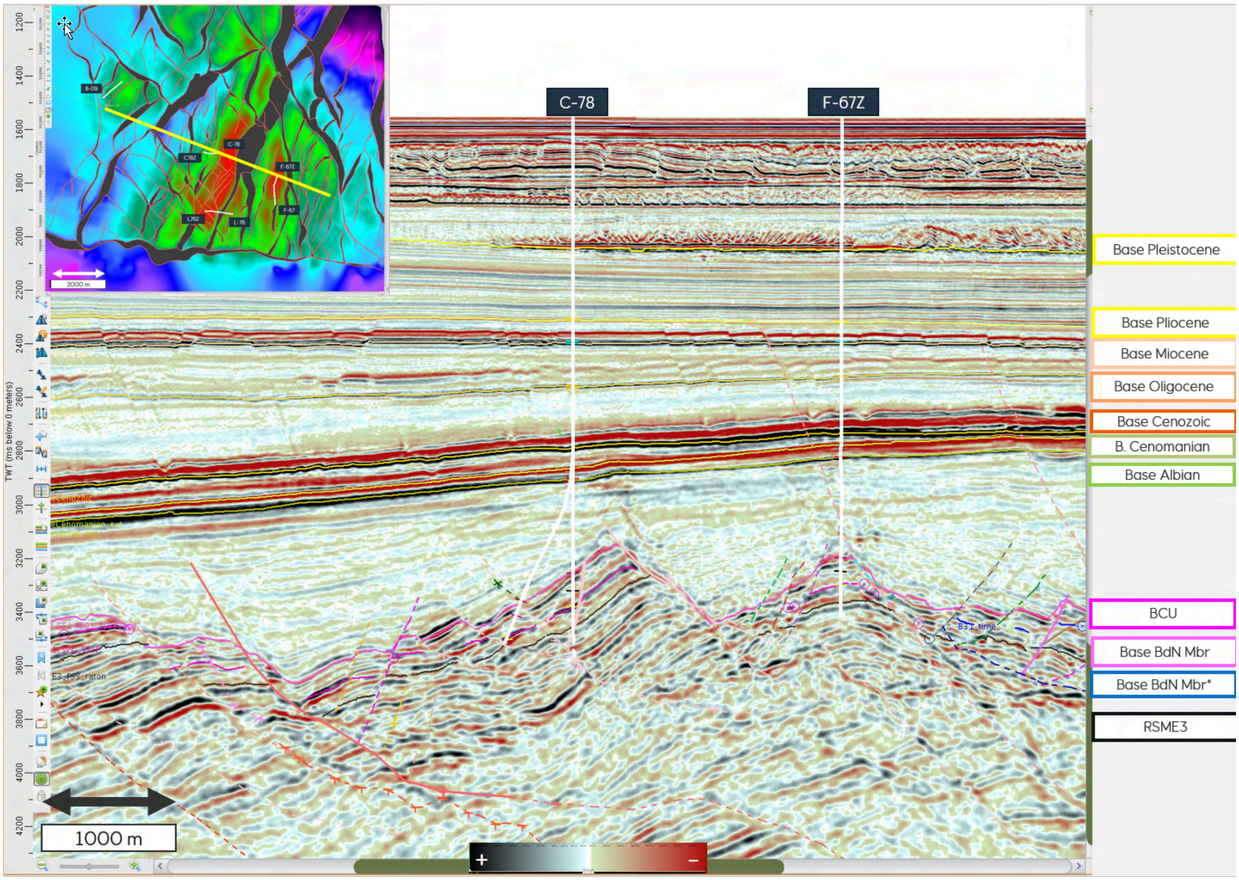


Figure 4.43 Example Seismic Line E through the Bay du Nord and Bay de Verde Structures

Reservoir Section

The seismic interpretation of the reservoir section was focused on the following interfaces:

- Mizzen member top (equivalent to the Base Cretaceous);
- Mizzen member base (equivalent to the Top BdN_1 member);
- Bay du Nord member base; and
- Bonaventure member (BVT_4) base.

The correlation of these interfaces and previous reservoir nomenclature is illustrated in Figure 4.44.

Age	Group	Fm	Mbr	Unit	Strat. surface	Old Names	Grand Banks
Early Berriasian	HIBERNIA GP.	Hibernia Fm.	Baccalieu Mbr.	BAC_3		Baccalieu Sandstone	Upper Baccalieu
				BAC_2			Lower Baccaleiu
				BAC_1	- Msq-5 FS-2		
Late Tithonian	FLEMISH GP.	Upper Bodhran Fm.	Mizzen Mbr.	MIZ_3		Bodhran Fm. 5.1	Ti4 sandstone and shale
				MIZ_2		Bodhran Fm. 4.1	Ti3 sandstone and shale
				MIZ_1	- Msq-4 RSME-5		Ti2 sandstone and shale
			Bay du Nord Mbr.	BDN_1		Bodhran Fm. 3.1	Ti2b sandstone and shale Ti2 sandstone and shale Ti2a sandstone and shale
		Middle Bodhran Fm.	Bonaventure Mbr.	BVT_4	- Msq-4 SB-4 - Msq-4 RSME-3	Bodhran Fm. 2.2	Ti1a sandstone and shale
				BVT_3	- Msq-4 RSME-2	Bodhran Fm. 2.1	Ti1 sandstone and shale
				BVT_2	- Msq-4 FS-1.5	Bodhran Fm. 1.2	Ti0a sandstone and shale
				BVT_1	- Msq-4 MFS-1	Bodhran Fm. 1.1	Ti0 sandstone and shale
			Gallants Member	GAL_1			
			Base Middle Bodhran Shales Mbr.	BMB_2			
				BMB_1			

Figure 4.44 Nomenclature Correlation of unit names DG2 and DG1.

The relation between elastic and acoustic log responses, zero-offset synthetic seismograms, and well markers is shown for all wells in Figure 4.45, with the explanations of the symbols in Figure 4.46. Observing the calcite cementation log (vol_calcite) is critical, as cementation has a significant impact on the elastic/acoustic response.

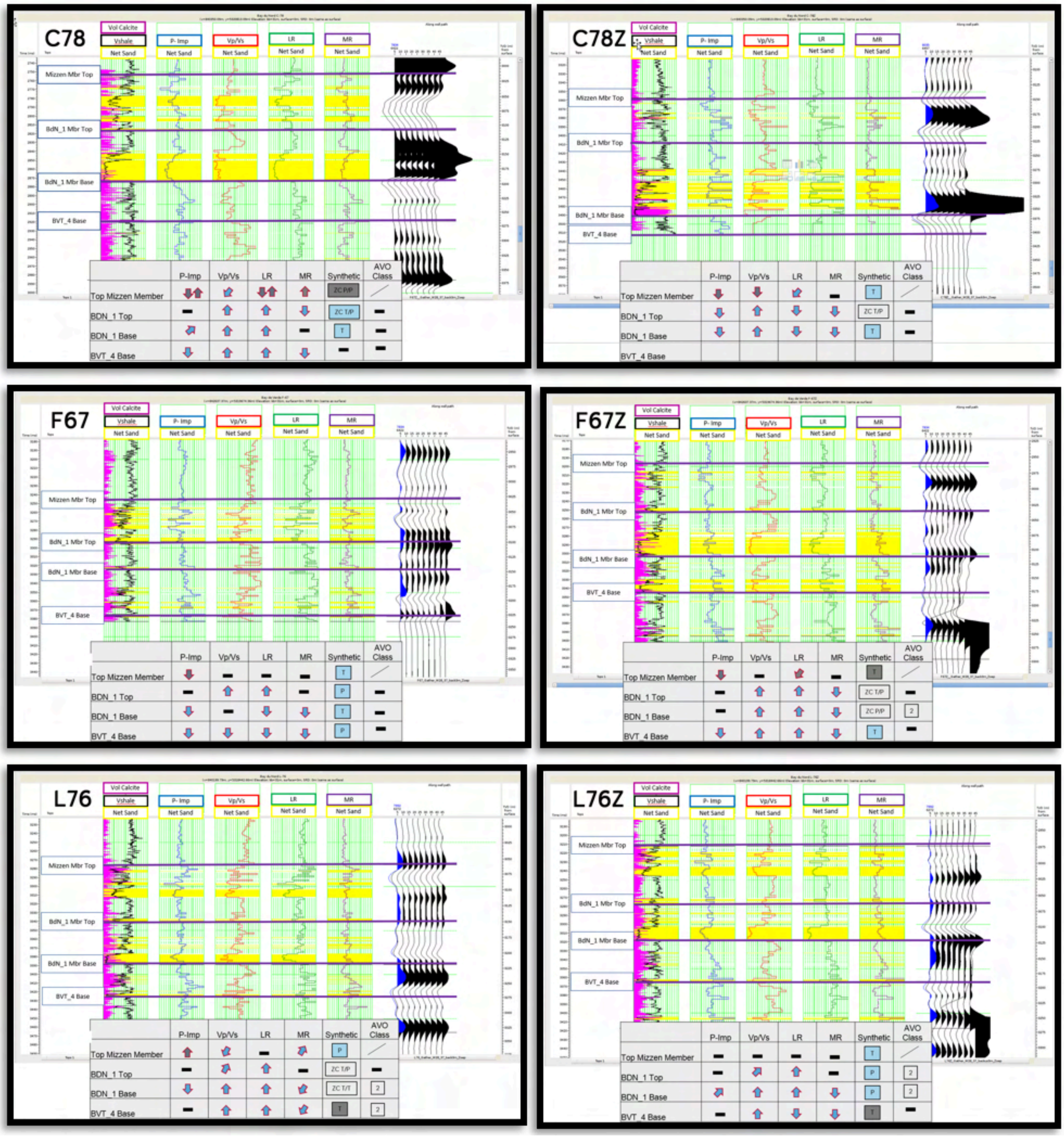


Figure 4.45 Geologic Formation Members and Elastic/Acoustic Interfaces

Symbol	Explanation
↓	Decrease near by
↓	Decrease at interface
↑	Increase near by
↓	Increase at interface
↓ ↑	Two trends
↙	Gradual decrease
↗	Gradual increase
▬	no trend
P T	Peak/trough at interface
P T	Peak/trough near interface
ZC P/T	Zero crossing peak to trough
ZC P/P	Zero crossing between two peaks

AVO class:
Refers to the specific sand bodies

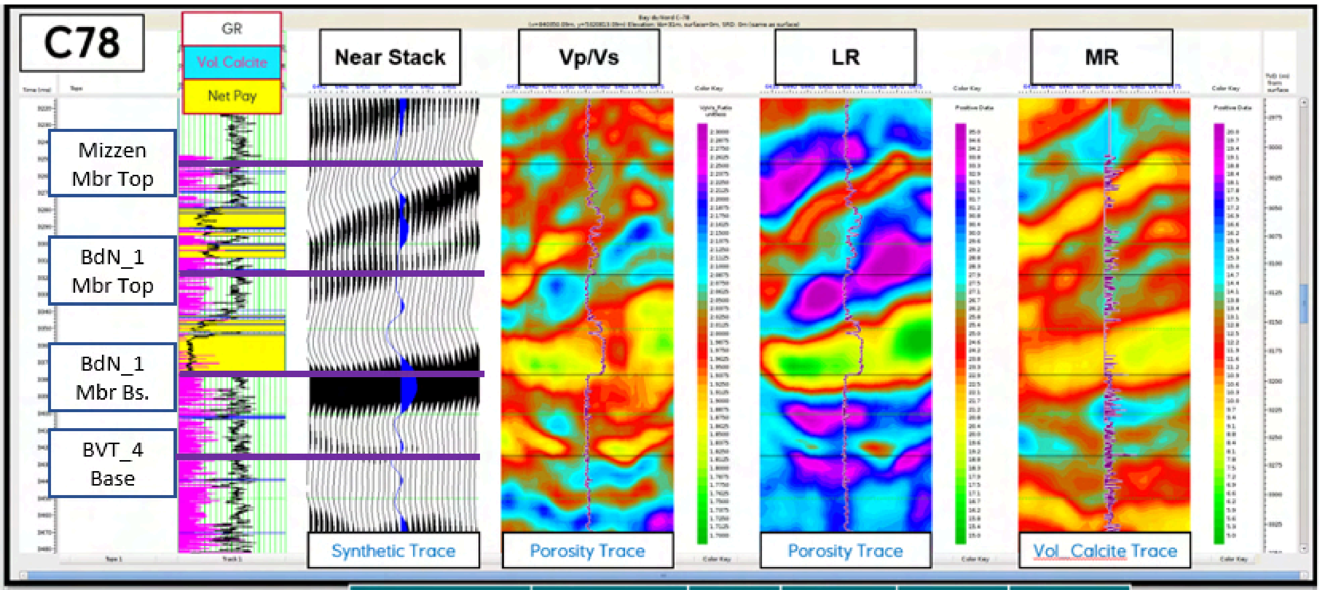
Figure 4.46 Annotation for Previous Figure

Based on well markers and log responses, it is concluded that:

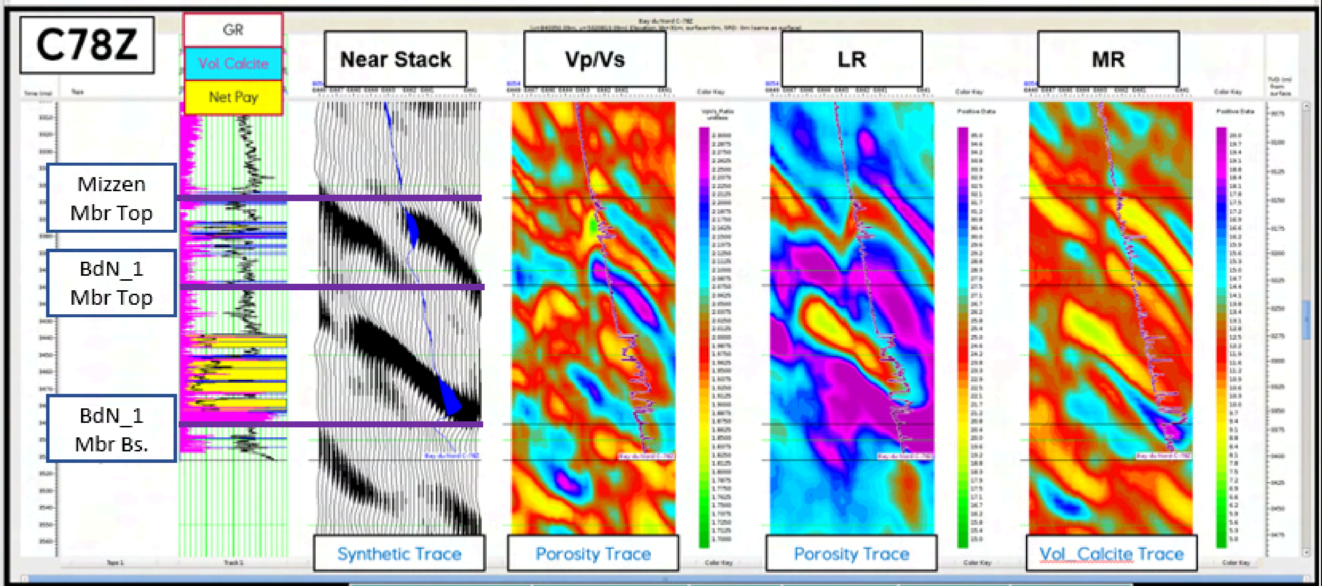
- Mizzen member top is best captured by a reduction in Zp and corresponding trough on the near-stack;
- Mizzen member base is best captured by an increase in Vp/Vs (compressional-velocity / shear-velocity ratio);
- Bay du Nord member base is best captured by LMR inside the channel (Vp/Vs poorly discriminates cementation); and
- Bonaventure member 4 base is best captured by a reduction in Zp and corresponding trough on the near-stack.

The correlation of the well markers to the near-stack, Vp/Vs inversion, LR and MR volumes is shown in Figure 4.47, Figure 4.48 and Figure 4.49. Based on these ties, the following interpretation strategy is adopted:

- Mizzen member top > trough on near-stack;
- Mizzen member base > no unique signature - surface not continuously picked on seismic;
- Bay du Nord member base;
  - Base clean sand > increase on LR volume;
  - Base cemented sand > decrease on MR volume;
  - Outside channel > peak on near-stack; and
- Bonaventure member (BVT_4) base > trough on near-stack.



Top	Lithology	NEAR	Vp/Vs	LR cube	MR cube
Top Mizzen Mbr.		Trough	----------	Decrease	Decrease
BDN_1 Top		ZC P/T	----------	Increase	Increase
BDN_1 Base	Clean Sand	Peak	Increase	Increase	Increase
	Cemented SS	--------	----------	----------	----------
BVT_4 Base		ZC P/T	Increase	Increase	Decrease

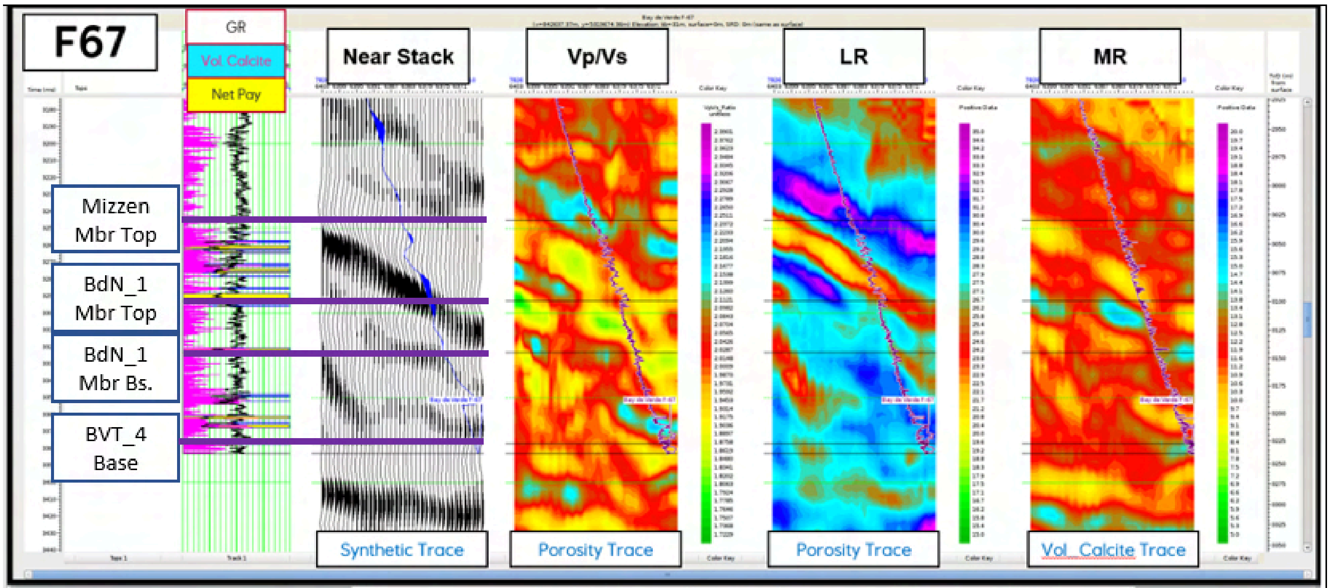


Top	Lithology	NEAR	Vp/Vs	LR cube	MR cube
Top Mizzen Mbr.		Trough	----------	----------	Decrease
BDN_1 Top		Peak	Decrease	----------	----------
BDN_1 Base	Clean Sand	Peak	Increase	Increase	Increase
	Cemented SS	Trough	----------	----------	Decrease
BVT_4 Base					

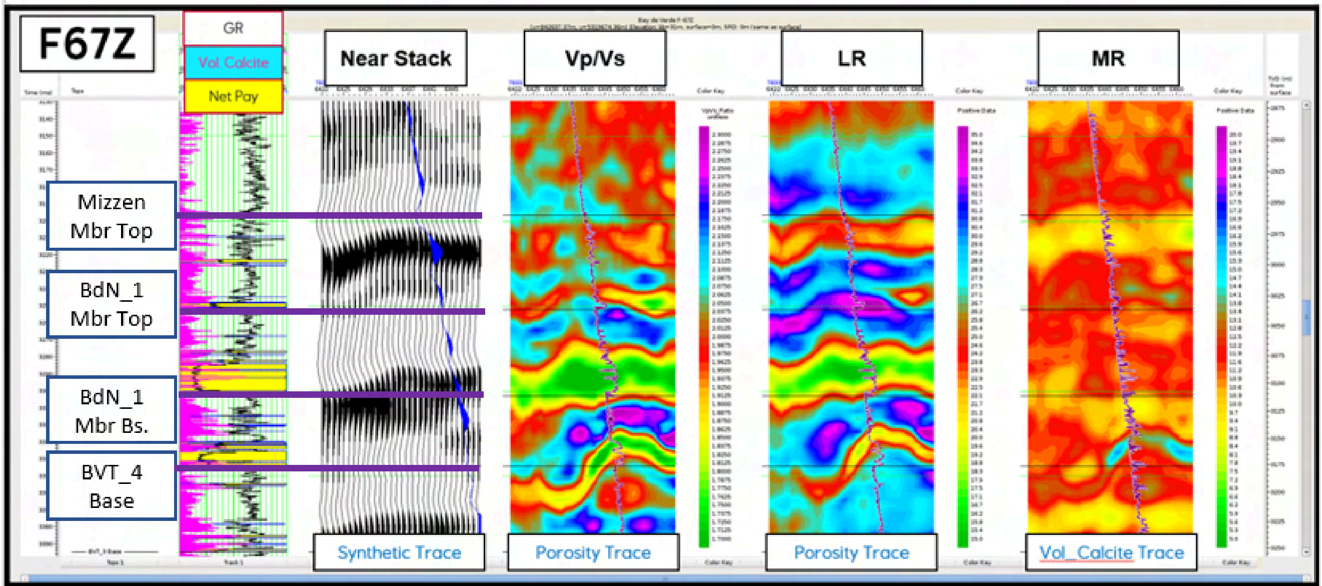
Figure 4.47 Correlation of the Geologic Formation Members to the Near-Stack, Vp/Vs Inversion, LR and MR Volumes

It is important to note that the seismic character of the Bay du Nord member base changes going from the main fairway of the valley to the valley edge. Outside of the valley there is no significant LMR character and the interface correlates with a peak. The F-67 well is a reference for the seismic character outside of the valley depositional fairway.

The summary of the mapped horizons is provided in Figure 4.50.



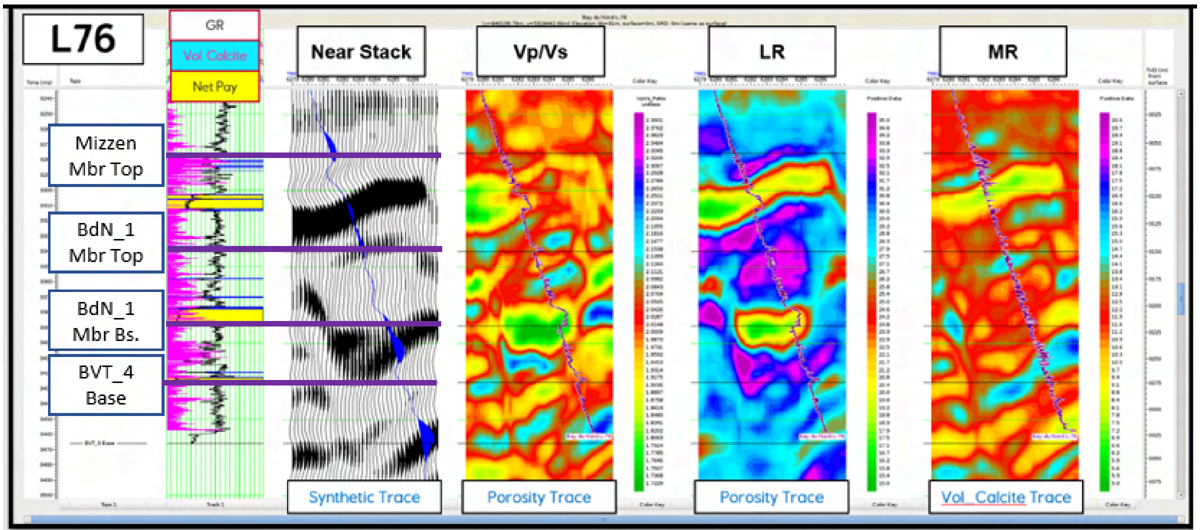
Top	Lithology	NEAR	Vp/Vs	LR cube	MR cube
Top Mizzen Mbr.		Trough*	----------	----------	----------
BDN_1 Top		Peak	----------	Increase	Increase
BDN_1 Base	Clean Sand	Peak	----------	----------	----------
	Cemented SS	--------	----------	----------	----------
BVT_4 Base		ZC P/T	Increase	----------	Increase



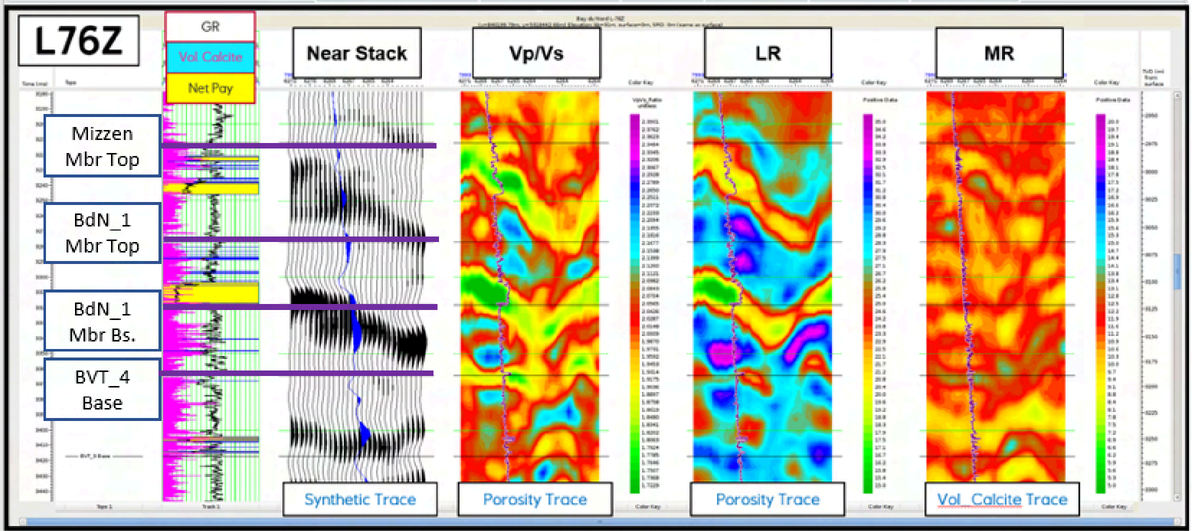
Top	Lithology	NEAR	Vp/Vs	LR cube	MR cube
Top Mizzen Mbr.		Trough	Decrease	Decrease	Decrease
BDN_1 Top		Trough	----------	----------	----------
BDN_1 Base	Clean Sand	Peak	Increase	Increase	Decrease
	Cemented SS	--------	--------	----------	----------
BVT_4 Base		ZC P/T	Increase	Increase	----------

Figure 4.48 Correlation of the Geologic Formation Members to the Near-Stack, Vp/Vs Inversion, LR and MR Volumes

The Bay du Nord member base interpretation is a combination of several picks. Within the valley system, the base of the Bay du Nord member corresponds to the base high-quality sand pick on the LR volume, and the base cemented sand on the MR volume. Outside the valley, where no LMR response is visible, the interpretation corresponds to a trough on the near-stack.



Top	Lithology	NEAR	Vp/Vs	LR cube	MR cube
Top Mizzen Mbr.		Trough	----------	Decrease	----------
BDN_1 Top		Peak	----------	Increase	Increase
BDN_1 Base	Clean Sand	ZC T/P	Increase	Increase	Increase
	Cemented SS	--------	--------	----------	----------
BVT_4 Base		Trough	Increase	----------	Decrease



Top	Lithology	NEAR	Vp/Vs	LR cube	MR cube
Top Mizzen Mbr.		Trough	Decrease	Decrease	----------
BDN_1 Top		--------	----------	----------	----------
BDN_1 Base	Clean Sand	ZC T/P	Increase	Increase	----------
	Cemented SS	--------	--------	----------	----------
BVT_4 Base		--------	Increase	----------	----------

Figure 4.49 Correlation of the Geologic Formation Members to the Near-Stack, Vp/Vs Inversion, LR and MR Volumes

Formation Member	Lithology	NEAR	Vp/Vs	LR cube	MR cube
Top Mizzen Mbr.		Trough	----------	----------	----------
BDN_1 Top		N/A	N/A	N/A	N/A
BDN_1 Base	Clean Sand	--------	----------	Increase	----------
	Cemented SS	--------	----------	----------	Decrease
	Outside Channel	Peak			
BVT_4 Base		Trough	----------	----------	----------

Figure 4.50 Interpretation Strategy Reservoir: Selected Volumes and Picks

There is no unique seismic signature for the base Mizzen member, and the seismic inversion attributes are also not uniquely sensitive to the sand within this geological sequence. In particular, F-67, F-67Z, and B-09 show variation in Vp/Vs and LMR which do not correlate correctly to the sand. The correlation problem is given in the log domain as well as in the seismic domain.

B) Fault Interpretation

Given the structural complexity of the reservoir section in the greater Bay du Nord Area, multiple seismic attributes in both the horizontal and vertical planes were used to conduct the fault interpretation. In addition to the post-stack data and pre-stack inversion volumes, optimal structural seismic attribute volumes were created using the workflow outlined in Figure 4.51. The fault interpretation was conducted on the following seismic attribute volumes:

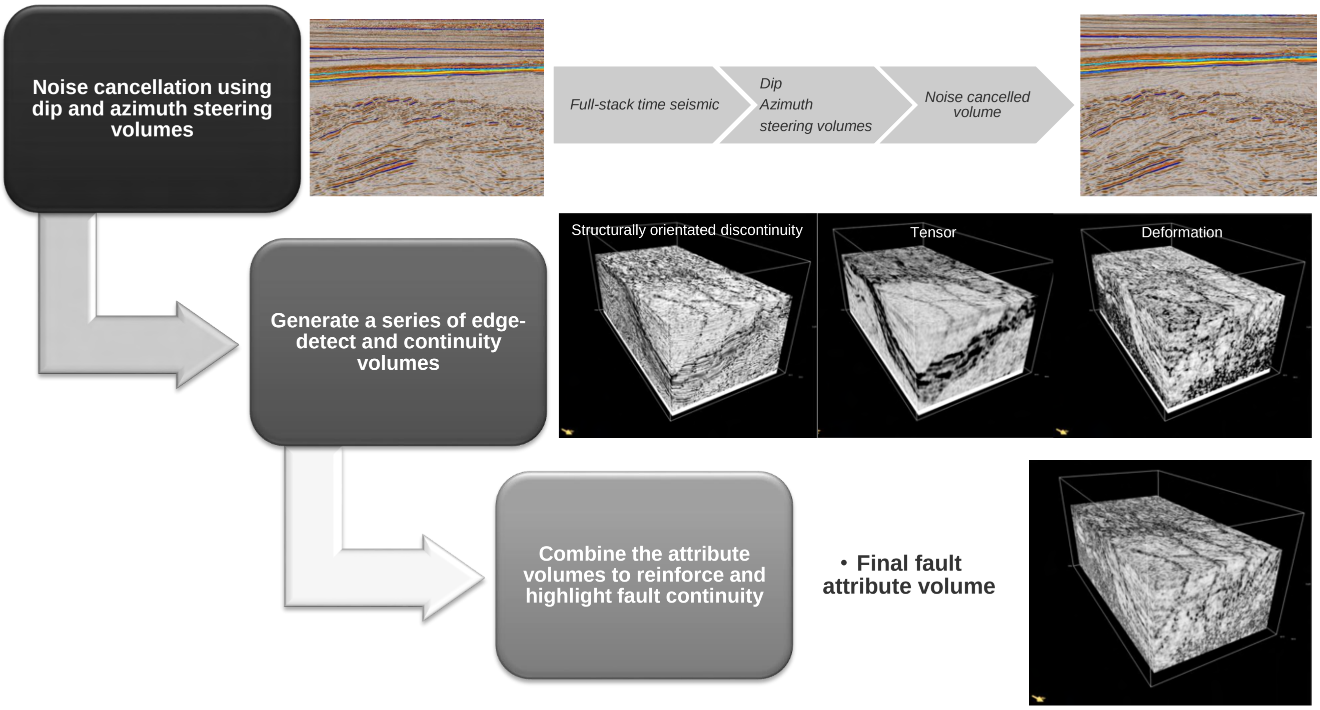


Figure 4.51 Workflow Fault Interpretation

- Coherence/Semblance/Tensor volumes;
- Near Stack Volume (before and after noise reduction);
- Lambda-Rho; and
- V_P/V_S.

Faults were first identified in planar view using the attribute volumes, and the fault interpretation was further defined using vertical seismic sections oriented perpendicular to the fault orientation (Figure 4.52). Interpreting the faulting in a vertical plane perpendicular to the fault trend permits the true structural geometry to be captured, and gives insight into the structural kinematics.

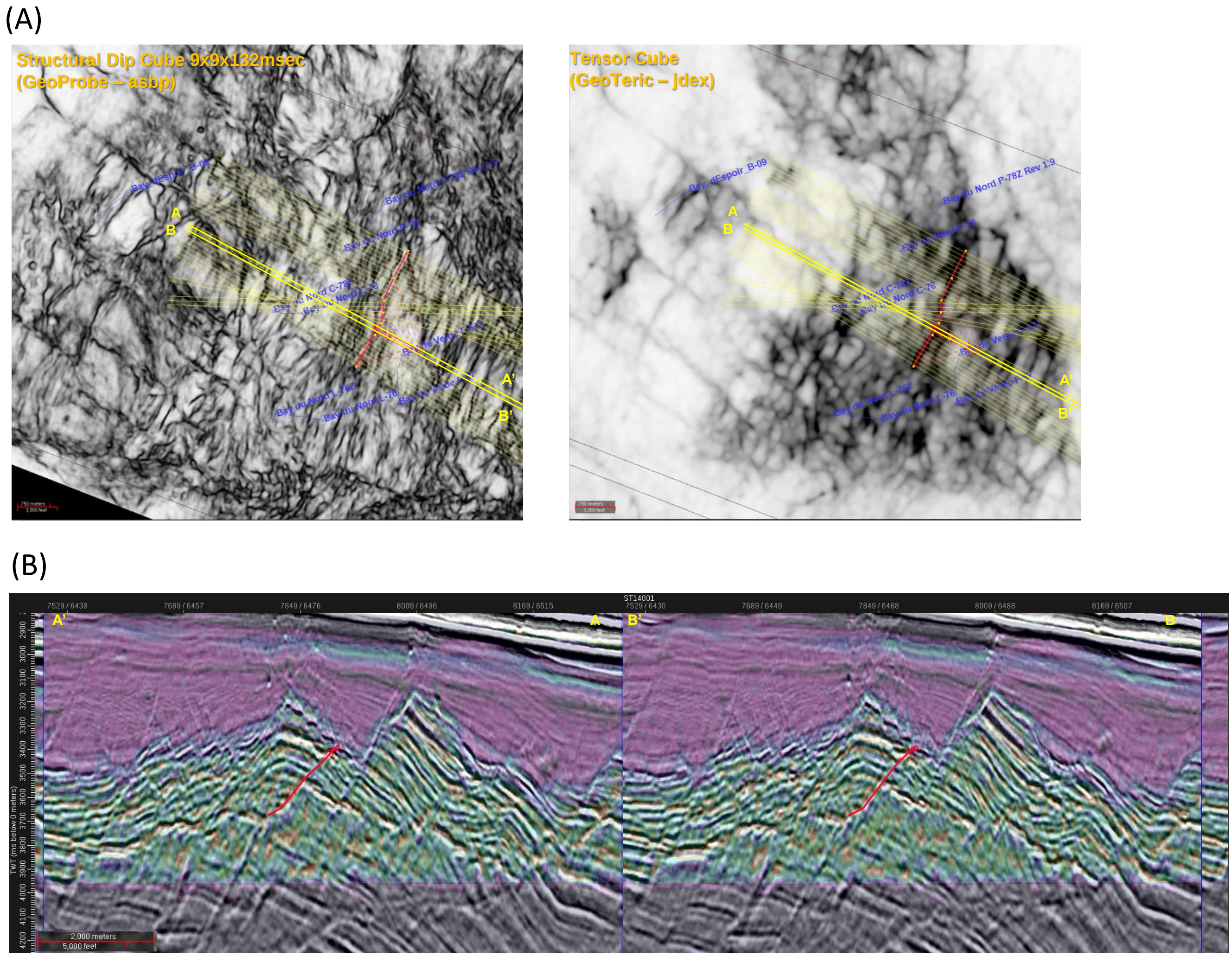


Figure 4.52 Fault Interpretation Workflow (A) Step 1: Various optimal seismic structural volumes built for fault interpretation are displayed in map view (time slice). A fault segment in then interpreted and used to assemble seismic vertical sections perpendicular to its orientation. (B) Step 2: Fault segments are interpreted in seismic vertical sections using various seismic data volumes. Note the location of vertical sections A-A' and B-B' in plan view.

In general, both seismic amplitude and inversion data are equally good for fault interpretation. The inversion data was used to guide the faults in the reservoir section, while the seismic amplitude was used for the overburden and underburden sections. The inversion data, however, communicates better the spatial thickness variation of the main reservoir (Bay du Nord member, Figure 4.53). Consequently, different combinations of seismic attributes were implemented during the interpretation process.

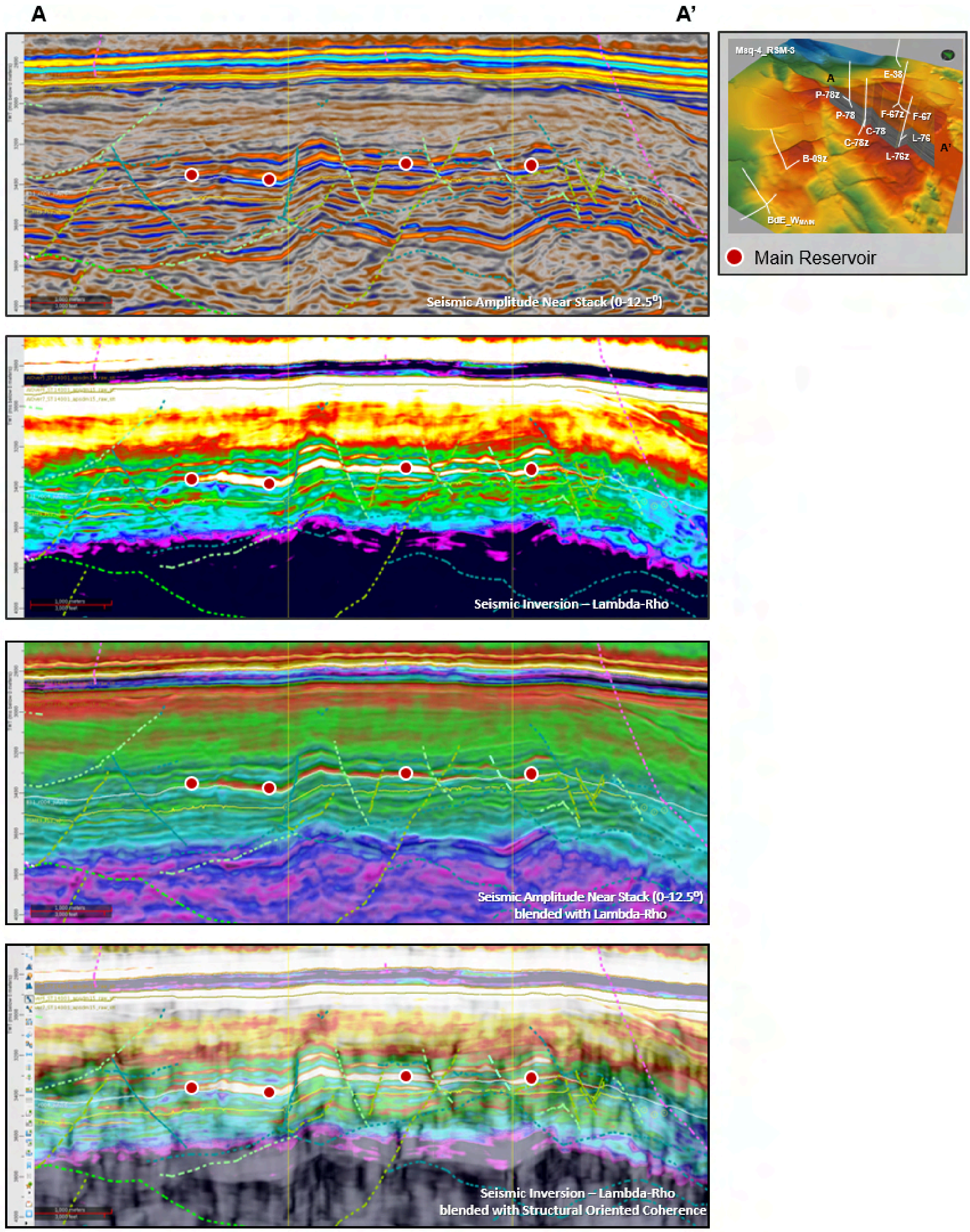


Figure 4.53 Seismic Volumes Used in the Structural Interpretation The inversion data (Lambda-Rho) constrains the spatial thickness variation of the main reservoir very well (Bay du Nord member).

The ability to identify the top and base of the reservoir from the inversion volume allows us to investigate juxtaposition seals (Figure 4.54). However, only a full 3D analysis can allow for a robust interpretation of the juxtaposition seals.

Figure 4.55 shows a compilation of the seismic structural interpretation in the core area of the Project.

The interpreted faults were converted into fault segments and the interpretation was analyzed in a 3D view.

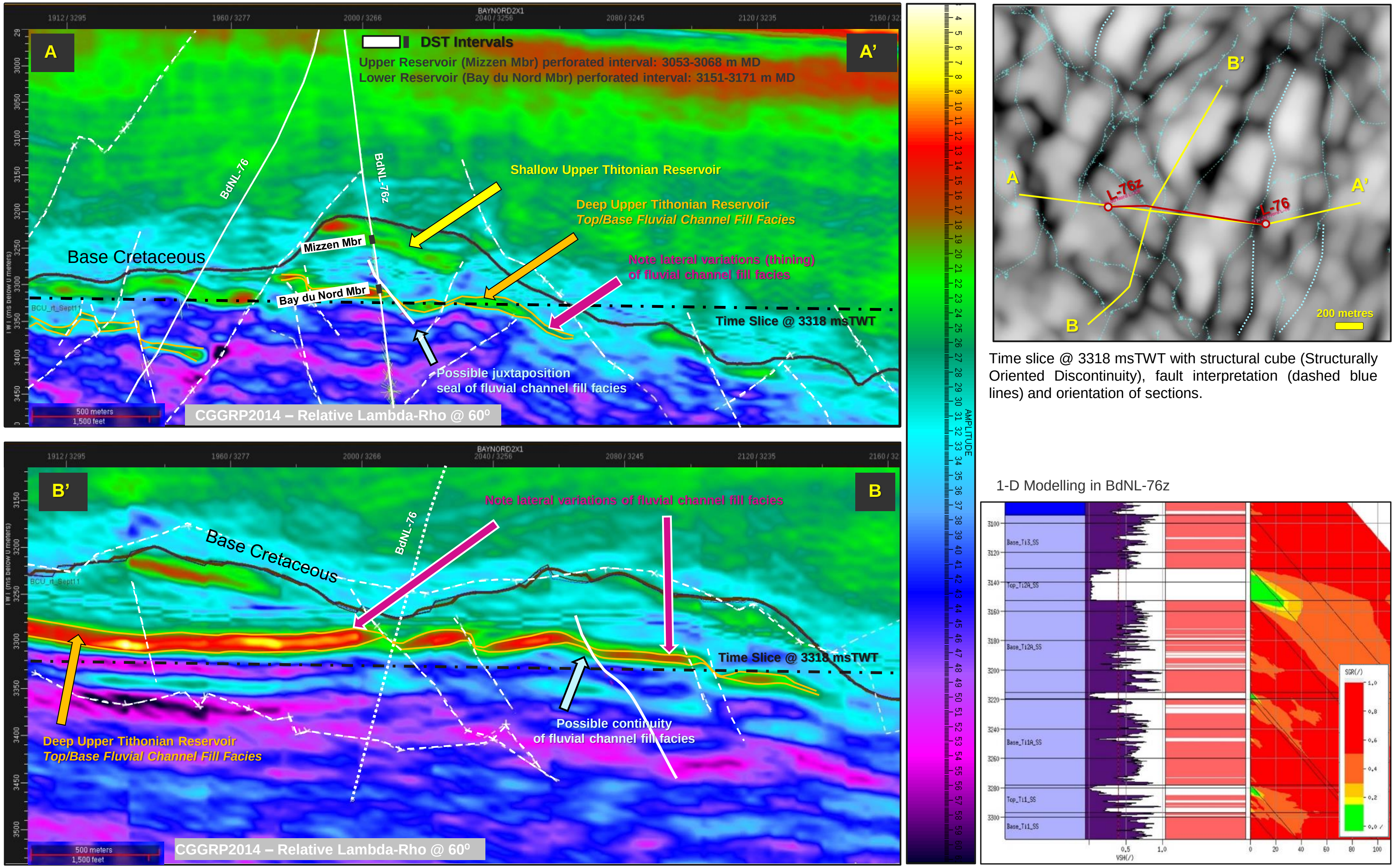


Figure 4.54 Seismic Vertical Sections of the Inversion Volume in the Area of the Bay du Nord L-76 and L-76Z Structure Benefits of the inversion volume for fault seal analysis: The ability to identify the top and base of the reservoir from the inversion volume allows us to investigate juxtaposition seal without the need to build 3D models.

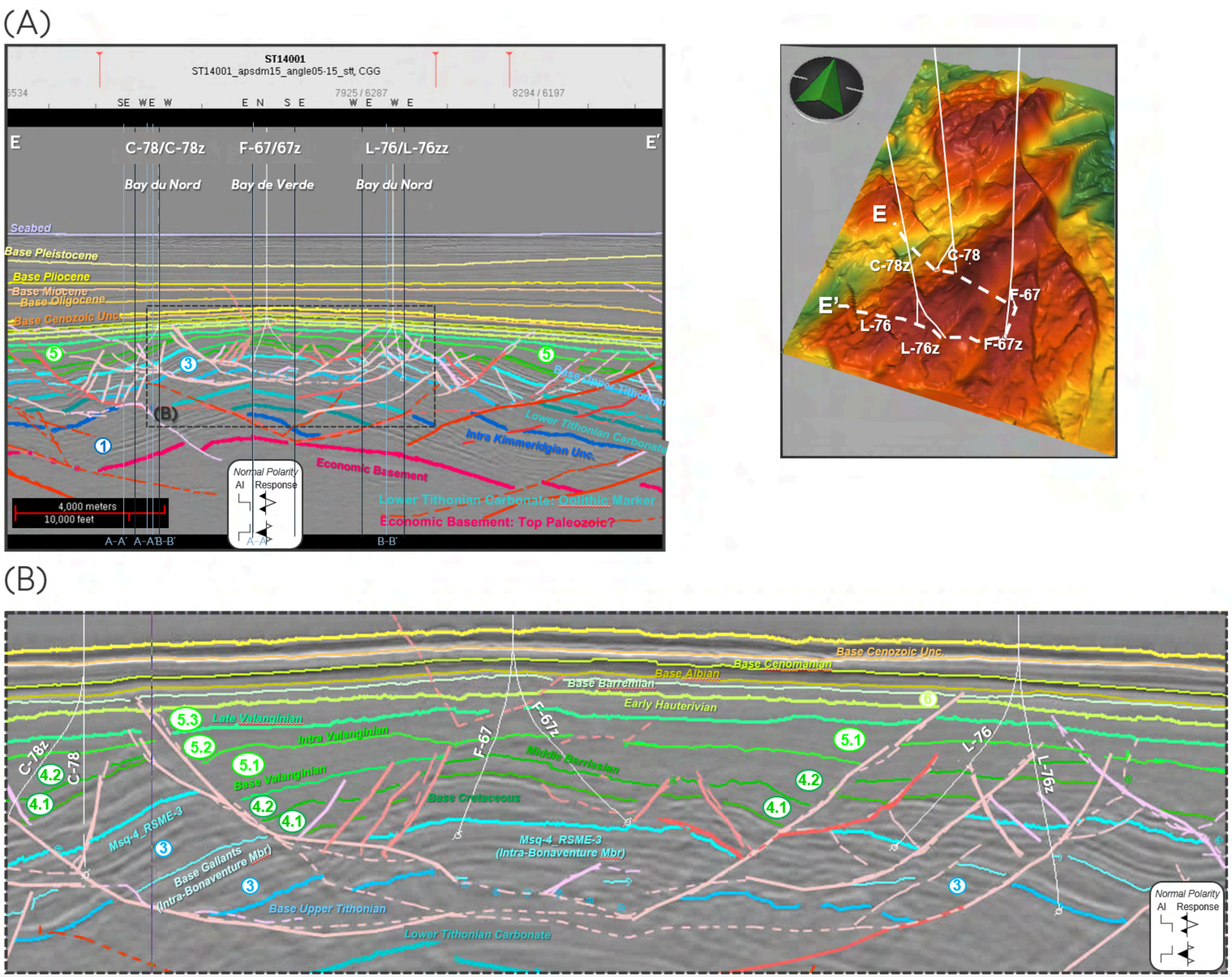


Figure 4.55 Seismic Correlation in the Bay du Nord Area (A) Seismic Correlation Section E-E' through wells in the Bay du Nord (C-78, C-78Z. L-76, L-76Z) and Bay de Verde (F-67, F-67Z) structures. Note the structural complexity of the field. (B) Zoom of the vertical seismic section in the Bay du Nord and Bay de Verde structures.

4.2.4 Seismic Velocity Analysis and Depth Conversion

4.2.4.1 Pre-Stack Depth Migration Velocities and Depth Conversion

The PSDM provides seismic data in depth. However, the PSDM depth is not equivalent to the geological depth. It is a processing depth, which is close to the geological depth only if the velocity model and anisotropy are perfectly parametrized. Due to the inherent complexity of velocity and anisotropy in the subsurface, additional depth conversion, or "depthing", of the PSDM is often necessary. At Bay du Nord, the PSDM processing workflow carefully captured both the vertical velocity field and the anisotropy, which resulted optimal gather flattening and produced reasonably accurate ties to the well correlations in Table 4.3. Therefore, the PSDM depth was selected as the reference case for the Bay du Nord depth model.

Table 4.3 Comparison of the Top Mizzen Member and Base Bay du Nord Member Well Picks to the Equivalent PSDM Seismic Surface Depths at the Well Locations

Mizzen Member Top			
Well	Well Pick TVDSS	PSDM	Difference PSDM-Well Pick
Bay de Verde F-67	3029.8	3025.7	-4.1
Bay de Verde F-67Z	2960.3	2945.3	-15.0
Bay d'Espoir B-09	3212.3	3230.9	18.6
Bay Du Nord C-78	3013.5	3026.4	12.9
Bay du Nord C-78Z	3148.5	3158.5	10.0
Bay du Nord L-76	3059.8	3053.6	-6.2
Bay du Nord L-76Z	2973.8	2974.5	0.7

Base Bay du Nord Member			
Well	Well Pick TVDSS	PSDM	Difference PSDM-Well Pick
Bay de Verde F-67	3145.7	3118.4	-27.3
Bay de Verde F-67Z	3112.2	3095.9	-16.3
Bay d'Espoir B-09	3354.1	3358.8	4.7
Bay Du Nord C-78	3195.0	3201.6	6.6
Bay du Nord C-78Z	3370.0	3380	10.0
Bay du Nord L-76	3220.1	3222.5	2.4
Bay du Nord L-76Z	3121.8	3131	9.2

The velocity profile for an example line through the Bay du Nord area is shown in Figure 4.56. Using the PSDM seismic data in depth, i.e. the PSDM velocity field, the resulting depth maps for the top Mizzen member and base Bay du Nord member are shown in Figure 4.57 and Figure 4.58 respectively.

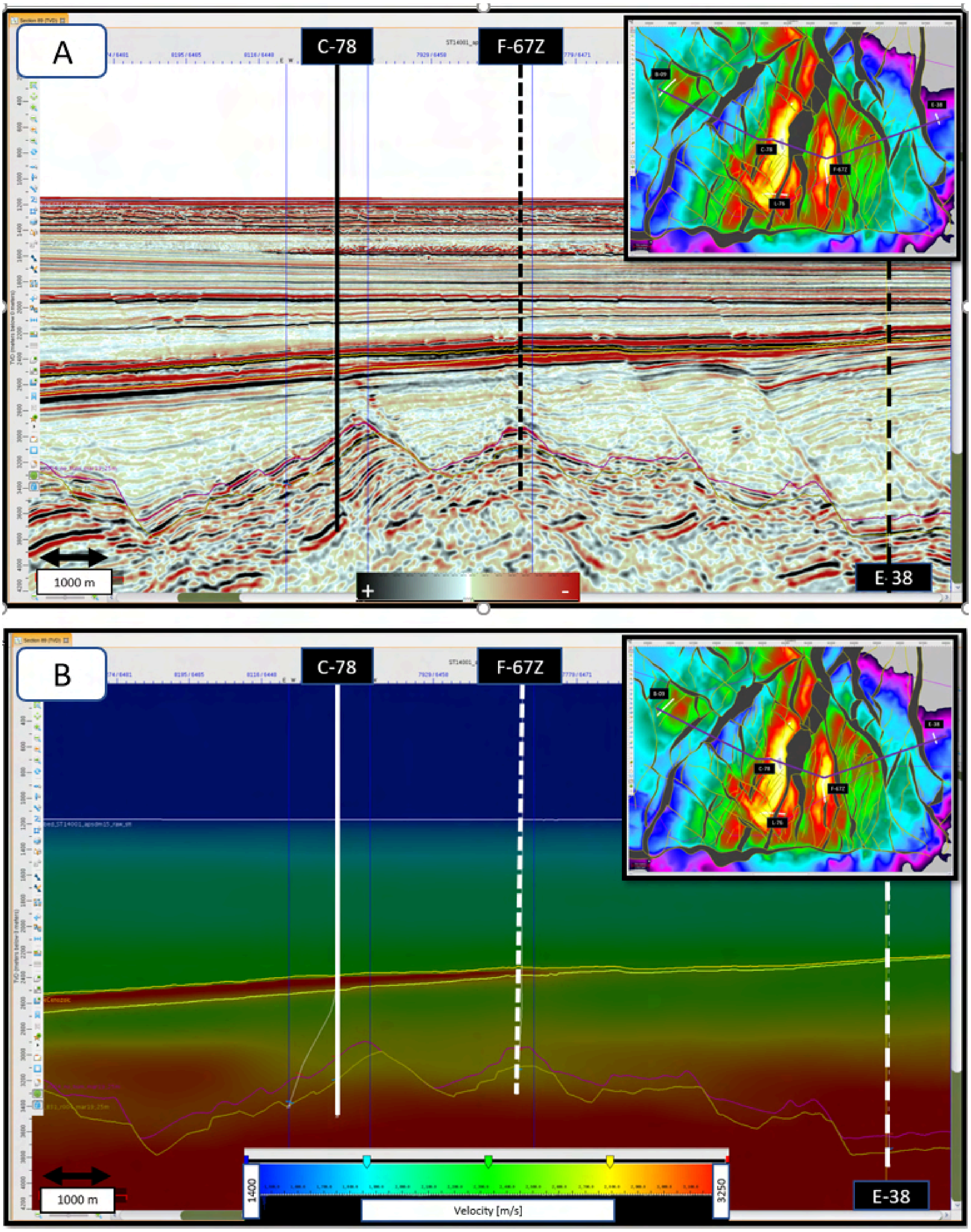


Figure 4.56 Example Line A) PSDM section through Bay du Nord; B) Corresponding PSDM velocity field.

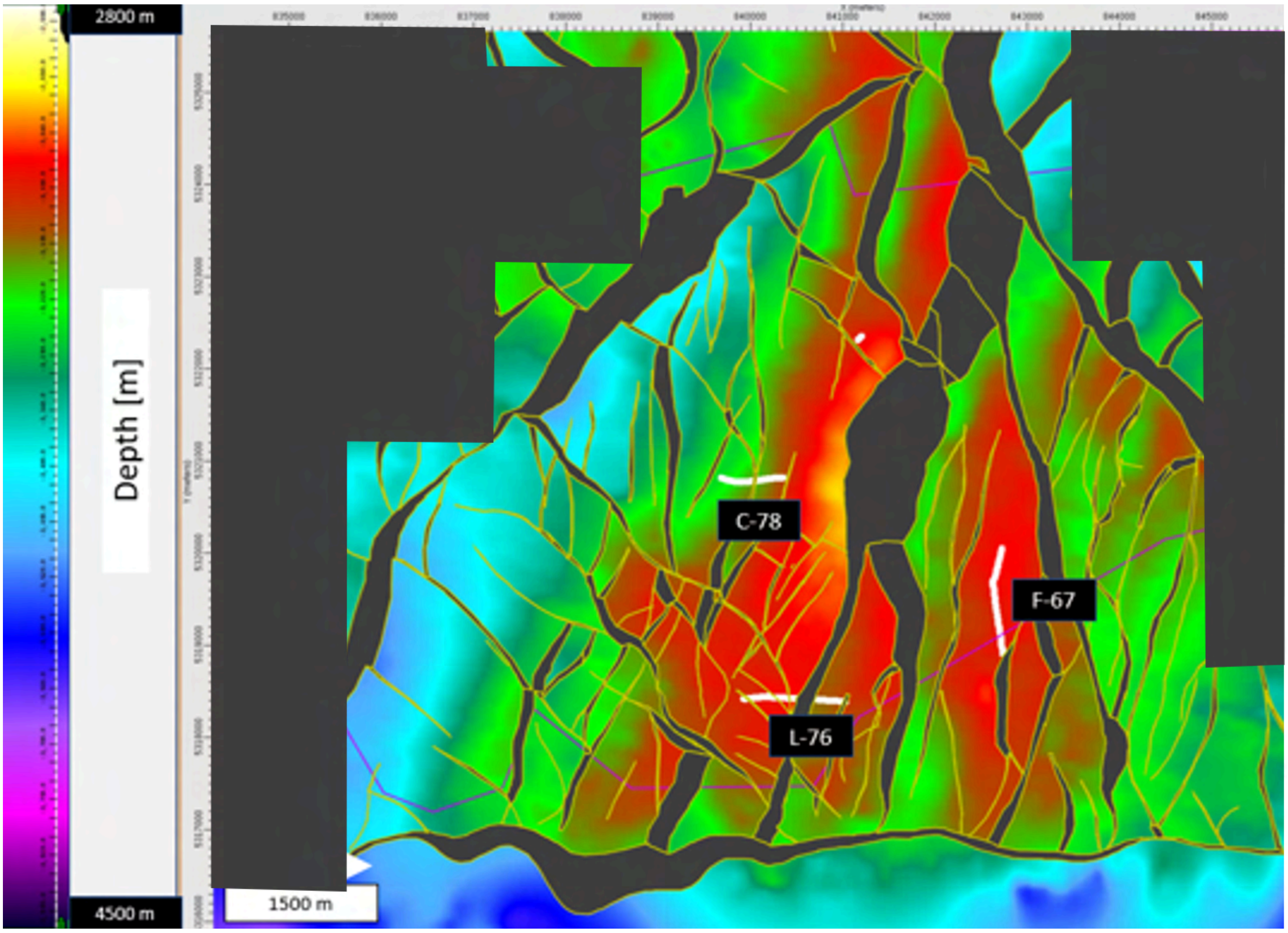


Figure 4.57 Mizzen Mbr Top Depth Map based on PSDM Velocities

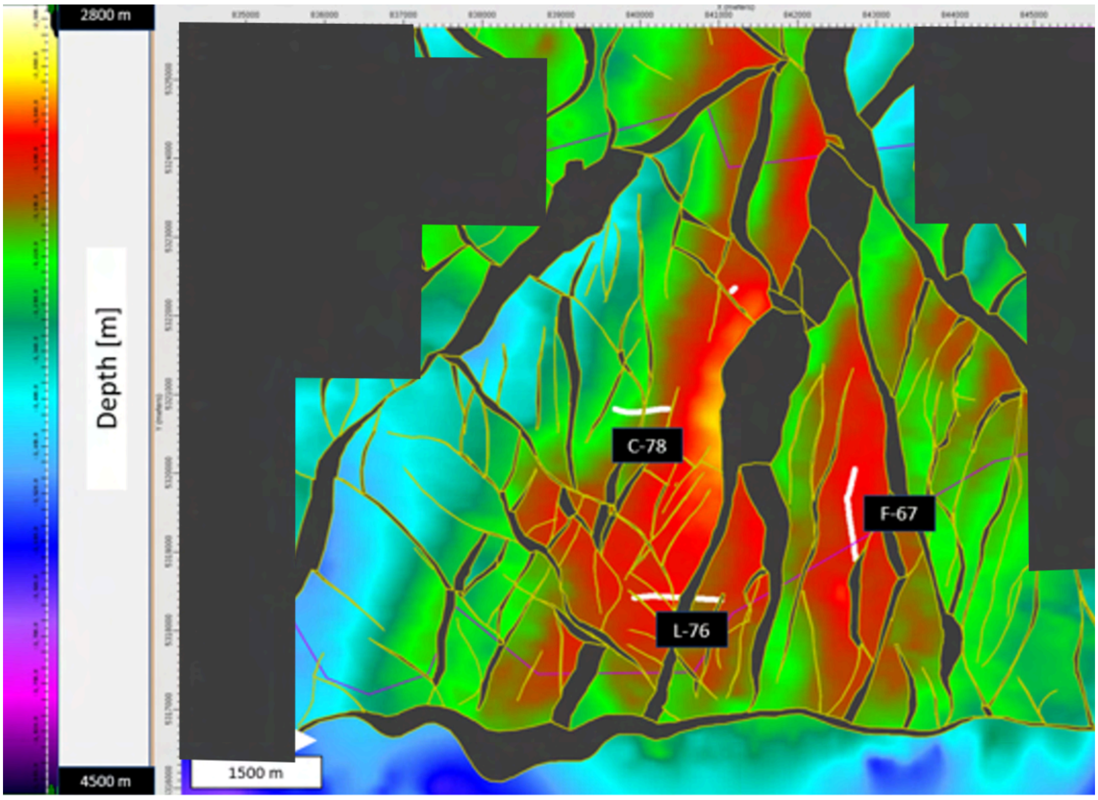


Figure 4.58 Bay du Nord Mbr Base Depth Map based on PSDM Velocities

4.2.4.2 Alternative Depth Conversion

A number of alternative depth conversions were carried out based on a conventional depth conversion approach with the objective to understand the uncertainty of the PSDM depths. These alternative conversions were based on layer-cake velocity model with the horizon picks in time.

Based on VSP data, the major velocity boundaries were identified. The VSP data suggested a constant vertical layer velocity for the following intervals:

- Seismic Reference Datum (SRD) to seafloor;
- Cenozoic to Cenomanian; and
- Mizzen member top to Bay du Nord member base.

Constant or, alternatively, depth-dependent velocity approximations are suggested for:

- Seabed to Cenozoic; and
- Cenomanian to Mizzen member top.

Three layer-cakes models were investigated and the respective velocity functions are shown Figure 4.59.

Models one and two, which have a separate Cenozoic to Cenomanian layer with constant vertical velocities, also include a horizontal velocity trend. The implementation of a horizontal trend was indicated because the Cenozoic-Cenomanian velocity changes with the isopach thinning towards the East; this change was also manifested in the PSDM velocity field (Figure 4.60). The lateral changing velocity field is shown in Figure 4.61. Furthermore, a constant velocity (Vo) trend was used between Cenomanian and Mizzen member Top in model one, and between the Cenomanian and BDN_1 Base in model two. Interval velocities in these respective layers show a distinct east-west trend that is affected by the geologic structure (Figure 4.62). To honour the structural component of the east-west trend in the Vo map, an additional guide point was introduced (Figure 4.63).

Table 4.4 shows the comparison between the depth conversion depths and the actual well marker depths in tabular format. However, these tables cannot be related to the quality of the layer-cake depth conversion when a Vo trend map was used, as the Vo trend maps force a good well tie. However, these alternative depth conversions provide an estimate of uncertainty away from well locations within the greater Bay du Nord area.

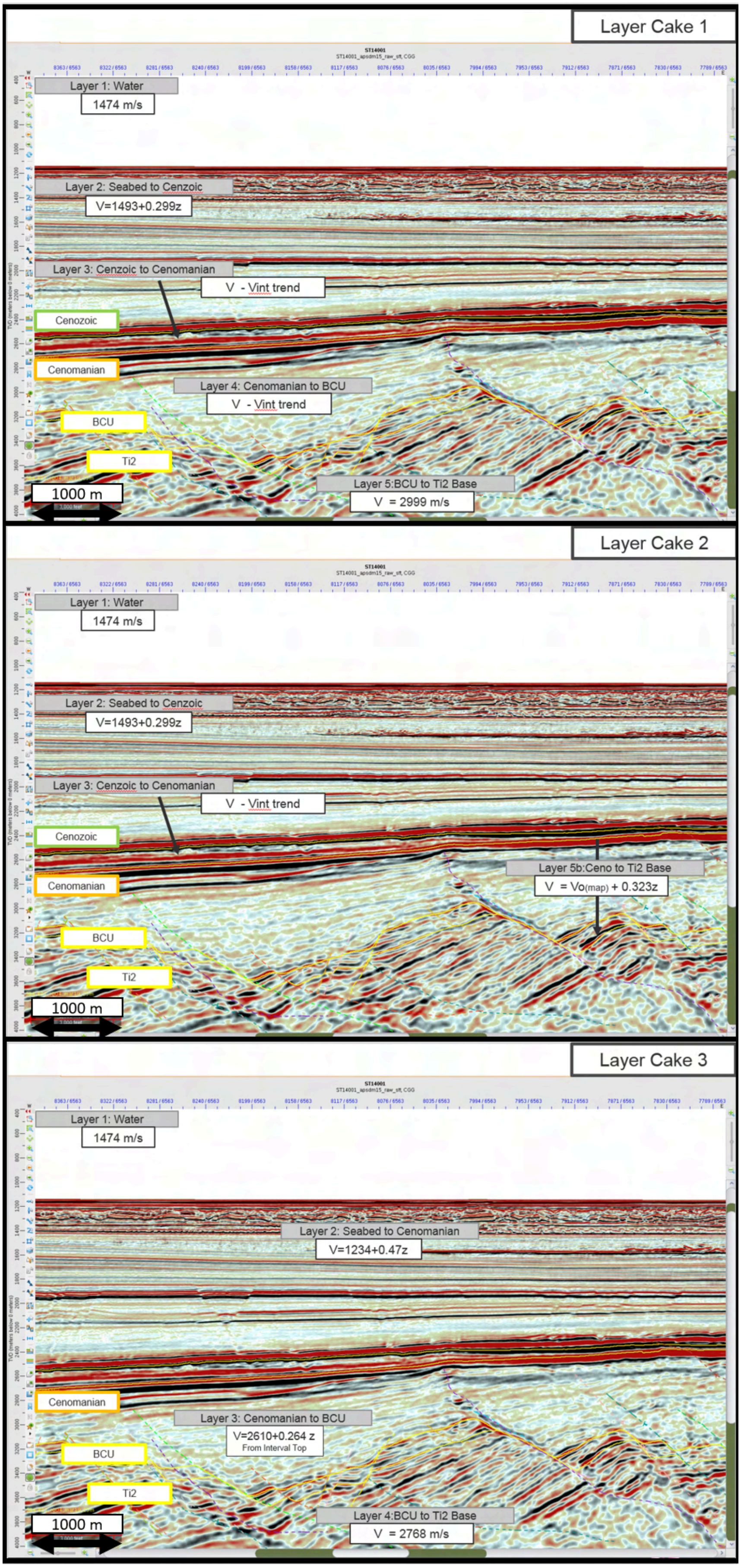


Figure 4.59 Layer Cake Velocity Models for Conventional Depth Conversion

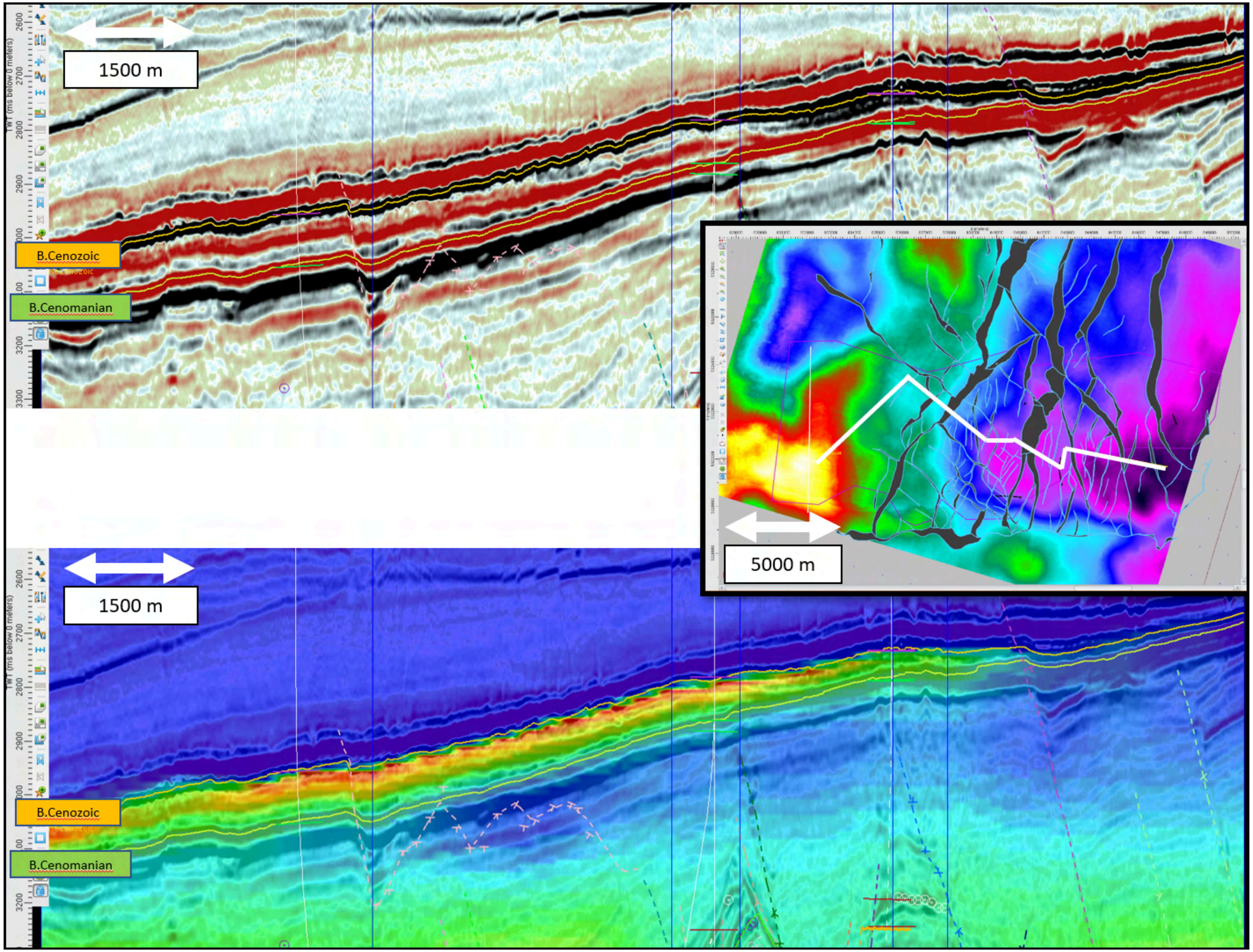


Figure 4.60 Example Line Showing the Cenozoic-Cenomanian Reflection Character and the Corresponding PSDM Velocities Colder colours correspond to lower velocities.

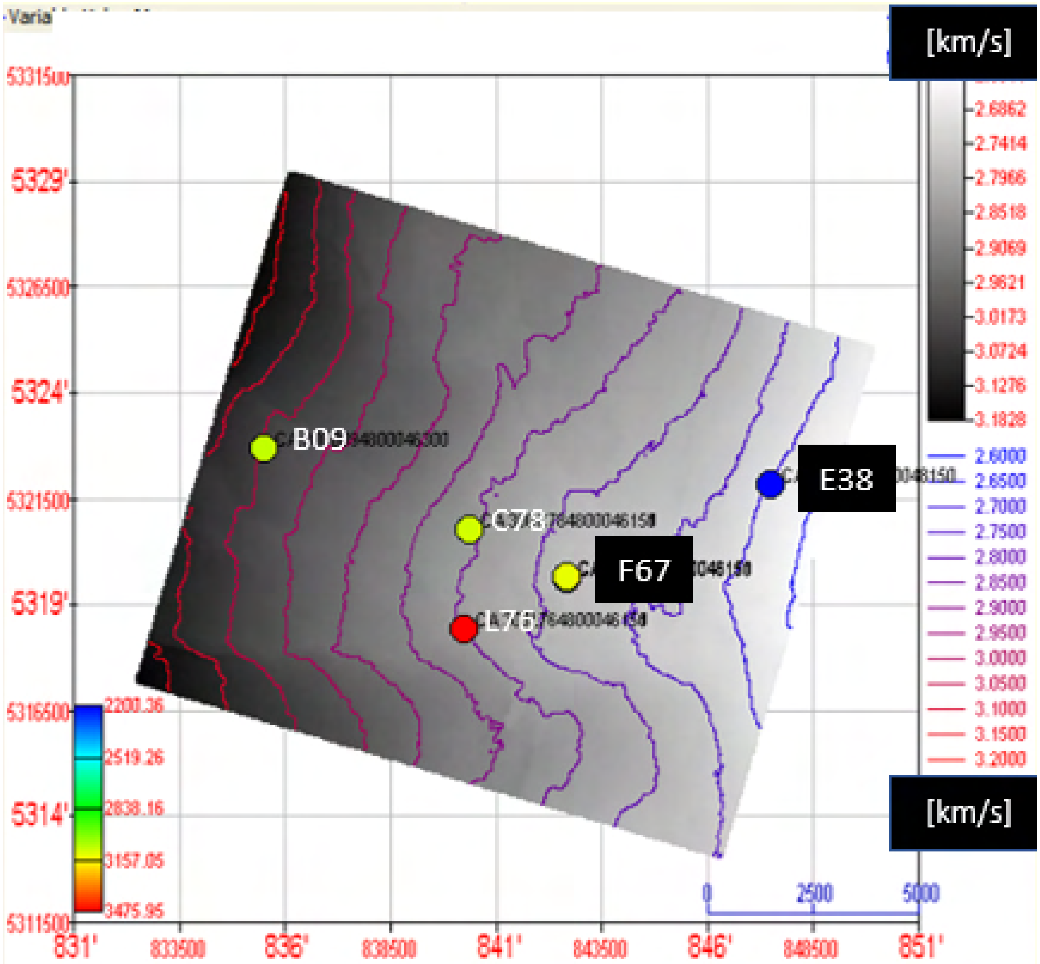


Figure 4.61 Interval Velocities for the Cenozoic Cenomanian Interval Velocity contouring and grey shading is given on the right side. Individual well velocities are color coded with the respective color bar in the lower left.

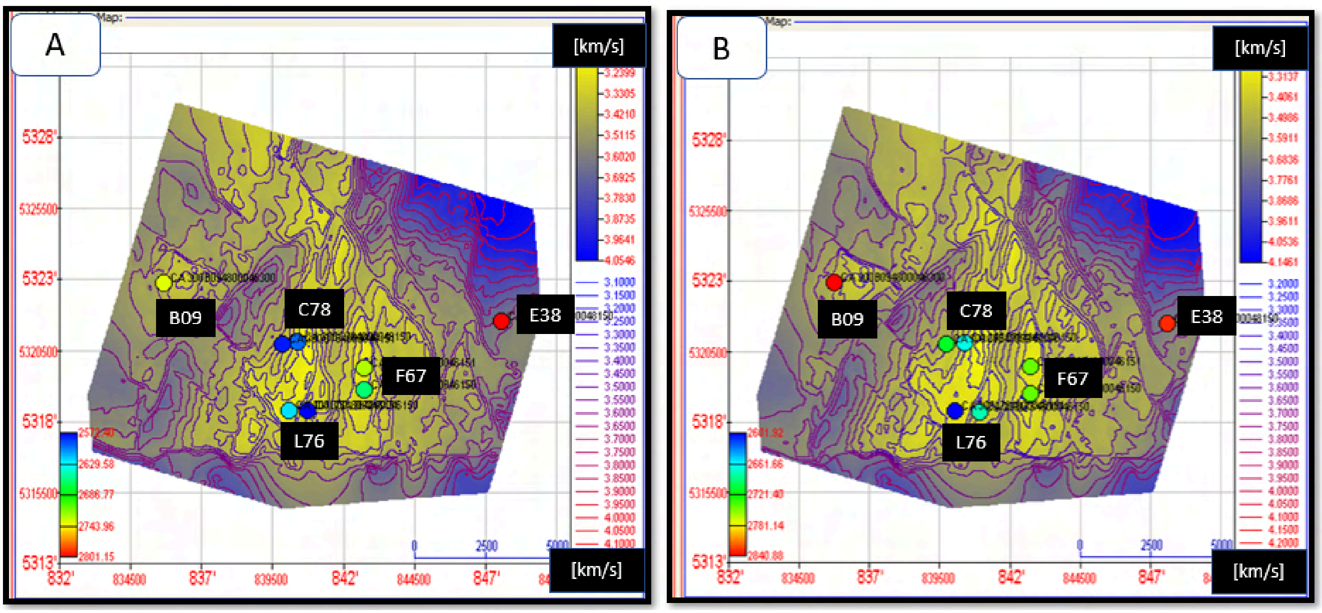


Figure 4.62 Interval Velocities: A) Cenomanian to Mizzen member. Top B) Cenomanian to BdN_1 Base Velocity contouring and color shading is given on the right side. Individual well velocities are color coded with the respective color bar in the lower left.

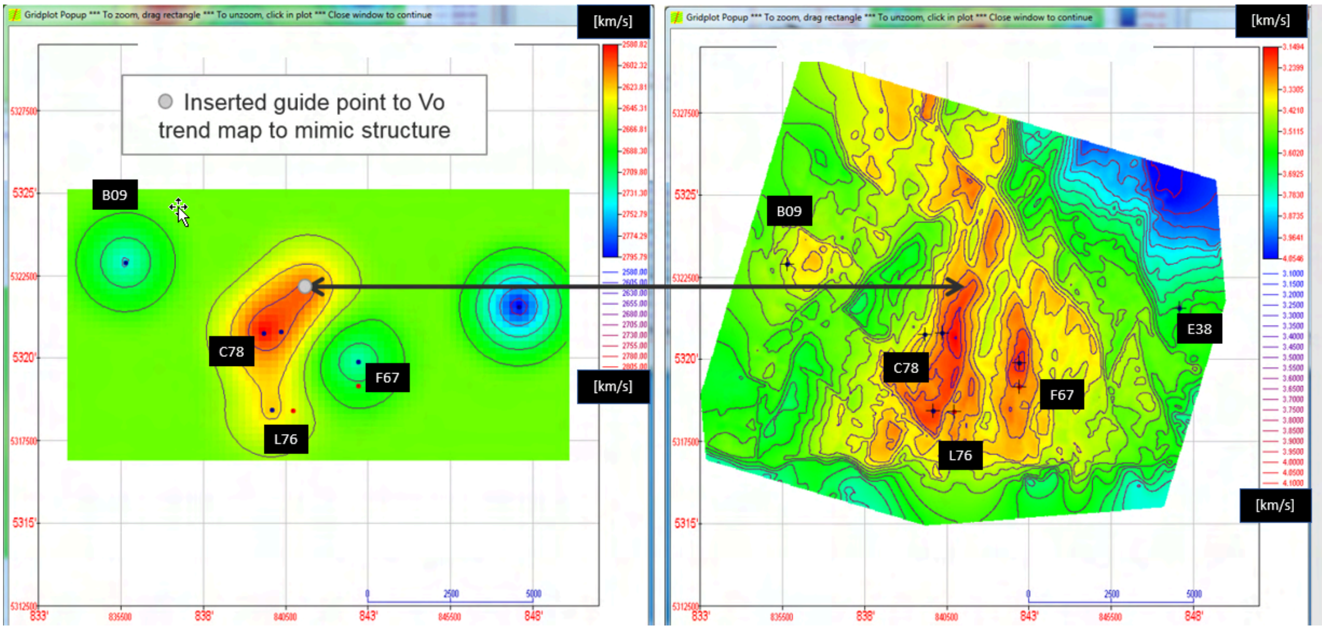


Figure 4.63 Vo Trend Map with Structure Consistent Guide Point

Table 4.4 Comparison PSDM Depth and Layer Cake Depth

BCU (Top Mizzen Mbr)

Absolute Depth						
	Well Pick		PSDM	Cake 1	Cake 2	Cake 3
Well	TVDSS				BCU not included	
Bay de Verde F-67	3029.8		3025.7	3039.2		3045.6
Bay de Verde F-67Z	2960.3		2945.3	2959.2		2953.4
Bay d'Espoir B-09	3212.3		3230.9	3211.3		3210.9
Bay Du Nord C-78	3013.5		3026.4	3013.5		3029.4
Bay du Nord C-78Z	3148.5		3158.5	3149.5		3169.4
Bay du Nord L-76	3059.8		3053.6	3075.1		3080.2
Bay du Nord L-76Z	2973.8		2974.5	2974.3		2966.5
Portugal Cove E-38	3615.6		3626.5	3611.9		3615.9

Difference to Well Pick						
	Well Pick		PSDM	Cake 1	Cake 2	Cake 3
Well	TVDSS				BCU not included	
Bay de Verde F-67	3029.8		-4.1	9.4		15.8
Bay de Verde F-67Z	2960.3		-15	-1.1		-6.9
Bay d'Espoir B-09	3212.3		18.6	-1		-1.4
Bay Du Nord C-78	3013.5		12.9	0		15.9
Bay du Nord C-78Z	3148.5		10	1		20.9
Bay du Nord L-76	3059.8		-6.2	15.3		20.4
Bay du Nord L-76Z	2973.8		0.7	0.5		-7.3
Portugal Cove E-38	3615.6		10.9	-3.7		0.3

Base BdN Mbr

Absolute Depth						
	Well Pick		PSDM	Cake 1	Cake 2	Cake 3
Well	TVDSS					
Bay de Verde F-67	3145.7		3118.4	3140.6	3145.4	3145
Bay de Verde F-67Z	3112.2		3095.9	3120	3111.55	3101.7
Bay d'Espoir B-09	3354.1		3358.8	3342.1	3352	3329.4
Bay Du Nord C-78	3195.0		3201.6	3202	3196.5	3203.3
Bay du Nord C-78Z	3370.0		3380	3357.9	3369.8	3363.4
Bay du Nord L-76	3220.1		3222.5	3230.4	3219.7	3224
Bay du Nord L-76Z	3121.8		3131	3148.8	3122.9	3128.5
Portugal Cove E-38	3732.1		3749.3	3720.4	3731.9	3715.7

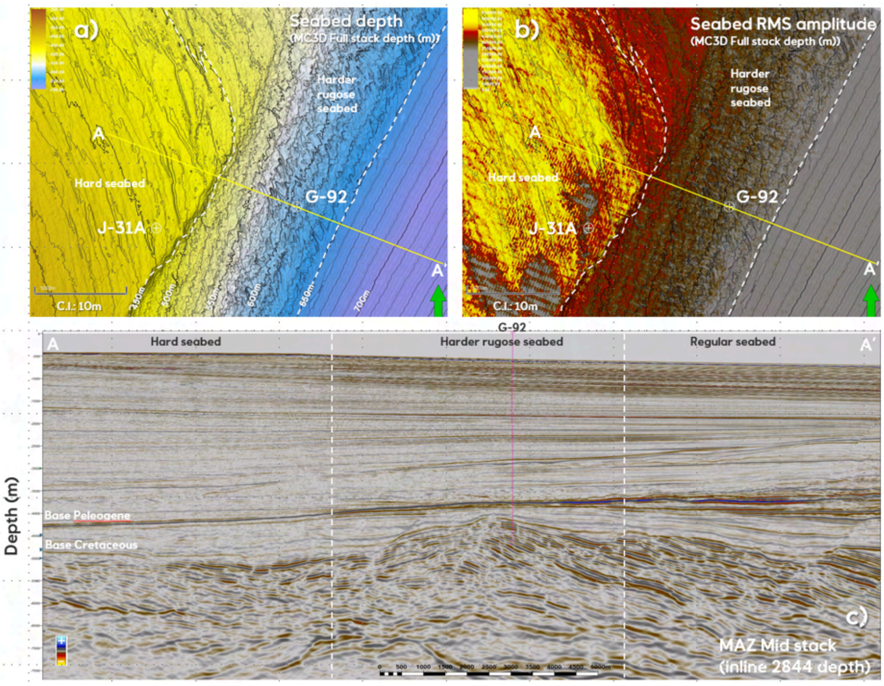
Difference to Well Picks						
	Well Pick		PSDM	Cake 1	Cake 2	Cake 3
Well	TVDSS					
Bay de Verde F-67	3145.7		-27.3	-5.1	-0.3	-0.7
Bay de Verde F-67Z	3112.2		-16.3	7.8	-0.6	-10.5
Bay d'Espoir B-09	3354.1		4.7	-12	-2.1	-24.7
Bay Du Nord C-78	3195.0		6.6	7	1.5	8.3
Bay du Nord C-78Z	3370.0		10	-12.1	-0.2	-6.6
Bay du Nord L-76	3220.1		2.4	10.3	-0.4	3.9
Bay du Nord L-76Z	3121.8		9.2	27	1.1	6.7
Portugal Cove E-38	3732.1		17.2	-11.7	-0.2	-16.4

4.3 Cambriol Field

4.3.1 Seismic Data Quality

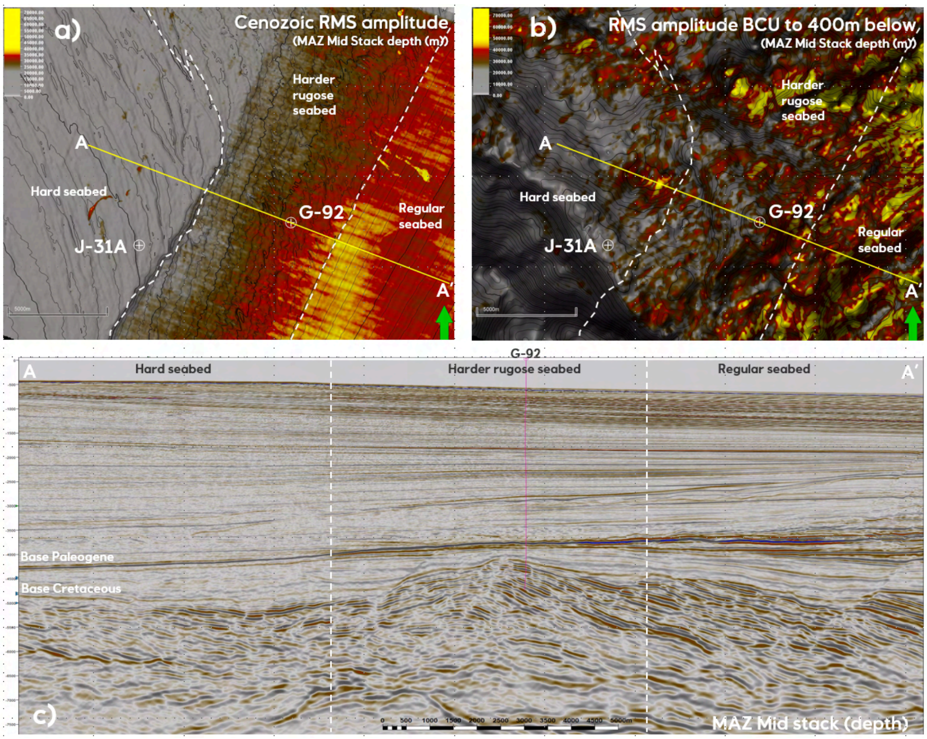
The seismic volumes from the 2021 MC3D PGS acquisition and the MAZ processing of the MC3D and reprocessed ST12002 data (R22ZST12002) were used in the assessment of the Cambriol Field.

The seismic data quality in parts of the Cambriol area is significantly impacted by seafloor elevation and "hardness". Figure 4.64 depicts the transition zone from a shallower hard seabed, which is characterized by the paleo glacial Sackville morraine, to the deeper soft seabed. The characteristics of the hard seabed impact the seismic amplitudes, particularly at the reservoir interval. The lateral change in the data quality affects the mapping uncertainty, which is discussed in Section 4.3.5 Horizon Uncertainty Modelling. The Root Mean Square (RMS) amplitude extractions demonstrate the lateral variation in the seismic data quality and denote the transition between the hard and soft seabed (Figure 4.65). The low RMS values indicate that the hard seabed is limiting the seismic energy reaching the deeper sediments and reservoir interval.



a) Seabed depth
b) Seabed RMS amplitude
c) MAZ Mid stack (depth) seismic inline 2844 across Cambriol structure

Figure 4.64 Seafloor Elevation and Seismic Data Quality (Seismic data courtesy of TGS)



a) Cenozoic RMS amplitude
b) Base Cretaceous to 400m below RMS amplitude
c) MAZ Mid stack (depth) seismic inline 2844 across Cambriol structure

Figure 4.65 Seismic Data Quality QC (Seismic data courtesy of TGS)

Standard workflows were applied to assess the quality of the MC3D and R22ZST12002 data, which included move-out, Normalized Root Mean Square (NRMS), signal-to-noise, and bandwidth assessment. The move-out and NRMS assessment at +/- 100 ms around the Base Cretaceous for the MC3D and MAZ data is illustrated in Figure 4.66. The move-out comparison was similar for both datasets, with relatively flat gathers in the Cambriol Field and more indications of noise to the west and northwest. The NRMS map indicates that both datasets have degradation in data quality in areas with a hard seafloor, but that the data quality is good in the vicinity of G-92 and the Cambriol development area. Figure 4.67 depicts signal-to-noise and bandwidth extractions at the Base Cretaceous, which also show the same data degradation trend in the areas with a harder seabed.

Overall, the 2021 processing velocities are consistent with the structure as illustrated in Figure 4.68. However, the PSDM model does not adequately capture the geological complexity and depth shifts are required to tie the wells to the seismic data. This topic is discussed in more detail in Section 4.3.4 Seismic Velocity Analysis and Depth Conversion.

The spectrum of the MAZ mid and full stack volumes is illustrated in Figure 4.69. With an upper frequency limit of 28 Hz and an average reservoir velocity of approximately 3500 m/s, the resolution is calculated with R = $\lambda/4$ = 1/4 v/f to approximately 31.25 m. However, the dominant frequency is closer to 17 Hz, which corresponds to a resolution of 51.5 m (Figure 4.70). With the limited frequency content of the 3D seismic, only the Mizzen 1 sandstone and the Bonaventure 3 sandstone can be resolved with the full stack data.

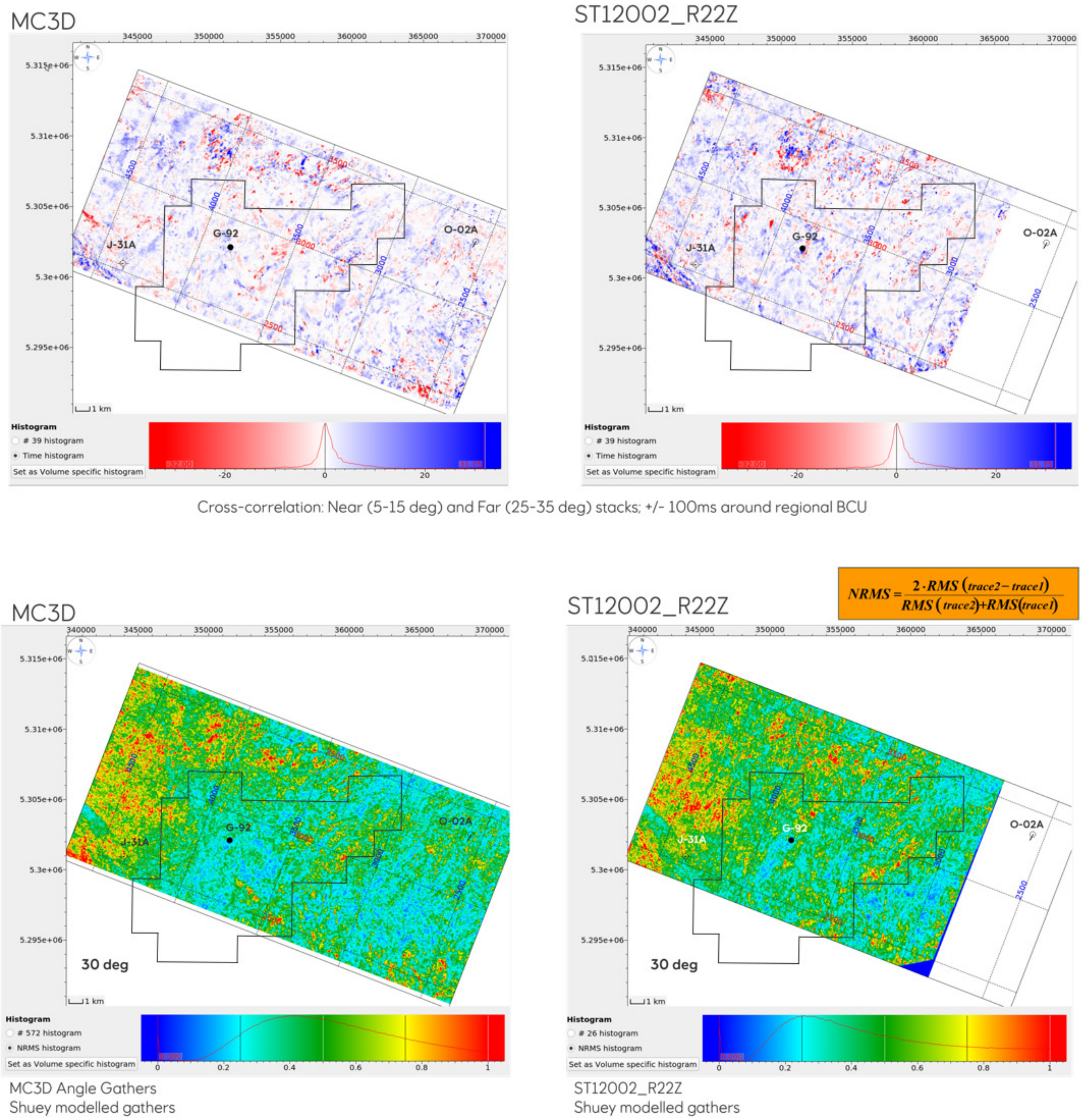


Figure 4.66 Normal Move-out and NRMS Data QCs Map display of move-out (cross-correlation of near and far stacks) and NRMS (comparison of real and synthetic gathers) at +/- 100 ms around the Base Cretaceous horizon for the MC3D acquisition (right) and ST12002R22Z reprocessing (left). The move-out QC identifies where the gathers are flat (white) or curving up (blue) or down (red), and indicates that the gathers are reasonably flat within the Cambriol field. The NRMS is an assessment of similarity between the data and synthetic modeled gathers at 30 deg. The blue areas represent minimal difference while the yellow-to-red areas have significant misfit. The NRMS map identifies that both surveys have degradation in data quality in areas with a hard seafloor (Seismic data courtesy of TGS and Fugro).

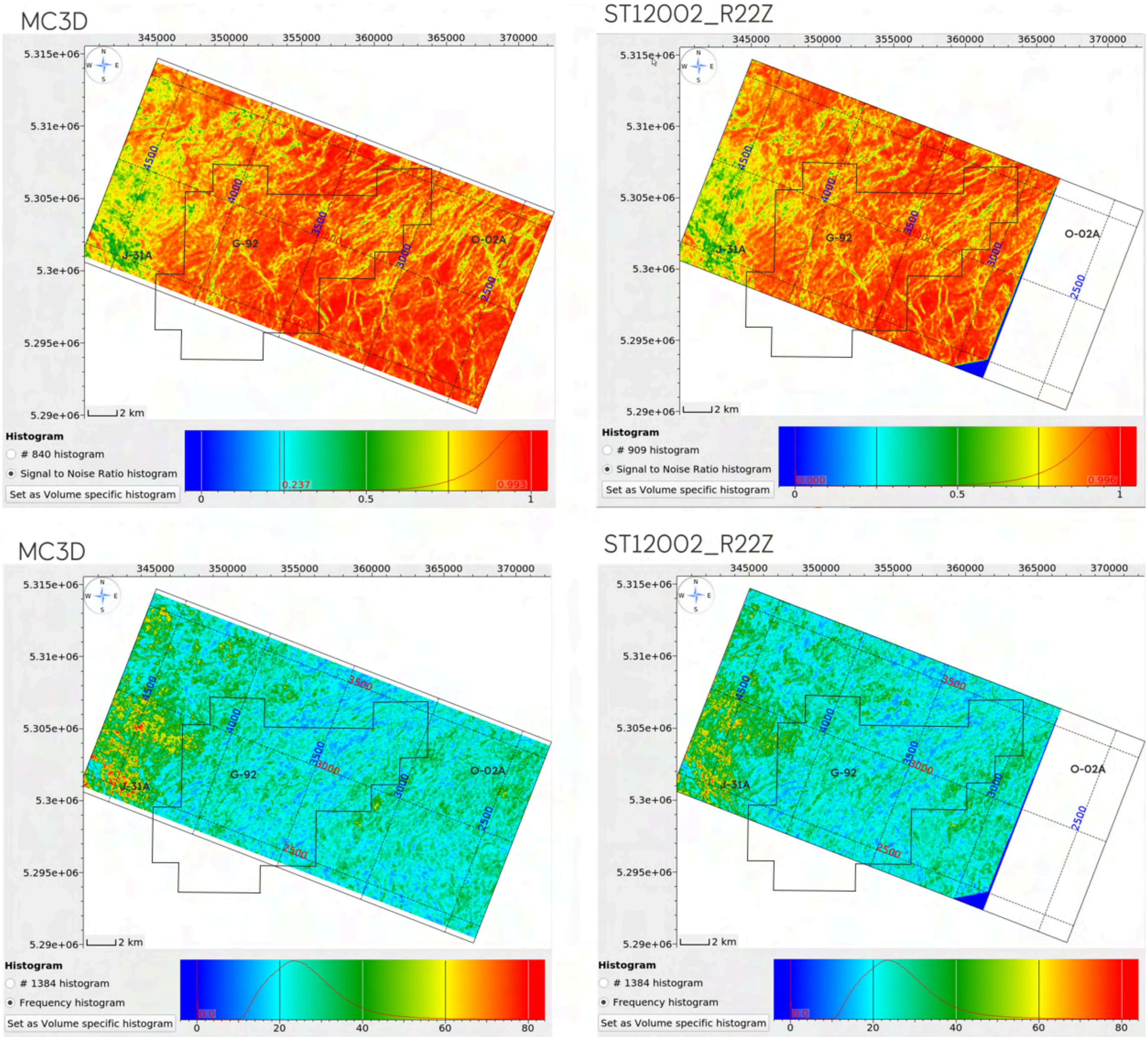


Figure 4.67 Signal-to-Noise and Bandwidth QCs Signal-to Noise (S/N) and Bandwidth extraction at the Base Cretaceous for the MC3D and ST12002R22Z data. Both surveys show similar response with decreasing S/N and changing bandwidth in the region with a hard seafloor (Seismic data courtesy of TGS).

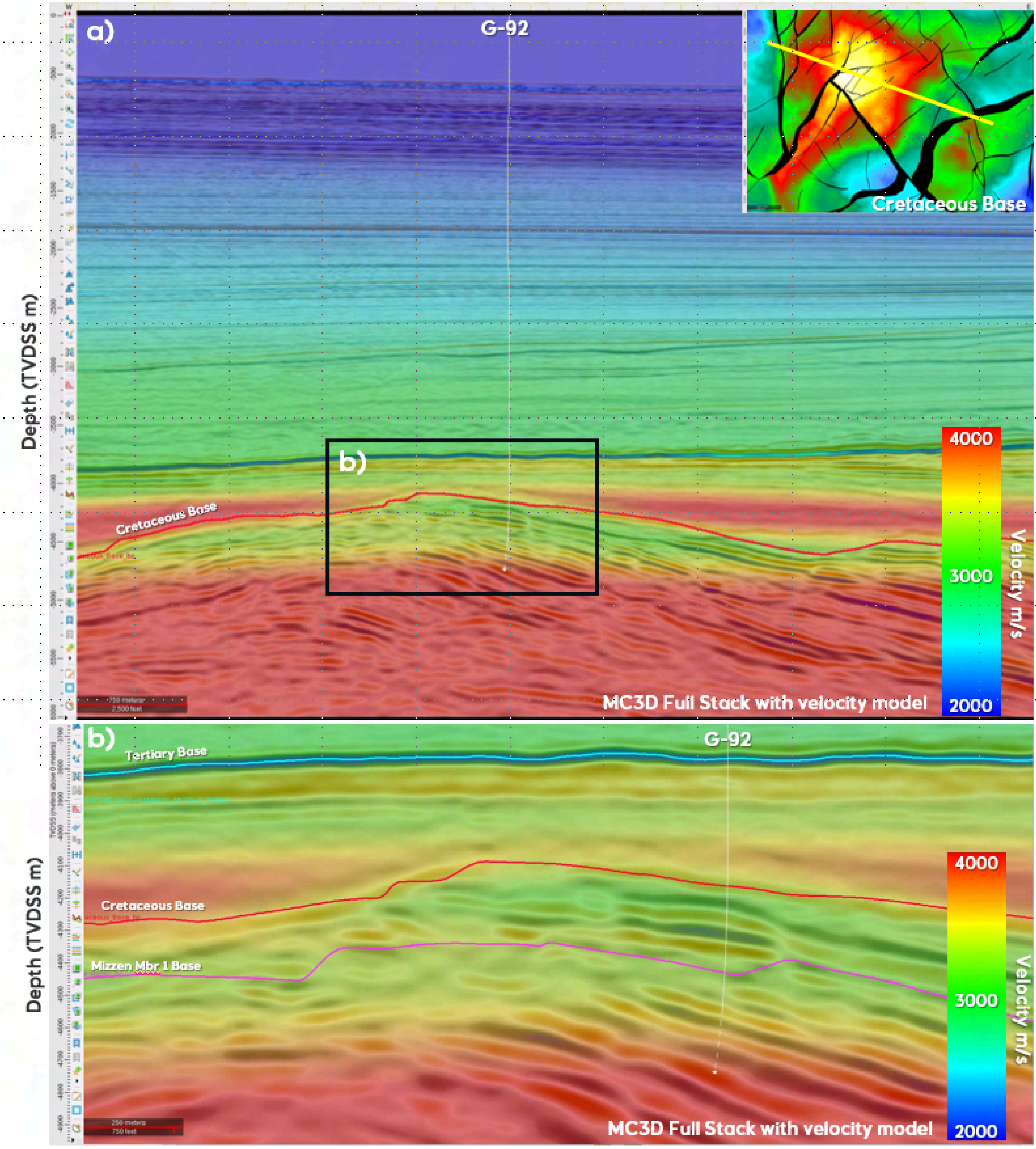


Figure 4.68 Cambriol Structure and Processing Velocities a) MC3D seismic inline 2844 with velocity model overlay; b) Zoom MC3D seismic inline 2844 with velocity model overlay showing core of Cambriol structure and discovery (Seismic data courtesy of TGS).

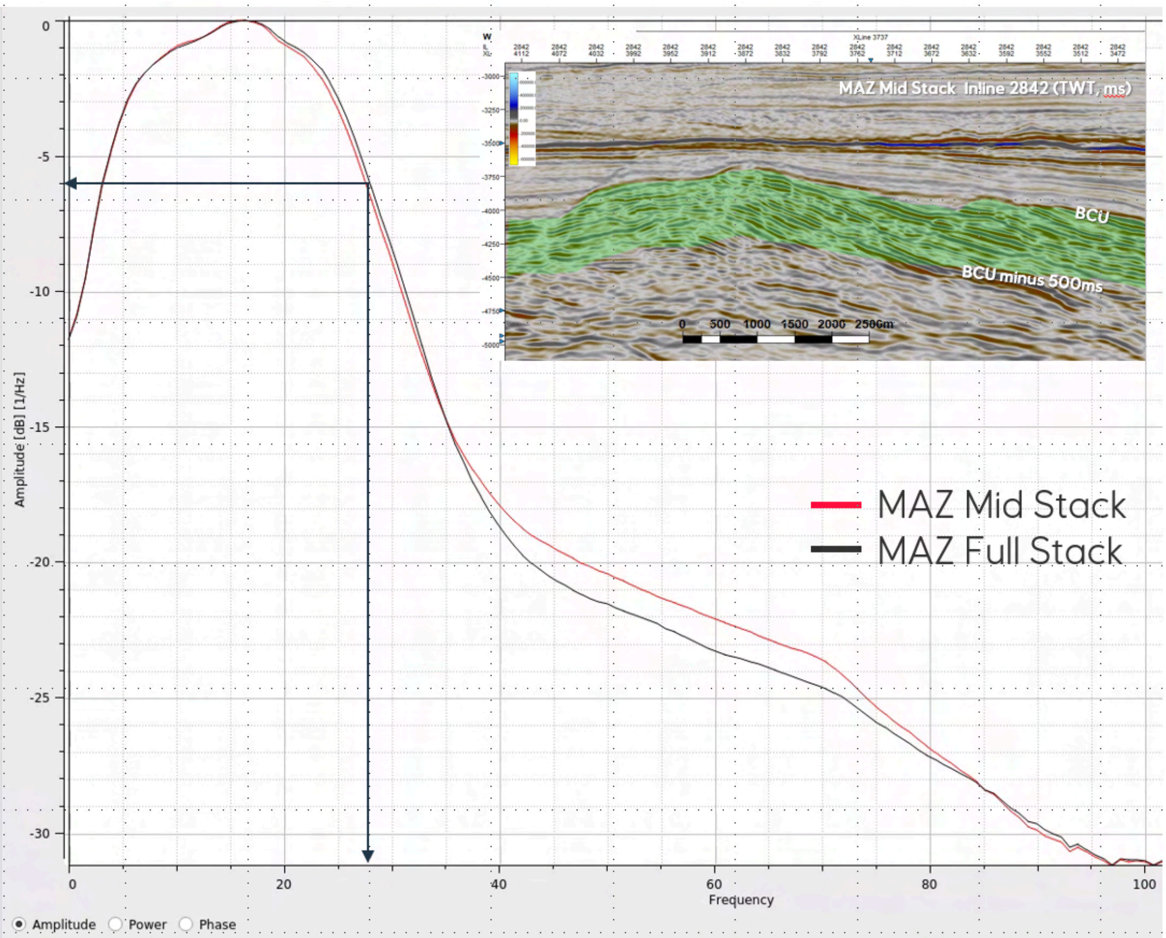


Figure 4.69 Cambriol Spectrum The spectrum is extracted between inlines 3320-4180 and crosslines 2341-3221. The extraction time window is Base Cretaceous to 500ms below (shown in shaded area on seismic section) (Seismic data courtesy of TGS).

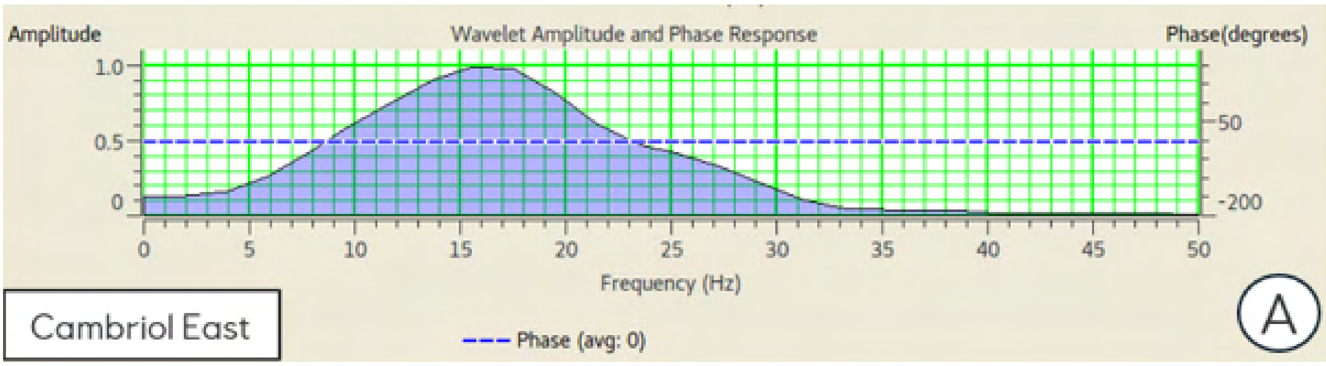


Figure 4.70 Dominant Frequency Frequency plot indicating that the dominant frequency in the Cambriol Field is 17Hz

4.3.2 Seismic Well Correlation

The Cambriol G-92 exploratory well was drilled in 2020 using reprocessed ST12002 data before the 2021 MC3D data was acquired. Consequently, the seismic well correlation was assessed on multiple vintages of data. The depth-depth G-92 well-tie to the MAZ and MC3D PSDM volumes yields a mistie of 30.8 m at the reservoir interval (Figure 4.71). This is comparable to the mistie evident on the legacy data, which yielded a mistie of up to 35 m (Figure 4.72).

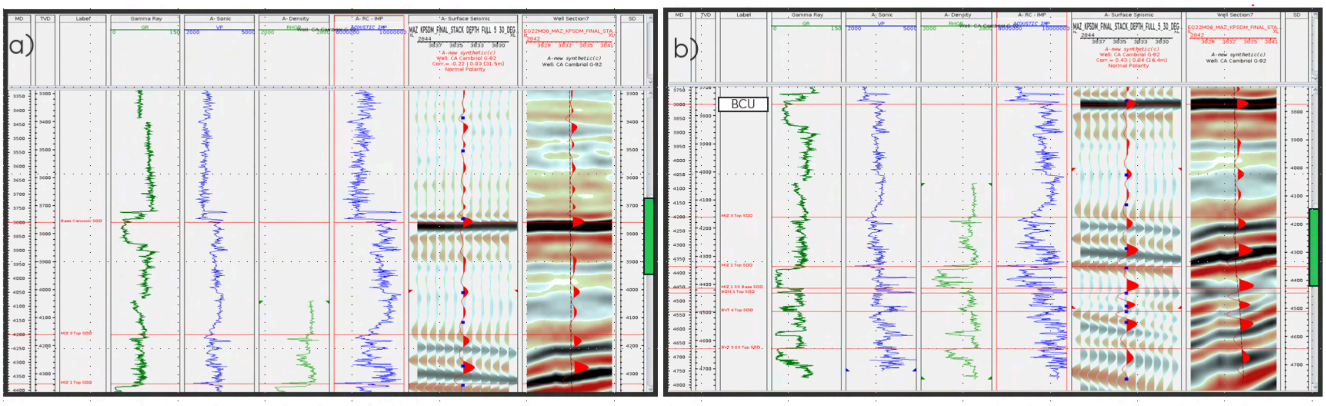


Figure 4.71 Cambriol G-92 Well Tie a) Optimizing for Base Tertiary requires an upwards shift of 14.4m. b) Optimizing for Base Mizzen 1 mbr requires a 14.4 + 16.4m = upwards 30.8m shift

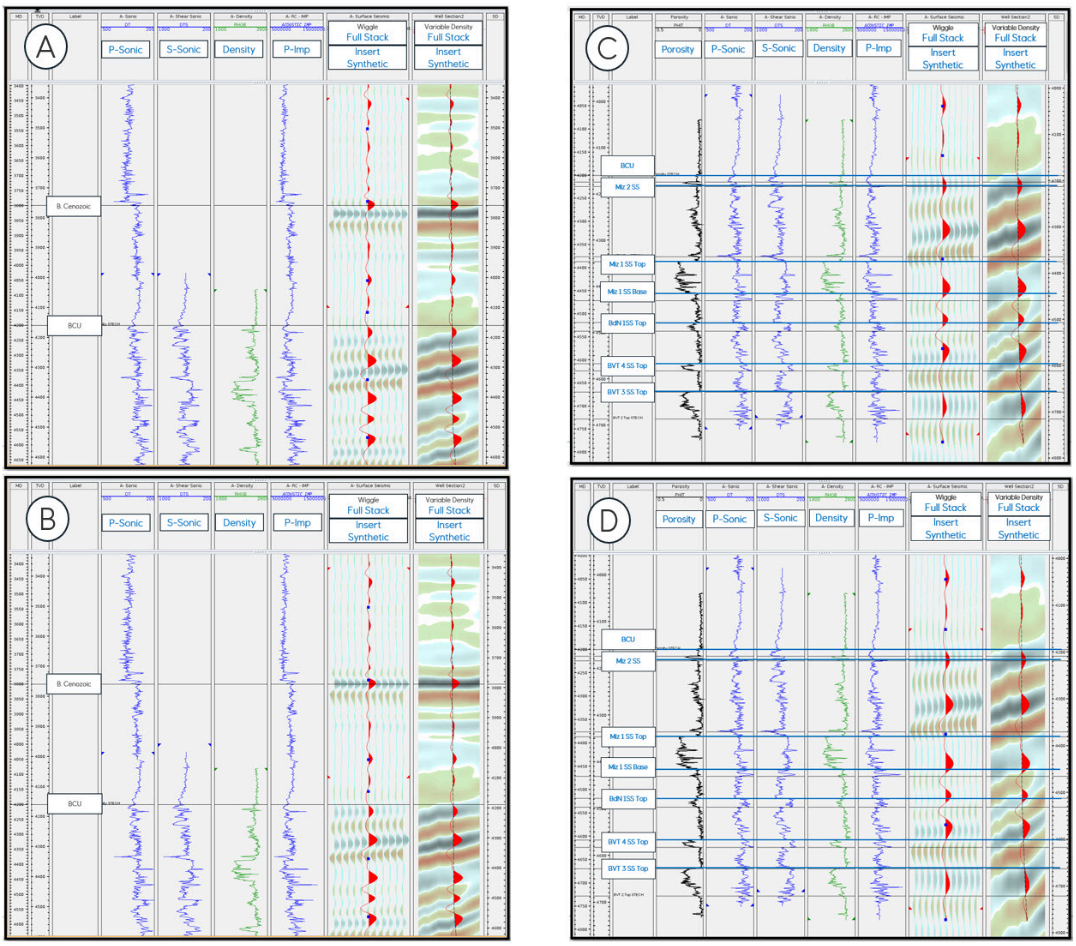


Figure 4.72 Cambriol G-92 Well Tie A) Raw well tie has a mistie of 28.7 m at the Base Tertiary level. B) Well tie after shift 28.7 m to match the Tertiary reflection. C) An additional stretch of 6 m necessary to match the Tithonian reflection. D) Final well tie after shifts.

Given the depth uncertainty at Cambriol, the well-tie was extensively assessed in the time domain on the legacy data. For this purpose, the PSDM depth volumes are stretched to time using the migration velocities. Figure 4.73 illustrates the synthetic to full stack well-tie on the top and pre-stack well tie at the bottom. Overall the well-tie is good. However, the amplitude pattern at the Top Mizzen 1 sandstone level does not correlate well to the data. This mistie is more significant on the pre-stack data. It is remarkable (Figure 4.74) that the zero offset VSP corridor stack matches the 3D volume at this level very well (except for the shift noted above). It is also obvious that the deeper section requires an additional time shift to optimize the match. This is an indication that the PSDM velocity model does not optimally represent the subsurface velocities. This observation is also made on the MC3D data and is discussed in Section 4.3.4 Seismic Velocity Analysis and Depth Conversion.

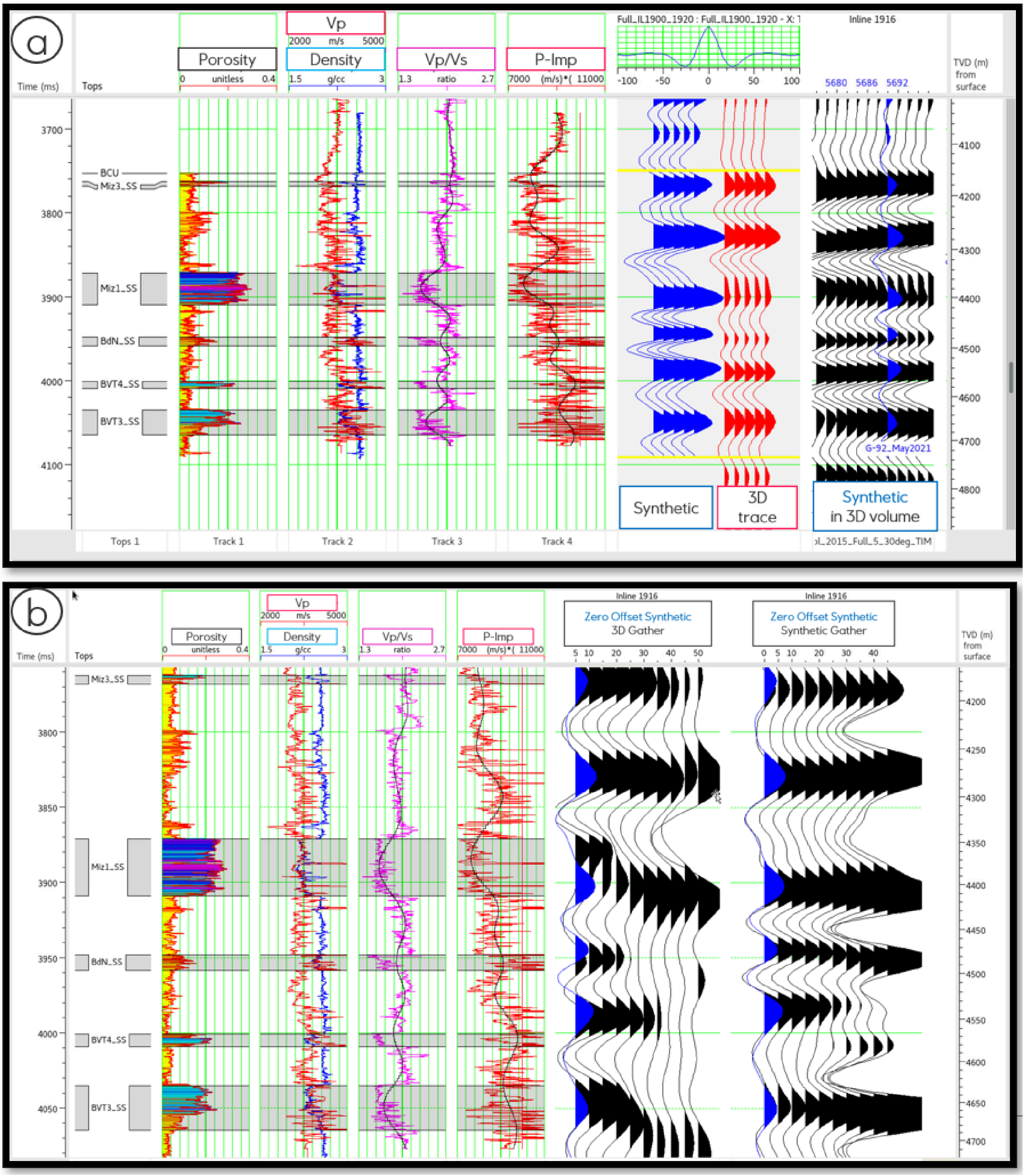


Figure 4.73 G-92: Post and Pre-Stack Well Tie

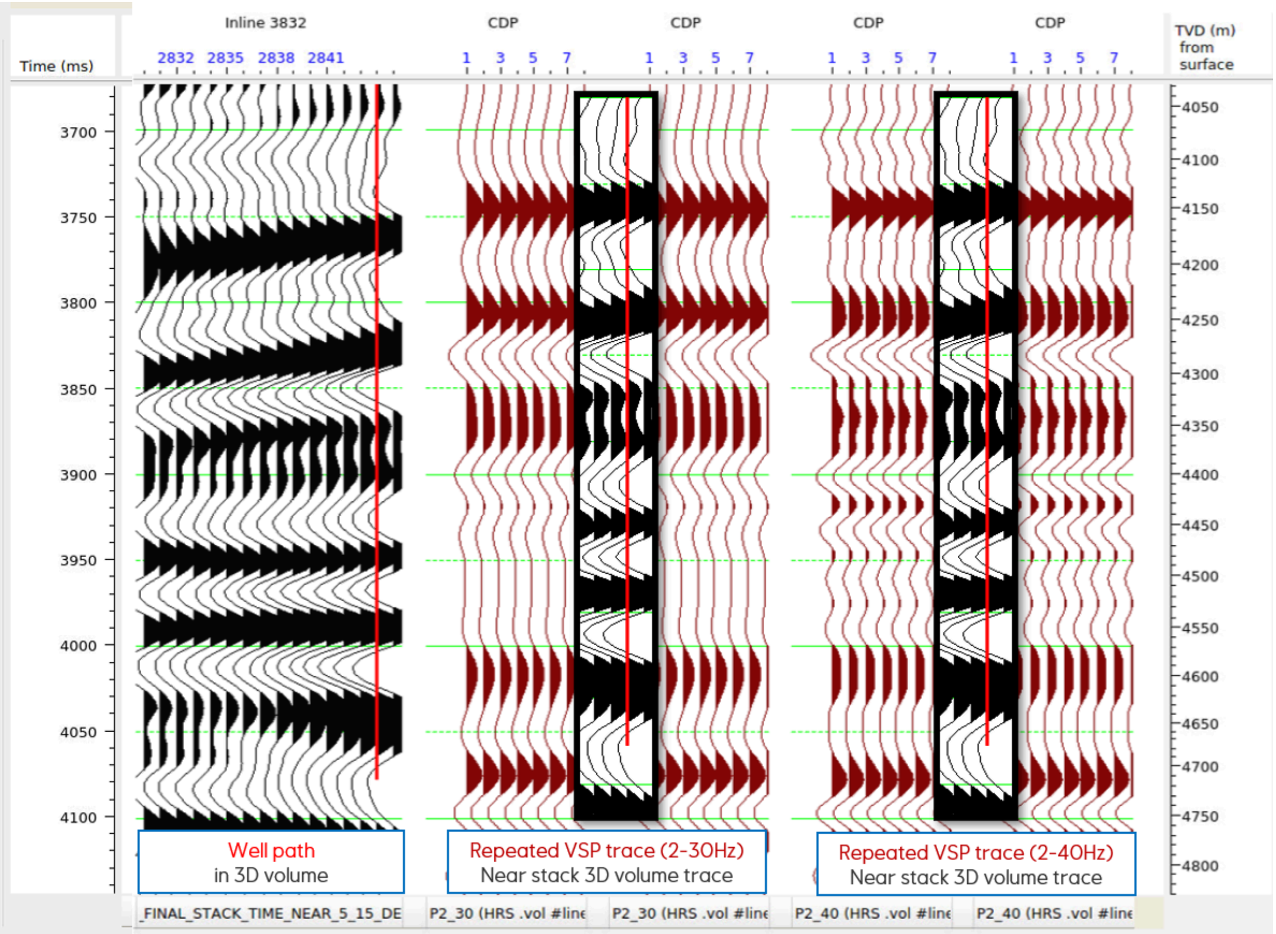


Figure 4.74 G-92 VSP Corridor Stack Well Tie

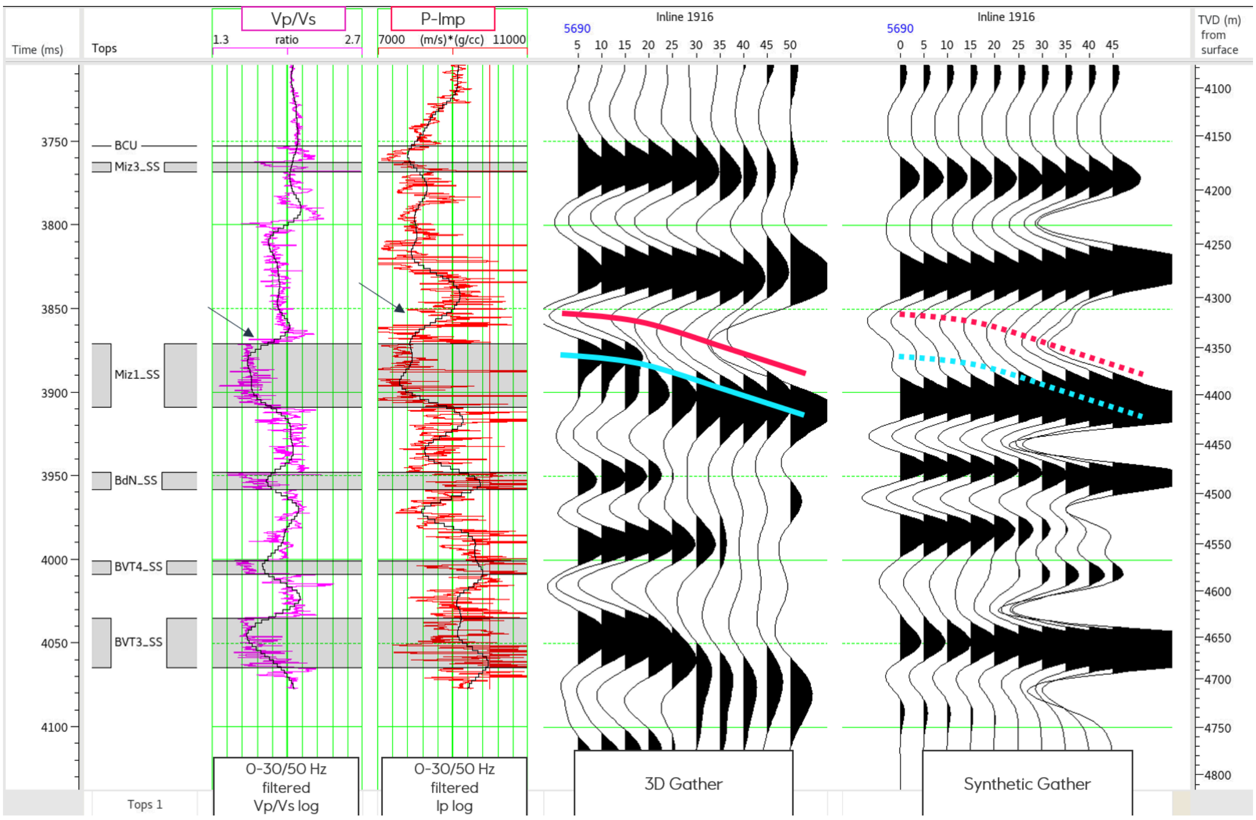


Figure 4.75 G-92 Pre-Stack Well Tie

Extensive 1D modelling of intra-bed multiples and a multiple analysis based on the VSP up-going wavefield could not identify any cause for the near stack mistie at the Mizzen 1 sandstone level. A possible explanation could be that the P-impedance change occurs at a higher level than the Vp/Vs change, and this combination triggers a curved event, i.e. far stack arrives later than near stack (Figure 4.75). This curved event is less visible on the synthetic which could be related to tuning.

Analysis of the well-tie on the MC3D and MAZ partial stacks was completed to determine the most reliable stack for horizon mapping. Figure 4.76 identifies that the MC3D and MAZ mid-stacks show the best quality well-tie, with a good match between the generated synthetic and the seismic data. Consequently, the mid stacks from the MC3D and the MAZ were used primarily for the horizon interpretation. An example of a mid-stack volume is shown in Figure 4.77. The horizon interpretation was supported by the visualization of the near and far stacks, along with the seismic inversion volumes, which are described in Section 19.5.2.1 Seismic Inversion. The fault interpretation was predominately performed on the MC3D full stack sections, which are processed to a depth of 10,000 m. However, the MC3D and MAZ near and mid stacks were also used to guide the fault mapping. An example of the full stack volume is shown in Figure 4.78.

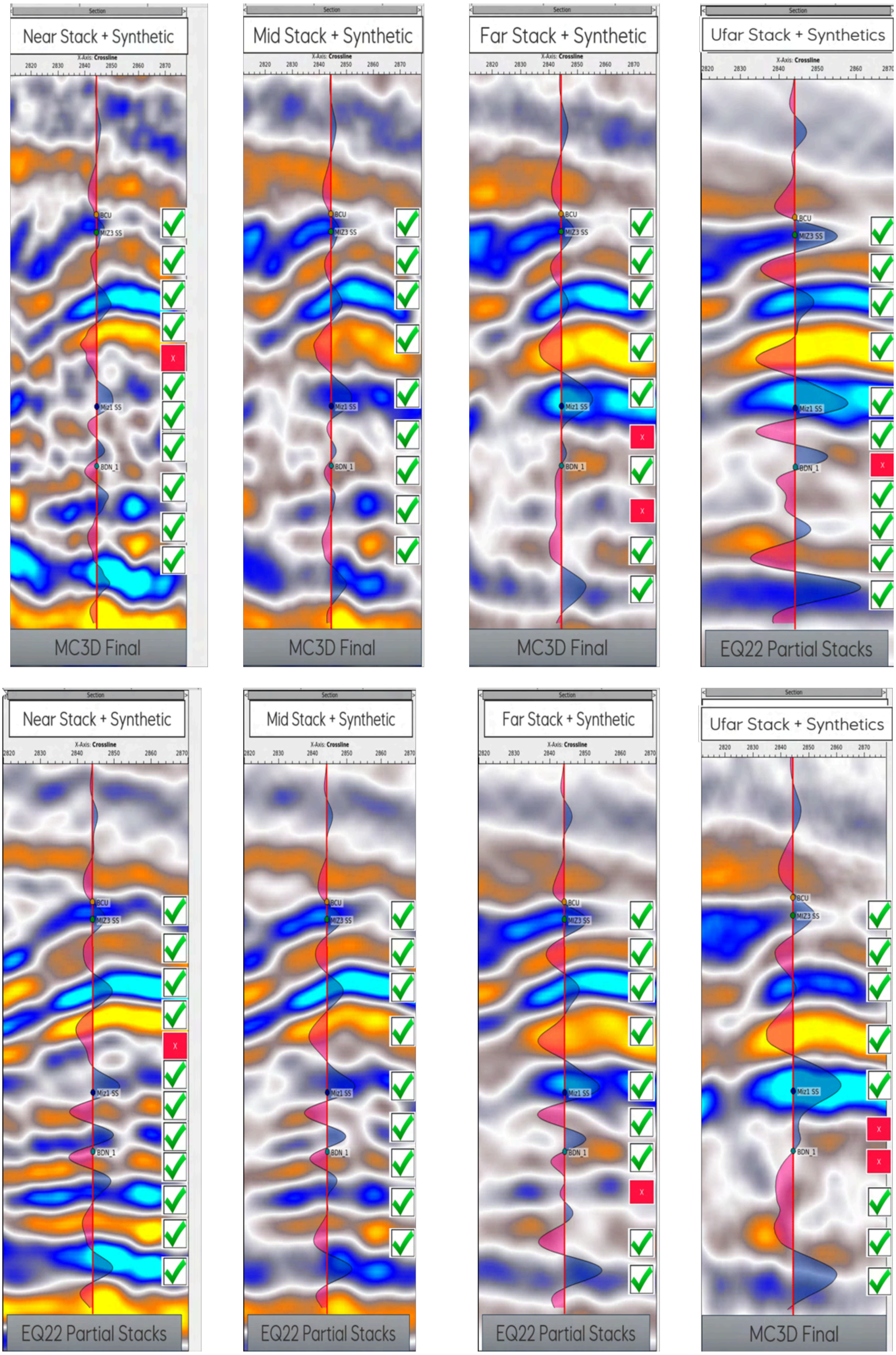


Figure 4.76 Well Tie Assessment Well-ties were analyzed on each partial stack volume (near, mid, far, ultra-far) to assess the quality of the tie and to determine the optimal stack for horizon interpretation. The well-tie on the mid-stack has the best match between the generated synthetic and the seismic data for both the MC3D and MAZ surveys.

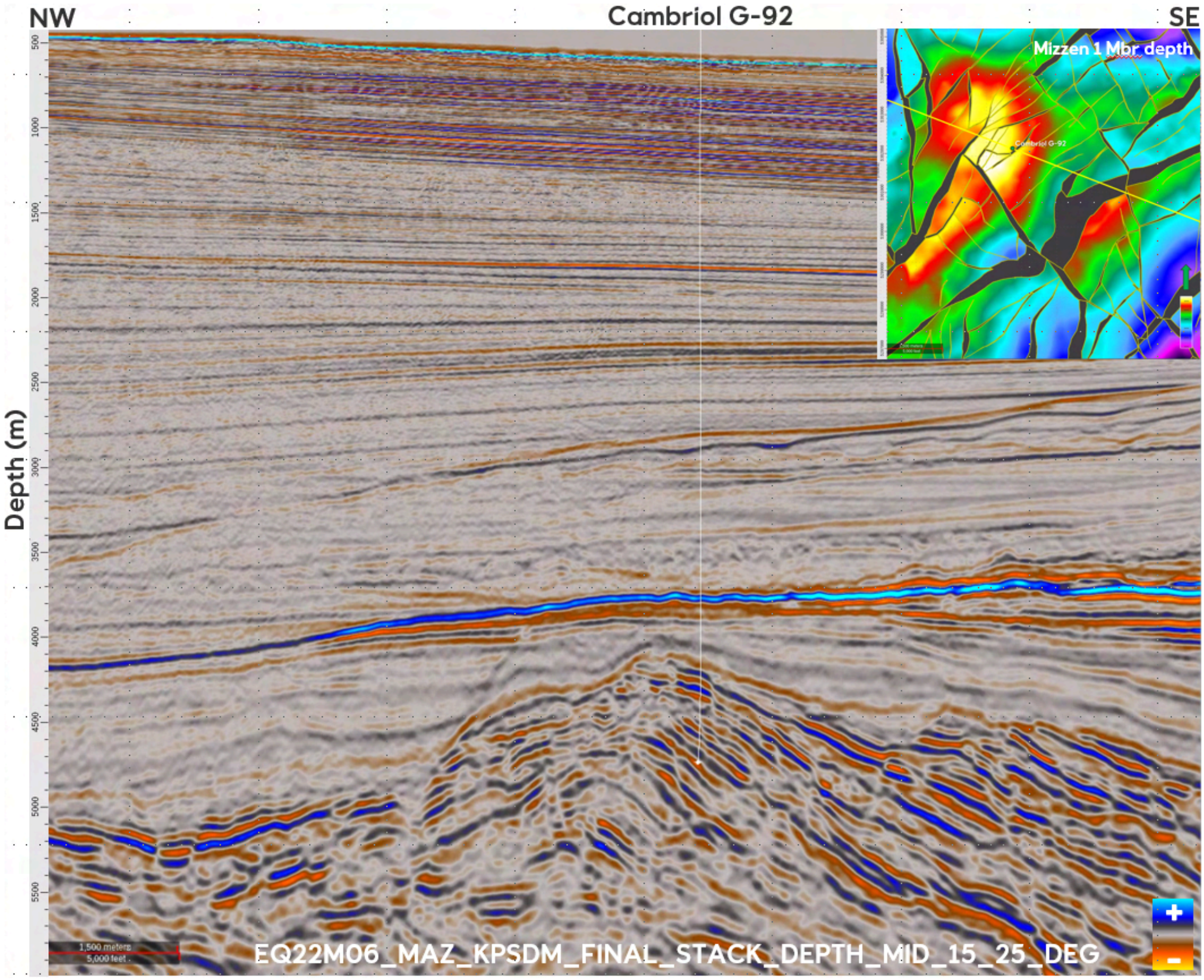


Figure 4.77 MAZ Mid-Stack PSDM Section Seismic section through the Cambriol structure and the G-92 well on the MAZ mid stack (15-25 deg). The mid stacks from the MC3D and MAZ datasets were the primary volumes used for horizon and fault interpretation (Seismic data courtesy of TGS).

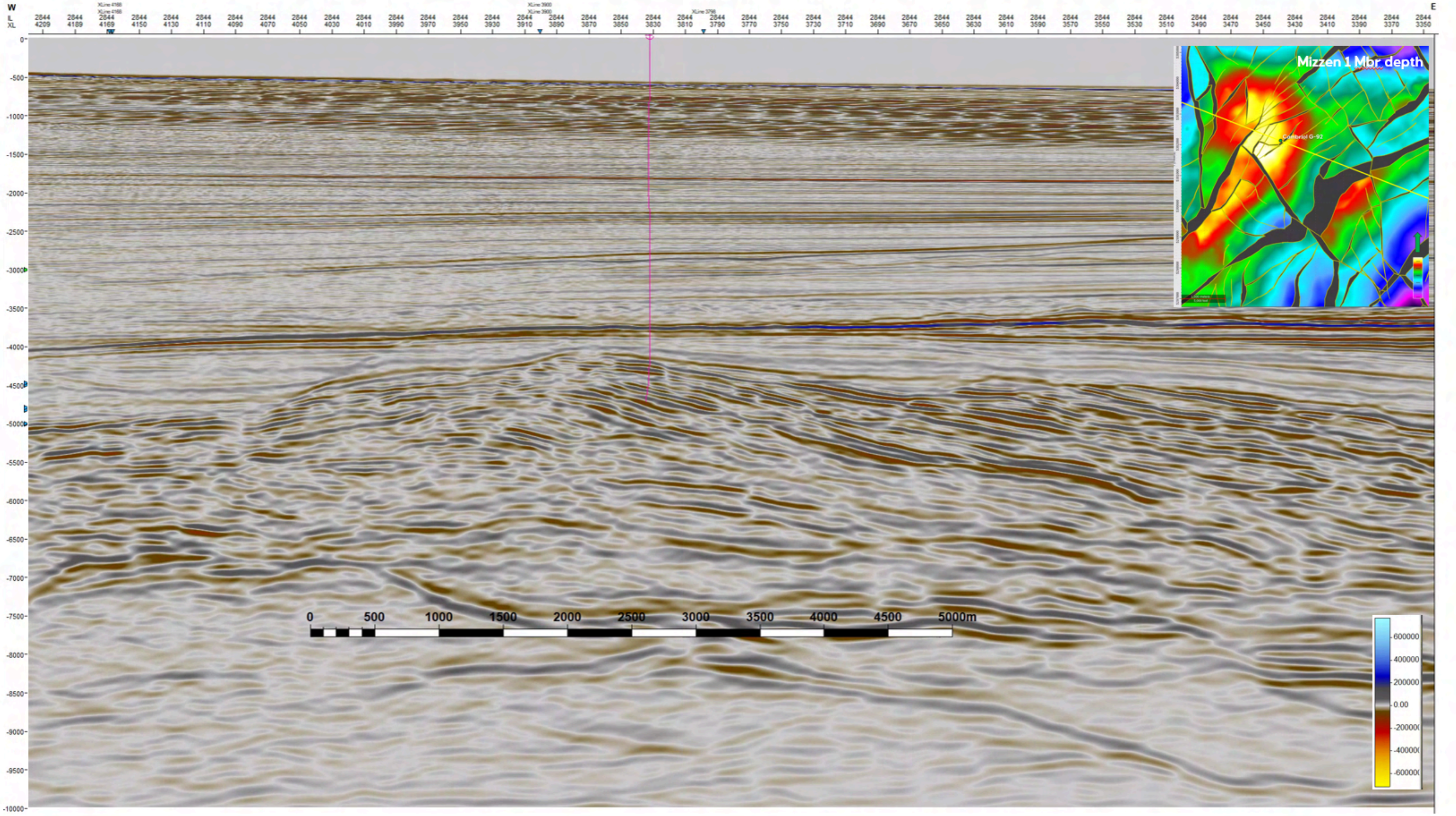


Figure 4.78 MC3D Full Stack PSDM (Seismic data courtesy of TGS)

4.3.3 Structural Seismic Interpretation

The interpretation strategy based on the well tie G-92 is shown in Figure 4.79 and summarized in Figure 4.80. This chapter is primarily focused on the interpretation of the reservoir section. The interpretation pick of the Base Cretaceous is impacted by the relative location to the Valanginian unconformity. Frequently the Base Cretaceous and the Valanginian unconformity fall together and are picked on the same trough. Throughout most of the Cambriol structure the Base Cretaceous is picked as a trough, which is in accordance with almost all other Flemish Pass well ties. However, as it is an unconformity it does change within the Cambriol area. For example, at the apex of the structure near the G-92 well, the interpretation pick is a zero-crossing (trough to peak). The Base Mizzen member 1 sandstone interpretation pick is a peak. Three example lines which tie G-92 and are perpendicular to some key faults are illustrated in Figure 4.81, Figure 4.82, and Figure 4.83. The resulting maps are illustrated in Figure 4.84: A: Base Tertiary depth structure; B: Valanginian unconformity; C: Base Cretaceous unconformity; and E: Base Mizzen 1 sandstone.

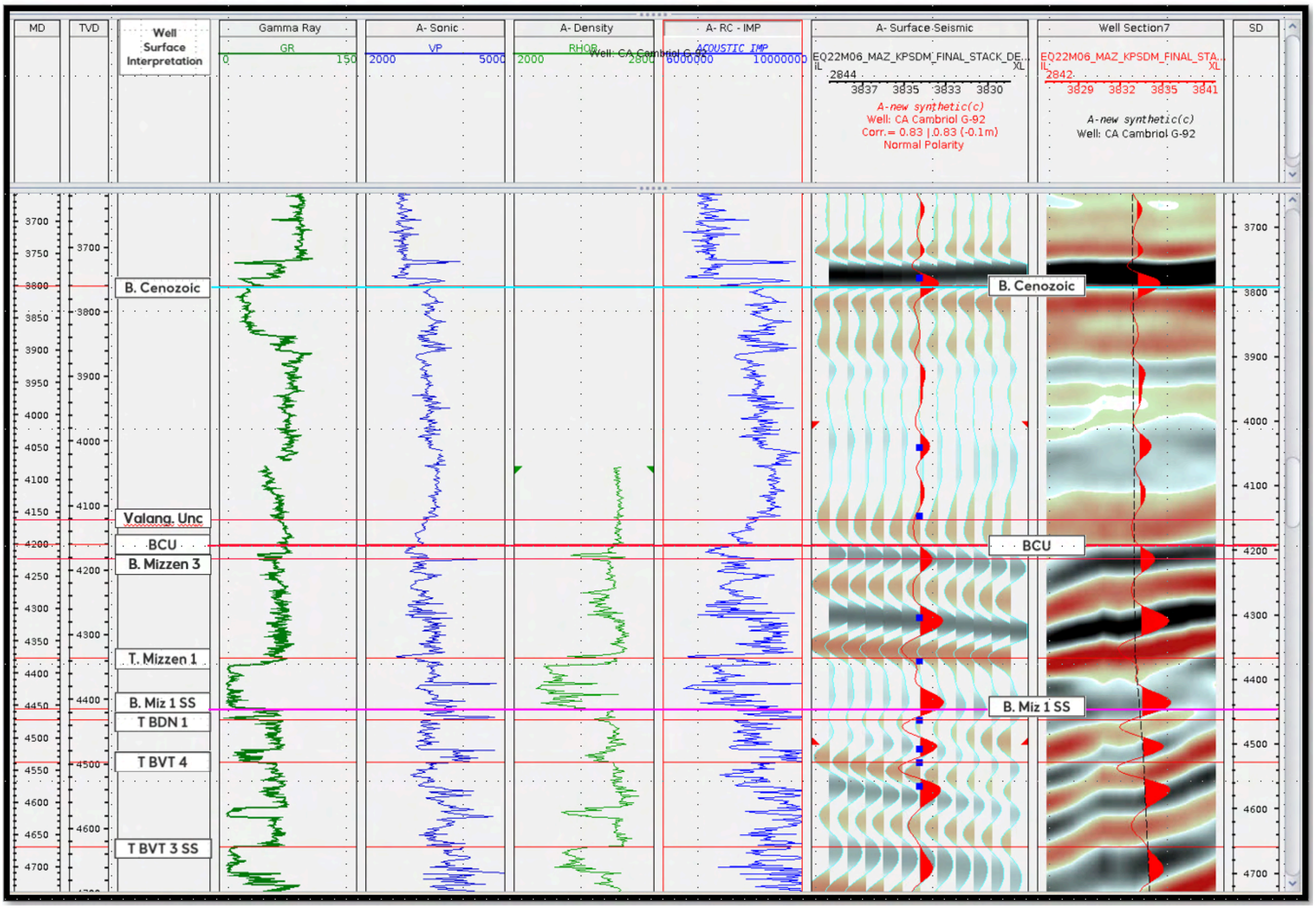


Figure 4.79 Well Tie and Seismic Horizons

Structural Interpretation Concept

The horizon interpretation strategy outlined above has been guided by geological concepts that are summarized in Figure 4.85 which illustrates four common fault types that are repeatedly encountered across the Cambriol Field.

Horizon Name	Acustic Impedance	Interpreted Phase*	Confidence	Remarks
Seafloor	Increase	Peak	High	Seismic is zero phase with a peak at an increase of acoustic impedance.
Base Tertiary	Increase	Peak	High	Consistent with well-tie
Valanginian Unconformity	Decrease	Trough	Variable	Predominantly trough, interferes with BCU, frequently not a separate event
BCU	Decrease	Trough	Variable	Predominantly trough but as an unconformity it does change
Base Mizzen 1 Sandstone	Increase	Peak	Variable	Predominantly peak, guide by inversion* results

*Character on full stack
*Inversion products include Bayesian Crava inversions (Density, LR, MR), and P cube inversions (Sand and Porosity Probability)

Figure 4.80 Interpretation Strategy

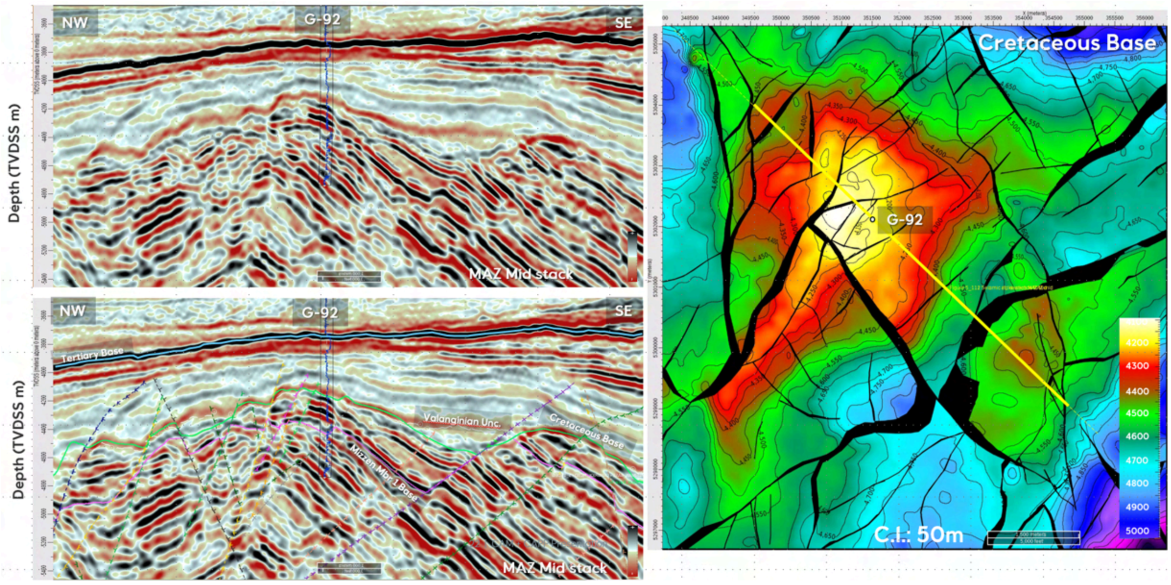


Figure 4.81 Cambriol NW-SE Seismic Section (Seismic data courtesy of TGS)

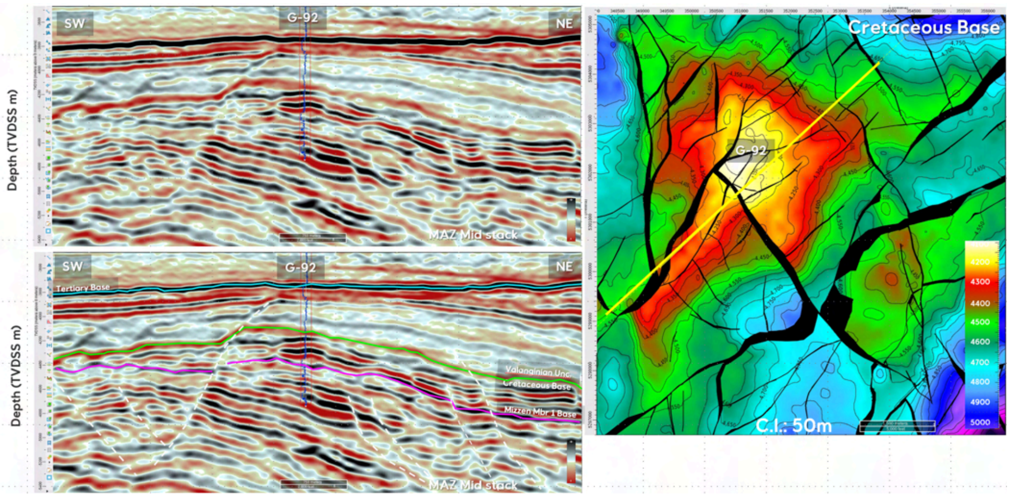


Figure 4.82 Cambriol NE-SW Seismic Section (Seismic data courtesy of TGS)

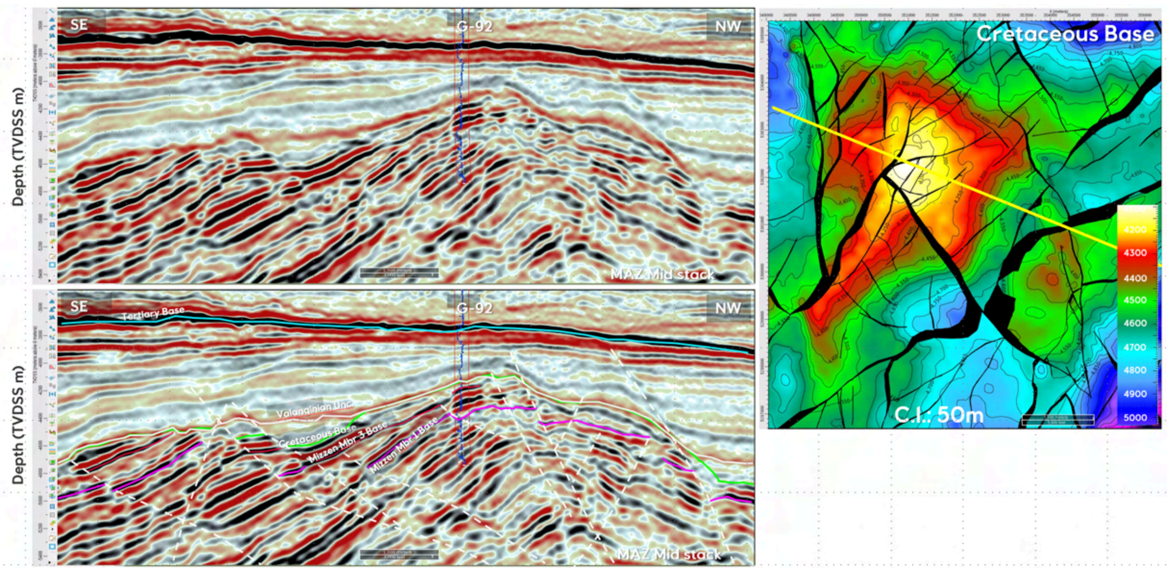


Figure 4.83 Cambriol Inline 2844 (Seismic data courtesy of TGS)

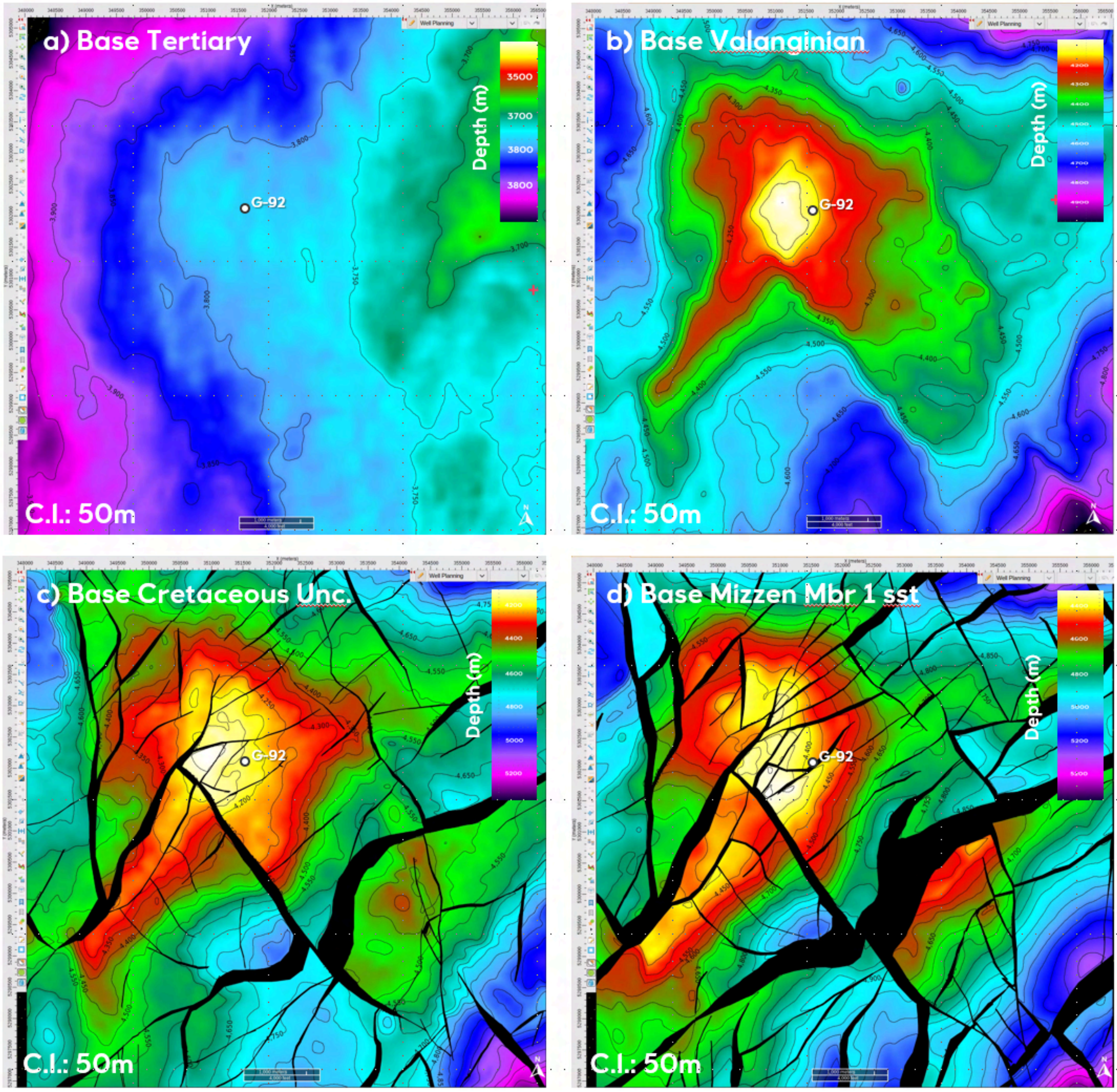


Figure 4.84 Structure Maps a) Base Tertiary depth structure; b) Valanginian unconformity; c) Base Cretaceous unconformity; d) Base Mizzen Mbr 1 sandstone (Seismic data courtesy of TGS).

These fault types are also consistent with (and derived from) the structural development concept presented in Section 2.4 Cambriol Field. Fault F1 shows minor faulting in Late Tithonian during deposition of the Mizzen member. F1 becomes inactive before reaching the Base Cretaceous level, suggesting a subtle fault activity during deposition of the lower to middle Mizzen member. It is however not possible to seismically resolve whether that fault growth is happening within the Mizzen 1 sand itself, or in the shales above and thus slightly later (but the assumption is that it's possible there could be some limited fault growth in the Mizzen 1 sand). Fault F2 shows major fault activity in Berriasian-Valanginian (300+ m throw), and is also truncated by the Valanginian unconformity - creating a composite unconformity and fault scarp/erosion in the footwall. This composite erosion by Base Cretaceous/ Valanginian is seen elsewhere in other rotated fault blocks in Cambriol, and this concept was used when interpreting Base Cretaceous. Faults F3 and F4 shows minor faulting in Late Tithonian during deposition of Mizzen 1 but appears truncated by Base Cretaceous and therefore it is not possible to rule out there is a certain amount of Cretaceous movement on these faults - or perhaps even only Cretaceous movement. Faults F5 and F6 shows late faulting in Aptian and are cross-cutting some of the older faults at a high angle (Aptian faults typically strike northwest-southeast).

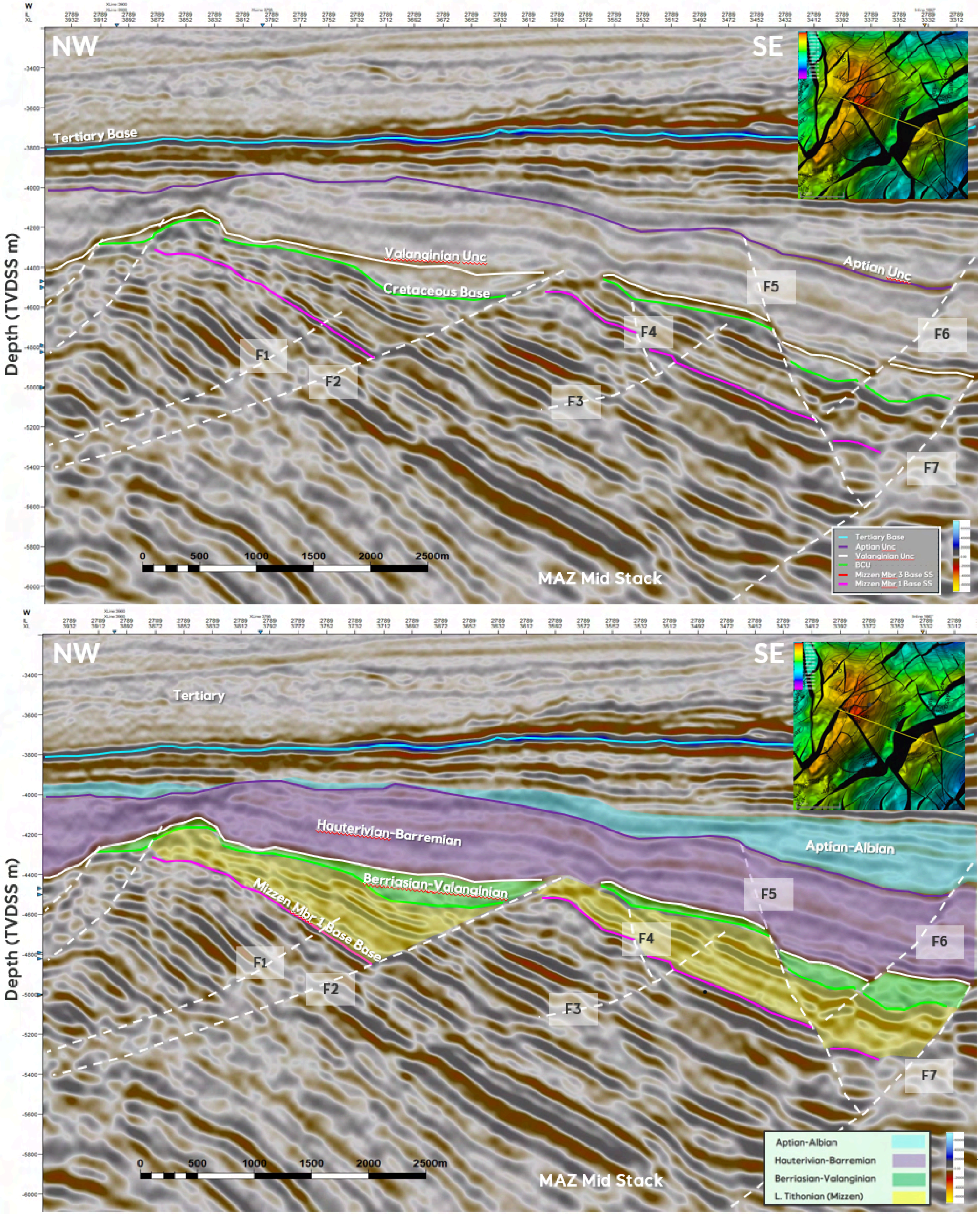


Figure 4.85 Cambriol Structural Interpretation Concept A) Inline 2789 with interpretation, B) Inline 2789 with interpretation and legend. Observed fault types that are repeatedly seen in other areas in Cambriol, F1-F4 see text for more details (Seismic data courtesy of TGS).

4.3.4 Seismic Velocity Analysis and Depth Conversion

The 2021 MC3D seismic acquisition and MAZ reprocessing provided improved imaging and data quality compared to the legacy data; however, there is still a significant depth shift required to tie the wells to the seismic data (Figure 4.86).

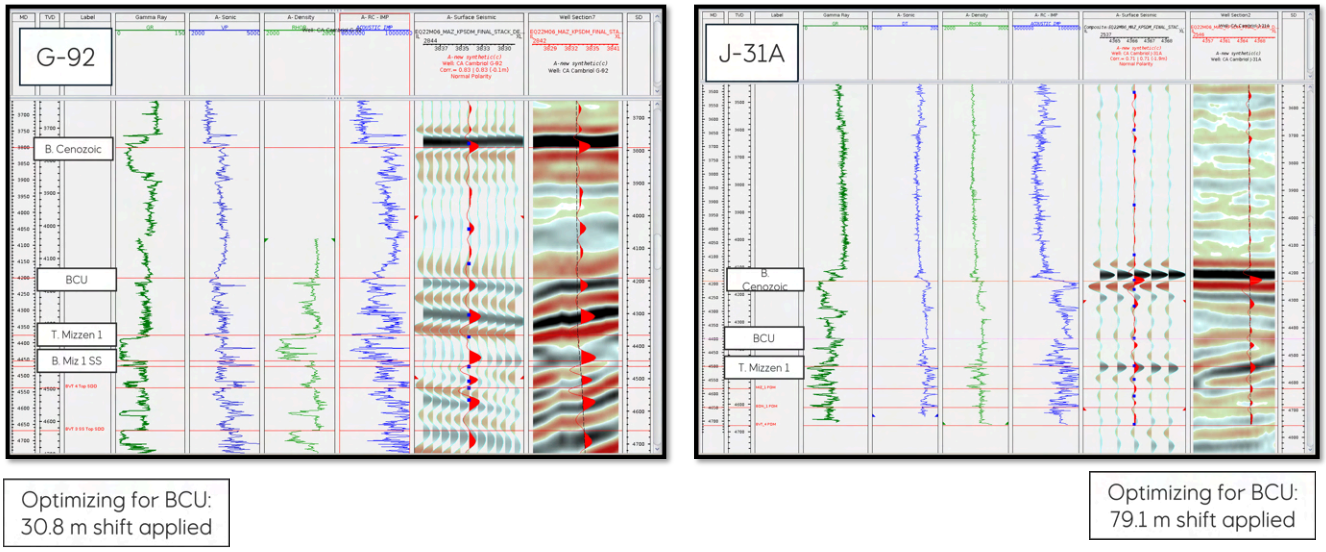


Figure 4.86 Depth Shifts for Cambriol Wells Well-ties for Cambriol G-92 and J-31A wells with the depth shift required to tie the wells indicated (30.8 m and 79.1 m shifts, respectively).

While the processing migration velocities produce a reliable stacked section and improved imaging for structural interpretation, comparison of the VSP data and the PSDM velocity model reveal velocity anomalies that are not captured in the velocity model (Figure 4.87). This confirms the general knowledge that PSDM processing velocities do not necessarily correlate to a good depth conversion velocity. In the Cambriol area, velocity modelling is challenged by seafloor gradient and hardness, and also the coalescing of sediments below the Paleocene Base Figure 4.88. The Cambriol development area is less impacted by these challenges, but they are more impactful towards the northwest and in the vicinity of the offset J-31A well.

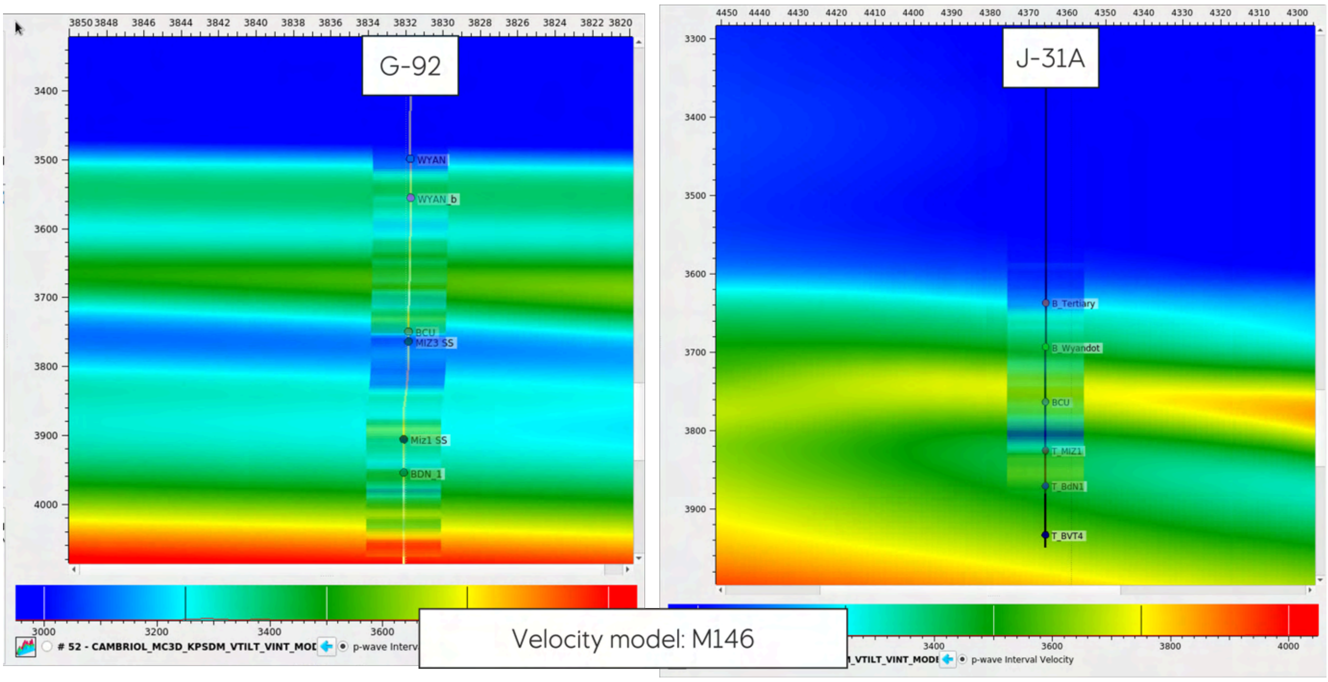


Figure 4.87 Velocity Profile and Seismic Section Comparison of the VSP velocities and the processing velocity model indicates that the PSDM model does not capture the variability evident at the well location (Seismic data courtesy of TGS).

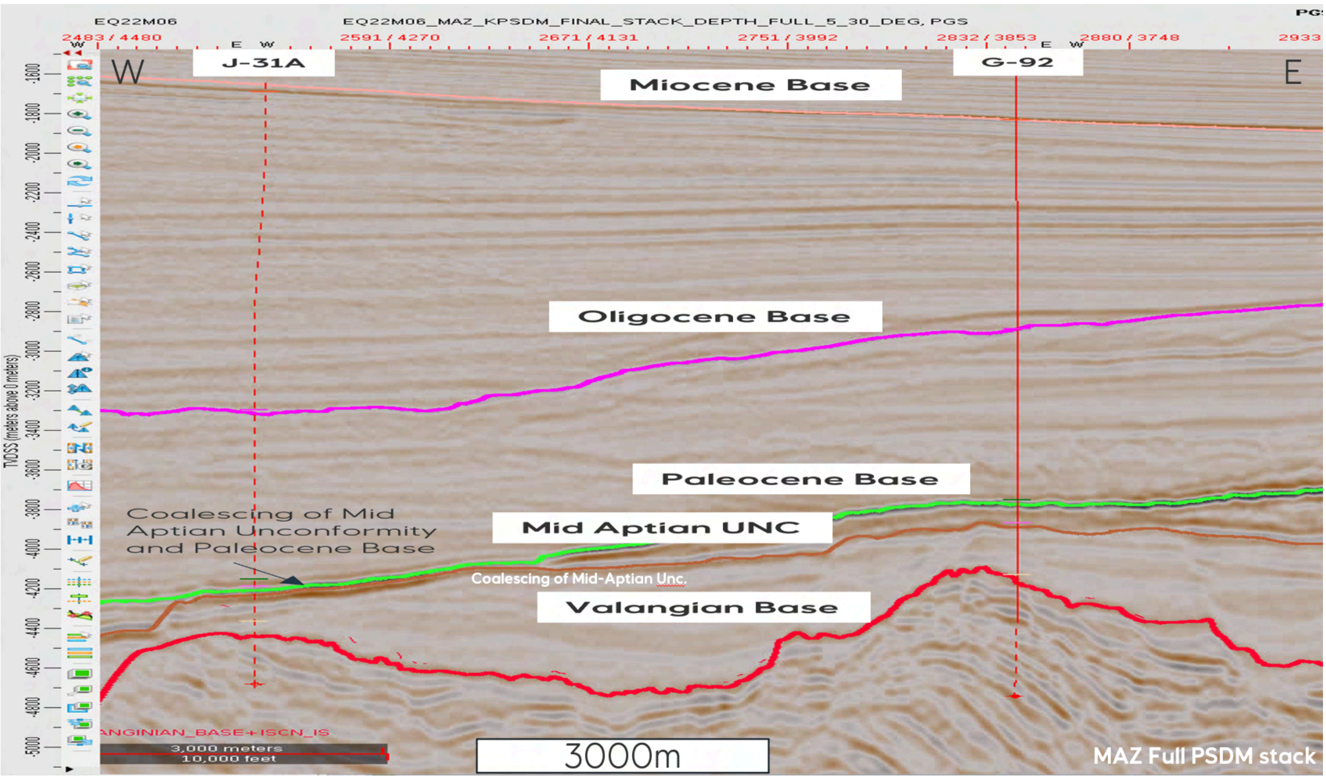


Figure 4.88 Coalescing of Mid Aptian Unconformity Coalescing of sediments below the Paleocene Base makes velocity modeling challenging in the greater Cambriol area. This is more impactful in the J-31A area, which has a greater depth uncertainty (Seismic data courtesy of TGS).

Considering the depth-depth well mis-tie illustrated in Figure 4.86, the PSDM velocities and the resulting PSDM depth section are uncertain with respect to the absolute depth values. For capturing the depth uncertainty, standard Equinor workflows for velocity modeling were undertaken using Decision Space Geoscience Landmark software. The modelling extended from the seafloor to below the base Valanginian unconformity (regional Base Cretaceous proxy). The G-92 well and surfaces used in the modeling are shown in Figure 4.89. Simple constant

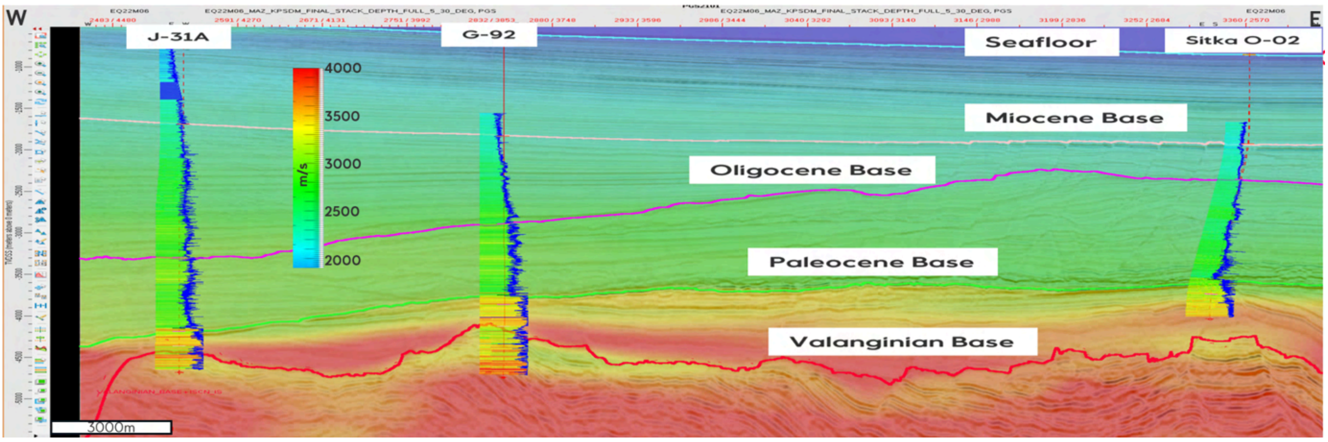


Figure 4.89 Velocity Model The regional surfaces and well data used in the velocity modeling workflow. The seismic overlay is the PSDM velocity model (Seismic data courtesy of TGS).

interval velocity, linear velocity analysis and statistical regression models were calculated to assess the depth conversion uncertainty. Figure 4.90 shows the statistics for the depth uncertainty for the individual velocity models. Figure 4.91 depicts the depth uncertainty and the Cambriol G-92 and Cambriol J-31A well locations.

Column Statistics — **Valanginian Base**

	Statistic	Linear Velocity	Statistical Regression	PSDM	Constant Vint
1	Count	2.0	2.0	2.0	2.0
2	Minimum	8.2	-21.5	-75.9	-16.4
3	Maximum	52.6	50.8	-41.9	123.2
4	Average	30.4	14.6	-58.9	53.4
5	RMS	37.6	39.0	61.3	87.8
6	Median	30.4	14.6	-58.9	53.4
7	Std Dev σ	31.4	51.1	24.0	98.7
8	Variance $σ^2$	983.8	2,611.4	577.5	9,735.5
9	Kurtosis	-2.8	-2.8	-2.8	-2.8

Figure 4.90 Depth Uncertainties at Valanginian Base Statistical summary of the depth uncertainty associated with each velocity model at the Valanginian Base, which is a proxy for the top Mizzen Formation. The average depth uncertainty for each model is highlighted in yellow.

Well Pick Sensitivity Analysis — **Valanginian Base**

Define Area of Interest — 748.4323 km2 from extents

Surface picks: Valanginian Base — Select...

Wells: Camb_Capp_Sitka — Select...

Time surface: VALANGINIAN_BASE+PGS21_s — Select...

Misties (ΔZs) in m between surface picks and model

	Well	UWI	Linear Velocity	Statistical Regression	PSDM	Constant Vint
1	CA Cambriol J-31A	CA Cambriol J-31A	49.3	47.0	-79.0	120.6
2	CA Cambriol G-92	CA Cambriol G-92	8.2	-21.5	-41.9	-16.4

Figure 4.91 Well Pick Sensitivity Analysis Comparison of the misties associated with each velocity model for Cambriol G-92 and Cambriol J-31A at the Valanginian Base, which is proximal to the top of the Mizzen Formation.

4.3.5 Horizon Uncertainty Modelling

The uncertainty of the horizon structure is the combined uncertainty of the picking uncertainty and the depth conversion uncertainty. With the reservoir model being constrained by the Base Cretaceous and the Base Mizzen 1 sandstone, the focus is on capturing the uncertainty in the interval of these two horizons. Especially on the northwestern side of the structure (B block) there is a larger picking (interpretation) uncertainty due to data quality, structuration and distance to well control.

As discussed in Section 4.3.4 Seismic Velocity Analysis and Depth Conversion, depth uncertainty modelling analysis was performed in the Cambriol area, and the depth uncertainty at the Valangianian Base (which is proximal to the Base Cretaceous and top Mizzen member) is summarized in Figure 4.90 and Figure 4.91.

Given that Cambriol has minimal well control (one well in the development area and one offset well), a "rule of thumb" uncertainty of 1.5 to 2.0% of the depth is necessary to account for the total uncertainty range. The depth uncertainties calculated in the velocity analysis fell within this "rule of thumb" uncertainty range.

Based on well control and data quality, the Cambriol area was split into 3 regions of uncertainty (Figure 4.92).

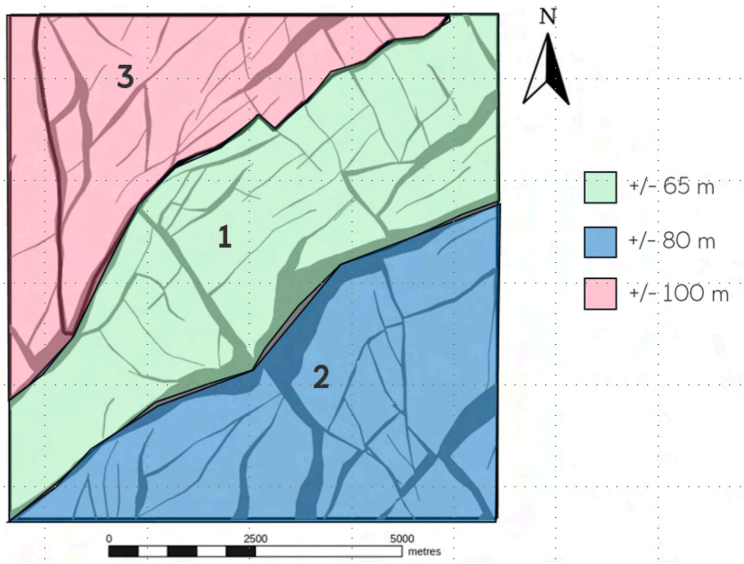


Figure 4.92 Cambriol Regions of Horizon Uncertainty.
Three regions of horizon uncertainty

5 Reservoir Models

5.1 Summary

The static reservoir models were built in the Roxar RMS software package (version 14.1), utilizing the data and interpretations discussed in Section 2 Geology, Section 3 Petrophysics, and Section 4 Geophysics. For each model, a structural-stratigraphic framework was built based on seismic interpretations (horizons and faults) and thickness maps (based on well picks, seismic interpretation, and conceptual understanding). The 3D grid model derived from the structural-stratigraphic model was then populated with facies and petrophysical properties following the geological conceptual model and observed data trends. The 3D reservoir models were built to calculate in-place volumes and simulate production to assess recoverable volumes (Section 9 Reserves and Resource Estimates; Section 7 Reservoir Exploitation). Separate reservoir models were built for the Bay du Nord Field and Cambriol Field. A basic overview map illustrated at the Base Cretaceous level for the Bay du Nord Field is shown in Figure 5.1 to visualize the reservoir model and the major area subdivisions. Figure 5.2 shows a more detailed overview of the regions of the Bay du Nord Field. Figure 5.3 is a basic overview map detailing the main regions of the Cambriol Field, also at the Base Cretaceous level. A series of maps, created in Roxar RMS, are included in the individual model sections to display model trends and results.

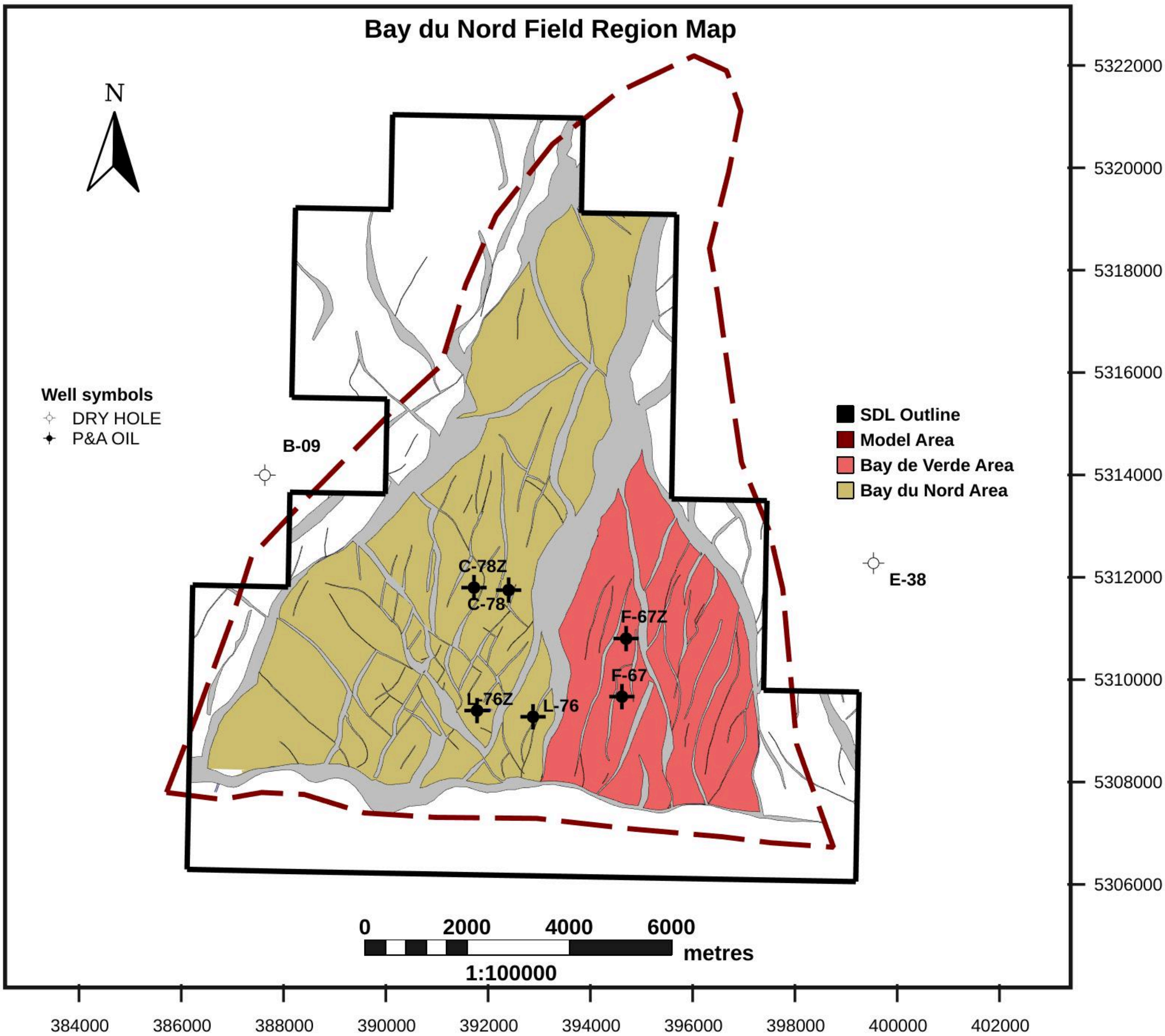


Figure 5.1 Bay du Nord Field Overview

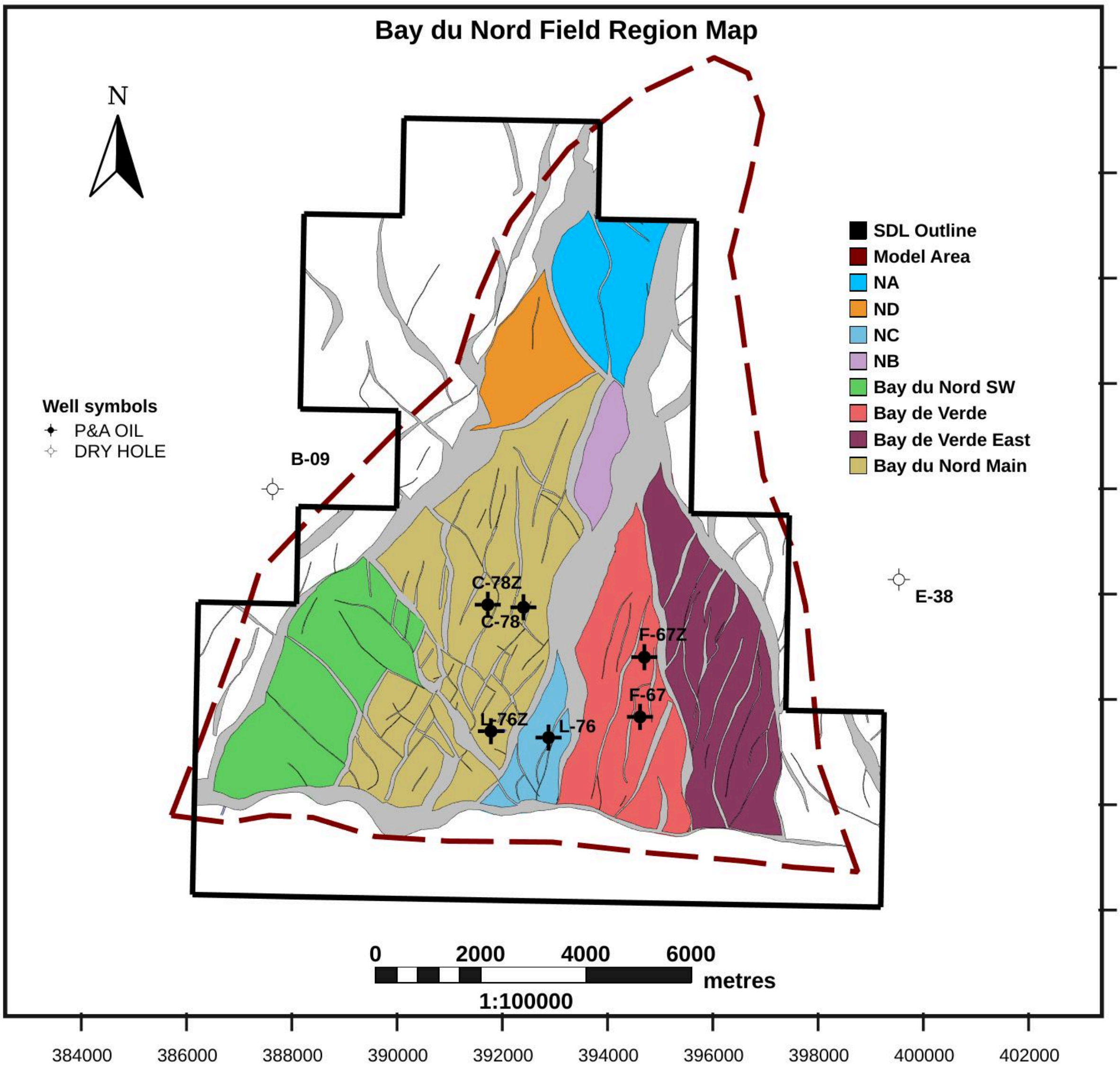


Figure 5.2 Bay du Nord Field Region Overview

For the evaluation of field development projects, Equinor ASA applies an in-house developed integrated reservoir modelling approach. The process, named Fast Model Update (FMU), allows for the creation of multiple models through a common static and dynamic workflow. The workflow is linked to an uncertainty design matrix that allows for uncertainties in both the static and dynamic models to be populated automatically in a range of models at the same time. The Palisade @RISK software was used to produce the uncertainty design matrix. The workflow can then be used to vary well placement and drainage strategy options to evaluate their impacts across the uncertainty range. This approach allows for a development strategy that is optimised for more than a single expected case, or a high, a base and a low case, ensuring a higher confidence in the selected development concept, drainage strategy, and resource estimate. It also enables evaluation of elements of the development strategy under specific conditions, such as the impact of poorer water-flood performance on facility capacity, by varying parameters such as relative permeability, net reservoir quality, and fluid properties across a combination of scenarios. In a fluvial dominated environment, like the Bay du Nord Field, well placement can also be optimized for the uncertainty in incised valley presence, reducing the risk of sidetracks. The data acquisition strategy can also be planned based on situational outcomes such as the value of determining an Oil-Water Contact (OWC) for planning future wells and estimating reserves.

The approach provides a more robust method for evaluating future Improved Oil Recovery (IOR) opportunities, which are opportunities to improve recovery beyond the assumptions made in the base development plan. IOR opportunities for the Project will be discussed in Section 7.7 Improved Oil Recovery. The FMU approach may be used to:

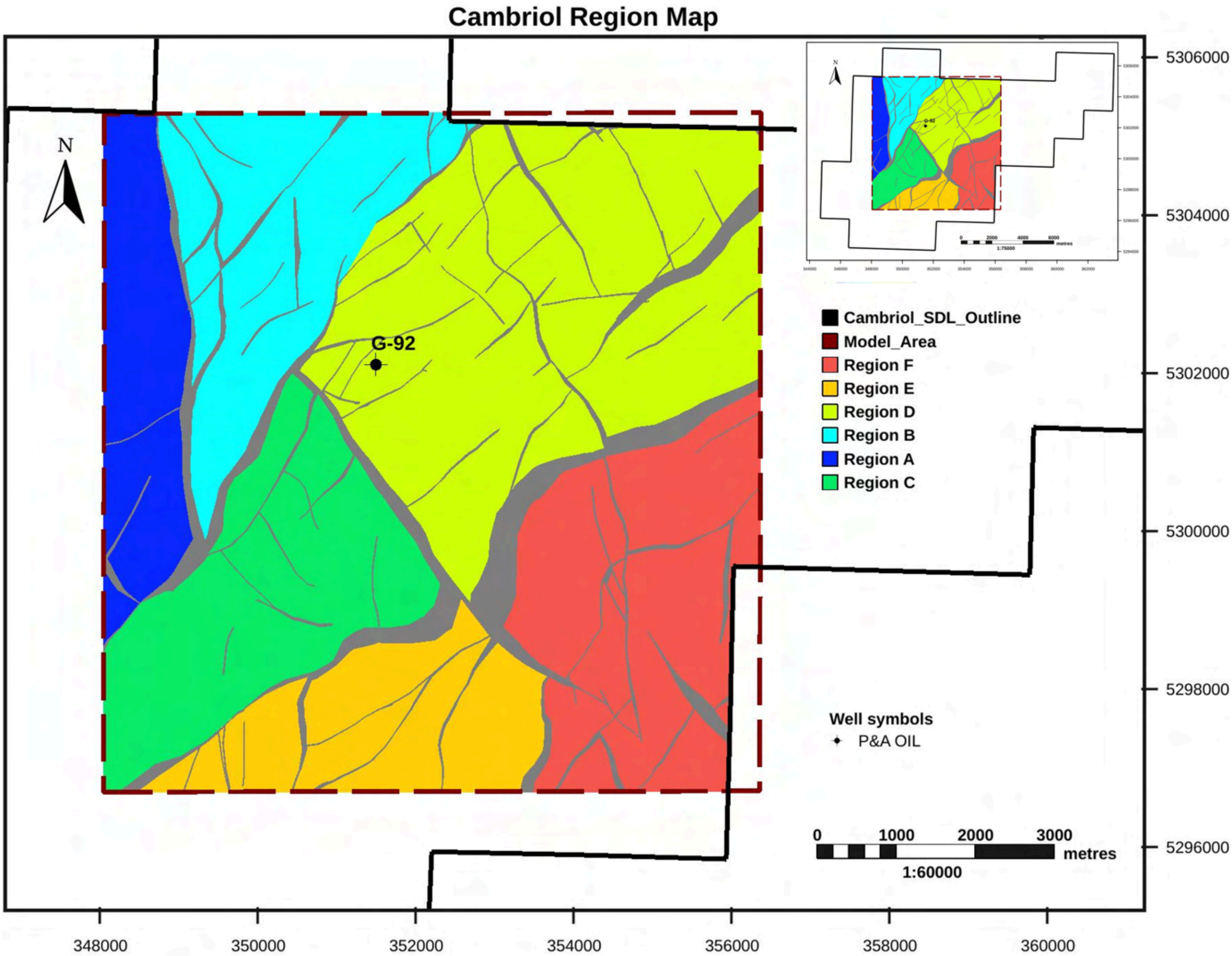


Figure 5.3 Cambriol Field Overview

- Define a realistic recovery factor range to apply to regions not included in the base development;
- Assign a probability for development to the undeveloped regions;
- Evaluate bypassed oil and possible infill drilling opportunities within the developed area; and
- Assign value to a data acquisition strategy that allows for the maturation of the resource description with a focus on identifying future development opportunities.

The number of models, referred to as realizations, in an evaluation can range from a single reference case to several cases covering the recovery range from P90 to P10, to hundreds of stochastic cases. For the original hydrocarbon-in-place estimates in the Development Plan (Section 9.2 Original Hydrocarbon-in-Place Estimates), 500 realizations are considered for each of the fields. For simulation modelling and the recoverable resource estimates (Section 9.3 Recoverable Resource Estimates), 51 cases are then considered. This covers the uncertainty range for each field and provides a robust set of inputs for the integrated production forecasting and dynamic uncertainty assessment of the full project. However, the maps shown in the following sections are derived from the reference case model for each field.

5.2 Bay du Nord Field

The structurally complex Bay du Nord Field comprises several fault segments and can be subdivided into the Bay du Nord and Bay de Verde areas (Figure 5.1). The modelled reservoir interval consists of two zones, the Bay du Nord and Mizzen members of the Bodhran formation. The Bonaventure member also encountered pay in a couple of the exploratory wells, but it is not interpreted to be extensive and was not included in the reservoir model. In Figure 5.4, a North-South oriented section shows the structural-stratigraphic framework for the Bay du Nord feature, illustrating how the reservoir zones are vertically bound by the seismic derived Mizzen member top (Base Cretaceous) and Bay du Nord member base. An intra-reservoir surface, the Bay du Nord member top, was defined utilizing an isochore map based on thickness observations from well data (hard conditioning), seismic interpretation (soft conditioning) and structural conceptual understanding (soft conditioning). Figure 5.5 illustrates the structural-stratigraphic framework into the Bay de Verde area in a West-East oriented section.

The subsequent 3D grid model uses base conform layering for both zones, the Bay du Nord (120 layers) and Mizzen (180 layers) members, and a grid increment of 100 x 100 x 1 m (on average). The latter results in a reservoir model of about 1.3 million active cells. In the modelling workflow no upscaling was applied for the simulation grid.

Of the interpreted facies associations at Bay du Nord (Figure 2.20), seven modelling facies were defined based on their petrophysical and depositional environment similarities. These model facies were populated in the grid following facies distribution maps that were created for each sequence stratigraphic interval (Figure 2.30, Figure 2.31). The petrophysical properties (e.g. porosity, permeability) are distributed throughout the grid following the modelled facies property. The property distributions used in the simulation were based on the data for a facies within each zone. Water saturation was defined through a log-based saturation vs. height model. The facies and petrophysical properties were conditioned to well data in the reservoir model.

Six sets of maps, encompassing three structural surfaces (Base Cretaceous, Top Bay du Nord member and Base Bay du Nord member) or two zones (Mizzen and Bay du Nord members), have been prepared for the Bay du Nord Field to summarize the reservoir modelling results.

- Structural-stratigraphic framework (Figure 5.4, Figure 5.5);
- Structure maps (Figure 5.6, Figure 5.7, Figure 5.8);
- Gross isopach maps (Figure 5.9, Figure 5.10);
- Net pay isopach maps (Figure 5.11, Figure 5.12);
- Isoporosity maps (Figure 5.13, Figure 5.14); and
- Hydrocarbon pore volume maps (Figure 5.15, Figure 5.16).

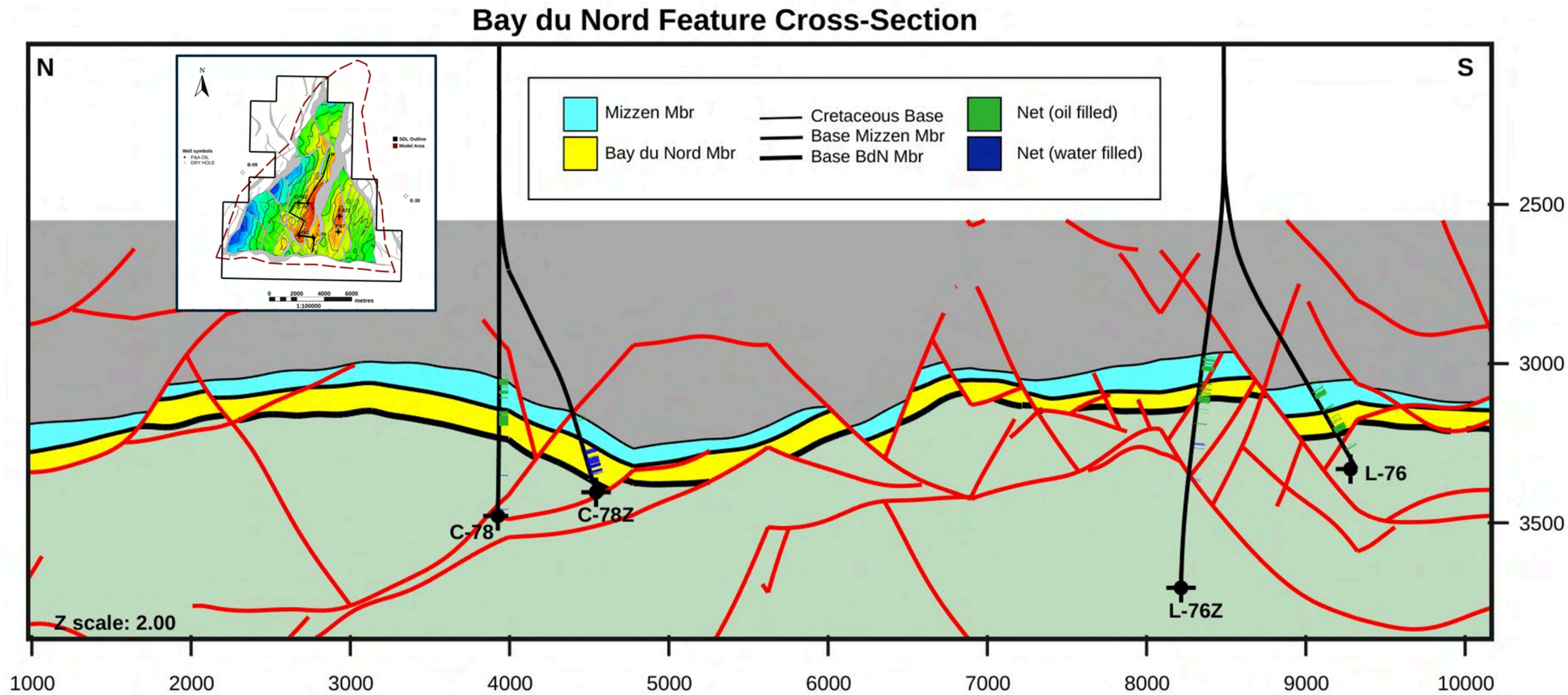


Figure 5.4 Structural-Stratigraphic Framework Cross-section illustrating the reservoir structure and zonation of the Bay du Nord feature.

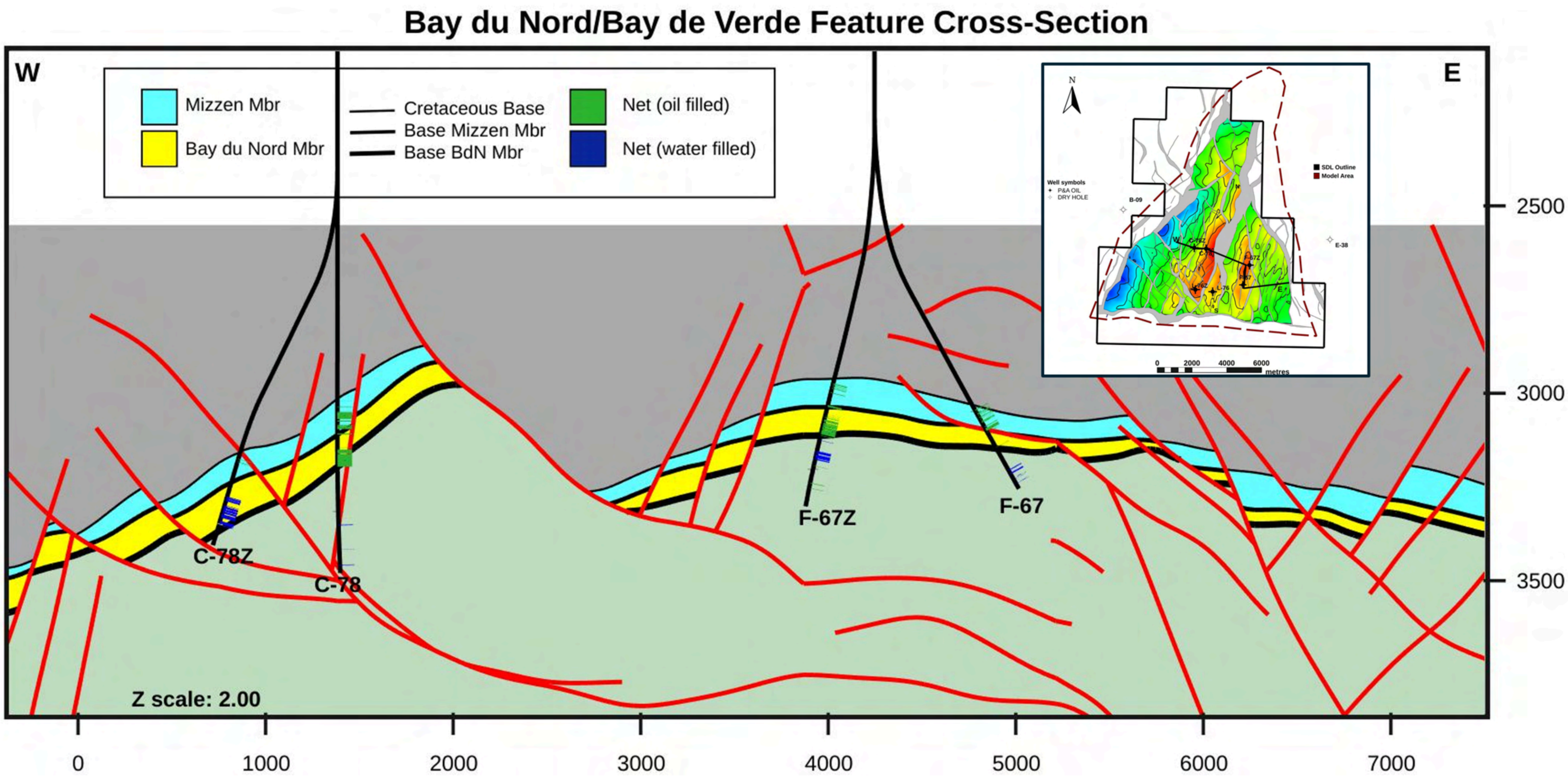


Figure 5.5 Structural-Stratigraphic Framework - Bay de Verde Cross-section illustrating the reservoir structure and zonation of the Bay du Nord and Bay de Verde feature.

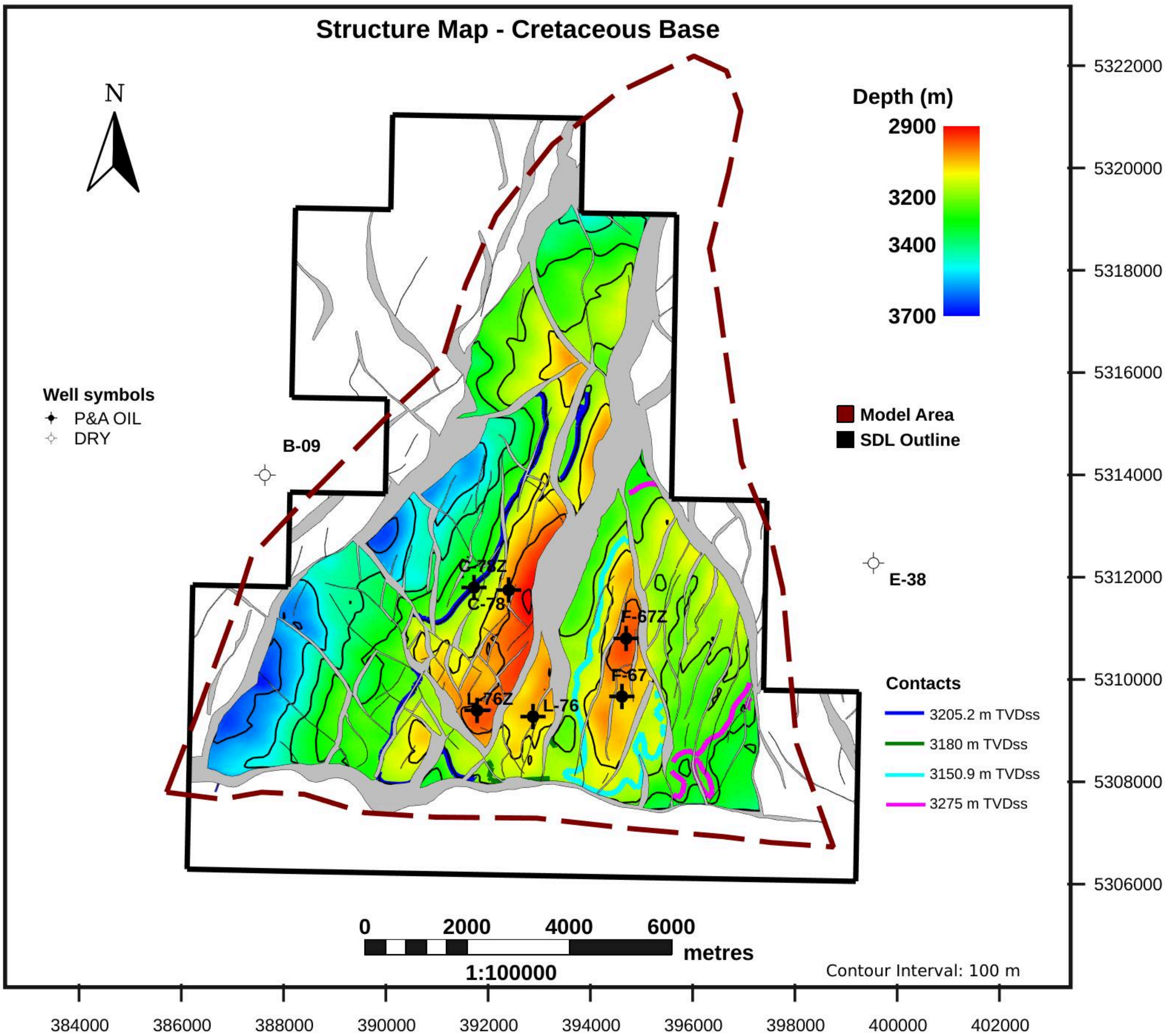


Figure 5.6 Structure Map, Cretaceous Base Contacts displayed on the structure maps represent the expected contacts. However, a range of contacts and different scenarios were used in the uncertainty analysis to generate the reserve and resource estimates.

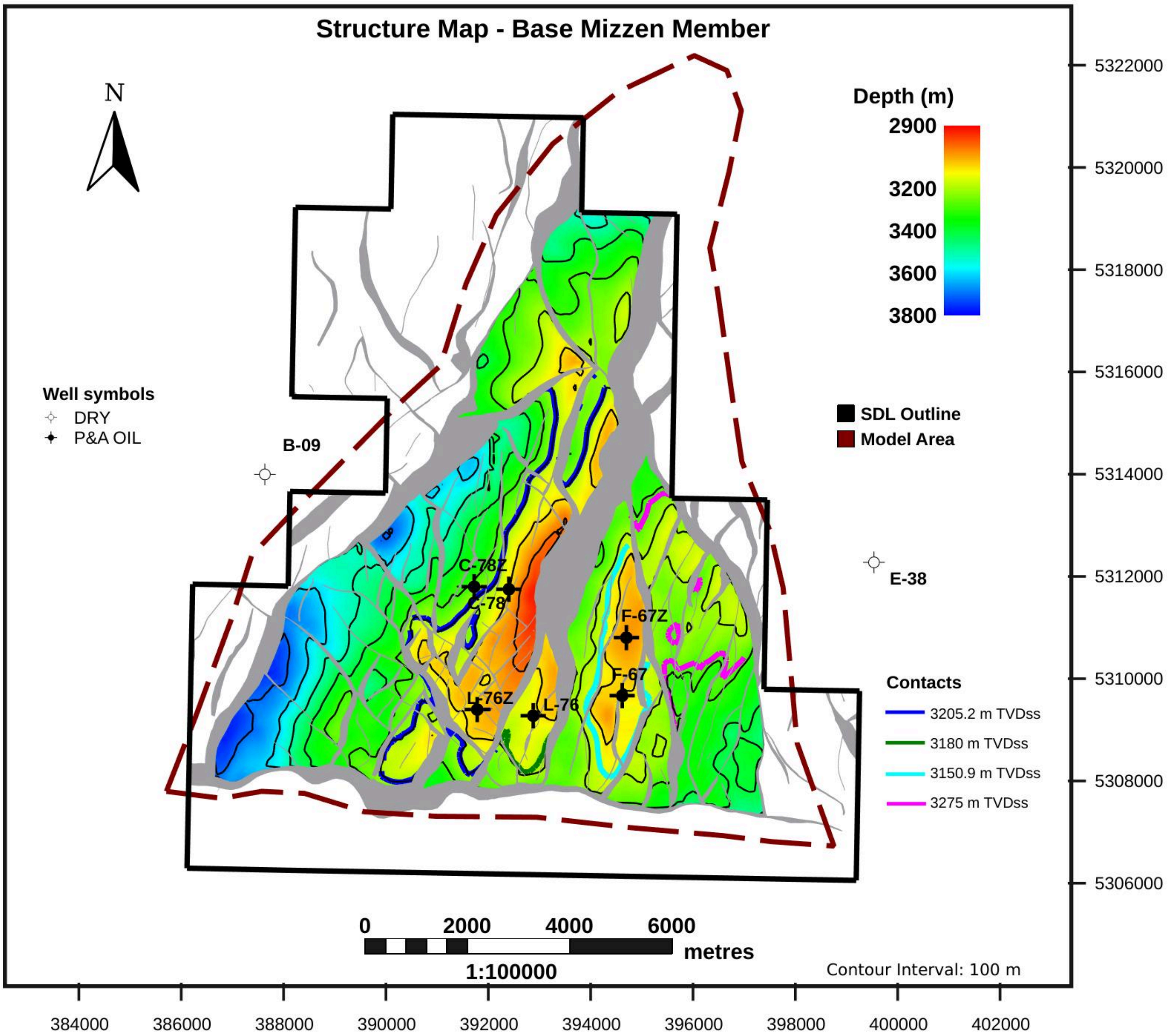


Figure 5.7 Structure Map, Base Mizzen member Contacts displayed on the structure maps represent the expected contacts. However, a range of contacts and different scenarios were used in the uncertainty analysis to generate the reserve and resource estimates.

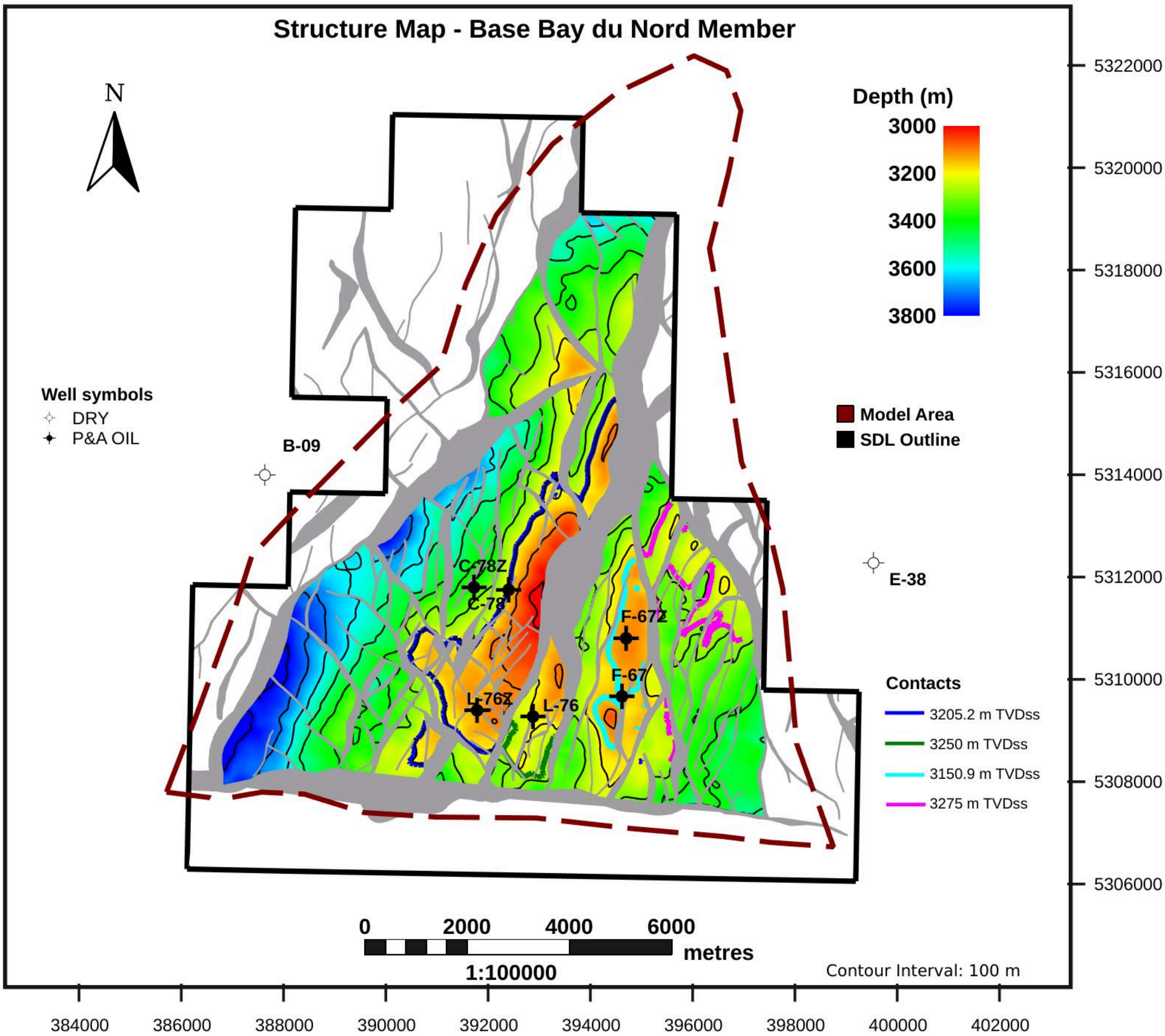


Figure 5.8 Structure Map, Base Bay du Nord member Contacts displayed on structure maps represent the expected contacts. However, a range of contacts and different scenarios were used in the uncertainty analysis to generate the reserve and resource estimates.

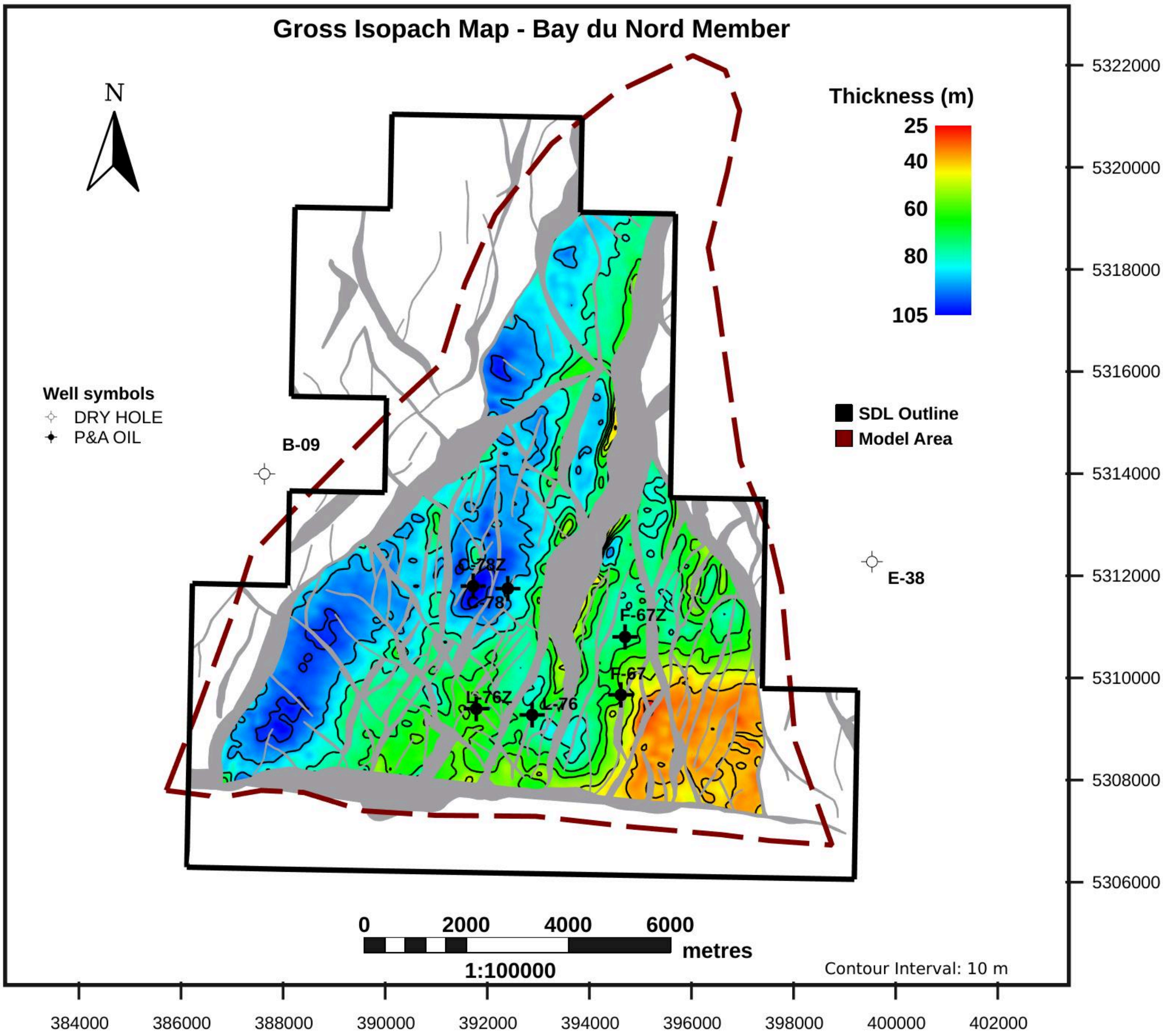


Figure 5.9 Gross Isopach Map - Bay du Nord member

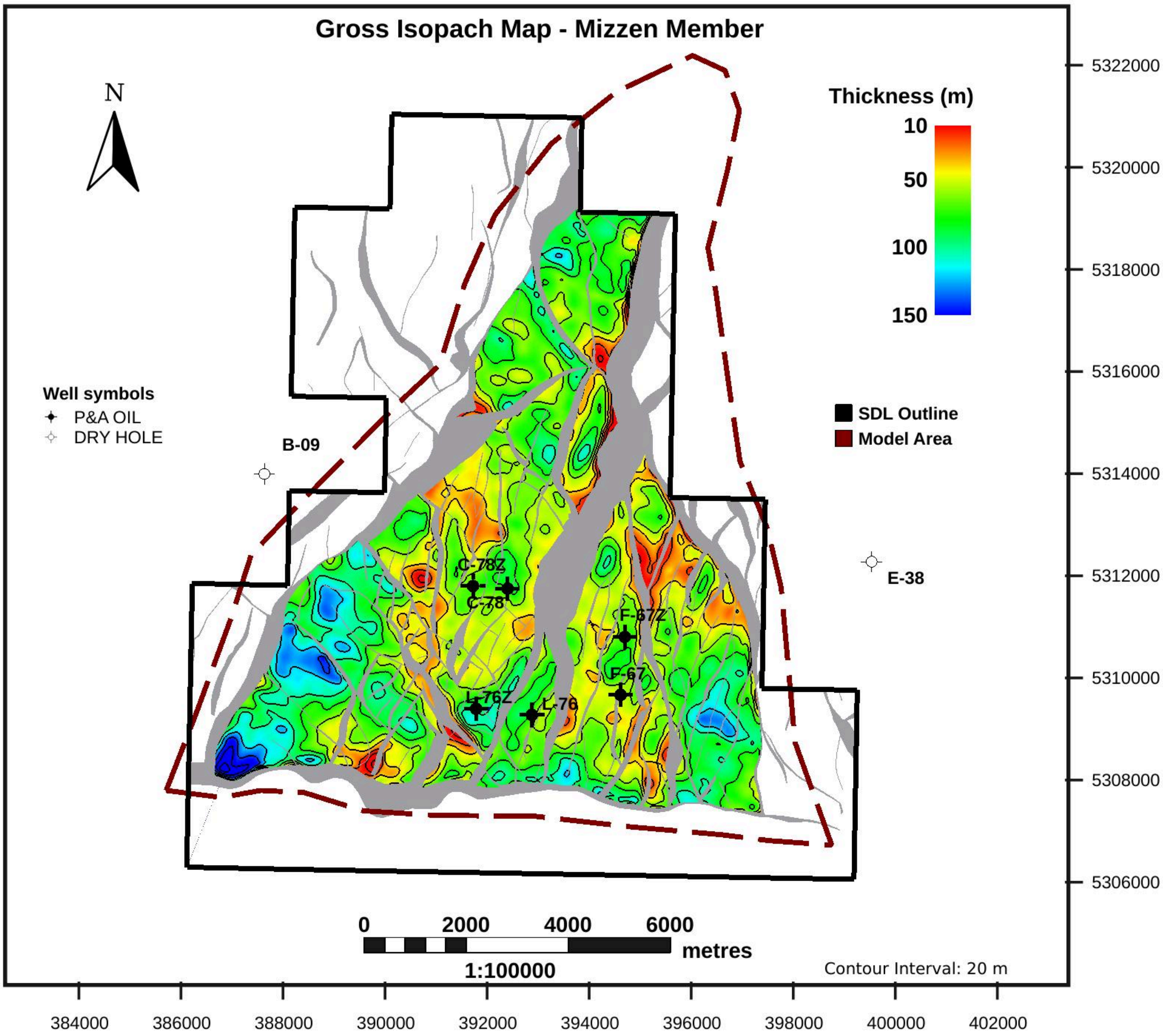


Figure 5.10 Gross Isopach Map - Mizzen member

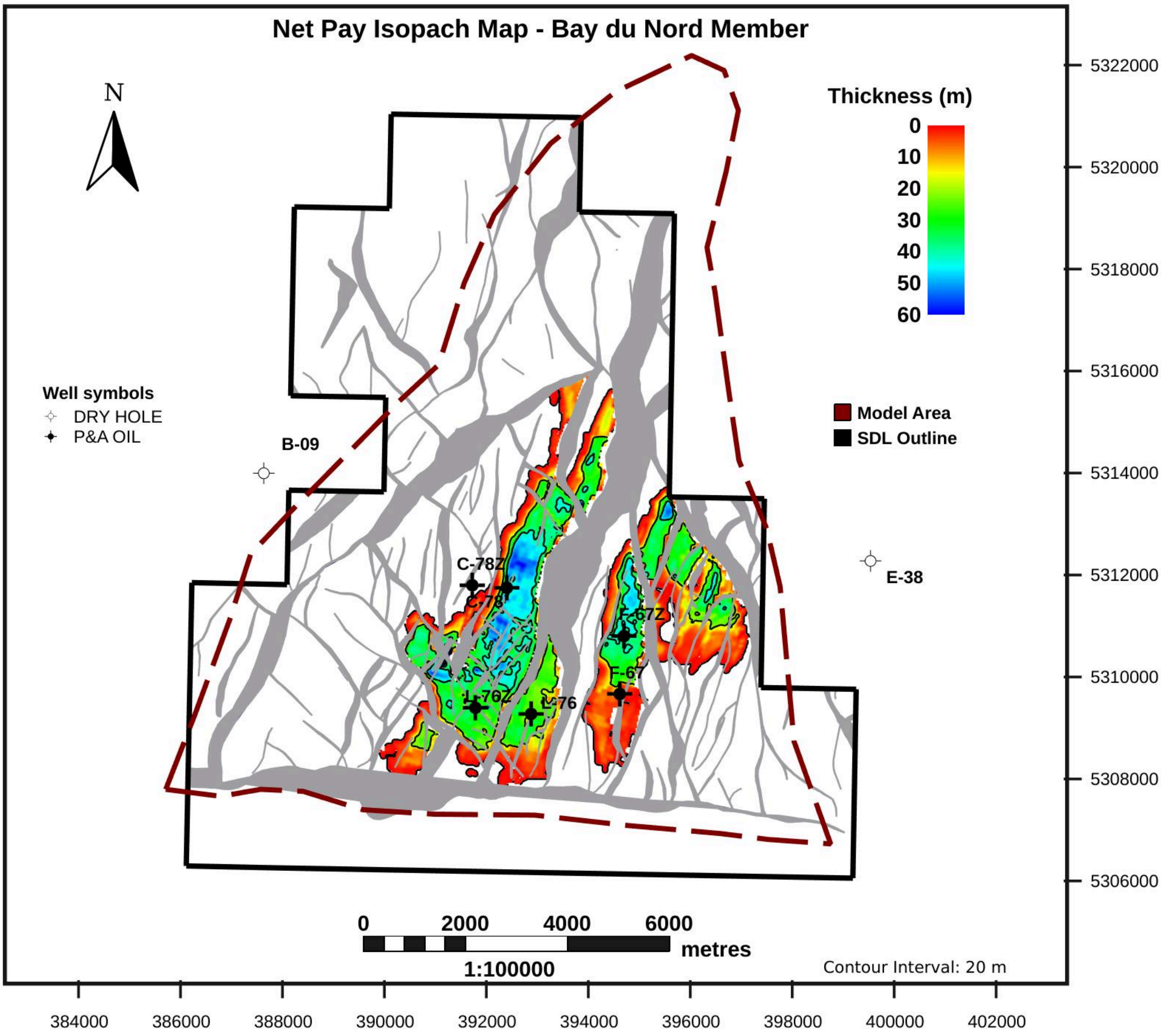


Figure 5.11 Net Pay Isopach Map - Bay du Nord member

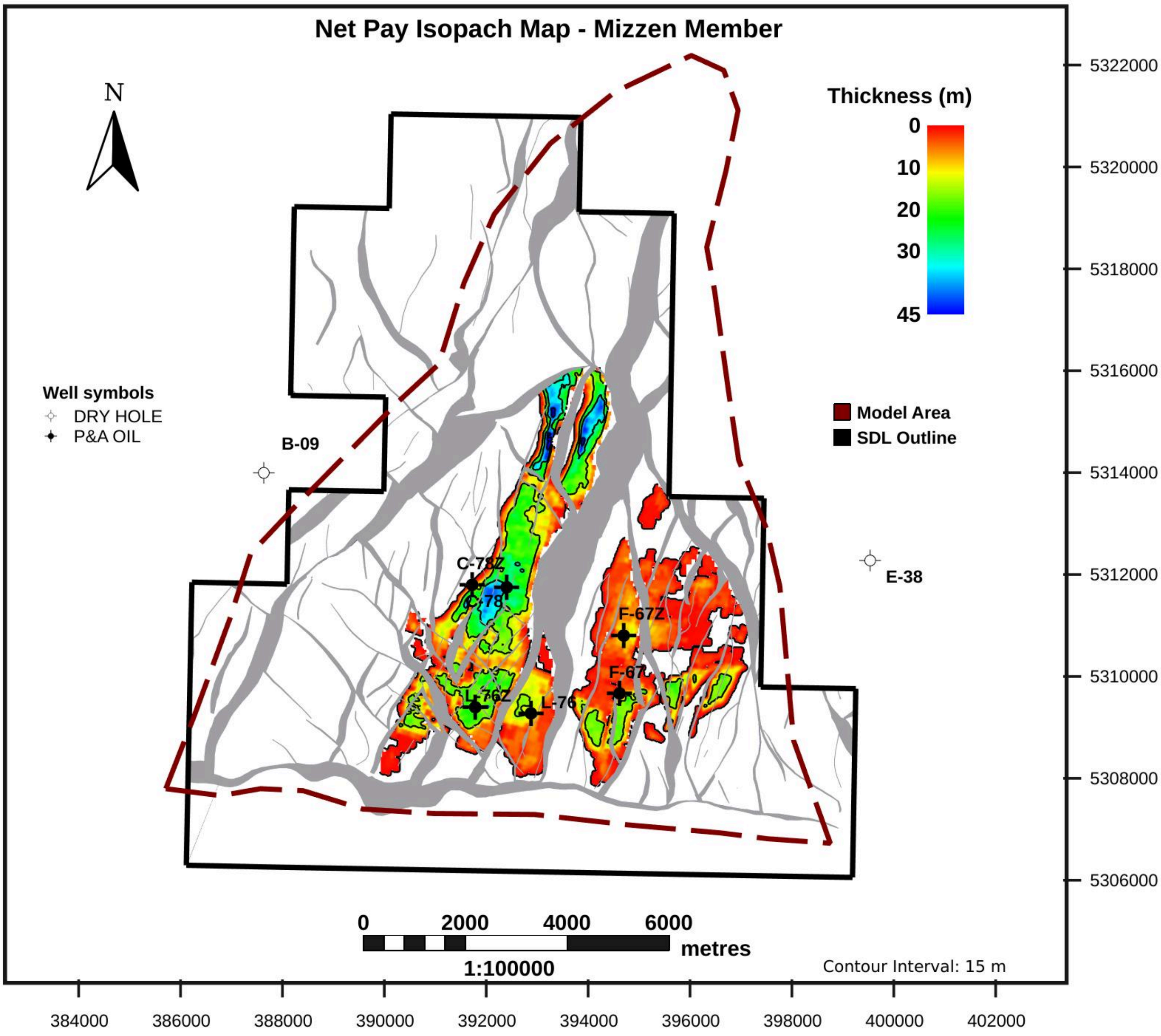


Figure 5.12 Net Pay Isopach Map - Mizzen member

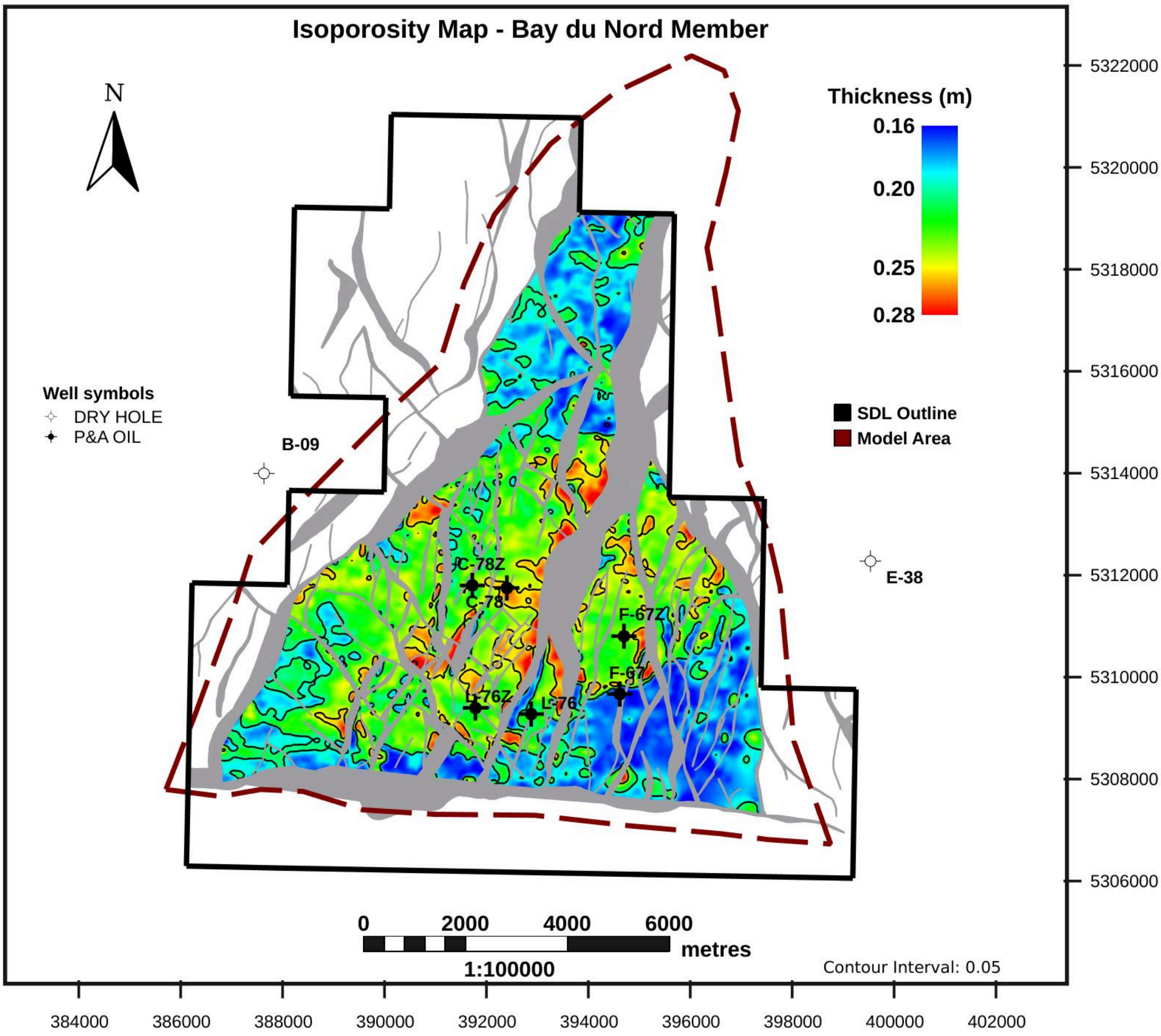


Figure 5.13 Isoporosity Map - Bay du Nord member To best illustrate porosity trends, the isoporosity maps represent the average porosity of the net facies over each zone.

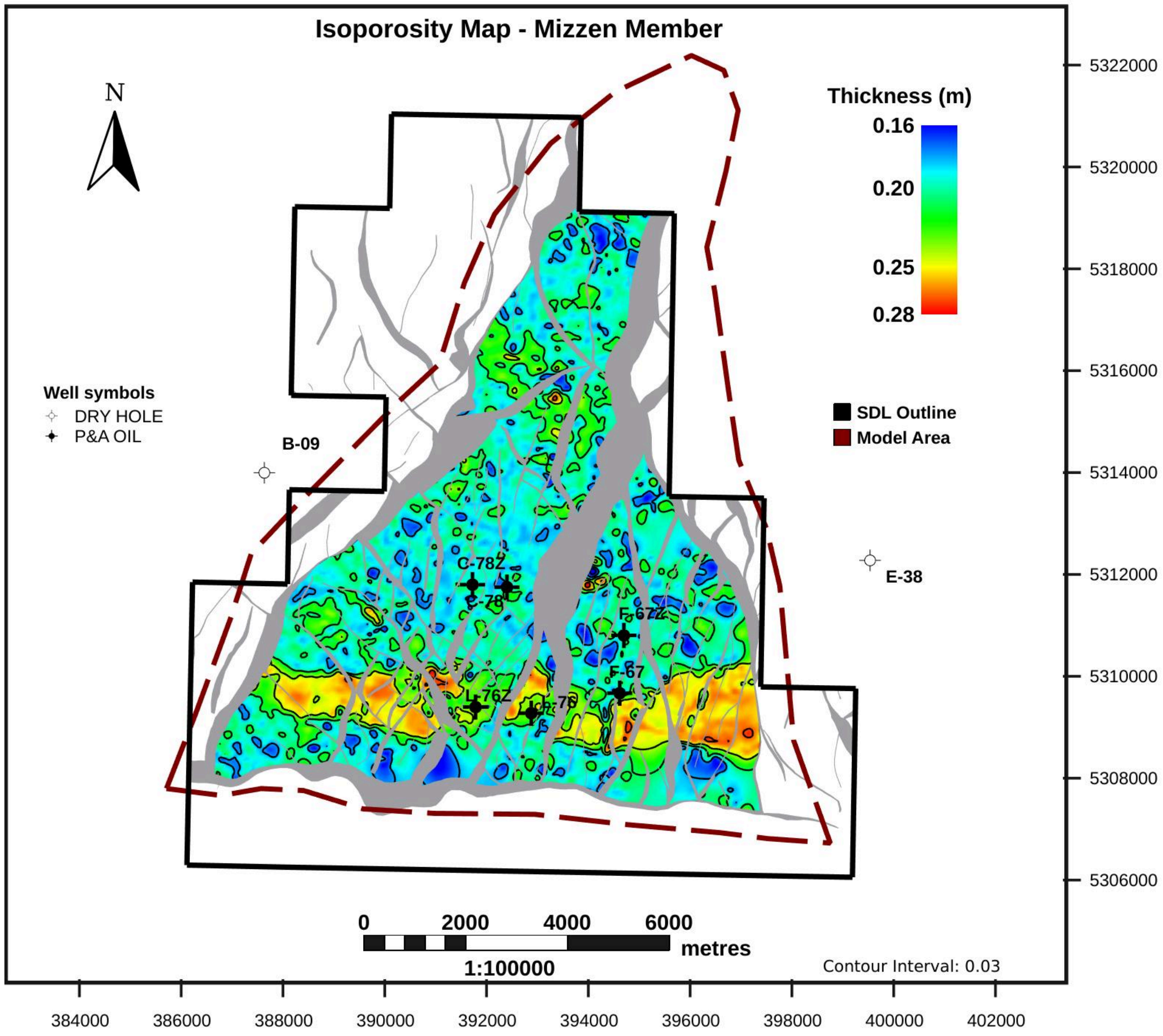


Figure 5.14 Isoporosity Map - Mizzen member To best illustrate porosity trends, the isoporosity maps represent the average porosity of the net facies over each zone.

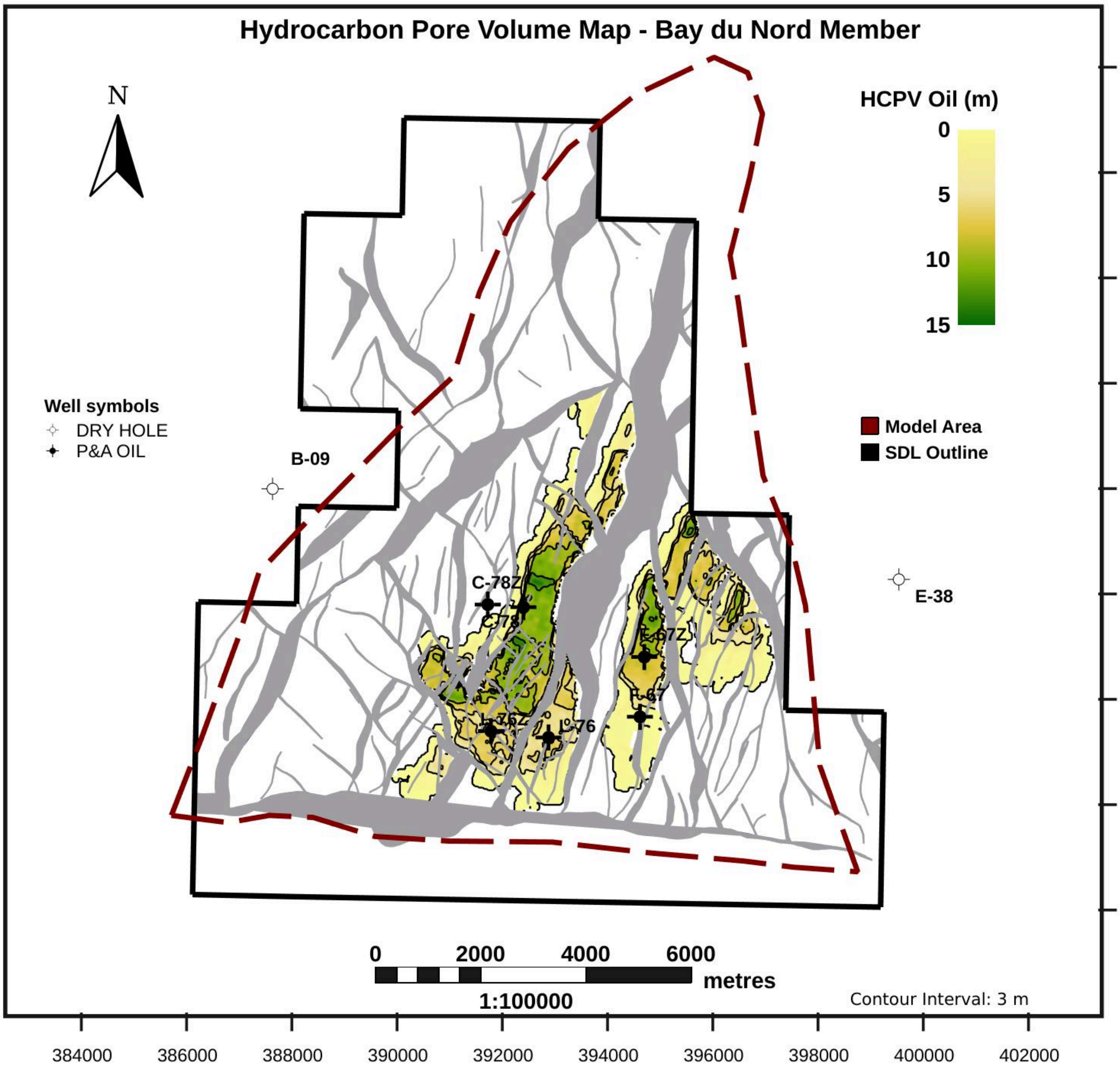


Figure 5.15 Hydrocarbon Pore Volume Map - Bay du Nord member

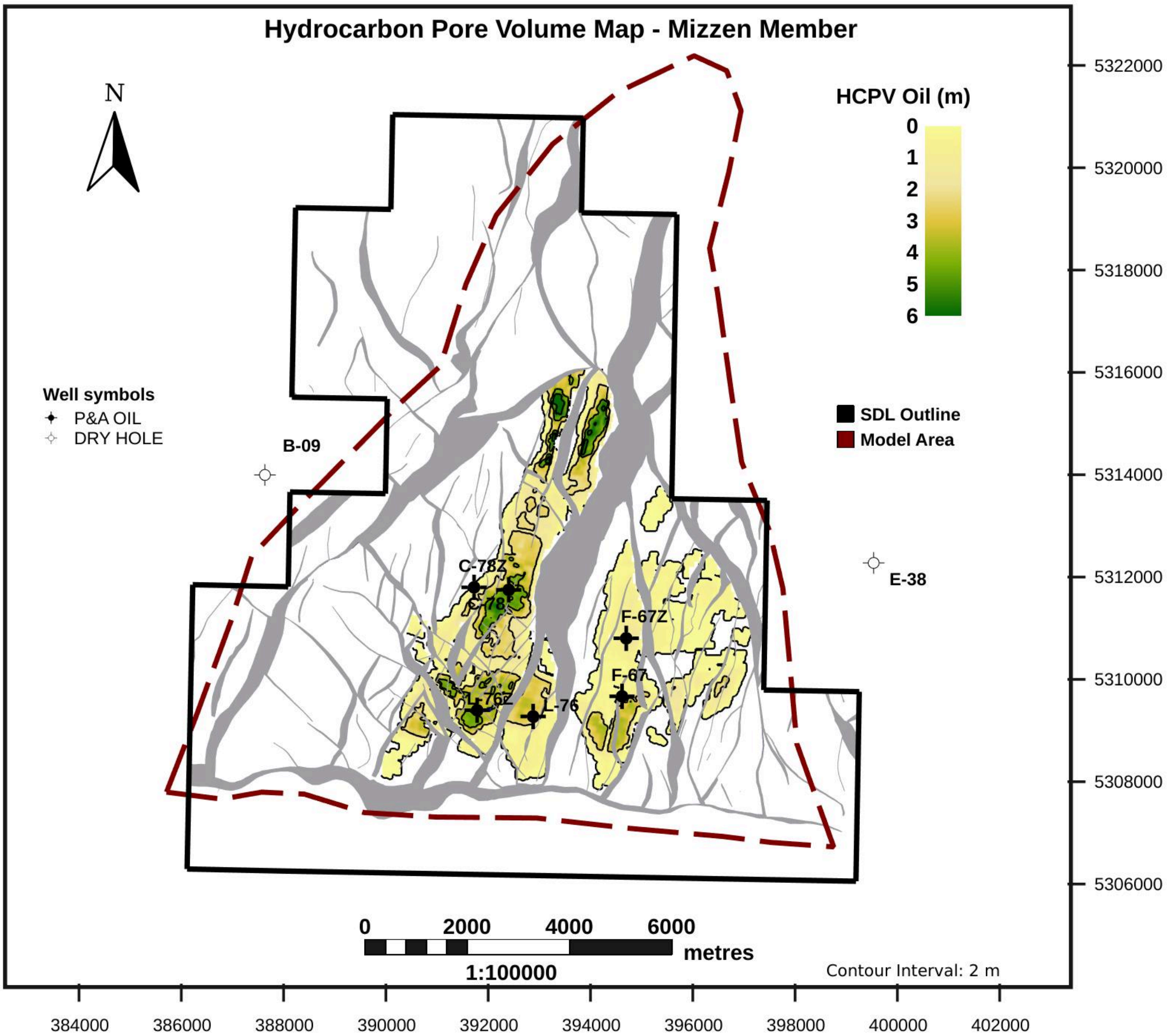


Figure 5.16 Hydrocarbon Pore Volume Map - Mizzen member

In the static reservoir model for the Bay du Nord Field, the main parameter uncertainties included in the evaluations are summarized in Table 5.1 below.

Table 5.1 Bay du Nord Static Uncertainty Parameters

Uncertainty Parameter		Description
Structural (depth) model	Scenarios	Three grid scenarios are available in the uncertainty design matrix, representing a base case, low case, and high case structural interpretation. Note, the low and high cases were generated using the base case structural model as input in the Roxar RMS Horizon Uncertainty Modelling (HUM) tool. Details are provided in Section 4.2.4 Seismic Velocity Analysis and Depth Conversion; and Section 19.5.1.4 Uncertainty Analysis.
Oil water contacts	Distribution	A contact range was determined for each contact region. For undrilled regions, contacts were based on structural analysis and hydrocarbon column heights.
	Scenarios	Alternative contact ranges were proposed for several regions following uncertainties observed in the OWC analysis.
	Chance of success	To account for the uncertainty of hydrocarbon presence in undrilled segments a chance of success was applied to several undrilled regions (e.g., Bay de Verde East). The selected chance of success depends on several factors (e.g. seismic reservoir prediction and structural analysis) to understand juxtaposition with neighbouring oil-bearing drilled regions.
Facies modelling	Depositional scenarios	Based on the available geological data in the Flemish Pass Basin an incised valley to deltaic depositional model is the basis for the reservoir model. Two different variations on the interpretation of the incised valley in the Bay du Nord member were selected and included in the uncertainty design matrix.
	Facies distribution	The distribution of facies throughout the model was controlled by several modelling trend scenarios (e.g. sequence stratigraphic intervals, incised valley shape, deltaic likelihood maps) and applied in the reservoir model utilizing probability cubes. The trends and scenarios were based on conceptual understanding and related uncertainty.
	Facies volume fraction	A volume fraction range was defined for each facies based on well observations and conceptual understanding.
Petrophysical	Multiplier	A multiplier range was determined from a petrophysical uncertainty analysis.
Kv/Kh	Multiplier	Based on core plug measurements and analogue data a Kv/Kh multiplier range was determined for each of the modelled facies.
Fault seal	Low/Base/High	A fault seal study based on core and analogue data provided a low (tight), base, and high (open) case.

5.3 Cambriol Field

The reservoir interval of the structurally complex Cambriol Field is the Mizzen member of the Bodhran formation and is divided into six model regions (Figure 5.3). The reservoir zone primarily consists of the Mizzen 1 unit, with additional reservoir potential associated with the overlying Mizzen 3 unit. The structural-stratigraphic framework is summarized in Figure 5.17. The top of the reservoir zone is the seismic derived Mizzen member top (Base Cretaceous). The base of the reservoir is the Mizzen member base, created from the addition of a constant isochore of 16.5 m to the seismic-derived Mizzen 1 sandstone base.

The subsequent 3D grid model uses base conform layering of 350 layers for the Mizzen member, and a grid increment of 100 x 100 x 1 m (on average). The latter results in a reservoir model of about 1.63 million active cells. In the modelling workflow no upscaling was applied for the simulation grid.

From the interpreted facies associations (Figure 2.34), seven modeling facies were defined based on their petrophysical and depositional environment similarities. These model facies were conditioned to the Cambriol G-92 well and populated in the grid for the Mizzen 1 and Mizzen 3 units following facies distribution maps (Figure 2.38). The petrophysical properties (e.g., porosity, permeability) were conditioned to the well data and distributed throughout the grid following the modelled facies property. The property distributions used in the simulation were based on the data for a facies within each zone. Water saturation was defined through a log-based saturation vs. height model.

Five sets of maps encompassing two structural surfaces (Base Cretaceous and Base Mizzen member) have been prepared for the Cambriol Field to summarize the reservoir modelling results.

- Structure maps (Figure 5.18, Figure 5.19);
- Gross isopach maps (Figure 5.20);
- Net pay isopach maps (Figure 5.21);
- Isoporosity maps (Figure 5.22); and
- Hydrocarbon pore volume maps (Figure 5.23).

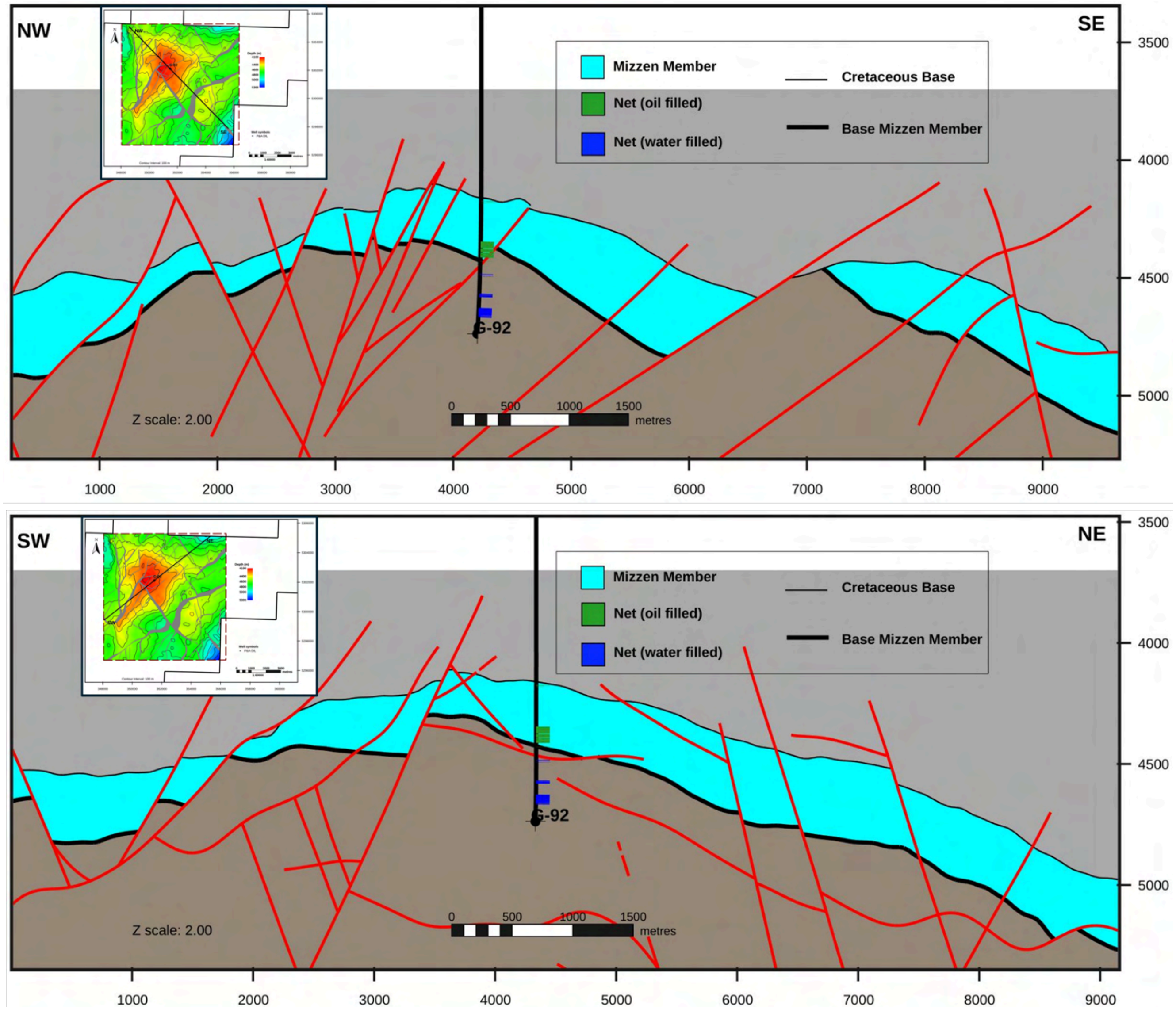


Figure 5.17 Cambriol Structural-Stratigraphic Framework Two cross-sections illustrating the reservoir structure and zonation.

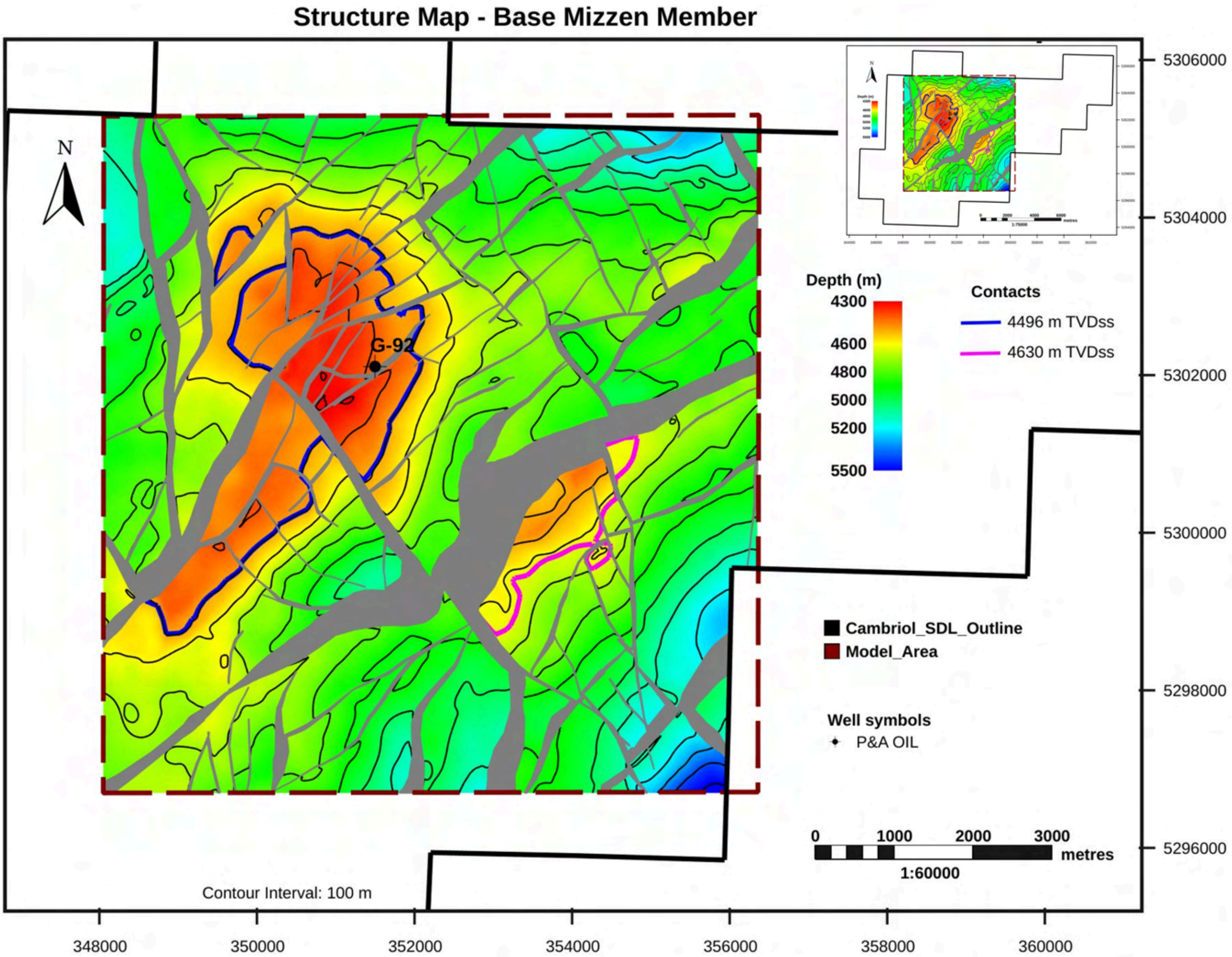


Figure 5.18 Structure Map, Base Mizzen member Contacts displayed on the structure maps represent the expected contacts. However, a range of contacts were used in the uncertainty analysis to generate the reserve and resource estimates.

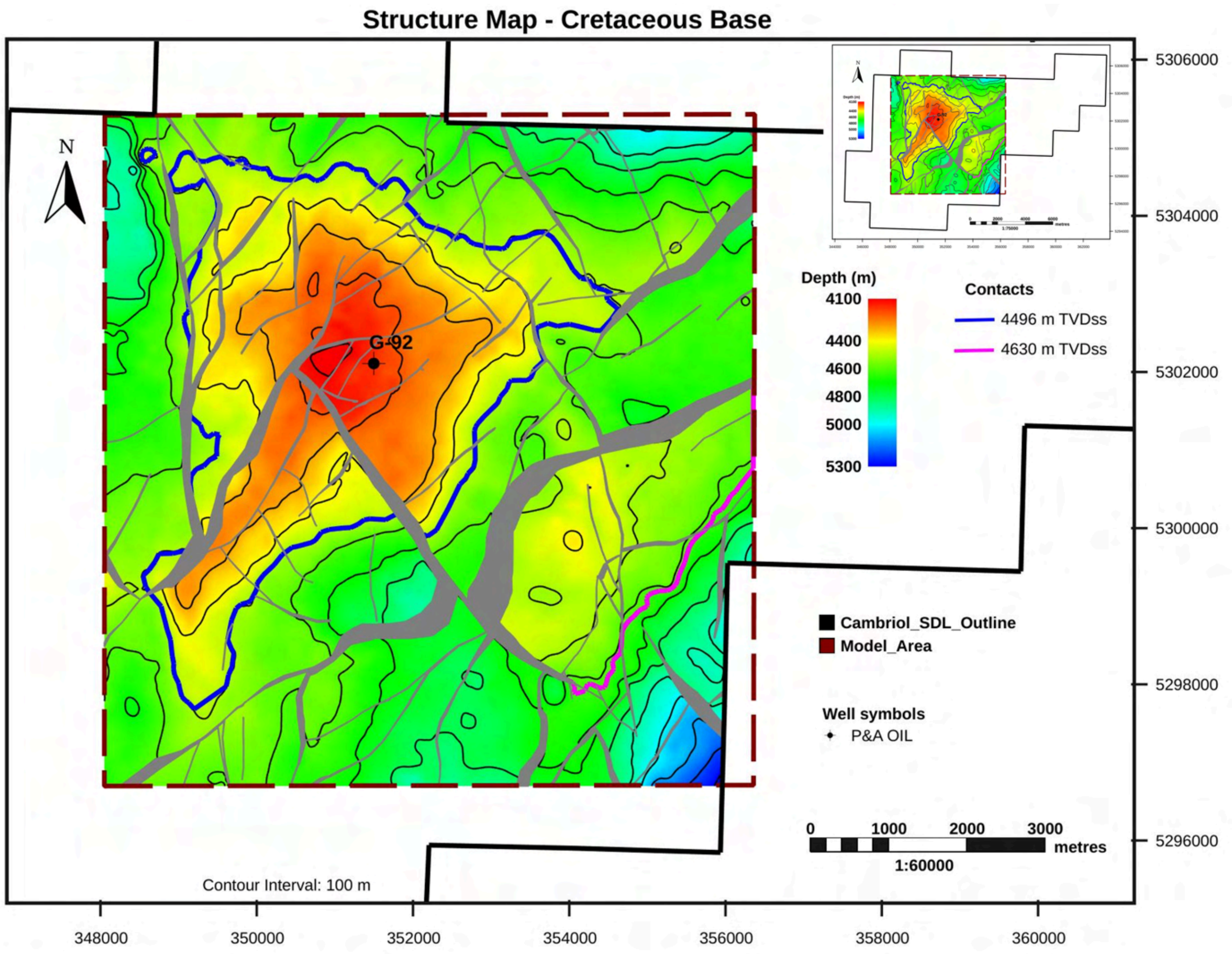


Figure 5.19 Structure Map, Cretaceous Base Contacts displayed on the structure maps represent the expected contacts. However, a range of contacts were used in the uncertainty analysis to generate the reserve and resource estimates.

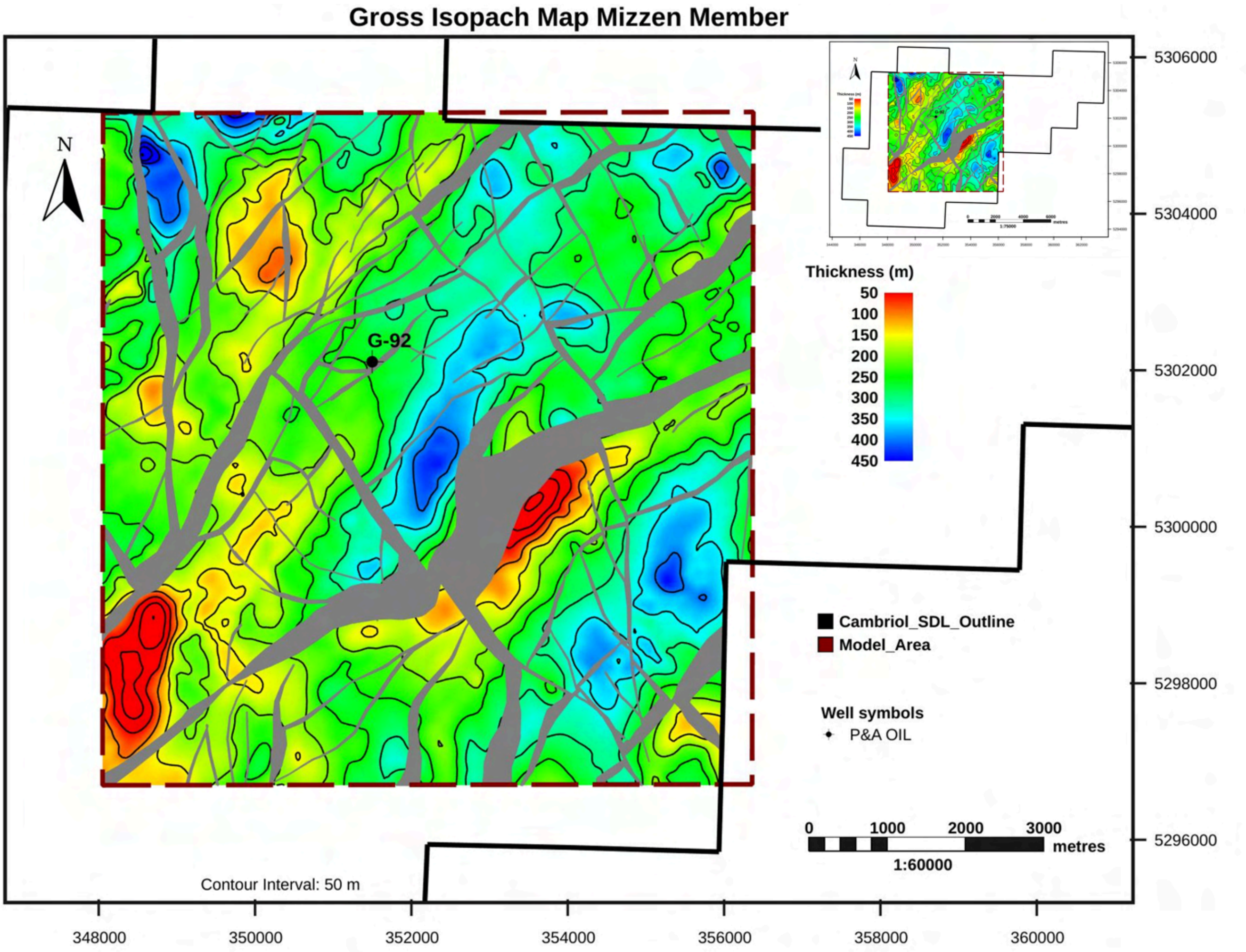


Figure 5.20 Gross Isopach Map - Mizzen member

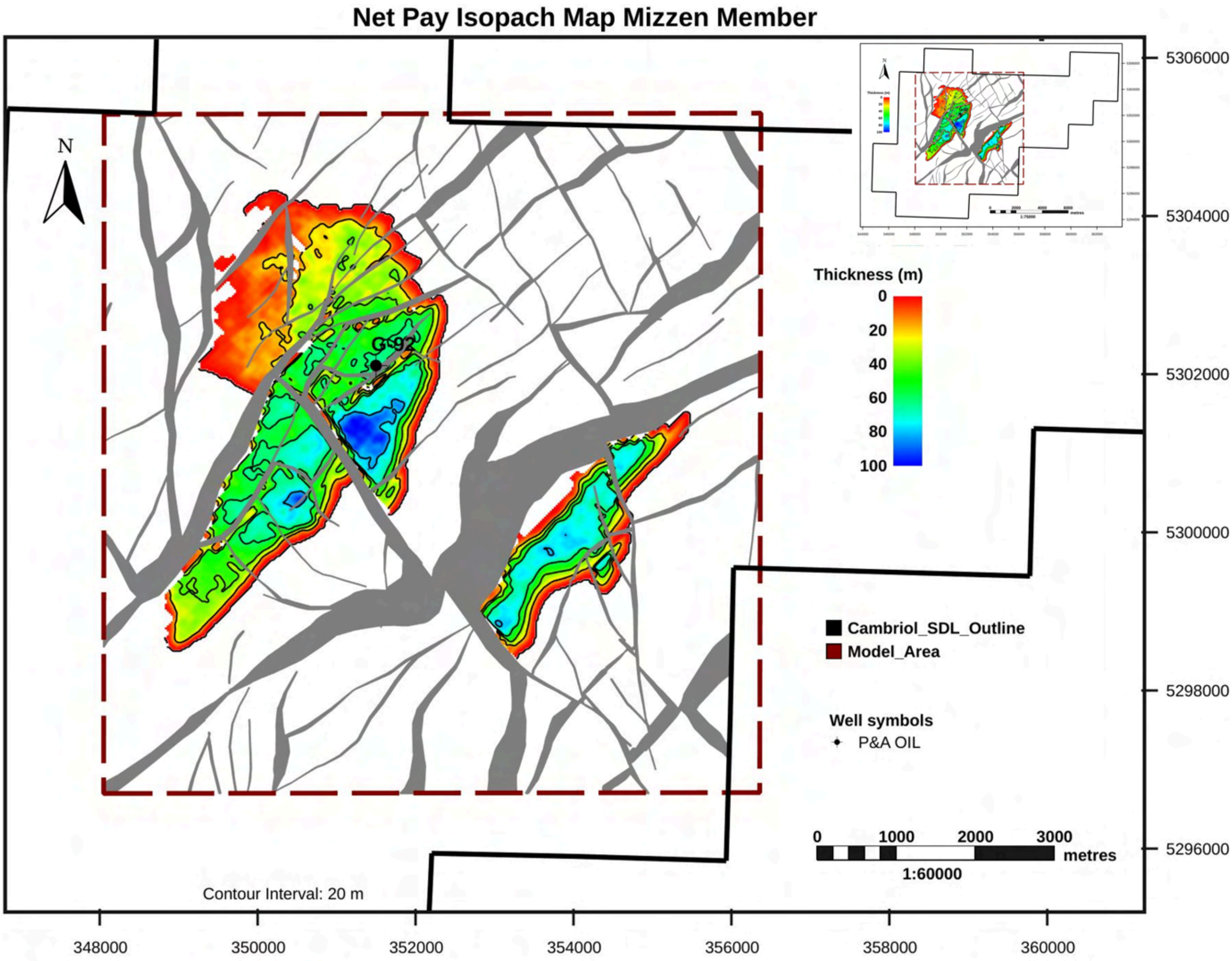


Figure 5.21 Net Pay Isopach Map - Mizzen member

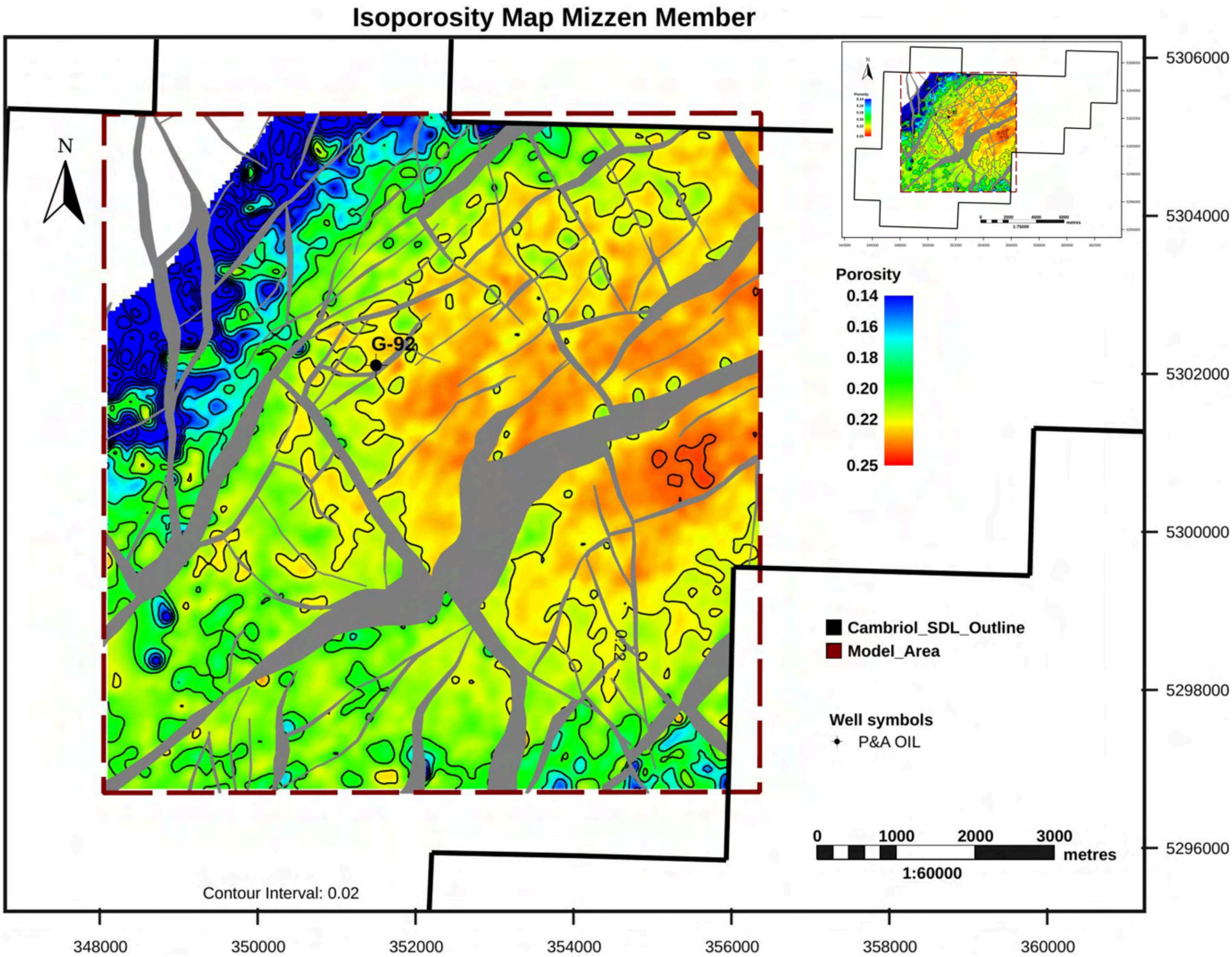


Figure 5.22 Isoporosity Map - Mizzen member

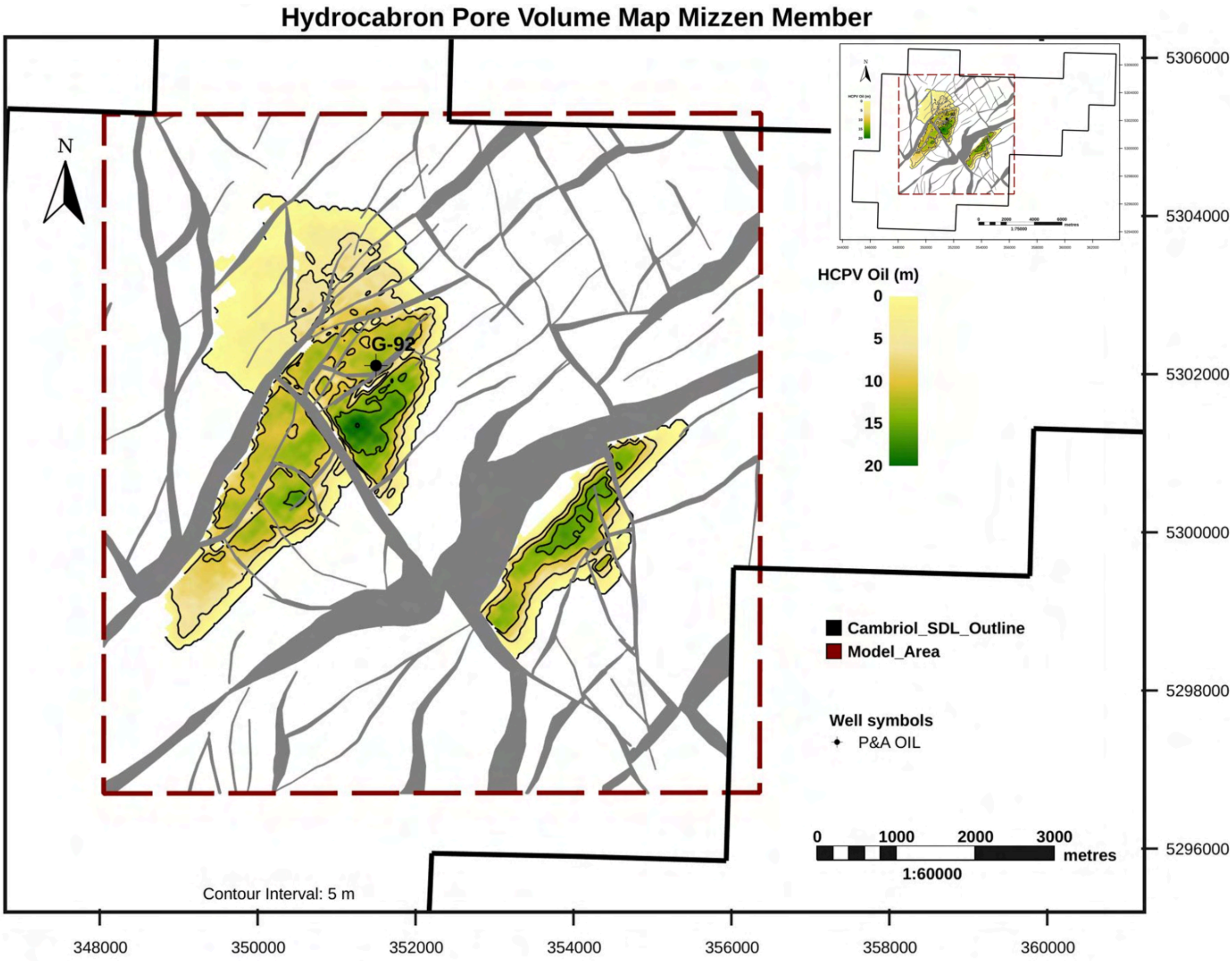


Figure 5.23 Hydrocarbon Pore Volume Map - Mizzen member

In the static reservoir model for the Cambriol Field, the main parameter uncertainties included in the evaluations are summarized in Table 5.2 below.

Table 5.2 Cambriol Static Uncertainty Parameters

Uncertainty Parameters		Description
Structural (depth) model	Scenarios	Four grid scenarios are available in the uncertainty design matrix, representing a base case, low case, and high case structural interpretation. The low and high cases were generated using the base case structural model as input in the Roxar RMS HUM tool. A fourth scenario is also considered in the uncertainty study that represents an alternative structural interpretation. Details are provided in Section 4.3.4 Seismic Velocity Analysis and Depth Conversion and Section 4.3.5 Horizon Uncertainty Modelling.
Oil water contacts	Distribution	A contact range was determined for each contact region using observations in the pressure data and structural analysis.
	Chance of success	To account for the uncertainty of hydrocarbon presence in undrilled regions a chance of success was applied to B, C, and F regions.
Facies Modelling	Depositional Scenarios/Facies Distribution	A range of depositional directions, widths, and thicknesses were considered in the uncertainty design matrix to control the facies distribution for both the Mizzen 1 and Mizzen 3 deltaic systems.
	Facies volume fraction	A volume fraction range was defined for each facies based on well observations and conceptual understanding.
Petrophysical	Multiplier	A multiplier range was determined from a petrophysical uncertainty analysis.
Kv/Kh	Multiplier	Based on core plug measurements and analogue data a Kv/Kh multiplier range was determined for each of the modelled facies.
Fault seal	Low/Base/High	A fault seal study based on core and analogue data provided a low (tight), base and high (open) case.

6 Reservoir and Production Engineering

6.1 Introduction

There has been significant reservoir and production engineering work used to define the drainage strategy and the resource estimates of the Bay du Nord Project (the Project). The data and interpretations are based on the Bay du Nord and Cambriol exploratory wells along with other regional well data and analogues from Equinor ASA's global operations.

6.2 Summary of Subsurface Dynamic Data

6.2.1 Reservoir Pressures and Temperatures

Formation pressures have been measured by modern wireline tools for the majority of wells in the Project Area. The formation pressure measurements are, in general, of good quality.

For the six wells in the Bay du Nord Field, a total of 258 pressure measurements were attempted in the Tithonian section, of which 87 tests were tight and 171 were good tests.

For the single well in the Cambriol Field, a total of 50 pressure measurements were attempted, of which one test resulted in a lost seal, 23 tests were tight and 26 were good tests.

Temperatures were recorded on each logging run and also during well testing and fluid sampling. The Horner method was used to estimate bottom hole temperature. Average reservoir pressure, overpressure, and temperature is summarized in Table 6.1.

Table 6.1 Average Reservoir Pressure and Temperature

Well	member	Pressure (bar)	Overpressure (bar)	Temperature (°C)
Bay du Nord C-78	Mizzen	375	73	70
	Bay du Nord	382		73
Bay du Nord L-76Z	Mizzen	370		67
	Bay du Nord	377		70
Bay du Nord C-78Z	Mizzen	383		73
	Bay du Nord	396		76
Bay du Nord L-76	Mizzen	377	72	75
	Bay du Nord	385		76
Bay de Verde F-67	Mizzen	363	62	74
	Bay du Nord	369		76
Bay de Verde F-67Z	Mizzen	360		71
	Bay du Nord	364		73
Cambriol G-92	Mizzen	781	354	138

6.2.1.1 Fluid Contacts

Fluid contacts for the Project's two fields are estimated based on the available well data, in conjunction with the seismic interpretation and the conceptual geological understanding of the area. Both Bay du Nord and Cambriol exploratory wells encountered a combination of oil-down-to and water-up-to results. No free gas is expected within the Project Area. Varying degrees of compartmentalization are interpreted within the fields and reservoirs planned for development. Consequently, there is uncertainty associated with the maximum extent of the hydrocarbon accumulations and additional information is required to fully constrain the fluid contacts. These contacts will likely evolve as development progresses and more data is acquired within the Project Area. Reservoir pressure versus depth and a summary of the known oil-down-to, water-up-to and reference case fluid contacts are provided in Figure 6.1 and Table 6.2. The areas of the fields used in the table are shown in Figure 5.2 and Figure 5.3.

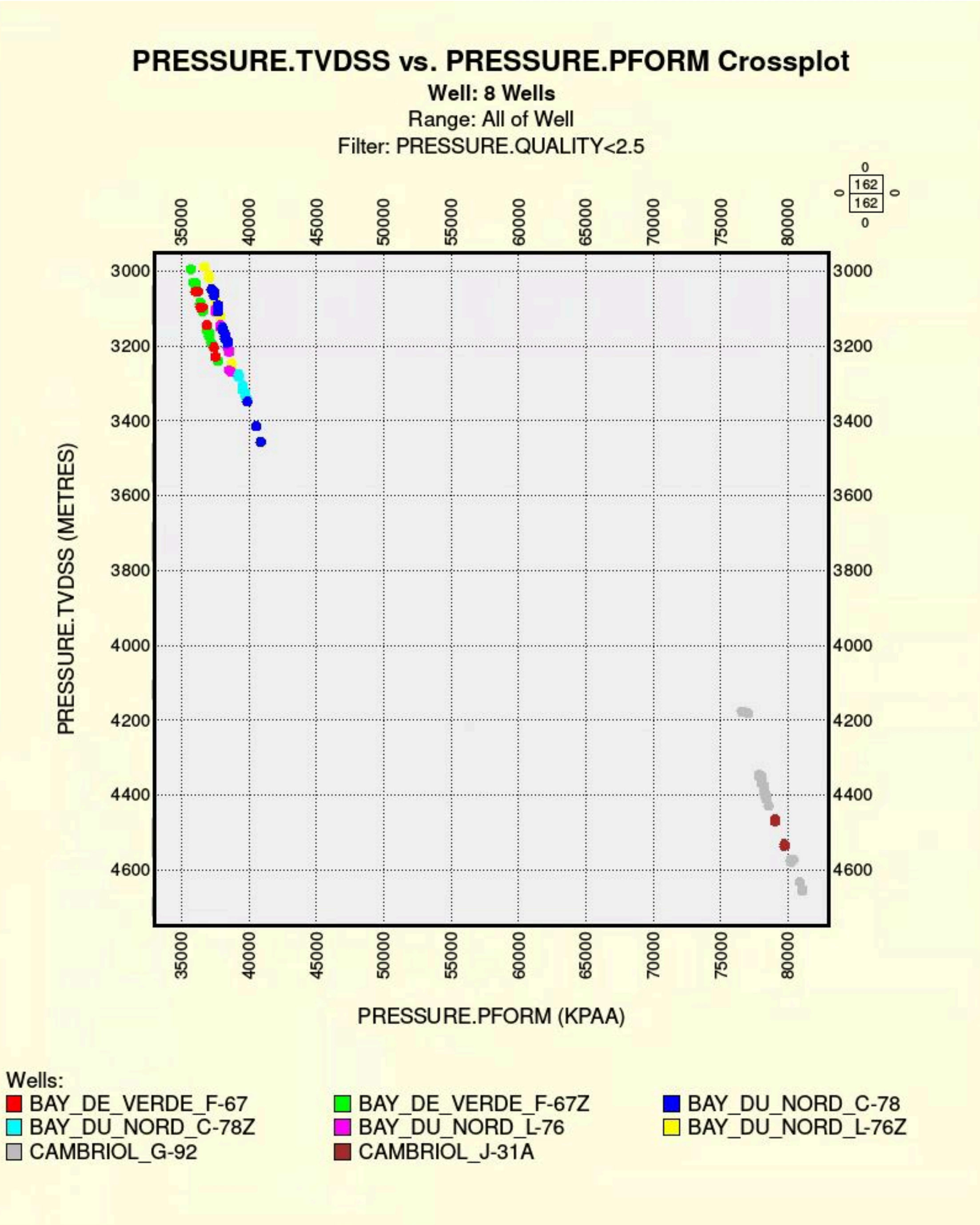


Figure 6.1 Formation Pressure versus Depth

Table 6.2 Reference Case Fluid Contact Distributions

Area	Well	Zone	ODT	WUT	FWL_{min}	FWL_{mean}	FWL_{max}
BdN Main	C-78	MIZ_Mbr	3109	-	3200	3205	3215
		BDN_1	3195	-			
		BVT_3	-	3350	-	-	-
	L-76Z	MIZ_Mbr	3063	-	3200	3205	3215
		BDN_1	3122	-			
		BVT_4	3188	-			
		BVT_3	-	3247	-	-	-
	C-78Z	MIZ_Mbr	3185	-	3200	3205	3215
		BDN_1	-	3274	-	-	-
BdN NC	L-76	MIZ_Mbr	3150	-	3155	3180	3210
		BDN_1	3220	-	3225	3250	3280
		BVT_4	3273	-	3273	-	-
BdN NB	Undrilled	MIZ_Mbr	N/A		3200	3205	3215
		BDN_1					
BdV	F-67	MIZ_Mbr	3100	-	3149	3151	3153
		BDN_1	3146	-	3149	3151	3153
		BVT_4	-	3202	-	-	-
	F-67Z	MIZ_Mbr	3036	-	3149	3151	3153
		BDN_1	3112	-	3149	3151	3153
		BVT_4	-	3153	-	-	-
		BVT_3	3240	-	3240	-	-
BdV East	Undrilled	MIZ_Mbr	N/A		3218	3275	3440
		BDN_1					
Cambriol D	G-92	MIZ_Mbr	4430	-	4445	4496	4715
		BVT_4	-	4567	-	-	-
Cambriol B	Undrilled	MIZ_Mbr	N/A		4445	4496	4715
Cambriol C							
Cambriol F					4500	4630	4700

6.2.2 Fluid Properties and Fluid Models

Six oil fields have been discovered in the Flemish Pass Basin: Mizzen, Harpoon, Bay du Nord, Baccalieu, Cappahayden and Cambriol. All six fields contain highly undersaturated oils with varying levels of biodegradation. There are no gas discoveries in the region, and based on the known fluid properties, there is no expectation for gas caps within the discoveries.

Multiple fluid samples have been collected from the productive reservoir intervals. These samples are used to define fluid properties, as well as to assist in determining the fluid contact best estimates. The fluid analyses were checked against the formation pressures to compare fluid gradients, and generally show good agreement. Fluid properties prior to any corrections are summarized in Table 6.3 and Table 6.4.

Table 6.3 Oil Properties from PVT Data

Area	Zone	Res Press bara	Temp DegC	Density *Stocktank oil* g/cc	Density *Res. Cond.* g/cc	API DEG	Bo v/v	GOR m3/m3	Viscosity *Res. Cond.*	Gradient Kpa/m
Bay du Nord	MIZ_Mbr	374	74	0.85	0.79	36	1.13	45	1.33	7.7
	BDN_Mbr	379	78	0.84	0.78					
	BVT_Mbr	383	80	0.84	0.77	37	1.14	48	1.38	
Bay de Verde	MIZ_Mbr	360	75	0.85	0.78	36	1.14	50	1.35	7.7
	BDN_Mbr	365	77	0.84	0.79					
	BVT_Mbr	379	81	0.85	0.78		1.16	56	1.06	
Cambriol	MIZ_Mbr	783	135	0.85	0.77	35	1.27	88	0.61	7.5

Table 6.4 Water Analysis Results Summary

Area	Well	Zone	Res Press bara	Temp DegC	Salinity *TDS* PPM	Density *Res. Cond.* g/cc	Res *25 DegC* OHMM	SG *15 DegC*	SO4 mg/l	Gradient Kpa/m
Bay du Nord	C-78Z	BDN_Mbr	392	77	30052	1.001	0.209	1.023	410	9.91
	C-78	BVT_Mbr	404	83	34575	1.010	0.184	1.027	2200	9.90
	L-76	BVT_Mbr	386	79	34600	1.011	0.198	1.027	3200	9.92
	L-76Z	BVT_Mbr	387	76	34001	1.013	0.196	1.026	2669	9.93
Bay de Verde	F-67	BVT_Mbr	374	76	34400	1.012	0.205	1.026	2800	9.93
	F-67Z	BVT_Mbr	371	76	32800	1.012	0.212	1.025	2700	9.92
Cambriol	G-92	BVT_Mbr	811	139	51700	1.004	0.137	1.038	970	9.87

6.2.2.1 Fluid Models

Fluid samples were obtained in all hydrocarbon-bearing sands in each well within the Bay du Nord and Cambriol fields. Preliminary analysis was performed on a sample from each well, in each sand, to confirm properties and the degree of contamination. Samples were then chosen for extended analysis based on sample quality and to ensure representative samples were available for each field. Fluid models have been built for each of the fields included in the Project for use in dynamic modeling and subsurface studies. Representative fluid compositions used in generating the fluid models are shown in Table 6.5. An example composition for injected gas is also provided. The composition of the injected gas is expected to change over time as the contributions from each field change.

The Project drainage strategy evaluations included options for the use and disposal of produced formation gas. To assist in simulation evaluations involving the injection of produced solution gas, swelling, and miscibility studies were performed on oils from the Bay du Nord Field. The studies provide information on how the oil and gas fluid properties change as a result of interactions in the reservoir following gas injection. The results of the studies are included in the development of the fluid models for the Bay du Nord Field.

The fluid models for the Bay du Nord and Cambriol fields have been generated for use in both black oil (E100) and compositional (E300) dynamic simulation models. Comparison of the Equation of State (EOS) model behaviour for gas flooding was performed between E100 and E300 for Bay du Nord. The models showed similar results for recovery and gas production behaviour. Due to the significantly increased simulation times required for compositional modelling, ranging from weeks-to-months versus hours-to-days, the evaluation work is performed using black oil simulation models.

Table 6.5 Bay du Nord Project: EOS Sample Compositions

Component Mole Percent	Nitrogen	Carbon Dioxide	Methane	Ethane	Propane	i-Butane	n-Butane	i-Pentane	n-Pentane	C6+
Bay du Nord C-78	0.10	0.16	22.16	3.84	4.95	1.37	3.37	1.58	2.16	60.31
Bay du Nord C-78Z	0.13	0.18	18.76	1.93	2.06	1.09	1.65	1.04	1.24	71.92
Bay de Verde F-67	0.12	0.16	24.28	3.33	4.66	1.36	3.46	1.77	2.01	58.85
Bay de Verde F-67Z	0.12	0.18	25.16	3.63	4.56	1.30	3.05	1.82	1.19	58.99
Bay du Nord L-76	0.11	0.14	21.43	3.71	4.93	1.22	3.25	1.57	2.10	61.54
Bay du Nord L-76Z	0.11	0.13	20.33	3.61	5.05	1.35	3.49	1.71	2.31	61.91
Cambriol G-92	0.20	1.54	27.57	5.58	7.38	1.57	4.32	1.78	2.36	47.69
Injection Gas	0.46	2.41	68.13	11.61	12.02	1.71	3.02	0.34	0.26	0.04

Available Fluid Samples Used in the Subsurface Fluid Models

Standard fluid analysis measurements were performed on oil samples from the Bay du Nord and Cambriol fields. The experiments include Constant Composition Expansion (CCE), Differential Liberation Experiment (DLE), separator tests, and oil viscosity measurements. If there were multiple samples from the same reservoir, the DLE experiment might be only measured for one representative sample. The number of analyzed samples for each reservoir are listed by well:

Bay du Nord C-78

- Mizzen member (2)
- Bay du Nord member (2)

Bay du Nord C-78Z

- Mizzen member (1)

Bay de Verde F-67

- Mizzen member (1)

Bay de Verde F-67Z

- Mizzen member (1)
- Bay du Nord member (1)
- Bonaventure member (1)

Bay du Nord L-76

- Mizzen member (1)
- Bay du Nord member (1)
- Bonaventure member (1)

Bay du Nord L-76Z

- Mizzen member (2)
- Bay du Nord member (2)
- Bonaventure member (1)

Cambriol G-92

- Mizzen member (3)

Fluid samples were acquired using three formation testing methods: Modular Formation Dynamics Testing (MDT), Formation Testing While Tripping (FTWT), and Drill Stem Test (DST). Samples taken from MDT and FTWT contained varying levels of contamination from the oil-based muds. With the exception of the samples from the DSTs, the contaminated mud components were included in the oil compositions, as the Pressure-Volume-Temperature (PVT) measurements were performed on contaminated samples. The level of contamination in the samples is considered low. After the fluid properties were matched by an EOS model, the mud components were removed numerically from the contaminated oil compositions. The resulting clean reservoir oil compositions were used for making the fluid model input for both black oil and compositional reservoir simulation models.

Bay du Nord Field Fluid Model

An EOS model was created based on the fluid samples available for the Bay du Nord Field. The common EOS model is a 14-component Peng Robinson EOS model with temperature dependent Peneloux density correction. Due to the density match difficulties at both reservoir and surface conditions, it was decided to use a temperature dependent Peneloux density correction. A Lohrenz-Bray-Clark (LBC) viscosity model was selected due to the good flexibility associated with this model.

The 14-component common EOS model was used to generate black oil tables for the Bay du Nord Field. Due to the consistency in fluid properties across the field, one table, based on a sample from the Mizzen member in the Bay du Nord C-78 well, was generated for use in the reservoir simulation models.

The process conditions used for the black oil tables are listed in Table 6.6. The same process conditions are used in the generation of the fluid models for each field in the Project.

Table 6.6 Bay du Nord Project - Assumed Process Conditions for Generation of the Fluid Models

Temperature (°C)	Pressure (bara)
60	15
78	2
15	1.01

To model the injection of the produced gas, the black oil properties were extended by swelling the original oil with separator gas. The resulting swollen oil tables were spliced to form the input to the reservoir simulation models. Swelling behaviours were not the same for all samples used in the fluid models, so the impact of differing models was simulated. Due to the small volume of gas available for injection in the Bay du Nord Field, relative to the volume of oil in place and the low initial solution Gas-Oil Ratio (GOR), it was determined that a single swollen oil model would be used for the entire field.

The injected gas composition (separator gas) will change over time as the composition of the produced gas changes. The solution gas composition from each field is different and as the oil production contribution from each field changes over time, the produced solution gas from the facility will change. Further, as produced gas is injected into the Bay du Nord Field, a portion of it will circulate through the reservoir and be produced again. The processing of the produced solution and recirculated gas results in a continuously changing injection gas composition. In the black oil simulation model it is not possible to vary the injected gas composition with time. To determine an appropriate gas composition for use in generating the black oil fluid models, compositional modelling was performed for varying injection gas compositions over time. The results of the compositional model were then compared to black oil models run with multiple fluid models, each based on a different injection gas composition. The most representative black oil model, as compared to the compositional models, was chosen for use in the black oil model, along with corrections to gas behaviour when deviation was seen.

The compositional fluid model was generated to allow for comparison to the black oil results when modelling gas injection. To achieve reasonable simulation speeds when performing compositional reservoir simulations, an eight-component Peng-Robinson 1979 EOS with Peneloux temperature dependent density correction was created. The compositional model is similar to the EOS model, except the 14 components were grouped into eight pseudo components as follows:

- C1N2;
- C2CO2;
- C3-C4;
- C5-C6;
- C7-C9;
- C10-C15;
- C16-C29; and
- C30+.

There is generally very good agreement between the compositional and EOS models.

Cambriol Field Fluid Model

An EOS model was created based on the fluid samples available for the Cambriol Field. The EOS model is a 21 component Peng Robinson EOS model with temperature dependent Peneloux density correction. An LBC viscosity model was tuned to match the viscosity data from the fluid studies. The fluid model is a dry oil model, as no gas injection option was evaluated for the field and the reservoir pressure will be maintained above the bubble point pressure.

Dynamic Model Initialization and Solution Gas-Oil-Ratios

To determine the conditions for the initialization of the fluid models in the reservoir simulation models, all fluid samples were examined to see if any fluid gradient could be determined. The fluid samples are undersaturated, and in general, the sample compositions are similar within regions. Within each field, there is a consistent relationship between oil density and viscosity, as well as a consistent relationship between the stock tank oil molecular weight and density. However, no clear fluid gradients could be identified, so the reservoir simulation models were initialized at constant GORs for each equilibrium region.

For black oil simulation, it is recommended that GORs, based on fluid samples from the wells, are used to initialize the specific reservoir segments. These GORs are adjusted to the sampling conditions from a set of production separator conditions. These conditions were provided by the facilities group at the time of the modelling work. The GORs used to initialize the model are provided in Table 6.7.

Table 6.7 Bay du Nord Project: GORs for Model Initialization

Region/Fault Block	Member	Sample Reference	Gas-Oil Ratio (m^3/m^3)
Bay du Nord Region	Bay du Nord	Bay du Nord L-76Z Bay du Nord member	49.72
Bay du Nord Region	Mizzen	Bay du Nord L-76Z Mizzen member	48.19
Bay du Nord NC Block	Bay du Nord	Bay du Nord L-76 Mizzen member	46.62
Bay du Nord NC Block	Mizzen	Bay du Nord L-76 Bay du Nord member	52.55
Bay de Verde Region	Bay du Nord	Bay du Nord F-67Z Bay du Nord member	51.21
Bay de Verde Region	Mizzen	Bay du Nord F-67 Mizzen member	50.77
Cambriol	Mizzen	Cambriol G-92	89.59

Water Properties

A water property table was also generated based on water salinity measurements. Table 6.8 compares water samples from each field with a sea water sample taken near the Bay du Nord Field. The water salinities for the fields are similar to seawater. As the properties of the seawater are similar to the reservoir water, and as seawater is to be injected for pressure maintenance and fluid displacement, a single water property table is generated for the Project based on the seawater properties.

Table 6.8 Bay du Nord Project: Water Sample Comparison

	Bay du Nord Field				Cambriol Field	Seawater
Well	Bay du Nord C-78	Bay du Nord C-78	Bay du Nord C-78Z	Bay du Nord L-76Z	Cambriol G-92	Sample
Member	Bonaventure	Bonaventure	BdN	Bonaventure	Bonaventure	
Depth [m TVD RT]	3381.2	3488.5	3306.3	3608.5	4698.97	
Pressure [bar]	399.2	408.6	399.2	386.9	810.7	
Temperature [°C]	80.7	84.4	77.1	81.8	145	
Date	September 2, 2013	September 1, 2013	September 22, 2013	June 5, 2015	August 24, 2020	September 1, 2017
Water Composition						
Cations [mg/l]						
Na^{+}	12444	12449	11521	13,200	18400	11419
Ca^{2+}	479	474	307	520	1430	412
Mg^{2+}	60.7	54.2	58.5	89.3	84.1	1237.1
Ba^{2+}	0.2	0.2	0.7	0.19	1.01	0.1
Fe	5	2.6	7.5	1.2	9.9	0.2
Sr^{2+}	42.6	28.7	54.1	31.9	72.2	10.9
K^{+}	64.7	61.7	76.6	77	131	396.8
B	66.3	65.6	63.5	60.5	153	
Anions [mg/l]						
Br^{-}	74	75	75	77	57	63.8
Cl^{-}	17819	17684	17604	17,400	30500	19147
SO_4^{2-} (ICP)	1557	2488	385	3,200	970	2633
SO_4^{2-} (IC)	1700	2500	410		890	
Total alkalinity [mmol/l]		29.5	18.9		14.1	
Total alkalinity [HCO_3 eqv., mg/l]		1800	1153	1952	860	232.4 (as $CaCO_3$)
Organic acids [mg/l]						
Ethanoic acid	780	870	320	1100	140	
Propanoic acid	120	130	73	150	<20	
Butanoic acid	<20	<20	<20	21	<20	
Pentanoic acid	<20	<20	<20	<20	<20	
Hexanoic acid	<20	<20	<20	<20	<20	
Properties						
Total Dissolved Salts [mg/l]	32663	33936	30052	34600	51700	34603

6.2.3 Special Core Analysis

Special Core Analysis (SCAL) studies were performed on core samples from Bay du Nord C-78, Bay du Nord L-76Z, and Cambriol G-92. The focus of the studies was to evaluate the static and dynamic properties of the reservoirs. A list of plug experiments is summarized in Table 3.3 from the Petrophysics section. SCAL experiments include:

- Overburden corrections;
- Formation factor and resistivity index;
- Capillary pressure measurements from porous plate;
- Mercury injection capillary pressure;
- Wettability measurements; and
- Relative permeability measurements.

6.2.3.1 Relative Permeability

The flow parameters model, or relative permeability model, for the Bay du Nord Field is a combination of the SCAL work from the Bay du Nord C-78 and the Bay du Nord L-76Z wells. The Cambriol Field model is based on the SCAL work for the Cambriol G-92 well.

The SCAL model results are combined with analogues from Equinor's SCAL database to deliver a representative model for each field.

For the Bay du Nord Field, a single SCAL model is provided for both the Bay du Nord and Mizzen members. Consideration was given to the differences between the two members and whether separate SCAL models were required. It was determined that a single model was appropriate as both of the members have similar facies. Consideration was also given to generating separate SCAL models based on facies type. As the majority of the available SCAL data is within the good quality facies, and the majority of the expected production is from these facies, there was no expected benefit from generating facies-based SCAL models. This approach was also used for Cambriol and the same conclusions were drawn: the generation of a representative field flow parameters model, versus facies or sand specific models.

Equinor uses the LET model (named for the L, E, and T parameters that define the curves) for characterising and generating relative permeability curves, versus the traditional Corey exponent method. The experiments used in generating the SCAL models, along with the LET parameters they provide, are:

- Multi-speed centrifuge for capillary pressure and for reliable estimates of residual oil saturation;
- Single speed centrifuge for relative permeability of the displaced phase at low saturations (displaced-phase L parameter) and a good estimate of residual oil saturation; and
- Steady-state to define the 'entire' range of the relative permeability curve (L, E, and T for both phases).

When interpreting the steady-state data, the endpoint saturations from the steady-state experiments were checked with those from the centrifuge experiments for residual oil saturation, and the porous plate experiments were checked for irreducible water saturation.

Experimental relative permeability data were evaluated and verified by a core flow simulator. In this evaluation process, relative permeability curves from each experiment were parametrized and input to the Equinor SCAL database, along with all relevant information such as core plug properties, well name, fluid properties, litho-stratigraphic formation and facies, flow parameters and experimental conditions. Entering this information in the database allows for the use of analogues based on formation, porosity, and permeability ranges or field name when experimental data is limited.

For each combination of shape, or LET, parameters, and end-point parameters global trend models have been established as functions of irreducible water saturation and permeability. The trend models are developed based on basic wettability theory, reservoir physics and historic data from within Equinor. The SCAL model for each field is created by calibrating the trend model for each of the parameters to the experimental data. The SCAL model includes a base case with upper and lower bounds to capture the spread and the uncertainty in the experimental results.

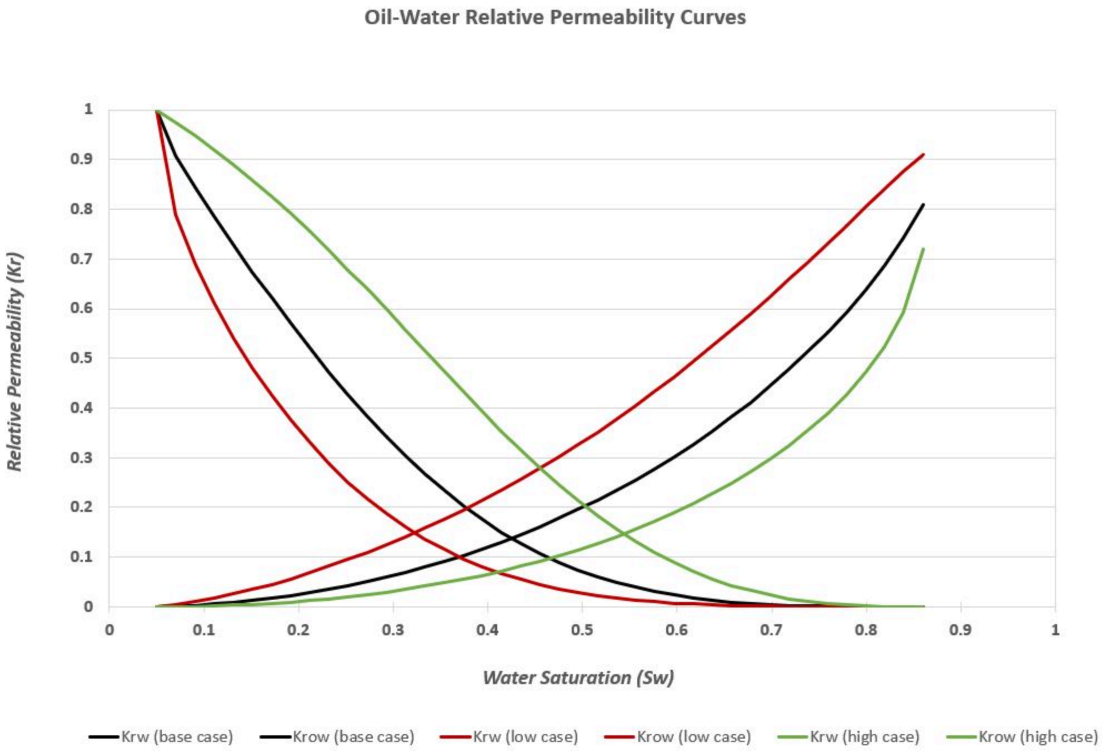


Figure 6.2 Bay du Nord Oil-Water Relative Permeability Curves

The Bay du Nord Oil-Water, Bay du Nord Oil-Gas, and Cambriol Oil-Water relative permeability curves are shown in Figure 6.2, Figure 6.3, and Figure 6.4, respectively.

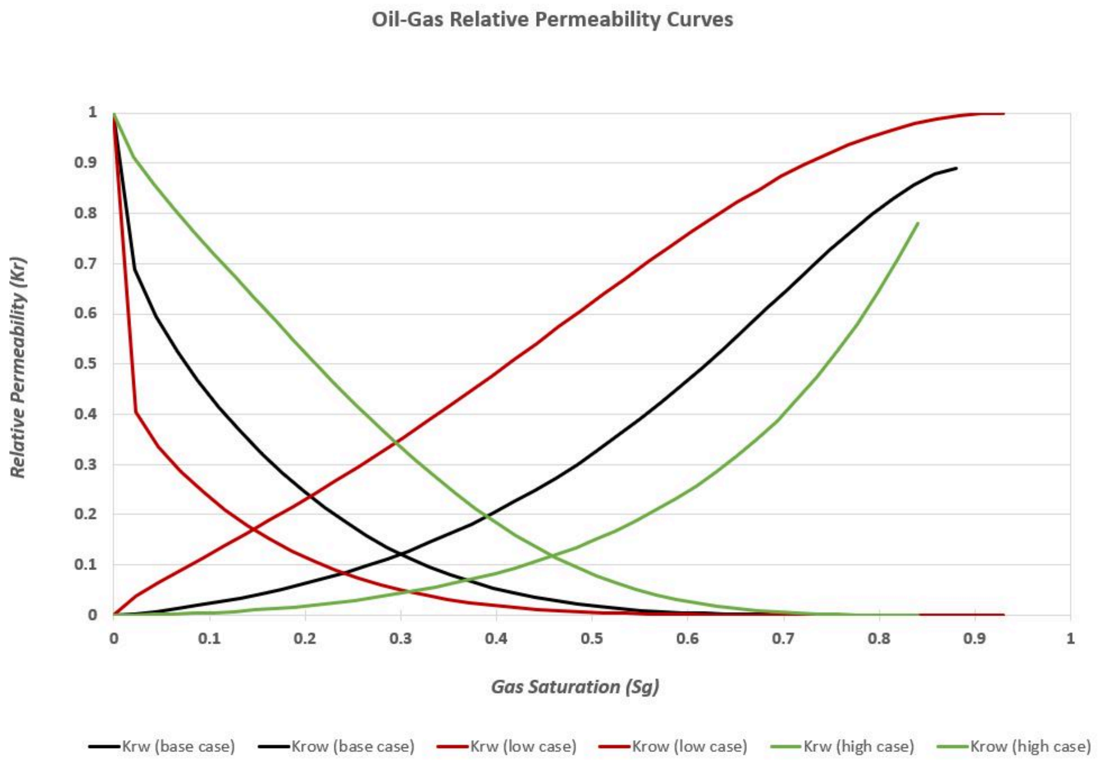


Figure 6.3 Bay du Nord Oil-Gas Relative Permeability Curves

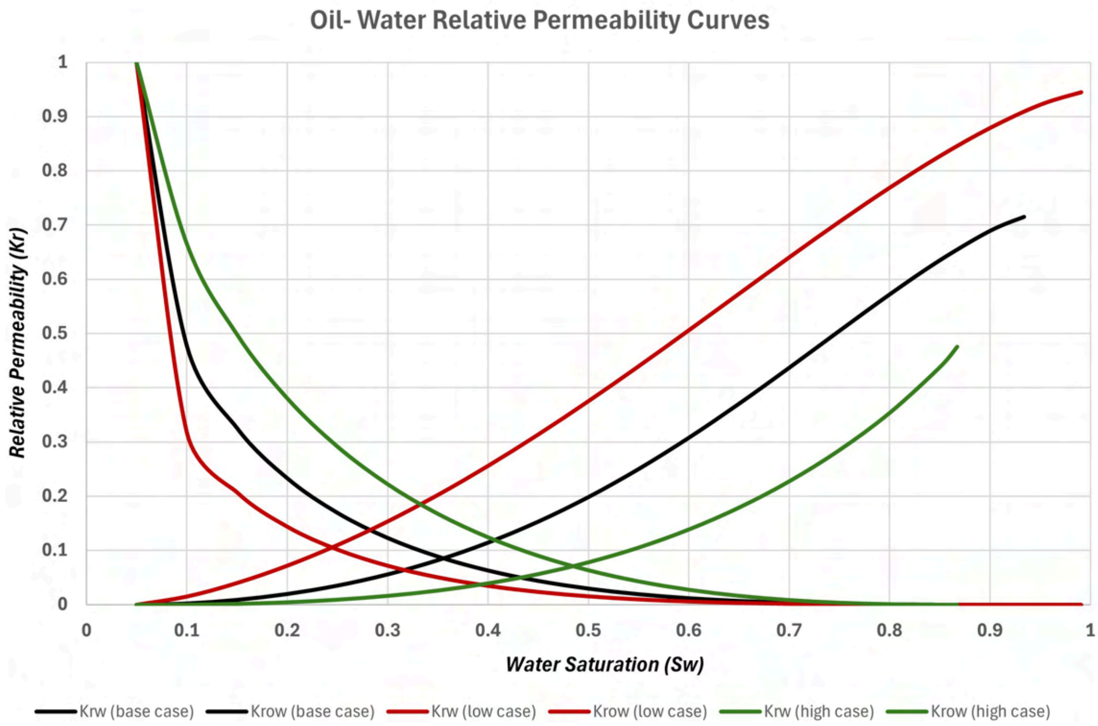


Figure 6.4 Cambriol Oil-Water Relative Permeability Curves

6.2.4 Well Tests and Interpretation

The Project has acquired a range of well test data using a variety of tools to ensure that key aspects of the reservoir are understood and captured within the reservoir descriptions and evaluations. Three forms of well testing were implemented within the Bay du Nord and Cambriol fields. They are:

- Mini-DST;
- FTWT; and
- DST.

These three tools provide dynamic data at different resolutions, and the data is used to characterize the reservoirs.

The summary of the well test data within the proposed development area are:

Bay du Nord C-78

- Bay du Nord member: Two mini-DSTs
- Mizzen member: 2 Mini-DSTs

Bay du Nord C-78Z

- Mizzen member: One Mini-DST

Bay de Verde F-67Z

- Mizzen member: One FTWT

Bay du Nord L-76Z

- Bay du Nord member: Two FTWT, one DST
- Mizzen member: Two FTWT, one DST

Cambriol G-92

- Mizzen member: One FTWT

A summary of the well test results is provided in Table 6.9. Note that the test intervals provided correspond to the test interpretation. In several instances, changes in sand quality within the interval tested or the presence of multiple sands requires the interpreter and the petrophysicist to make an assumption on what interval is contributing to the test.

The interpretation of the well test data provides information on permeability, vertical permeability (k_v/k_h), structural complexity, connected oil-in-place, and how the reservoir changes away from the wells. Summaries of the main tests in each field, the associated interpretations, and the implementation into the reservoir evaluation will be provided in the following sections.

Table 6.9 Bay du Nord Project: Summary of Well Test Results

Well	Field	member	Test Type	Interval	Fluid Type	Test Flow Rate	Oil Gravity	Pay	kh	Permeability	Skin Factor	Radius of Investigation
				(mMD RKB)		(m^3/d)	(API)	(m)	(mD-m)	(mD)		(m)
Bay du Nord C-78	Bay du Nord	Mizzen	Mini-DST	3085.7 - 3092	Oil	2.2	34.3	6.0	3570	595	NA	100
Bay du Nord C-78	Bay du Nord	Mizzen	Mini-DST	3119.7 - 3125.6	Oil	1.5	34.3	5.7	78	13.7	NA	18
Bay du Nord C-78	Bay du Nord	Bay du Nord	Mini-DST	3180 - 3183.3	Oil	1.4	36.1	3.1	612	190	NA	60
Bay du Nord C-78	Bay du Nord	Bay du Nord	Mini-DST	3195 - 3225.8	Oil	2.6	36.1	32.0	43000	1420	NA	NA
Bay du Nord C-78Z	Bay du Nord	Mizzen	Mini-DST	3393.4 - 3395	Oil	2.5	31.6	1.6	120	75	NA	51
Bay de Verde F-67Z	Bay du Nord	Mizzen	FTWT	3114.9 - 3119.5	Oil	9	35.4	4.0	5200	1300	-1	740
Bay du Nord L-76Z	Bay du Nord	Mizzen	FTWT	3033.5 - 3037.6	Oil	10	36.8	3.5	690	200	4.5	300
Bay du Nord L-76Z	Bay du Nord	Mizzen	FTWT	3058.3 - 3068.8	Oil	10	36.8	9.0	47000	5200	0	500-900
Bay du Nord L-76Z	Bay du Nord	Mizzen	DST	3053 - 3069	Oil	1075	36.5	8.9	48000	5400	0.4	2400
Bay du Nord L-76Z	Bay du Nord	Bay du Nord	FTWT	3154.5 - 3173.3	Oil	10	36.3	18.4	125000	6800	0	500-1100
Bay du Nord L-76Z	Bay du Nord	Bay du Nord	DST	3151 - 3171	Oil	1400	37.1	18.2	135000	7400	5.1	3600-4900
Cambriol G-92	Cambriol	Mizzen	FTWT	4392.5 - 4393.5	Oil	8	36	15	15750	1050	130	300

6.2.4.1 Bay du Nord C-78 and C-78Z Well Test Overview

The Bay du Nord C-78 well was the first well drilled in the Bay du Nord Field. Following the discovery of hydrocarbons, the well was sidetracked to the Bay du Nord C-78Z location to gain additional information on sand extent, reservoir quality, and oil column height. As part of the formation pressure sampling and fluid acquisition program, four Mini-DSTs were performed in the C-78 well: two in the Mizzen member, and two in the Bay du Nord member. One Mini-DST was performed in the Mizzen member of the C-78Z well. A summary of the well test and the interpretation results is provided in Table 6.10.

The Mini-DST interpretation provides information on reservoir permeability, vertical communication, and sand extent that can be used in conjunction with the petrophysical, geological, and geophysical interpretations to characterize the reservoir, build static models, and support the results of dynamic modelling and reservoir performance.

The primary objective of these tests is to validate log-based permeability values based on the kh products obtained from the test interpretation, as discussed in Section 3.1.1 Comparison of Petrophysical Results to Well Tests. Within the Bay du Nord Field, it has been challenging to determine the correct value of reservoir thickness to use in the determination of permeability. Reservoir quality may vary vertically within the well, drawing into question the thickness of the connected zone contributing to flow, or the reservoir thickness may vary away from the well. In the C-78 well, good estimates of permeability are determined for three of the four tests, with the uncertainty in thickness reflected in the interpretation of the third test. A good estimate of permeability was obtained from the test in C-78Z.

In three of the C-78 tests, estimates of vertical permeability were made. These values highlight the varying levels of communication between zones within the reservoir based on the positions of the testing probes. In test 3, the logs indicate cement stringers as shown in Figure 6.5. This figure also shows the uncertainty in the thickness of the tested interval, as the cement stringers exist within the tested sand and possibly reduce the contributing interval from 10.2 to 3.2 m.

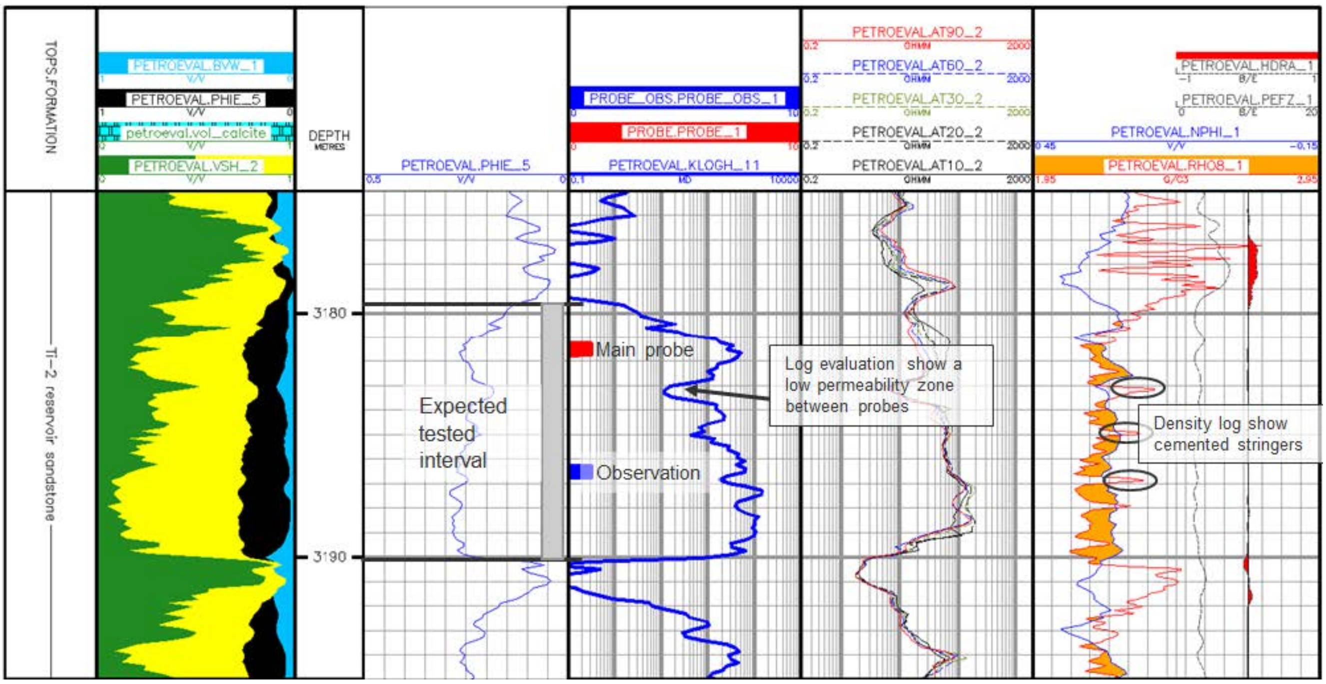


Figure 6.5 Bay du Nord C-78 CPI Plot - Mini-DST # 3

In the first C-78 test, the data quality and extent permits estimation of near-well boundaries. A Mini-DST is sensitive to the low draw-down achieved in the test, resulting in many possible interpretations for the boundaries from faults to sand edges.

Table 6.10 Bay du Nord C-78 and C-78Z Well Test Interpretation

Well/Test	C-78 Test 1	C-78 Test 2	C-78 Test 3	C-78 Test 4	C-78Z Test 1
	2018	2018	2018	2018	2018
member	Mizzen	Mizzen	Bay du Nord	Bay du Nord	Mizzen
kh (mD-m)	3570	78	612	43000	120
Net pay (m)	6	5.7	3.2 / 10.2	30.2	1.6
Permeability (mD)	595	13.7	190 / 60	1420	75
kv/kh	0.27	1	0.0013 / 0.154	-	-
Boundaries	20 m, 30 m	-	-	-	-

6.2.4.2 Bay de Verde F-67Z Well Test Overview

The Bay de Verde F-67 well was the first well drilled in the Bay de Verde area of the Bay du Nord Field. The well was drilled down dip on the Bay de Verde structure to evaluate the correlation between seismic response and reservoir presence, with the intention of a sidetrack (Bay de Verde F-67Z) to evaluate the primary reservoir targets. As part of the data acquisition program for the F-67Z well, the Schlumberger FTWT tool was used to gain dynamic information on the Mizzen member and obtain fluid samples for analysis.

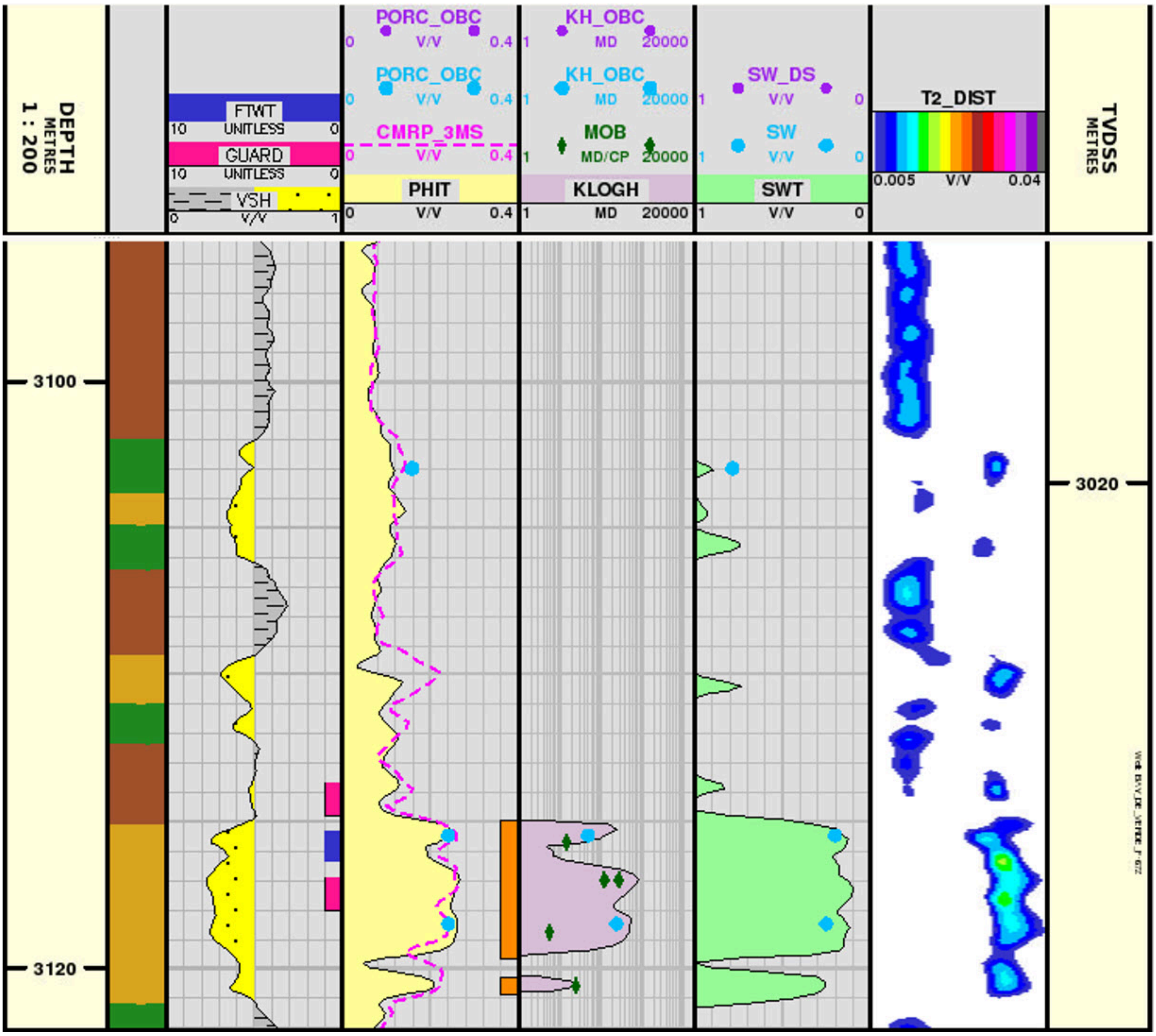


Figure 6.6 Bay de Verde F-67Z CPI Log - Well Test interval

The well encountered a thin section of the Mizzen member, which was tested using FTWT technology. The possible contributing interval thickness within the net sand varies from 2.9 m to 5.3 m. In consultation with the petrophysicist, a contributing interval of 4 m was assumed for the test interpretation. The test provides an opportunity to evaluate the lateral continuity of thin Mizzen member sands, as they are below the current resolution for seismic mapping. Two different multi-linear models were created to evaluate the possible shape of the tested sand. While the reservoir orientation was not indicated, the test resolves a sand body that is narrow in the vicinity of the wellbore, but then widens and improves in quality from 500 m to 750 m away from the wellbore. Away from the well, the reservoir is imaged as a long, wide, and thin sand body. As the thickness is assumed constant, it could be that the sand thickens and is actually shorter and narrower. Regardless, the potential for thin sands to have good communication for more than a kilometre shows that there is potential for thin Mizzen member development if the Project is able to map and define targets throughout the life of the field. Options for developing the Mizzen member are discussed in Section 7.3 Bay du Nord Field Exploitation.

In Section 6.2.4.3 Bay du Nord L-76Z Well Test Overview, the definition of baffles within the reservoir as boundaries in the FTWT interpretation will be discussed. For F-67Z, it is possible that the connected sand in production time would be greater than the connected sand predicted from this test, as the test typically indicates a minimum connected volume.

The FTWT configuration includes a guard and a sample interval, as depicted in Figure 6.6. For this test, the guard interval provided better quality data than the sample interval, and was the only probe used in the test interpretation. The guard interval alone does not permit an estimate of skin, so this interpretation is not included in the test results.

The test interpretations are shown in Table 6.11 and Table 6.12.

Table 6.11 Bay de Verde F-67Z Well Test (FTWT) Interpretation

Saphir model name	U ML mid	Channel ML mid2
Well location	Centre	Centre
Channel type	U-shaped	Linear
Variation in channel parameters	Width	Width
kh-product, kHh (mDm)	6000	5200
Horizontal permeability, kH (mD)	1300	1300
Initial Pressure, pi (bar)	359.87	359.87
Radius of investigation (main build-up), rinv (m)	640	430
Radius of investigation (total test time), rinv (m)	1100	740
Well placement (segment no.)	2	2
Well placement (xD, yD)	0.5 / 0.5	0.5 / 0.5
Segment 1 Length and width (m)	100 / 45	1350 / 30
Segment 2 Length and width (m)	60 / 45	37 / 30
Segment 3 Length and width (m)	50 / 170	135 / 115
Segment 4 Length and width (m)	530 / 300	270 / 190
Segment 5 Length and width (m)	2000 / 1300	1400 / 700

Table 6.12 Bay de Verde F-67Z Well Test (FTWT) Interpretation - Thickness Sensitivity

Model name	Channel ML mid	Channel ML mid3	Channel ML mid2
Producing thickness (m)	4	2.9	5.3
Well location	Centre	Centre	Off-centre
Channel type	Linear	U-shaped	Linear
Variation in channel parameters	Width	Width	Width
kh-product, kHh (mDm)	5200	5200	5200
Horizontal permeability, kH (mD)	1300	1800	980
Initial Pressure, pi (bar)	359.87	359.87	359.87
Radius of investigation (main build-up), rinv (m)	430	500	400
Radius of investigation (total test time), rinv (m)	740	860	690
Well placement (segment no.)	2	2	2
Well placement (xD, yD)	0.5 / 0.5	0.5 / 0.5	0.5 / 0.5
Segment 1 Length and width (m)	1350 / 30	1560 / 35	1250 / 28
Segment 2 Length and width (m)	37 / 30	43 / 35	35 / 28
Segment 3 Length and width (m)	135 / 115	156 / 133	125 / 107
Segment 4 Length and width (m)	270 / 190	310 / 220	250 / 180
Segment 5 Length and width (m)	1400 / 700	1600 / 800	1300 / 600

6.2.4.3 Bay du Nord L-76Z Well Test Overview

The Bay du Nord Field is comprised of a highly faulted reservoir with varying sand thickness. Thin sands and significant faulting result in a high likelihood of isolated compartments and poor communication between wells. This risk was recognized early in the planning phase for the exploration wells following the Bay du Nord C-78 discovery. The Bay du Nord L-76Z well location was planned specifically to evaluate the thinner sands in the southern, highly faulted region, and to assess reservoir communication within the area through well testing. Well testing was planned in both the Bay du Nord and Mizzen members using DSTs and FTWTs. At the time of planning, the well test program was considered an ideal opportunity to compare the traditional DST with the new FTWT well test method. Through the planning, execution, and interpretation processes, it was identified that the DST and FTWT would provide a unique combination of results to define the reservoir.

Bay du Nord Member FTWT

Two FTWTs were performed in the Bay du Nord member targeting the upper and lower sections of the sand as shown in Figure 6.7. Several tests were performed at each location. The tests were planned to evaluate vertical communication across the sand. Due to the high kh product in the test interval, it was uncertain whether the FTWT would be able to provide reliable data for interpretation. During the evaluation of the test data, it was determined that several tests had poor data quality over time as expected. The final interpretation was performed on a test from the lower interval and the results are shown in Table 6.13. The FTWT interpretation was performed prior to the DST interpretation. The FTWT interpretation of permeability and near-well boundaries is very similar to the DST. As the FTWT was conducted only in the lower section of the sand, it indicates that there is good vertical communication within the sand.

Bay du Nord Member DST

The DST in the Bay du Nord member was performed in a thick, continuous sand. One of the most significant results of the DST is the radius of investigation, which directly relates to the area investigated and the interpretation of Oil-in-Place (OIP) in communication with the well. The radius of investigation at the L-76Z location is estimated at 3600 m during the main build-up. Due to the complicated structural and sedimentological nature of the area, this distance is not a straight line, but represents the communication across and around baffles and faults through the area.

One of the other main observations from the DST is the impact of rate and draw-down on the imaging of near-well baffles and boundaries. The results of the DST interpretation are shown in Table 6.14. The interpretations of permeability and the near-well compartment are very similar to the FTWT, but the size of the compartments away from the well are interpreted as larger in the DST. It is assumed that the differences are the result of draw-down,

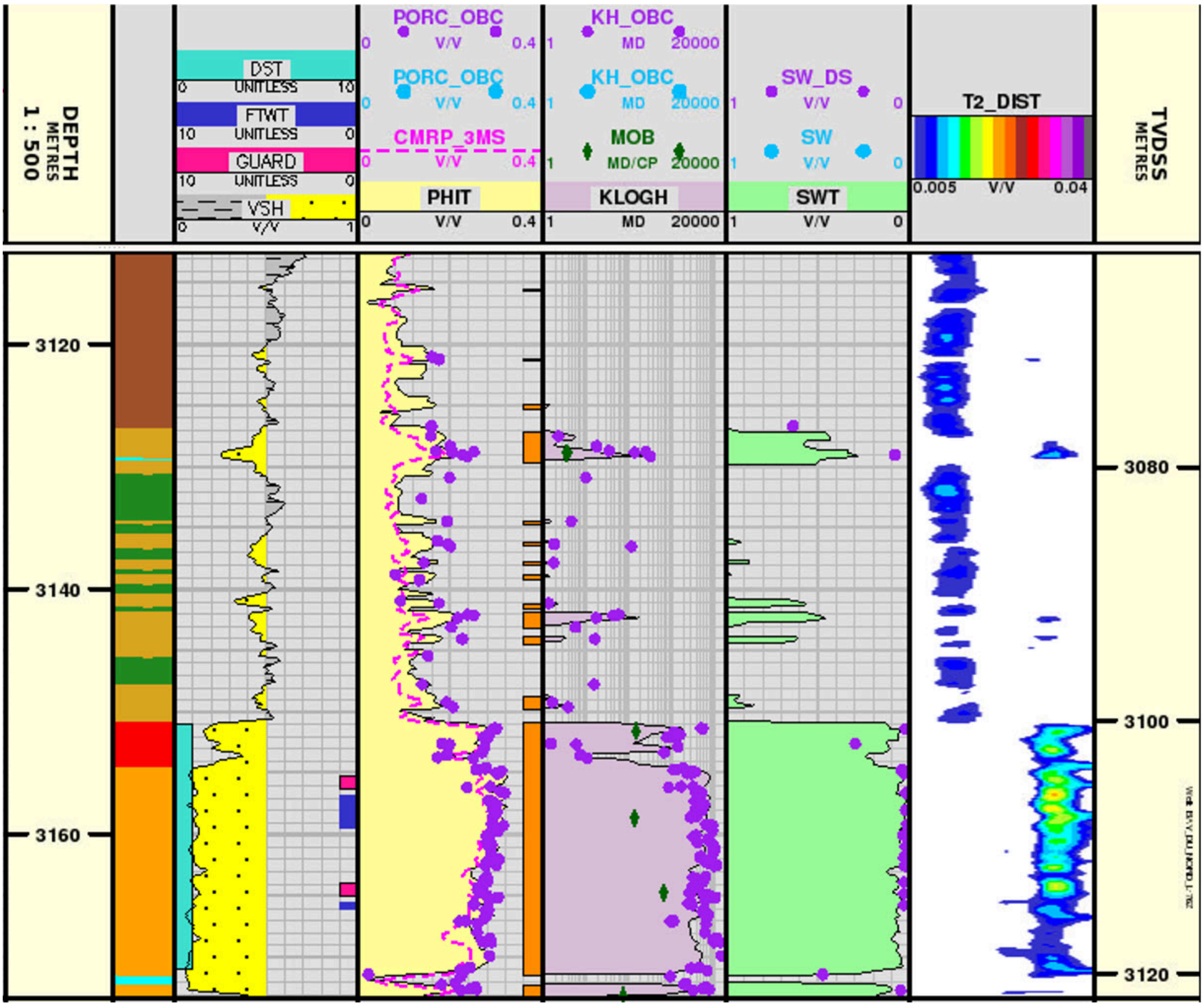


Figure 6.7 Bay du Nord L-67Z Well Test Intervals - Bay du Nord Member

with the DST having a greater draw-down and easier time overcoming baffles within the reservoir. The history match of the DST suggests that some of the boundaries observed in the FTWT may exist in the early draw-down and build-up interpretations of the DST; however, by the main flow and build-up periods flow across or around these features has occurred and they no longer impact the interpretation. This suggests that localized baffles will not have an impact on long-term production and recovery.

A detailed fault seal study was conducted to understand the nature of the faults and the potential for communication or isolation across them. When interpreting the DST, the fault seal study must be considered as one input. However, a boundary may be evident within the test, in an area that is expected to be open based on the fault seal analysis. This boundary may exist for several reasons, including:

- Uncertainty in facies juxtaposition across a fault;
- Uncertainty in fault offset;
- The potential for a fault damaged zone near the well; and
- Simplifications in the fault modelling process that may combine multiple faults into a single fault.

The impact of uncertainty in fault juxtaposition, multiple faults being modelled as one fault, and fault orientations were evaluated to understand the results of history matching activities. The observations from the history matching exercise result in a minimum level of communication that must be maintained within the dynamic models. Several options for matching the well test interpretation to the dynamic models, based on different levels of communication across baffles and faults within the region, were evaluated. In highly faulted scenarios, a large volume of oil must

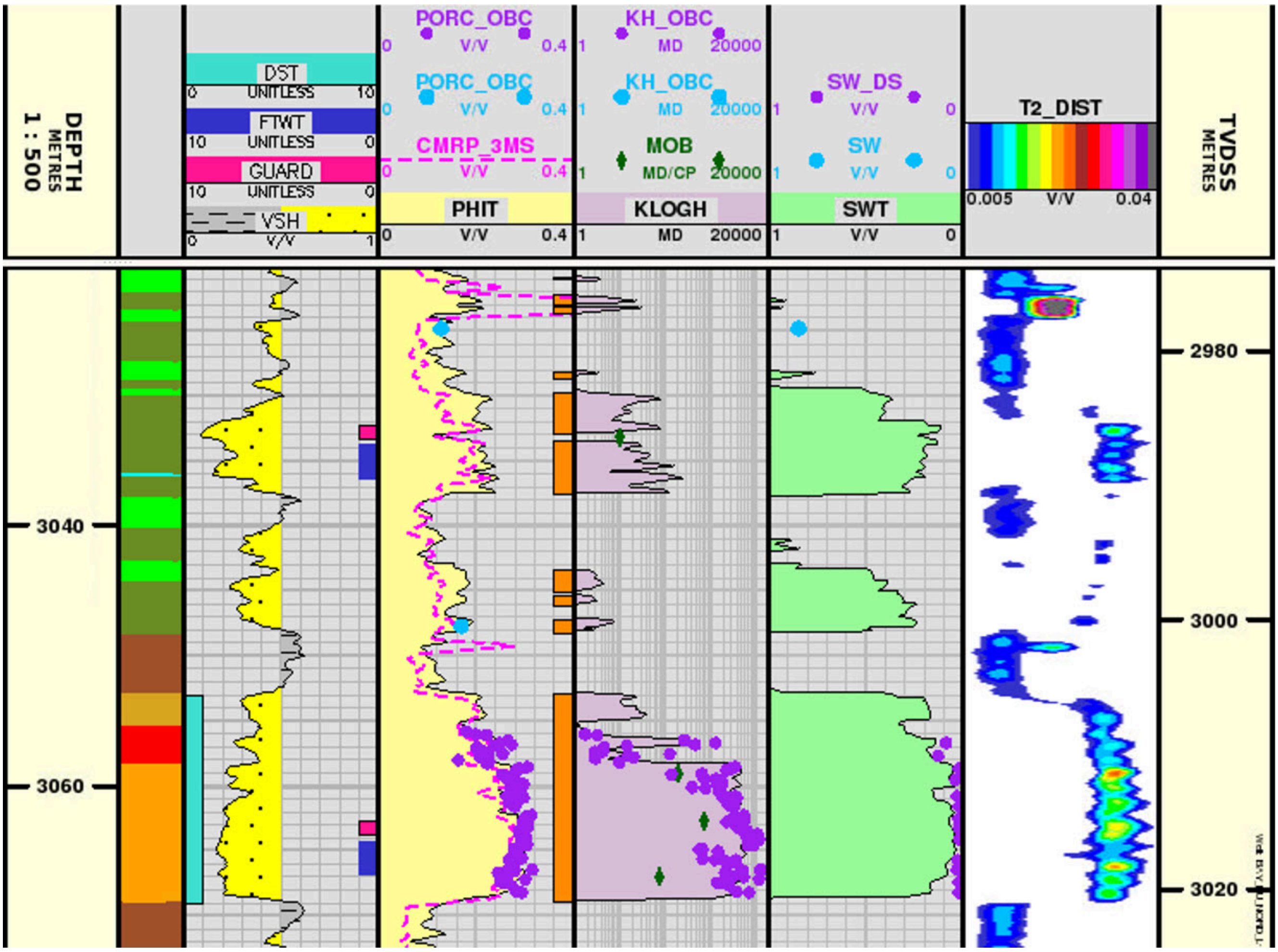


Figure 6.8 Bay du Nord L-67Z Well Test Intervals - Mizzen Member

exist closer to the well. When there is more communication, the OIP near the well may be lower but the well must communicate to an area outside of the highly faulted zone. Equinor's approach to dynamic modelling is discussed in Section 7.2 Reservoir Modelling and Uncertainty. In establishing the models for evaluating drainage strategy, it was ensured that uncertainty in OIP, faulting, and structure are considered in the cases with a minimum level of compartmentalization tolerated based on the test interpretation.

Mizzen Member FTWT

The Mizzen member is separated into three sands at the L-76Z location, with a test performed in each of the two upper sands. For the interpretation, the tests are designated as the upper and lower tests. The FTWT tool has three probes that are used to help define communication across the test interval. The tested sands and the locations of the probes are shown in Figure 6.8. The interpretation results for the upper test are shown in Table 6.15 and Table 6.16. The interpretation of the sample and guard interval data indicates that the location of the guard interval is in poor communication with the sample interval, likely due to a shale within the sand. This results in the interpretation of a small compartment near the well around the guard probe. The area around the sample interval is characterized by small compartments that open to a larger sand within 100 m of the well.

The lower test results are shown in Table 6.17. The test indicates a high-quality, elongated sand. Poor quality in the late-time data results in a wide interpretation range for the sand length. Responses in the observation, sample and guard probes indicates that there is good communication vertically within the sand. This interval was also tested with a DST, and the comparison of the DST and FTWT results will be discussed with the DST interpretation.

Mizzen Member DST

The Mizzen member DST interval is shown in Figure 6.8, and the DST results are listed in Table 6.18. The interpretation of permeability and near-well boundaries is consistent between the DST and the FTWT; however, the DST images the widening of the connected sand away from the well. The Mizzen member DST supports the same conclusions as the Bay du Nord member DST, which are that boundaries observed by the FTWT are likely associated with localized sedimentological or geophysical baffles and are overcome by larger draw-downs. Similarly, the test results prompt further examination of the boundary characteristics observed during the late-time phase of the DST, raising the question of whether these features represent barriers or baffles. Within the larger valley trend, incised valleys and channel abandonment deposits can contribute to localized baffles that may show as barriers in the well test interpretation and history match but have a limited impact on flow.

The well intersects the Mizzen member approximately 25 m from the nearest mapped fault. The close proximity of the fault, and the interpretation of boundaries near the well, suggest that the well is drilled through a fault damaged zone.

The Mizzen member test was also history matched within the dynamic model, and the results indicate that the model likely requires an additional fault in the south. Figure 6.9 shows a cross-section through the seismic interpretation along with the modelled faulting in the dynamic model. The circled area represents a possible fault or change in reservoir quality that is observed in the well test. Based on the results, a fault is recommended in the dynamic model as the simplest way to represent the baffle, as the well test does not suggest a sealed fault. The OIP in the region is based heavily on the well results and the geological concept, as resolving the Mizzen member on seismic data is challenging. The ability to match the well test within the model provides a high confidence for connected volume and the ability to develop the sand in this region.

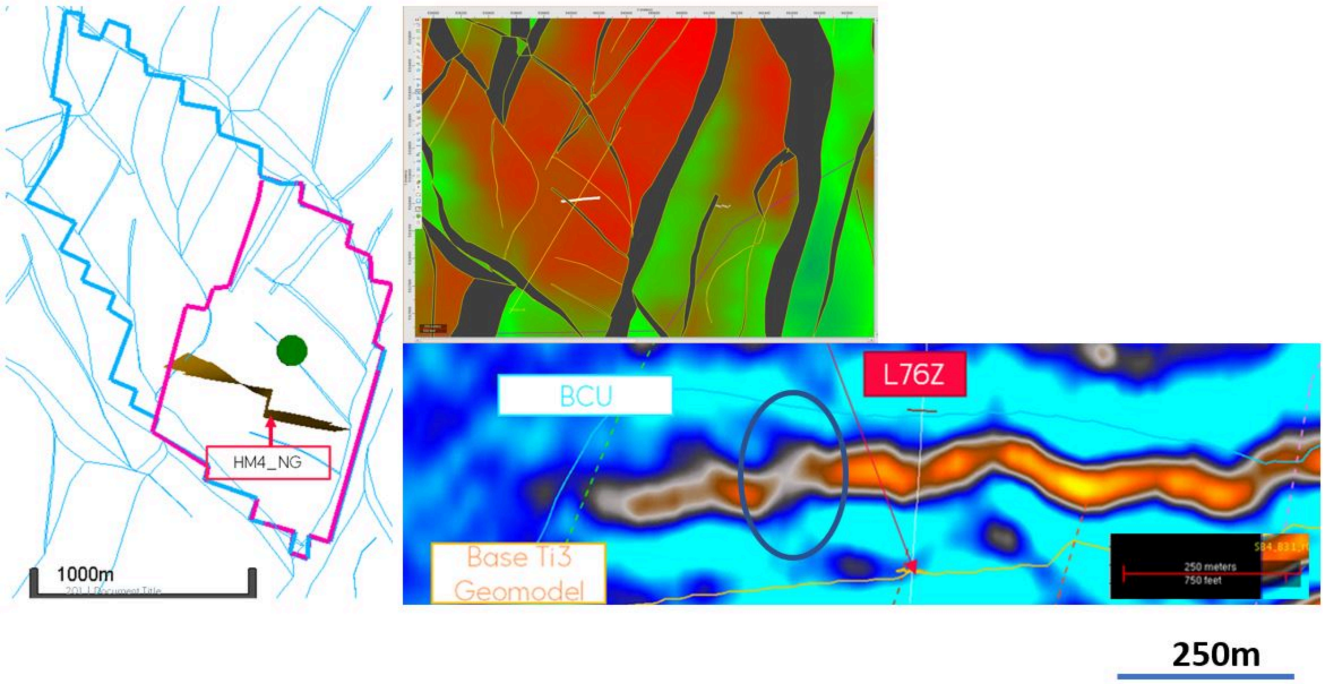


Figure 6.9 Bay du Nord L-76Z DST - Mizzen Member History Match and Faulting

Interpretation and Impact on Development Planning

Several history matches were evaluated to consider alternate arrangements of faults and communication pathways, juxtapositions, and transmissibilities. The interpretations were compared against uncertainty in the petrophysical, geophysical, and geological models to ensure alignment on most likely assumptions for the region. The different interpretations were tested for life of field production impacts and the learnings integrated into the drainage strategy. The main learnings are:

- Ensure that production wells cross the known and potential barriers and baffles within the area;
- Ensure that injection support is available in multiple locations to allow for optimization of communication pathways during the operational phase;
- Plan for inflow control within the producer to manage uncertainty in fluid movement and balance production across the whole well;
- A life of field data acquisition strategy is essential for proper management of the region. Consideration for flow control, tracers, fluid sampling, pressure monitoring in both producers and injectors, and the feasibility

for 4D seismic all should be considered within the strategy; and

- Creating pressure differences across the reservoir is important to ensuring flow across faults and geological features.

Table 6.13 Bay du Nord L-76Z FTWT Interpretation - Bay du Nord Member

Parameter	Model
kh-product, kHh (mDm)	125000
Horizontal permeability, kH (mD)	6800
Radius of investigation, rinv (m)	500 - 1100
Zone 1 Length and width (m)	100 / 275
Zone 2 Length and width (m)	120 / 320
Zone 3 Length and width (m)	550 / 120
Zone 4 Length and width (m)	Long / 140

Table 6.14 Bay du Nord L-76Z Bay du Nord DST Interpretation - Bay du Nord Member

Parameter	Multi-linear model
kh-product, kHh (mDm)	135000
Horizontal permeability, kH (mD)	7400
Total skin, s	5.1
Wellbore storage constant, C (m^3/bar)	0.007
Initial pressure, pi (bar) at 3095.02 m MD RKB	373.09
Radius of investigation (main build-up), rinv (km)	3.6
Radius of investigation (total test time), rinv (km)	4.9
Well position: xD / yD (1st block)	0.5 / 0.5
Zone 1 Length and width (m)	100 / 210
Zone 2 Length and width (m)	90 / 510
Zone 3 Length and width (m)	740 / 260
Zone 4 Length and width (m)	1100 / 490
Zone 5 Length and width (m)	460 / 200
Zone 6 Length and width (m)	Long / 180

Table 6.15 Bay du Nord L-76Z FTWT Interpretation - Upper Mizzen Member, Sample Interval

Sample Interval	Model I	Model II
kh-product, kHh (mDm)	690	690
Horizontal permeability, kH (mD)	200	200
Total skin, s	4.5	4.5
Wellbore storage constant, C (m^3/bar)	2·10-5	2·10-5
Initial pressure, pi (bar)	368.05	368.35
Radius of investigation (main build-up), rinv (km)	200	200
Radius of investigation (total test time), rinv (km)	300	300
Well position: xD / yD (1st block)	0.5 / 0.3	0.5 / 0.3
Zone 1 Length and width (m)	5.0 / 13.0	5.0 / 13.0
Zone 2 Length and width (m)	10.0 / 21.0	10.0 / 21.0
Zone 3 Length and width (m)	41 / 47	41 / 47
Zone 4 Length and width (m)	10 / 39	10 / 39
Zone 5 Length and width (m)	52 / 124	52 / 124
Zone 6 Length and width (m)	Long / 310	Long / 180

Table 6.16 Bay du Nord L-76Z FTWT Interpretation - Upper Mizzen Member, Guard Interval

Guard Interval	Type Curve Analysis
kh-product, kHh (mDm)	520
Horizontal permeability, kH (mD)	350
Total skin, s	4
Wellbore storage constant, C (m^3/bar)	1·10-5
Initial pressure, pi (bar)	368.4
Radius of inner circle, r (m)	6
Mobility and diffusivity ratio to outer circle (M1-2&D1-2)	2
Distances to 90° wedge boundaries (m)	20 and 30
Radius of investigation (BU #3), rinv (m)	80

Table 6.17 Bay du Nord L-76Z FTWT Interpretation - Lower Mizzen Member

	Minimum case	Maximum case
kh-product (mDm)	47000	47000
Permeability, kH (mD)	4300 to 5200	4300 to 5200
Distance to barriers (m)	22, 50 and 150	25, 80 and 300
Radius of investigation, rinv (m)	500	900

Table 6.18 Bay du Nord L-76Z DST Interpretation - Mizzen Member

Parameter	Multi-linear model
kh-product, kHh (mDm)	48000
Horizontal permeability, kH (mD) (h= 8 / 11 m)	5400 / 4400
Total skin, s	0.4
Wellbore storage constant, C (m^3/bar)	0.005
Initial pressure, pi (bar) at 2982.93 m MD RKB	364.75
Radius of investigation (main build-up), rinv (km)	1.4
Radius of investigation (total test time), rinv (km)	2.4
Well position: xD / yD (1st block)	0.36 / 0.5
Zone 1 Length and width (m)	73 / 150
Zone 2 Length and width (m)	58 / 440
Zone 3 Length and width (m)	230 / 220
Zone 4 Length and width (m)	150 / 160
Zone 5 Length and width (m)	150 / 110
Zone 6 Length and width (m)	290 / 160
Zone 7 Length and width (m)	360 / 180
Zone 8 Length and width (m)	Long / 150

6.2.4.4 Cambriol G-92 Well Test Overview

The Cambriol G-92 well encountered hydrocarbon-bearing reservoir sandstones in the Mizzen member. One well test was performed using the FTWT tool. A summary of the well test and the interpretation results is provided in Table 6.19.

Table 6.19 Cambriol G-92 FTWT Interpretation

Model parameter	Numerical model
Well model	Limited entry
Reservoir model	Homogeneous
Boundary model	Open channel
Kh (mDm)	15750
Permeability (mD)	1050
Skin	130
Distance to boundary (m)	50
Distance to boundary (m)	63
Radius of investigation (m)	300

The test was performed in the good quality Mizzen member, as shown in Figure 6.10. The main uncertainty in the interpretation is the thickness of the contributing formation. Between the top of the formation and the cement interval observed at 4415 mMD there is approximately 28 m of net pay. Using this thickness there is no match to the radial flow observed in the test. In the absence of any interpreted vertical boundaries within the test interval the maximum net thickness that can be matched to the radial flow period is used for the interpretation, 15 m. It is possible that the lower permeability zone at 4403 mMD is acting as a barrier due to the low draw down in the reservoir. The draw down was approximately 1 bar and with the high skin observed in the test the draw down in the reservoir is considered to be significantly lower. Based on observations from other tests within the Project Area, it is likely that the whole interval will be in communication during production. The permeability for the tested interval is estimated at 1050 mD, with the log permeability estimated at 1476 mD.

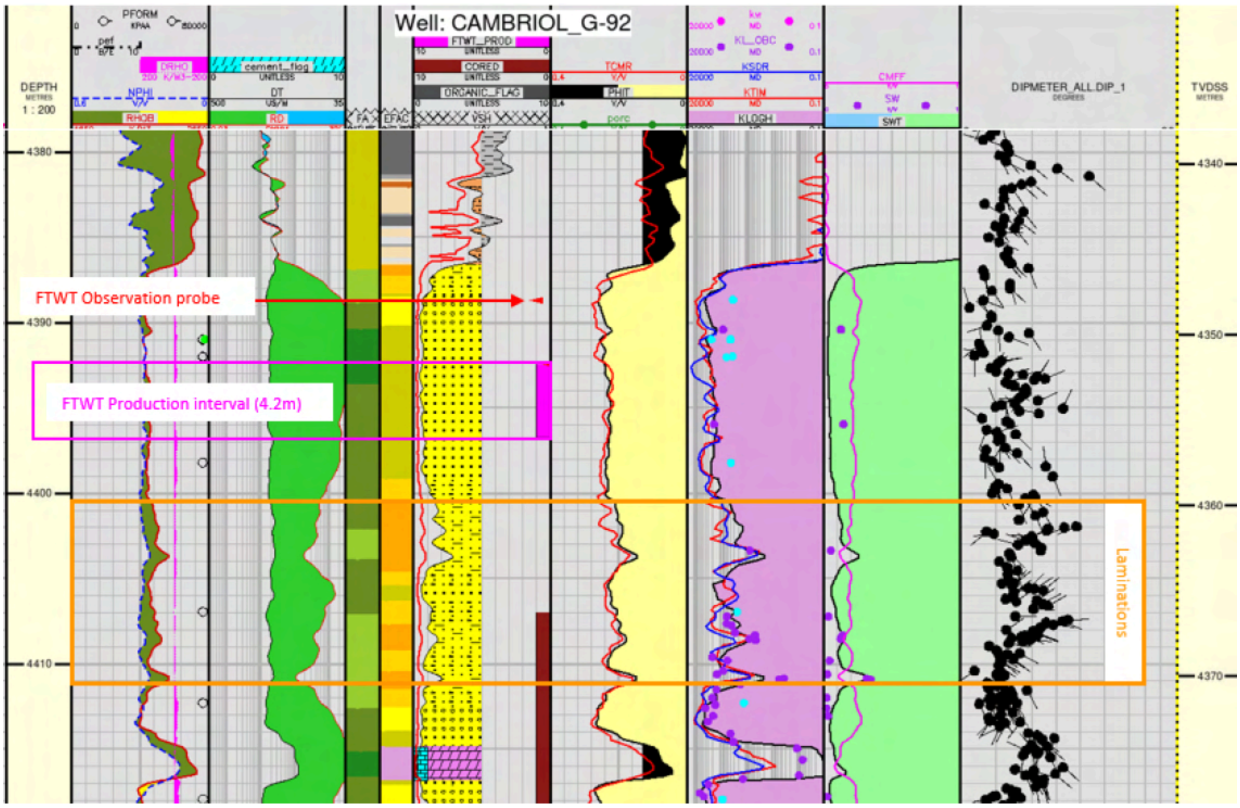


Figure 6.10 Cambriol FTWT Test Interval

The test interpretation indicates two no flow boundaries at 50 m and 63 m with one having limited extent. As shown in Figure 5.18, the well is approximately 100 m from a fault to the south and 200 m from a fault to the west. The combination of uncertainty in contributing thickness and low draw down make the interpretation of boundaries difficult. It is possible that they are sedimentological barriers to flow or sub-seismic faults. The impact of either on production is uncertain due to the low draw down of the test.

The well test results highlight the uncertainty in lateral connectivity that must be reflected in the reservoir models and addressed in the drainage strategy.

6.2.5 Rock Mechanics

Reservoir formation strength and elastic properties have been characterized through a combination of log evaluations, extended leak-off tests, and laboratory measurements. In addition, the Project's data acquisition strategy may include additional geomechanical data gathering to supplement the current data set as discussed in Section 7.5.3 Data Acquisition and Formation Evaluation Program.

Qualitatively, the Bay du Nord Field sands can be characterized by weak/soft to moderate strength and stiffness. The Cambriol Field sands have a higher strength than the Bay du Nord Field, but can also be considered weak to moderate strength.

Sand prediction analysis show that sand control is necessary for production and injection wells in the Bay du Nord and Cambriol fields. Grain size analyses indicate that an open hole Stand-Alone-Screen (SAS) solution is the optimal completion solution with the potential for gravel packs if lower quality or interbedded sands are encountered. With injection of colder fluids as part of the pressure maintenance scheme, it is expected that in-situ stresses will change over time.

Seabed subsidence is of minimal risk for the planned life of field reservoir pressure development in the Bay du Nord and Cambriol fields.

6.3 Production Engineering

6.3.1 Reservoir Flow Assurance Consideration

6.3.1.1 Scaling Evaluation

Scaling evaluations have been performed for the Bay du Nord and Cambriol fields. The evaluations consider the potential for scaling risk within wells, flowlines, risers, as well as topsides at a range of pressures and temperatures. The basis of the evaluations is the interaction between formation water and the increasing presence of seawater through field life. The results of the evaluations show the risk of barium and strontium sulphate scale is low for all fields, whereas calcium carbonate scale risk is present for all fields. In particular, carbonate scaling risk is elevated for the Cambriol Field and topsides.

Cambriol's high temperature and water-cut in productive oil wells, lead to a significant risk of carbonate scaling in tubing and subsea wellheads. Functionality for downhole continuous injection of scale inhibitor above the production packer shall be included in the design for producers at Cambriol. Functionality for backup injection upstream of the subsea choke is recommended in the case where subsurface injection fails. Acid treatment from a vessel for the wells and subsea cooler modules shall also be possible. The Bay du Nord Field has a medium risk of carbonate scaling at the wellhead and subsea template. Functionality for continuous injection of scale inhibitors upstream of the subsea choke shall be included in the design of Bay du Nord producers.

Due to high temperature in the Cambriol field, the large calcium carbonate scaling risk continues to topsides. When pressure is reduced there, the driving force to create calcium carbonate increases, thus, a robust scale mitigation strategy should be planned for, including continuous dosing with scale inhibitor. Chemicals suitable for subsea application often comes with limitations concerning chemical types and concentration. Therefore, two different scale inhibitor products/systems are required – one for subsea and one for topsides.

6.3.1.2 Wax Evaluation

There are two phenomena related to wax that have been investigated:

- Gelling of oil may occur if the system operates below the fluid's pour point; and
- Wax deposition restricts flow when the fluid temperature is below the Wax Appearance Temperature (WAT) and there is a driving force for molecular diffusion due to a temperature difference between the fluid and inner wall of the pipe or tubing.

Issues with gelling in the production system from the reservoirs to the separator are not expected, as the minimum pour point of separator oil is lower than the seabed temperature for all fields except Cambriol. Cambriol's pour point was measured at 4 °C, but this will be further depressed to below seabed temperature when the oil contains dissolved gas, as it will in the flowlines.

The WAT vary between upper 30 °C to mid 40 °C for all samples. For all oil samples, it was also observed that a very low solids fraction precipitates until around 25 °C.

During normal production, the fluid temperature in the production system will be kept above WAT (about 40 °C) by sufficient insulation for the flowlines. In addition to insulation, the electrical heat tracing on the Cambriol flowline can be used to heat the fluid to above WAT for low-rate production.

There will be no need for active measures to remove wax during normal operation for the production lines during early project life. Due to reservoir cooling, there is a possibility for temperatures to fall below WAT for the Bay du Nord Field production lines. Also, for abnormal operations with lower flow rates there is a possibility that the fluid temperature will be below WAT.

There are two main strategies for wax removal. The strategy for the Bay du Nord Field is two-fold. From topside to South manifold, to use the pair of flowlines as a flow loop and remove wax by hot oil flushing. Further out, to the North template, there is only one flowline, and therefore subsea to topside wax pigging is to be used.

The wax removal strategy for the Cambriol production flowline involves pigging for mechanical removal of wax deposits, if required.

The use of wax inhibitor is also under consideration as a backup option. Injection points will therefore be available at the template for both fields.

6.3.1.3 Asphaltene Evaluation

Studies have been performed on fluid samples from the Bay du Nord and Cambriol fields to understand the potential for asphaltene deposition in the production system and wells. Measurements of Asphaltene Onset Pressure (AOP) for both fields show a low tendency to precipitate asphaltenes on de-pressurization. The impact of injection gas on asphaltene precipitation has also been evaluated via gas titration experiments on Bay du Nord field, and a high risk of asphaltene precipitation was not identified.

Several asphaltene screening tools, such as the De Boer diagram as shown in Figure 6.11, have also been used to evaluate the potential for asphaltene deposition. This diagram shows low asphaltene risk for all fields except for the Cambriol Field, but experimental results for Cambriol showed low risk for asphaltene precipitation, and false positives on a De Boer diagram have been known to occur.

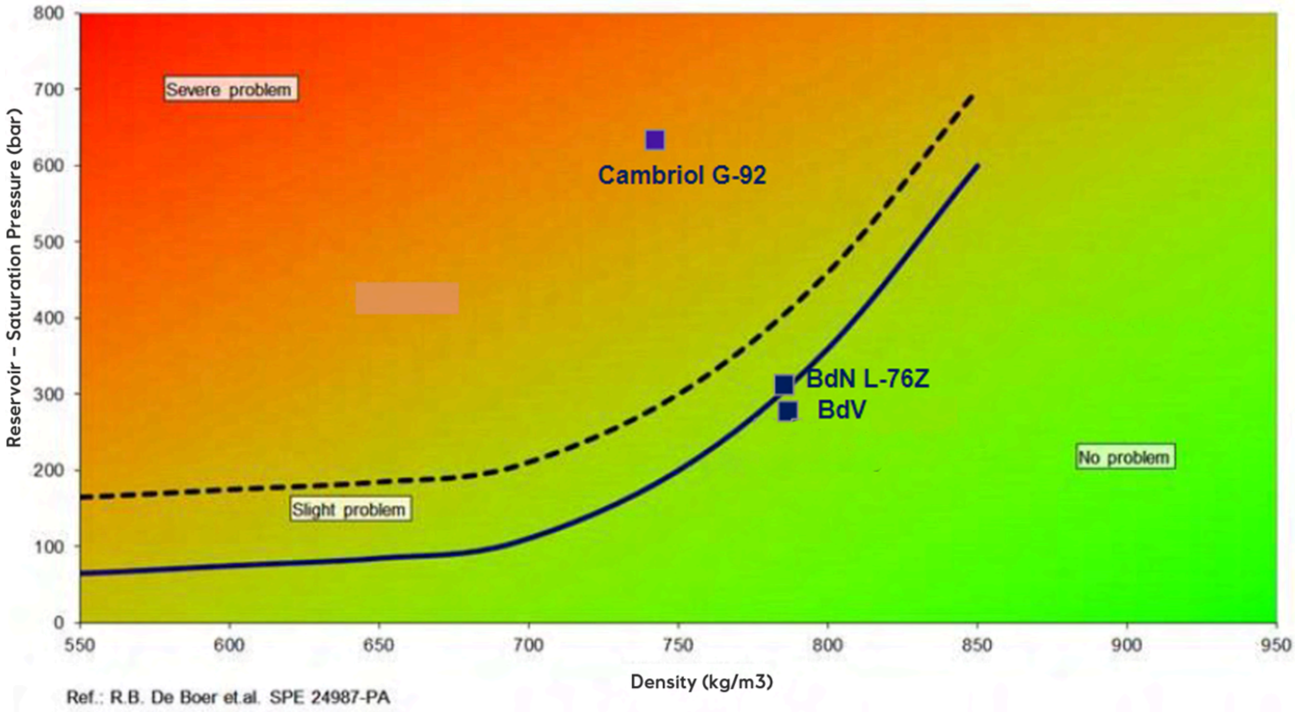


Figure 6.11 De Boer Diagram

Based on an integrated evaluation of asphaltene risk that considers asphaltene screening parameters and experimental results, the overall risk of asphaltene deposition is considered low and downhole chemical injection with asphaltene inhibitor is not required.

For the reservoir with gas injection (Bay du Nord), potential gas fingering with associated rapid increase of produced GOR may give a risk of asphaltene drop-out due to gas stripping. As a result, the possibility to inject asphaltene inhibitor at the Bay du Nord wellheads is maintained by the Project as a contingency.

6.3.1.4 Hydrate Evaluation

The deepwater, subsea development of the Project has a risk of hydrate formation within the subsea system (XT, manifolds, flowlines, riser bases and risers), the wells, and the reservoirs. The main elements of the hydrate management strategy for the subsea system are as follows:

- During normal production: maintain the fluid temperatures above the Hydrate Equilibrium Temperature (HET) using passive insulation in the subsea system.
- During prolonged production shut-ins:
  - For production flowline and riser loops, live fluids will be displaced with warm stabilized oil;
  - For single production flowline without electrical trace heating, live fluid will be displaced with injection gas and inhibited with mono-ethylene glycol (MEG); and
  - For flowlines with electrical-trace heating, live fluids will be kept warm or allowed to cool.
- During production start-up:
  - For production flowline loops and riser loops, the flowlines and risers will be warmed up from topside by circulation of warm stabilized oil prior to well start-up;
  - For single production flowline without electrical trace heating, MEG will be used to inhibit the water until fluid temperature in the entire flowline is above HET; and
  - For flowlines with electrical-trace heating, the flowlines will be re-warmed if allowed to cool down in order to clear any hydrates prior to production startup.

Warm deaerated seawater with biocide will be a back-up for circulation with stabilized oil both during shut-ins and start-ups of flowline and riser loops.

MEG will mainly be used as a Thermodynamic Hydrate Inhibitor (THI), and also used for subsea valve testing and equalization. MEG injection points will typically be upstream and downstream of the subsea choke, at the manifolds and riser bases. Detailed design for injection points will depend on the final design.

Hydrate studies have been completed for the Bay du Nord Field and the Cambriol Field.

A hydrate plugging risk study for Bay du Nord and Cambriol Fields fluid has been performed. The experiments showed that hydrate kinetics are unfavourable and hydrates are formed shortly after hydrate equilibrium conditions are reached. The plugging tendency of the fluid system was also found to be high based on the fluid's plugging characteristics and hydrate transportability.

The operation of a WAG drainage strategy on Bay du Nord Field generally has a high potential for hydrate formation because water and gas are available together at high pressure. Equinor ASA has several WAG wells in operation. There have been several incidents with hydrate plugs for WAG wells, and the learnings from these fields and incidents have been incorporated into the design of the Bay du Nord Field WAG system.

- The systems will be designed to prevent hydrates during normal operation and during switches between gas and water. For normal injection of either gas or water the main risk is leak across the valves separating gas and water on the manifold. An isolation valve (double expanding gate valve) between water and gas with the functionality for the cavity to be filled with high pressure MEG will prevent leakage across the valves. The risk of hydrate formation at wellhead, well, and reservoir during switch between gas and water will be managed by MEG injection and operational procedures.
- The hydrate formation potential is lowered for the WAG manifolds and wells by having insulated gas injection and water injection lines and risers to keep the injection fluid temperatures above the HET at the wellhead and well. Heating of the injection water is implemented to maintain the WAG well fluid conditions above the HET. This will also reduce the potential for reservoir cooling which could result in hydrate formation near the well and within the reservoir. The minimum fluid injection temperature at wellhead for WAG injection is planned to be 33°C.

6.3.1.5 Hydrogen Sulphide Souring Evaluation

Hydrogen sulphide (H_2S) has not been measured with well fluid samples taken in the Project Area, but a temperature-based correlation suggests that low levels of H_2S may be present in the initial reservoir fluids at the Cambriol Field. Additionally, it is expected that H_2S will be generated in all reservoirs when sulphate in injected seawater is metabolised by sulphate-reducing bacteria and archaea (prokaryotic micro-organisms). Reservoir souring simulations to assess the magnitude of reservoir souring in Bay du Nord and Cambriol fields have been conducted and demonstrated increasing H_2S levels through time as each field's water flood matures. Based on these results, the Project will be designed to manage the production of H_2S through the selection of appropriate materials and potential application of H_2S scavenger in injected gas.

6.3.1.6 Emulsion Management

Live oil batch separation studies have been performed on oil from Bay du Nord and Cambriol fields. The results of these studies show that Bay du Nord separation is the least challenging, with Cambriol being only slightly more challenging. Topsides use of emulsion breaker is required for the Project. Given the potential for emulsions in the small-bore subsea cooler piping at Cambriol, provisions will also be made for subsea emulsion breaker injection.

6.3.1.7 Sand Management

Sand prediction studies show that sand control is necessary for both production and injection wells. SAS is the preferred sand control solution that will be utilized. Optionality for alternative sand control solutions such as Open Hole Gravel Packing (OHGP) may be considered based on well performance. Assuming this sand control is in place, an expected solids production of 3 ppm by weight of produced liquid with a particle diameter of 84 μm is expected. In case of screen failure, sanding is considered possible until sand is detected by a monitoring system. Sand monitoring and calibration equipment are required on production wells and test separator. In addition, the inlet and test separator are planned with a jetting system that handles sand.

6.3.2 Well Productivity and Injectivity

6.3.2.1 Well Productivity

A probabilistic approach to calculating well productivity has been applied to each field for system hydraulic modeling and concept evaluations. Sensitivities based on petrophysical uncertainty analysis for reservoir permeability, thickness, and vertical anisotropy were defined and input into productivity models along with a range in completed well length and skin. The results from each sensitivity were fitted to probability distributions to define statistical parameters relating to possible well productivity outcomes.

Additionally, production tests for exploratory wells have been conducted in the form of Mini-DSTs, FTWTs, and DSTs. Results of these tests are described in Section 6.2.4 Well Tests and Interpretation. As part of the interpretation of those results, a productivity index was calculated for each test based on permeability-thickness derived from pressure transient analysis.

From a well productivity perspective, the Bay du Nord L-76Z well test interpretation validated the high-quality, high-permeability sands within the Bay du Nord Field. Using the meter corrected rates measured during the DST and the estimated draw-down from the downhole gauges, the measured well productivity from the Bay du Nord member DST is 125 Sm^3/d/bar.

Cambriol G-92 encountered high-quality, high-permeability sands similar to that encountered at Bay du Nord L-76Z. The G-92 FTWT produced at a lower rate than a DST with a higher skin factor observed leaving uncertainty in the well productivity estimation.

It is observed at Bay du Nord L-76Z that the pressure drop across near wellbore barriers, baffles, and internal faults has a greater impediment to inflow than the pressure drops associated with permeability or skin and the same is expected at Cambriol. These near wellbore impacts will be mitigated through the use of several horizontal wells with lengths ranging from approximately 100 m to 1500 m in the reservoir section. The variance in well length reflects the use of multi-target wells which cross faults. These wells may enter and leave the target reservoir or pass through low-quality sands that will not contribute to production. Therefore, the actual productive length of the wells will typically be lower than the lengths referenced.

6.3.2.2 Well Injectivity

Thermal fractures commonly develop in offshore subsea fields that employ water injection for pressure support. For the fields in the project, it is expected that well injectivity will be dominated by fractured injection, which generally provides an increased injectivity relative to matrix water injection. Injection studies have been completed for each field using modeling software, such as Reveal, Stimplan or a combination thereof, which models fracture development considering both thermal effects and plugging.

Additional geomechanical studies are ongoing to further refine injection well placement and ensure water injection at defined rates and pressures is feasible from both a safe injection and a well injectivity standpoint. Ensuring sufficient water quality to maintain injectivity and injection rate throughout the Project, while avoiding out-of-zone injection, forms the foundation of the Water Management Plan outlined in Section 7.5.2 Water Management Strategy. For fields with a WAG drainage strategy, matrix injection is expected during the gas cycle as fracture pathways close when water injection is stopped.

6.3.3 Field Hydraulic Studies

The selected concept for the Project consists of an FPSO that is connected to development wells through the SPS. A range of hydraulic modelling methods for the SPS was used to provide accurate assessment and optimization of the Project.

All production and injection wells are equipped with 7" OD tubing with maximum liquid rate of 8000 Sm3/day. The flowing wellhead temperature is calculated with geothermal gradient and tubing heat transfer coefficient of 7 W/m2/K. The hydraulic performance of the wells was modelled using the Prosper software program, which generated hydraulic tables for use in dynamic reservoir models and GAP software. Examples of the tubing performance curves are shown Figure 6.12 and Figure 6.13 for the Bay du Nord and Cambriol fields. The curves relate a wellhead pressure, liquid rate, water cut, and artificial lift rate to a bottom hole pressure. The well models were used in the assessment of tubing size and artificial lift solutions. Individual flowlines were also modelled using Prosper hydraulic tables and included in field-level reservoir simulations to capture the effect of flowline hydraulic constraints on field and well potential.

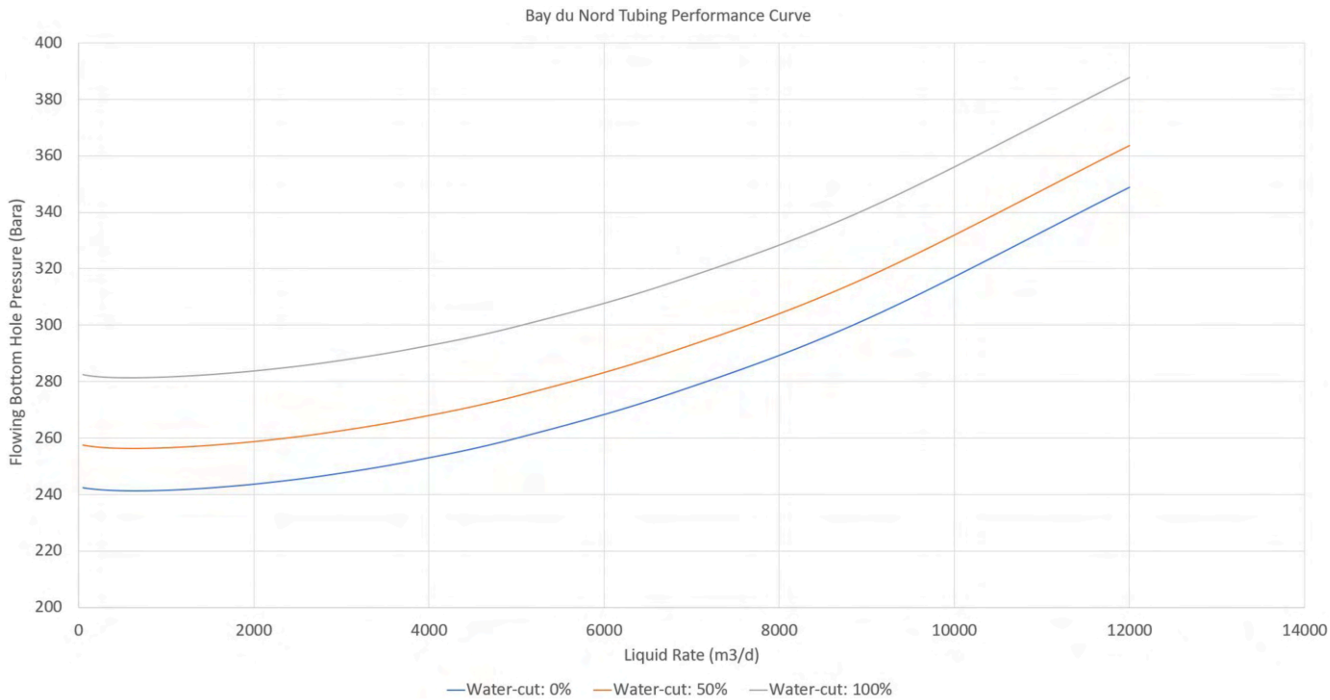


Figure 6.12 Bay du Nord Field: Example Tubing Performance Curve

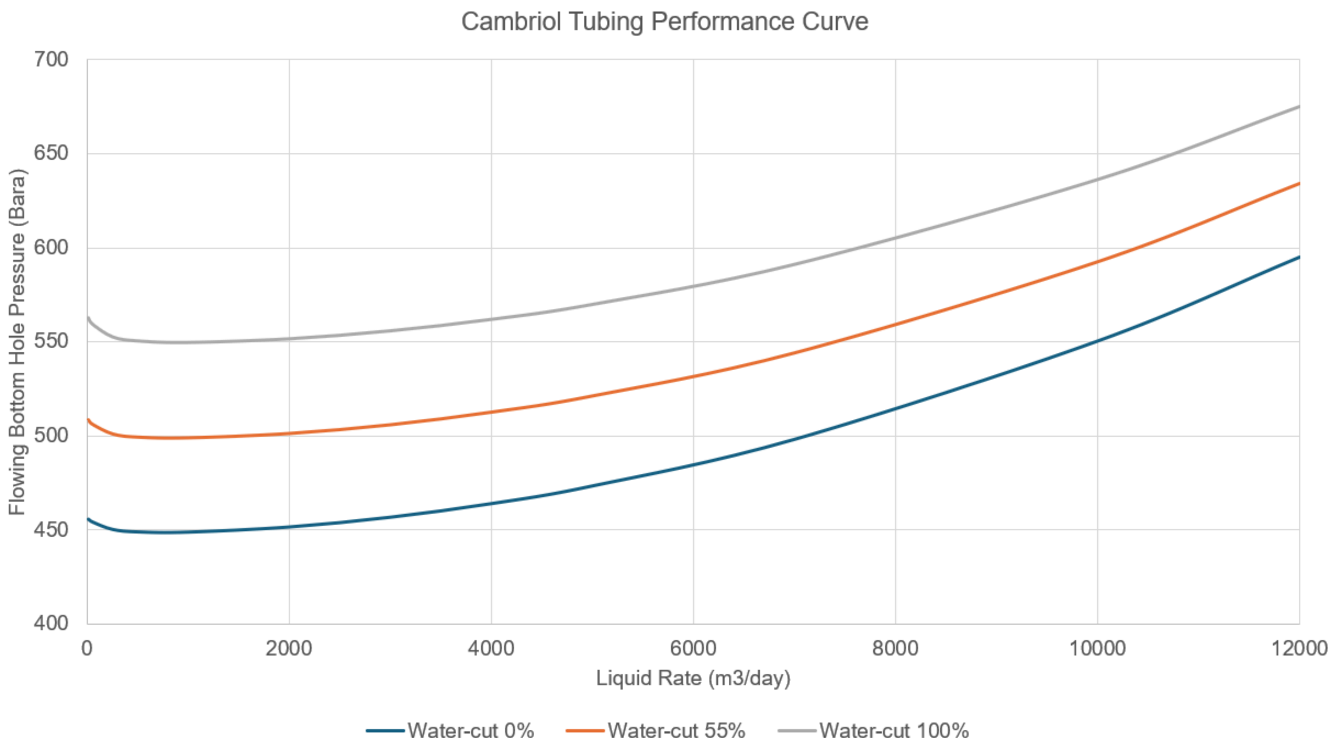


Figure 6.13 Cambriol Field: Example Tubing Performance Curve

Full modeling of the production network was accomplished through two methods. The first is hydraulic modelling in the GAP - Resolve - Eclipse software programs, and the second is coupled reservoir simulation modelling using only Eclipse and hydraulic tables.

- The GAP - Resolve - Eclipse model was set up for detailed study of project hydraulic performance and optimization potential under applied production and injection constraints such as liquid rate, gas rate, fluid velocity, operating pressures and temperature. Reservoir performance is driven by Resolve linked with Eclipse reservoir simulation models for each field where the well control and time stepping is taken over by Resolve. This method produced a detailed reference case for design basis.
- The coupled reservoir simulation model using Eclipse and hydraulic tables employed a simpler set of constraints and optimization algorithms but still accounted for the impact of risers and flowlines on reservoir performance, while enforcing a gas balance between all fields. This allowed simulating field drainage strategies impact on reservoir performance explicitly. This method enabled running an ensemble of reservoir models capturing uncertainty in production / injection profiles and oil reserves.

Flow assurance work in the project was performed by use of a transient multiphase simulator (OLGA by SLB). The flow assurance work consisted of establishing operating strategies, determining both host facility and subsea system requirements. The thermal-hydraulic design evaluates the life cycle performance of the entire production system. This also includes the assessment and strategy to handle either organic or inorganic solids that can result in flow reduction.

The flowline size has been evaluated by steady-state simulations (Prosper and GAP) with the criteria of available pressure drop, allowable erosional velocities and flow regime. The steady-state simulators assume constant parameters in time with regards to pressures, temperatures, flow rates and liquid hold-up. The transient flow assurance simulations provide the same output parameters as the steady-state simulations, but the variations of parameters will be shown as a function of time. This allows for modelling of dynamic phenomena, like slug flow, and the operation of the pipelines in more detail. Operations such as shut-downs, start-ups, liquid handling and rate changes are all captured. Evaluating the cool-down time has been particularly important for a deepwater oil system in order to determine the insulation level required for subsea equipment and to establish an effective hydrate control strategy.

The production flowline sizes have been recommended to maximize the production rates from the reservoirs, while also allowing for the production of individual wells to the test separator whenever feasible. The recommended flowline diameter is a balance between rates, structural integrity, installation feasibility and time, and cost. Additional studies on flow stability in the riser-flowline system are ongoing and may lead to changes in production line size at select fields.

7 Reservoir Exploitation

7.1 Overview

The Bay du Nord Project (the Project) is jointly targeting the development of hydrocarbons in the Bay du Nord and Cambriol fields. The reservoir exploitation plan assumes that production from both fields start simultaneously. This will be further assessed as the Project matures in the Front-End Engineering Design (FEED) and detailed design phases.

The Project will be the first deepwater development in the Canada-NL offshore area, and is the first project located outside of the Jeanne d'Arc Basin. These factors, combined with the reservoir and fluid characteristics of the fields, are important components in evaluating and selecting a safe, sustainable, and efficient drainage strategy for the Project.

The Project team has completed a comprehensive reservoir assessment and evaluated several drainage strategies. This evaluation involved assessing the seismic and data acquired during the exploration and delineation of the resources, and incorporating this analysis into simulation models to determine the most effective drainage strategy to maximize the recovery of the resource. Part of the drainage strategy assessment involved identifying mechanisms for Improved Oil Recovery (IOR), and assessing future development opportunities within the Project Area. The IOR mechanisms and future development opportunities, and the conditions that may lead to their incorporation into the depletion plan, are outlined and discussed in this section.

Extensive data acquisition, which included multiple seismic programs, numerous regional exploration wells and sidetracks, as well as multiple flow tests, was undertaken in the Project Area. Additionally, a wide range of subsurface and field development analyses and studies were completed to further the understanding of the reservoir extent, quality, and deliverability. Equinor has also incorporated analogue data and knowledge gained from producing operations in the Canada-NL offshore area, as well as from Equinor ASA's international project portfolio, to further optimize the Project reservoir exploitation plan. The Project will use all of these data and analyses to ensure that the recovery of the economic resources is maximized. The Project will continue to learn through the development and operations phases, via data acquisition and analysis, to improve understanding of future development opportunities and IOR opportunities. This strategy will ensure a robust development of the known and expected resources, along with the undefined potential resources within the Project Area.

The known hydrocarbon accumulations in the Flemish Pass Basin are all highly undersaturated oils with limited volumes of solution gas. With no commercial options to export the gas, the Project intends to develop the Bay du Nord Field with a crestal gas injection and Water-Alternating Gas (WAG) drainage strategy using the produced solution gas from both Bay du Nord and Cambriol fields. This approach allows for a flexible field design to adapt to the uncertainty of gas movement within an oil reservoir. The size of the WAG region within the fields can be adapted over time to address poor gas flood performance or an increase in hydrocarbon development and the requirement to manage additional produced gas. The development concept will also allow for future gas injection to other fields which may be required to develop new discoveries in the region or to manage gas from the existing fields.

The key objectives of the reservoir exploitation plan include:

- Defining an economic project based on a combination of known and expected hydrocarbon accumulations;
- Developing a robust drainage strategy that is responsive to the uncertainties and opportunities within the fields;
- Planning for wells that address uncertainties and allow flexibility to access resources in multiple blocks and net reservoir sands;
- Developing a knowledge-based depletion plan, using existing knowledge to plan and place early wells that in turn help plan and place future wells;
- Data acquisition and implementation of new technologies to improve understanding of the reservoir and resources throughout the development; and
- Focus on maturing options to improve recovery beyond the base development scope.

The Bay du Nord Field development focuses on delineated resources with a data acquisition strategy to permit the development of secondary targets. The data acquisition strategy will help identify opportunities to improve production performance, enhance recovery, and plan for infill wells and further development targets. Key objectives for data acquisition are to:

- Improve understanding of fluid contacts;
- Evaluate the extent of the incised valley and deltaic deposits in the Bay du Nord and Mizzen members;
- Evaluate the resource within undelineated blocks;
- Evaluate the impact of structural and sedimentological features on recovery; and
- Understand the behaviour of gas within the reservoir and use that gas to improve oil recovery.

The Cambriol Field development focuses on a combination of delineated and undelineated resources with a data acquisition strategy to permit the development of secondary targets. The data acquisition strategy will help identify opportunities to improve production performance, enhance recovery, and plan for infill wells and further development targets. Key objectives for data acquisition are to:

- Improve understanding of fluid contacts;
- Improve the quality of the seismic interpretation and the mapping of good quality reservoir sands;
- Evaluate the resource within undelineated blocks;
- Evaluate the extent of the delta front sands;
- Evaluate the resource potential within the Mizzen reservoir; and
- Evaluate the impact of structural and sedimentological features on recovery.

The level of delineation varies between fields and this is reflected in the depletion plans and data acquisition strategies for each field. There is sufficient well control within the Project Area to define the resources that support the development concept. However, there is still uncertainty in the hydrocarbon extent, as Oil-Water Contacts (OWCs) are not defined. The resource assessments and the depletion plans take into consideration the uncertainty in hydrocarbon presence and OWC locations. Well placement, well requirements, data acquisition strategy, concept flexibility, and resource estimates reflect the uncertainties in each field.

The Project is situated in water depths of approximately 600 M to 1200 m with the fields located from 5 km to 34 km to the proposed location of the Floating Production, Storage and Offloading (FPSO) facility. These form part of the unique production and flow assurance challenges for a project in the Canada-NL offshore area. The evaluations of these challenges, as they relate to reservoir exploitation, are covered in Section 7.5.6 Artificial Lift and Section 6.3.3 Field Hydraulic Studies.

Additional details related to the specific fields, their chosen drainage strategies, and alternate drainage strategies that were evaluated are provided in Section 7.3 Bay du Nord Field Exploitation and Section 7.4 Cambriol Field Exploitation. A detailed discussion on the gas management strategy, water management strategy, alternatives that were evaluated, and considerations for future developments are provided in Section 7.5 Reservoir Management.

7.2 Reservoir Modelling and Uncertainty

An overview of the static reservoir modelling workflow is given in Section 5 Reservoir Models. The dynamic models for each of the fields in the Project are presented in Section 7.3.1 Simulation Model and Section 7.4.1 Simulation Model.

Field-Level Modelling

As noted in Section 5.1 Summary, Equinor ASA uses an in-house developed integrated reservoir modelling approach. This approach allows for a workflow delivering models generated in Roxar RMS to be exported and simulated in Eclipse.

This approach allows for a more robust method of evaluating sensitivities and future IOR opportunities. IOR is defined as any opportunity to improve recovery beyond the assumptions in the base development plan. For the Project, the FMU approach may be used to:

- Define a realistic recovery factor range to apply to blocks not included in the base development;
- Assign a probability for development to the undeveloped blocks;
- Evaluate bypassed oil and possible infill drilling opportunities within the developed area; and
- Assign value to a data acquisition strategy that allows for the maturation of the resource description with a focus on identifying future development opportunities.

IOR opportunities for the Project are discussed in Section 7.7 Improved Oil Recovery.

The number of model instances, referred to as realizations, in an evaluation can range from a single reference case to several cases covering the recovery range from P90 to P10, to hundreds of stochastic cases. For the Development Plan assessment, 51 realizations are considered for each of the fields in the Project, referred to as an ensemble for a given field. This covers the uncertainty range for each field and provides a robust set of inputs for the integrated production forecasting and dynamic uncertainty assessment of the full project.

In the static reservoir models for the two fields, the main parameter uncertainties included in the evaluations are summarized in Table 5.1 and Table 5.2. In the dynamic reservoir models for the two fields, the cases include uncertainties from both the static uncertainty evaluation and a set of dynamic uncertainty parameters. The main dynamic parameters included in the evaluations are summarized in Table 7.1. Other parameters were screened for their impact on production and recovery prior to selecting these parameters for inclusion in the uncertainty study. These included the well production rates, fluid properties and facility capacities. The selected parameters were deemed to have the greatest influence and other parameters were excluded at this time to simplify the evaluations.

Table 7.1 Project Dynamic Uncertainty Parameters

Uncertainty Parameter	Description
Relative Permeability	Low, base and high relative permeability curves are defined as described in Section 6.2.3.1 Relative Permeability.
Skin	Three skin values are included to represent the uncertainty in mechanical skin created during the drilling and completion of the wells.
Water Injection Rate	There are practical limitations associated with the maximum water injection rates of each well. A range in maximum injection rates are applied to each well to account for limitations imposed by completion design and reservoir properties (e.g. permeability and high-quality reservoir facies thickness).
Fault Seal	Low base and high fault seal interpretations are applied by calculating fault permeabilities based on shale gouge ratio. Interpretations are based on assumed burial depth, temperature, phylosilicate content and analogue data.

The main considerations in the model set-up related to drainage strategy are:

- OWCs;
- Reservoir quality;
- Fault behaviour;

- Structural interpretation;
- Distribution of facies;
- Relative permeability;
- Well productivity; and
- Well injection rates.

Other parameters are retained in the uncertainty study because they have an impact on production rates and economy, or they provide insight into future opportunities for improvements in production.

These uncertainties form the basis for evaluations and decisions in defining the drainage strategy. Sensitivities to individual parameters for each field are presented in Section 7.3.4 Sensitivity Studies and Section 7.4.4 Sensitivity Studies along with the range in individual field production resulting from each field's uncertainty study.

Project-Level Modelling and Production Profile Generation

The two fields of the Project have separate dynamic simulation models. To generate Project level production profiles, two methods are employed:

- Coupled modelling; and
- Profile stacking.

Coupled modelling is when individual realizations for a group of fields are linked together and simulated as one dynamic modelling process with linked hydraulic modelling as detailed in Section 6.3.3 Field Hydraulic Studies. The Resolve software is used to couple GAP models of the oil production, water injection, and gas injection networks linking the fields, the topsides facility, and the subsea infrastructure with Eclipse models of the subsurface. This process takes significantly more time and resources than performing individual simulations for a field and is only used where consistency is required between fields for specific studies or reporting. Due to the robust modelling of production and injection streams from reservoir to FPSO, this modelling methodology exposes far more data than the standalone Eclipse models; temperatures, pressures, and rates are available from wellhead to the FPSO. Resolve coupled modelling is used to generate the base case provided in Section 7.6 Drilling Schedule and Production Forecasts. Eclipse coupled modelling is a similar, but slightly less robust, style of modelling. Here, temperatures are assumed to be constant and the hydraulic modelling is done using lookup tables produced by Prosper. An ensemble (set of 51 models/realizations) of Eclipse coupled models is used to assess the low and high cases in Section 7.6 Drilling Schedule and Production Forecasts.

Profile stacking is the process of integrating the results from independent dynamic simulation models into a common set of production profiles that honour common system constraints. This method does not perform reservoir simulations or material balance calculations itself; it uses existing simulation data as input. The input data comes from the Eclipse reservoir simulations for each field. This method can also use manually generated production profiles, in combination with profiles from other sources. The input production data is provided as a table of four columns. For an oil production well, the profile table consists of oil potential rate, water cut, and Gas-Oil Ratio (GOR) given as functions of cumulative oil production. In the presence of production constraints, the calculation of integrated well rates from the input production data is based on the summation of potential oil rates until one of the systems limits is violated: an oil, a water, a liquid or a gas limit. When a limit is reached, one or more of the well oil rates have to be reduced to honour the system constraint. At each time step the output well rates are determined by solving an optimisation problem to maximize the volume of oil produced within the system production constraints. Production constraints can also be included at other points beyond just the top-level to honour flowline or well level constraints. IPOS is the tool used to stack well profiles and assess project level recovery. As IPOS is only solving a relatively simple optimization problem instead of a complicated network of pressure, temperature, and flow calculations, the processing time is small and more realizations can be simulated. For this reason, IPOS is the tool used to populate Section 9.3 Recoverable Resource Estimates. A set of 1500 realizations of project level recovery is simulated and the statistics are used as the best estimate of recoverable resource for the project.

7.3 Bay du Nord Field Exploitation

The main depletion plan options evaluated for the Bay du Nord Field are associated with the type of pressure support, the type of wells, and the type of artificial lift required for the recovery of the expected resources.

The pressure support and voidage maintenance options evaluated are:

- Water-flood development;
- Water-flood development with a crestal gas-flood; and
- WAG flood.

No consideration was given to primary recovery within the Bay du Nord Field. The field is overpressured and highly faulted which makes it improbable that there will be an active aquifer to provide pressure support. The combination of structural and sedimentological baffles and barriers also increases the likelihood of low-pressure support from the flanks of the field. Finally, with a highly undersaturated oil, there is little natural energy within the reservoir outside of the initial over pressure. Following a brief period of production, it is expected that wells on primary production would be shut-in. The addition of artificial lift mechanisms to a primary depletion strategy were not pursued as traditional secondary drainage strategies provide for a more robust development concept.

The selected option is a combination crestal gas-flood/water-flood and WAG flood.

The Bay du Nord Field's depletion plan considers the use of the following subsurface technology in developing the reservoir:

- Multi-lateral wells;
- Multi-target wells;
- Zonal control;
- Inflow control; and
- Artificial lift;

The following sections describe the main elements of the base depletion plan along with opportunities over the life of the development. The chosen depletion plan meets the following criteria:

- Maximize the economically recoverable oil from the known and expected hydrocarbon accumulations within the field;
- Acquire data through the drilling of development wells and operation of the field to address the known uncertainties within the field and identify additional potential for development; and
- Ensure that the gas management strategy has the capacity to adapt to the uncertainty in the Project's recoverable resources and the potential for the development of other resources in the region to the production installation.

7.3.1 Simulation Model

The Eclipse 100 simulation software from SLB was used for drainage strategy and reservoir exploitation plan evaluations in the Project.

The geological model for the Bay du Nord Field is built in the RMS software from Roxar and exported to Eclipse for simulation with no upscaling performed. This ensures that the dynamic model honours the structural and geological concept developed by the geoscientists. The typical grid size is 100 X 100 X 1 m. The total number of cells in the model is 6,424,200 with 150,000 to 250,000 cells active during simulation, based on the area being evaluated. The model is separated into two main areas, the Bay du Nord area to the West and the Bay de Verde area to the East, as shown in Figure 7.1. The field is further divided based on the two members considered in the development, the Mizzen member and the Bay du Nord member. The Mizzen member includes layers 1-180, while the Bay du Nord member includes layers 181-300.

Maps showing the Original Oil-In-Place (OOIP) distribution of the Bay du Nord and Mizzen members are shown for the reference case in Figure 7.2 and Figure 7.3. As discussed in Section 7.2 Reservoir Modelling and Uncertainty, multiple models were generated for the field during the drainage strategy assessment. Unless otherwise noted, the cases shown are for a reference case that was chosen due to its representation of the expected OOIP and recoverable volumes.

The flow parameters model (SCAL) and fluid model (PVT) are described in Section 6.2.3.1 Relative Permeability and Section 6.2.2.1 Fluid Models. OWCs used in the reference case are described in Section 6.2.1.1 Fluid Contacts. A detailed fault seal analysis study was performed to characterize the nature of the faults and as input to the fault seal modelling work performed in RMS. The model was initialized with the base fault seal assumptions, which provide moderate restrictions to flow where high-quality reservoir facies are juxtaposed. Where the Bay du Nord and Mizzen members are juxtaposed, it is assumed that the faults are sealing within production time.

A summary of the OOIP distribution in the field is included in Section 9.2 Original Hydrocarbon-in-Place Estimates.

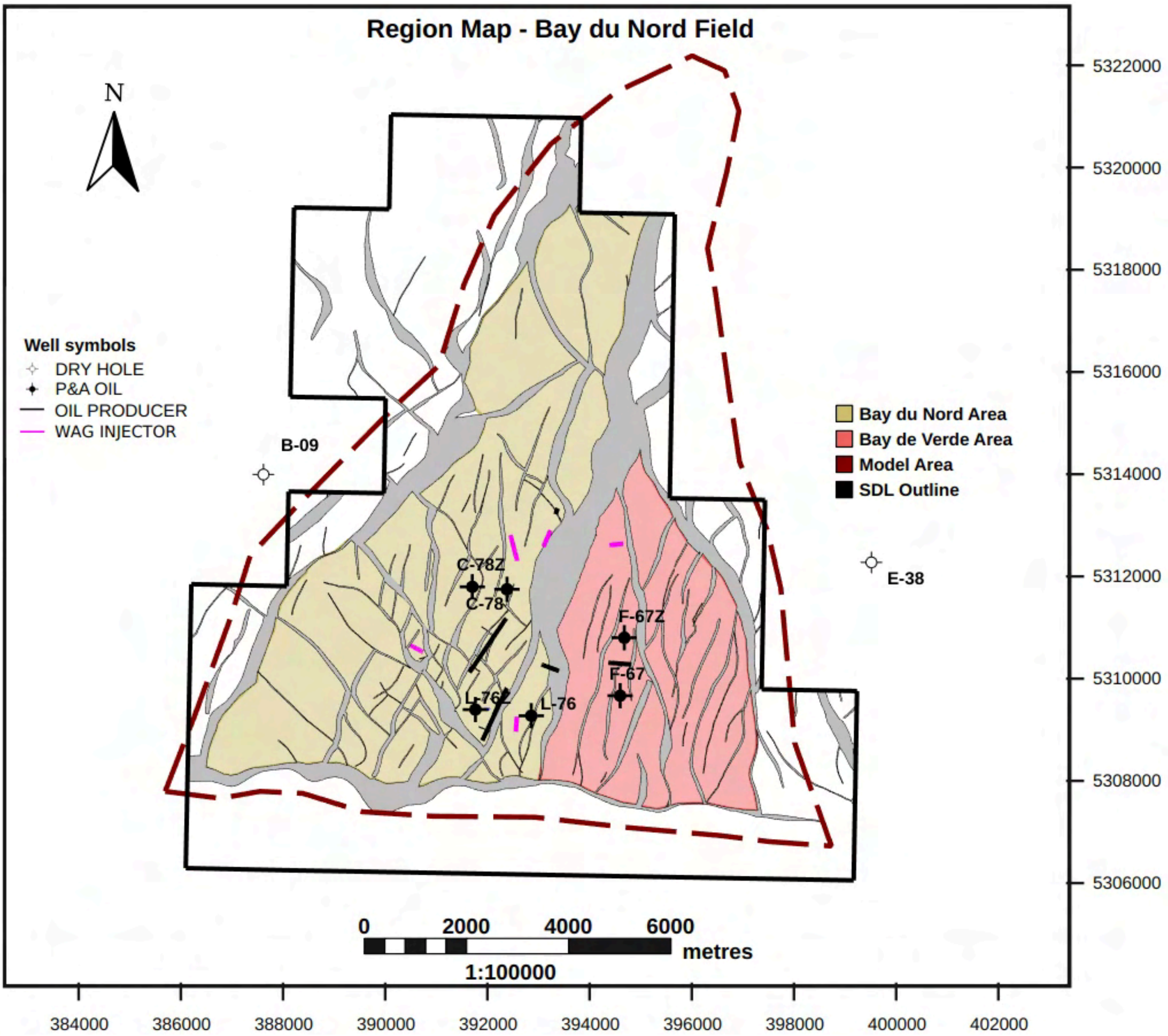


Figure 7.1 Bay du Nord Field - Regions

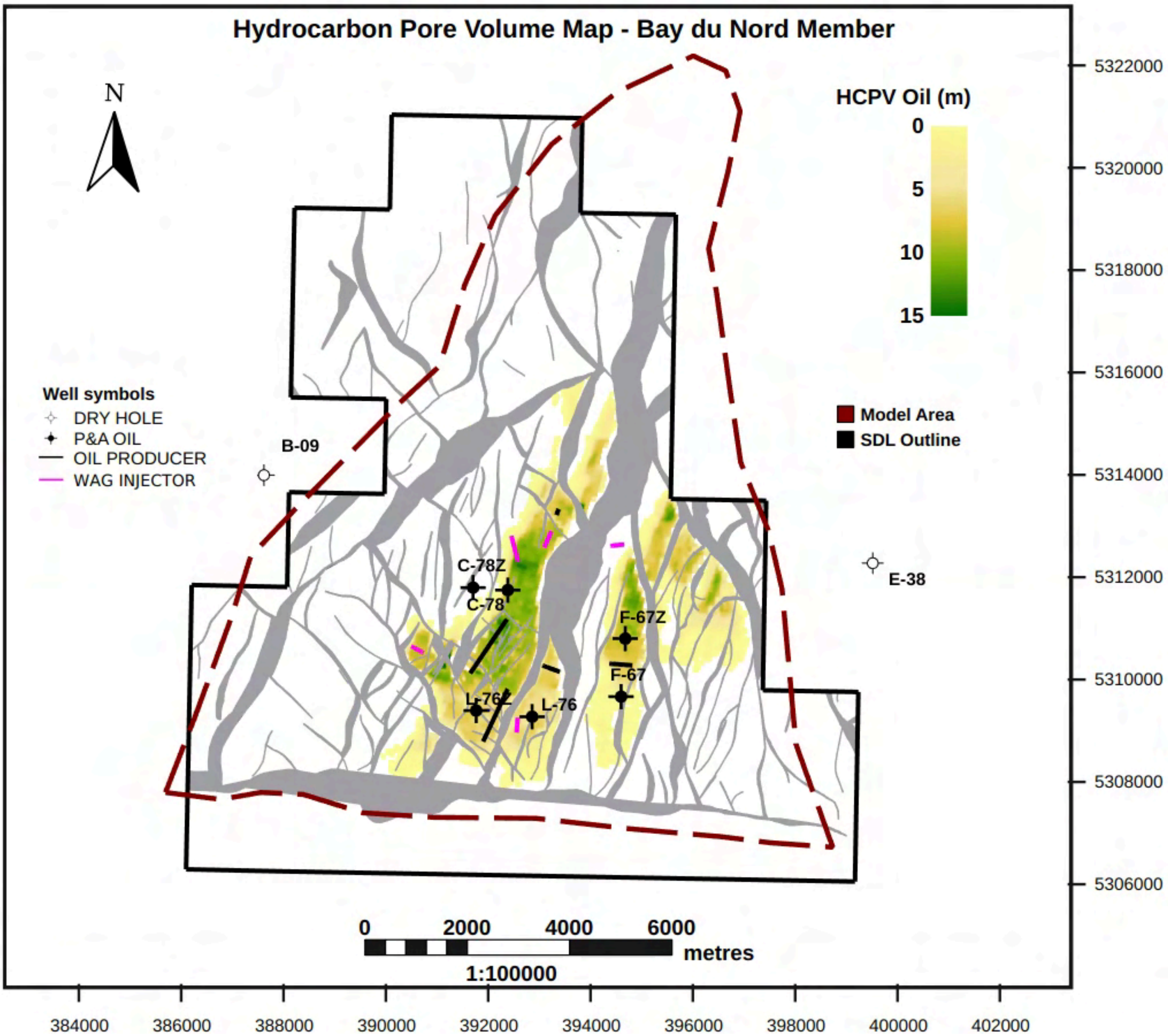


Figure 7.2 Bay du Nord Field - Bay du Nord member

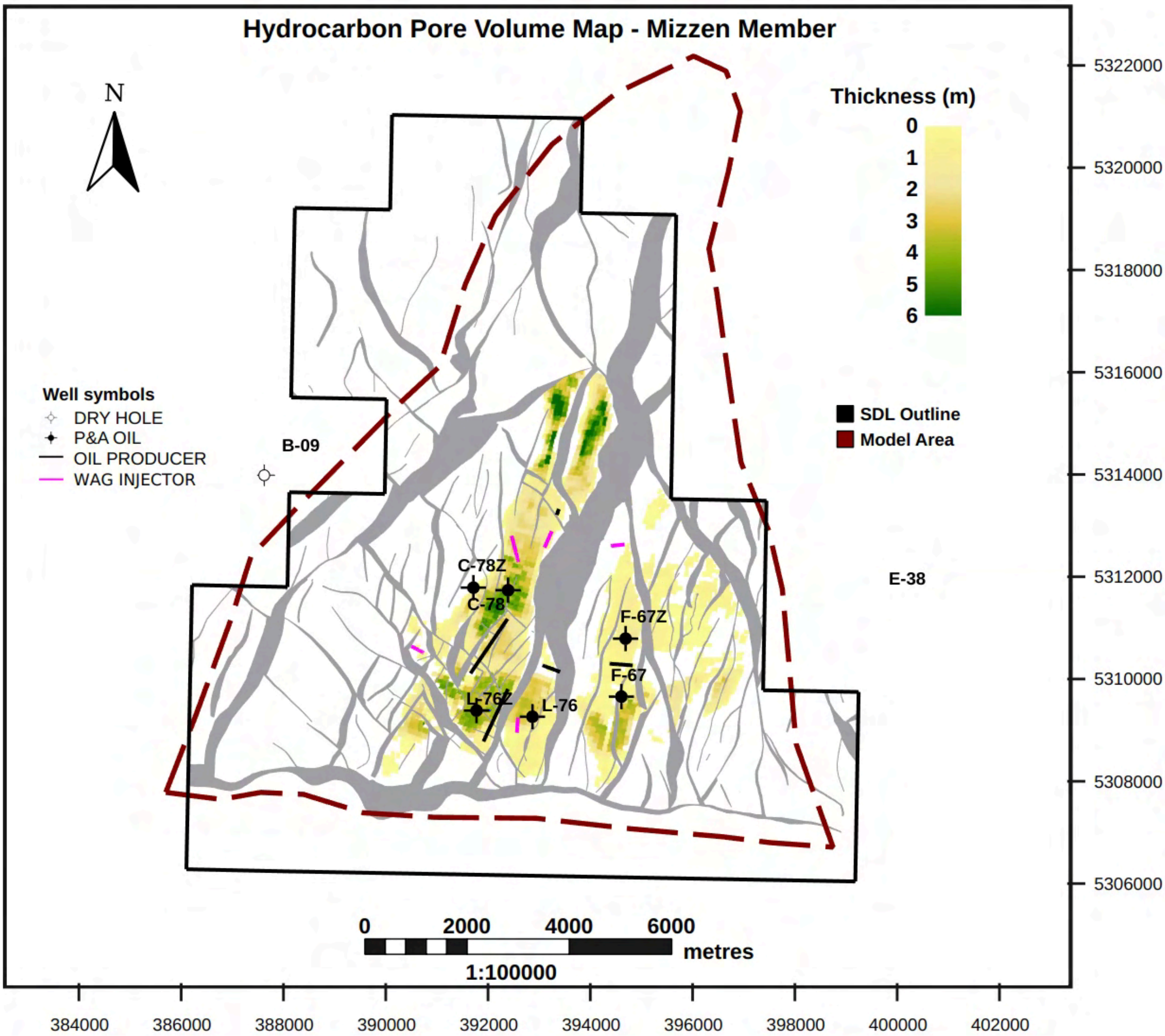


Figure 7.3 Bay du Nord Field - Mizzen member

7.3.2 Base Case Depletion Plan

For the Bay du Nord Field, the key considerations for determining the most effective drainage strategy are:

- It is an over-pressured reservoir with high production potential.
- The primary target is the incised valley within the Bay du Nord member. This is a high-quality reservoir, based on permeability, allowing for high deliverability wells with high recovery potential.
- The primary target in the Bay du Nord member is well-defined on seismic providing good control on well placement and resource distribution.
- The secondary target is the Mizzen member. The quality of the Mizzen member can vary spatially, and the thickness is too low to image reliably on seismic.
- In the Mizzen member a West-East trending incised valley deposit has been delineated in the south with the Bay du Nord L-76 and L-76Z wells. The well control in this area allows for potential development wells to be targeted in the Mizzen member. Away from this control in the south, central and northern development wells targeting the deeper Bay du Nord member will be used to assess and evaluate the Mizzen member reservoir quality, thickness and extent across the remainder of the field.
- The oil has a low GOR providing a limited amount of gas to manage, but also generating a low amount of energy within the reservoir.
- The light oil has a higher viscosity, which may impact water flood performance.
- There is a high level of faulting and a lot of small fault compartments. Uncertainty in fault behaviour and sand-to-sand juxtaposition may lead to quick water and gas breakthrough, bypassed oil, and a high risk of compartmentalization.
- There are many areas within the field that are characterized by thin reservoir sands. This increases the risk of poor production performance and poor injectivity within these areas.
- Opportunities may exist to expand the initial development area based on well results and production experience in both members.

The base case reservoir exploitation plan for the Bay du Nord Field is summarized as:

- A combination water- and gas-flood recovery process using both water and produced gas injection to provide pressure support and displace oil within the reservoir. Reservoir pressure will be managed over the life of the development to optimize recovery and manage gas injection.
- WAG functionality to allow for flexibility in gas management and to improve recovery.
- The drilling of five producers and five injectors in high confidence areas around the start of production with the optionality to adjust the total well count based on depletion plan optimization and drilling results through the operations phase. The base case depletion plan carries two spare slots, one on each template at Bay du Nord, available for infill drilling or targeting of new areas based on the results of the data acquired through the initial drilling and operations phases.

A map showing the base fault interpretation along with the base well layout is shown in Figure 7.1. The base well layouts are shown in Figure 7.2 and Figure 7.3 for each of the Bay du Nord and Mizzen members. The Mizzen member will be co-developed with the Bay du Nord member where this is determined to be the optimal development strategy. In the base depletion plan, this only occurs in the L-76 area. Well types in the field vary from deviated to near horizontal, depending on the specific requirements of the region. Due to the combination of a structurally and geologically complex field, several of the wells are planned as multi-target wells to allow for the development of otherwise isolated hydrocarbon accumulations. Multi-target wells also reduce the risk of compartmentalization and bypassed oil. The developed area in the base depletion plan is constrained by the known limitations on resource distribution at this time - the interpreted structure, mapping of the incised valley extent in the Bay du Nord member on seismic, delineation of a thinner incised valley in the Mizzen member, and information available on OWCs. Evaluations of options to develop resources outside of these constraints will be discussed further in this section and in Section 7.7 Improved Oil Recovery.

The well placement philosophy for the field is:

- To define the OWCs early so that future wells can be optimized based on the confirmed hydrocarbon extent;
- Use the extensively studied exploration wells to plan initial wells and step out in the reservoir as more

information on the subsurface is acquired;
- To avoid placing wells in compartments by using multi-target wells to connect reservoir sands and cross faults;
- To improve the understanding of both the Bay du Nord and Mizzen members where possible with a focus on reservoir thickness, connectivity and extent of the incised valley and deltaic deposits; and
- To manage the produced solution gas from the project through gas and WAG injection. Injection wells may be placed down-dip or up-dip depending on whether the wells are to primarily act as water or gas injection wells, respectively.

Individual wells will be placed based on the following information and considerations:

- Reservoir sand prediction from geophysical interpretation will be used to plan well locations. For production wells, it will be important to place the wells appropriately in the high-quality reservoir sand section to balance possible gas at the top of the reservoir and water at the bottom following injection. Directional drilling will be considered to help place wells following penetration of the high-quality reservoir sands.
- Information from past exploratory wells will be used to place development wells in several fault blocks. These development wells will provide additional information on the reservoir thickness and extent of the incised valley and deltaic deposits prior to drilling the next wells.
- In several areas, wells will need to cross faults to ensure that the reservoir achieves good sweep efficiency and high recoveries. It will be important to stay up-dip of faults on the flanks of the reservoir, as both thinning reservoir sands and fault effects could lead to poor injection performance. In the event of a deep contact, future sidetracks or infill wells may be required. Because of the highly dipping reservoir, the chance of bypassed oil down dip is small.
- The high permeability incised valley deposits should allow for high initial production rates. Maintaining production rates will depend on strong injection support. In general, injectors are placed down-dip on the structure where reservoir sands are interpreted as thinning. However, it is important to plan injectors in reservoir sands of sufficient thickness to meet target water injection rates. Seismic will be used to assist with injector placement where possible. The planned use of multi-target wells in some areas is coupled with consideration for zonal control in some of these wells. In the case of an injection well, the added flexibility may reduce peak water injection rates. Careful consideration has been given to water injector placement, completion design, and well count to ensure a robust base development. This evaluation will continue through to detailed well planning.
- It is important that the injectors maintain a sufficient stand-off from major faults to reduce risks associated with fault reactivation and out-of-zone injection when injecting water. The major faults have been screened to highlight faults at-risk and all wells are screened for proximity to major faults.

The order for drilling of the wells will be governed by the following priorities, while balancing the needs for production rate and data acquisition:

- Define the OWCs;
- Evaluate the extent of the Mizzen member;
- Address structural and geological uncertainty;
- Incorporate infill and improved oil recovery opportunities; and
- Integration with other fields for data acquisition and production optimisation.

The Bay du Nord Field has been the subject of extensive exploratory drilling, data acquisition, interpretation, and evaluation to ensure the implementation of a robust drainage strategy. A map of the Bay du Nord Field is shown in Figure 7.1 along with an Oil-In-Place (OIP) map showing the hydrocarbon distribution within the Bay du Nord member in Figure 7.2. The figure identifies the Bay du Nord and Bay de Verde areas within the field, and depicts the relative distribution of hydrocarbons.

The secondary reservoir target within the field is the Mizzen member. Figure 7.3 includes an OIP map showing the expected resource distribution within the Mizzen member. Only the West-East incised valley trend in the south, which was penetrated by two of the six exploratory wells in the field, has been included in the base Mizzen member development. North of this incised valley trend, deltaic deposits are present but in an unknown quantity and distribution for development. While a high concentration of OIP in the Mizzen member is interpreted near the Bay du Nord C-78 well, the deltaic reservoir is of lower quality and is sub-divided into several thinner reservoir sands at the C-78Z sidetrack well location. Without the ability to map the deltaic sands in the Mizzen member with as high confidence seismically, there is no basis for well placement and development outside of the incised valley reservoir in the south. Numerous development evaluations were undertaken for the Mizzen member within the Bay du Nord Field, with attempts to determine base well configurations that could be drilled without the aid of seismic or through delineation by the Bay du Nord member wells. No scenarios provided recoverable volumes sufficient to plan for development outside of the southern valley in the delineated fault blocks.

Additional work is planned for the Mizzen member prior to development drilling to support development evaluations over the life of the field. It is believed that new seismic technologies for both acquisition and interpretation may help improve the mapping of quality Mizzen member reservoir sands in both the incised valley and deltaic depositional environments. Combined with data acquisition during development drilling and production data from the south valley trend wells, it is anticipated that additional development opportunities will be defined within the Bay du Nord Field. Development options and drainage strategy for the Mizzen member, regardless of location and reservoir type, are expected to resemble that of the base development. One difference for opportunities outside of the base development may be the use of Multi-Lateral Wells (MLTs). Equinor ASA has a long history with MLTs on the Norwegian Continental Shelf (NCS) where they have been instrumental in improving field recovery and developing marginal reservoirs within fields. MLTs will be included in future evaluations to improve the economy of potentially isolated oil accumulations in a similar fashion to the multi-target wells in the base depletion plan.

The connectedness and confidence in the Mizzen member is limited by the fact that the inversion response of the deltaic sands is not as reliable as it is for the fluvial sands of the Bay du Nord member. The low resource density within fault blocks is a challenge for additional development of the Mizzen member.

To assist in the management of the multi-target wells, zonal control and inflow control options will be evaluated for each well. The completion considerations for the Project are included in Section 10.4 Completion Program.

Section 10.6 Interventions and Workovers provides a brief overview of intervention and workover activities, including types of interventions that may be considered to improve reservoir performance. The base depletion plan does not require interventions to deliver on the expected production; however, opportunities may exist over the life of the Project to improve well performance and recovery through interventions. Examples of possible intervention activities include zonal isolations and the stimulation of injection wells.

A detailed data acquisition strategy will be developed as the Project matures and prior to the detailed planning of development wells (refer to Section 7.5.3 Data Acquisition and Formation Evaluation Program).

OIP and recovery estimates are provided in Section 9 Reserves and Resource Estimates. Production profiles are provided in Section 7.6 Drilling Schedule and Production Forecasts.

Due to the higher pressure at the Bay du Nord Field, artificial lift is not required to lift fluids from the reservoir. Riser and template base gas lift will be used for flow stability as outlined in Section 7.5.6 Artificial Lift.

7.3.3 Alternate Depletion Plans

Alternate drainage strategies, well concepts, well completions, and artificial lift options were evaluated for the Bay du Nord Field.

Three drainage strategies were evaluated prior to selecting a combination water- and gas-flood with WAG functionality. The evaluation of the two alternate options, a full-field water flood and a water-flood with a dedicated gas-flood, is described in Section 7.5.1 Gas Management Strategy, as both these options are associated with the gas management strategy.

The initial well concept for the field was a combination of dedicated, deviated production and injection wells in individual fault blocks. Following the maturation of the subsurface description, the limitations on such an approach became apparent. The Mizzen member did not align for co-development with the Bay du Nord member targets. The Mizzen member and the smaller fault blocks within the Bay du Nord member held insufficient volumes to support dedicated wells. The benefits of highly deviated to horizontal wells and multi-target wells were identified and the well strategy matured from these options.

Multi-lateral wells were evaluated as an early option to develop the Mizzen member with the Bay du Nord member. The reservoir targets were evaluated but no candidates were identified. The main limitations were the high deliverability Bay du Nord member wells, which have limited capacity to co-produce with the Mizzen member targets evaluated in the C-78, L-76Z and L-76 areas. It was decided to use multi-zone wells for the Bay du Nord and Mizzen member producer and injectors in the L-76 area. Multi-lateral wells are likely a good option for the development of other secondary targets in the field once more data is collected during operations phase to define economic opportunities.

Inflow Control Devices (ICDs) continue to be evaluated for these purposes:

- Managing water production;
- Managing gas production; and
- Increasing conformance of production inflow along the length of the well completion.

The low viscosity contrast between the oil and the water limits the potential of viscosity based ICDs. Density based ICDs may be more applicable, as the density contrast between the oil and the water is larger. ICDs may also be considered in the future to improve inflow conformance along the long horizontal sections of wells, or to balance production between multi-target sections of wells. Gas management is another consideration for ICDs in the production wells. They may be used to limit the volume of gas entering a well at any time in the event that gas builds on the crest of the structure. The number, location, and type of ICDs will be considered on a well-by-well basis during detailed well planning.

Several options for artificial lift at the Bay du Nord Field were evaluated and are discussed in Section 7.5.6 Artificial Lift.

Additional considerations on depletion plan options are presented in Section 7.7 Improved Oil Recovery and Section 7.7.2 Enhanced Oil Recovery Considerations.

7.3.4 Sensitivity Studies

The approach to evaluating and selecting a drainage strategy, depletion plan, and development concept for the Bay du Nord Field is based on capturing subsurface uncertainties throughout the subsurface modelling process, as described in Section 7.2 Reservoir Modelling and Uncertainty.

To assist in communicating the risks associated with some of the main subsurface uncertainties, individual sensitivities were performed using the high and low inputs for each parameter. The results of these sensitivities are shown in Figure 7.4 and are presented at 1 year, 5 years and 20 years to distinguish between parameters that have an impact on initial rate versus those that have an impact on long term recovery. As shown, the three parameters with the greatest impact on recoverable volumes are Bay du Nord member incised valley distribution (or sand distribution), OWCs, and fault seal.

The Bay du Nord member incised valley distribution impacts the width and thickness of the terraces of the incised valley. This controls the extent of the high-quality reservoir and can both positively and negatively affect the efficiency of the base case depletion plan. This uncertainty affects the short-, medium-, and long-term recovery; a narrower or thinner incised valley results in less reservoir and less in-place oil. The opposite is true for a wider or thicker incised valley. Improving the definition around this uncertainty is integrated into the well planning and data acquisition plans for the Project.

The OWC uncertainty in the Bay du Nord Field is driven by the lack of any exploratory wells penetrating a contact, as noted in Section 6.2.1.1 Fluid Contacts. This, combined with a lower limit imposed by having an oil-down-to, leaves a skewed uncertainty with more upside than downside. Improving the definition around this uncertainty is integrated into the well planning and data acquisition plans for the Project.

The impact of fault seal is largely associated with communication within the reservoir. High fault seal assumes there is poor connectivity across faults. In this case more wells may be required than if fault seal is low, and there is good communication between the juxtaposed sands. There is also the potential to use 4D seismic monitoring to identify how fluids are behaving in the reservoir and respond early in the life of the field with changes to how wells are operated or where wells are placed. The sensitivity work does not reflect options that may exist during the production phase to better manage fluid behaviour. This uncertainty is much more apparent in the short-term, where it can be very impactful on initial well delivery in Bay du Nord Field. Improving the definition around this uncertainty is integrated into the well planning and data acquisition plans for the Project.

The mean recoverable volumes for the Bay du Nord Field are taken from simulation runs covering the full uncertainty span. In this case it is represented by 51 separate models sampling from the static and dynamic uncertainty parameters for the field but does not include any backout from combining Bay du Nord and Cambriol production at the FPSO. The result is the range in field recovery shown in Figure 7.5 and summarised in the table below.

Table 7.2 Bay du Nord Field Recovery Range

	Field Recovery (e^6m^3)	Field Recovery (MBO)
Min	29.7	186.5
P90	31.9	200.4
Mean	38.3	240.8
P10	45.4	285.3
Max	50.6	318.3

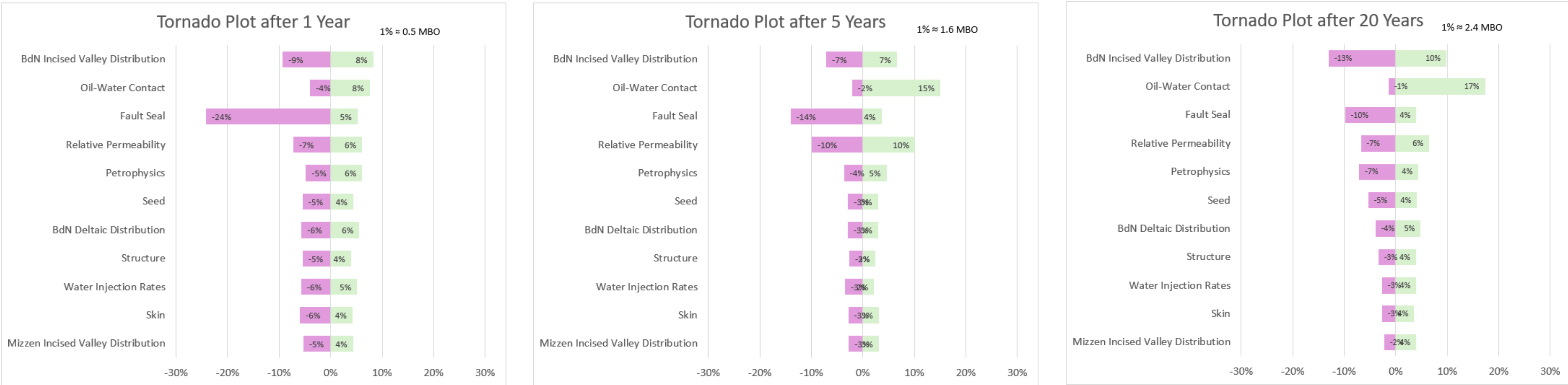


Figure 7.4 Bay du Nord Field - Key Uncertainty Sensitivities

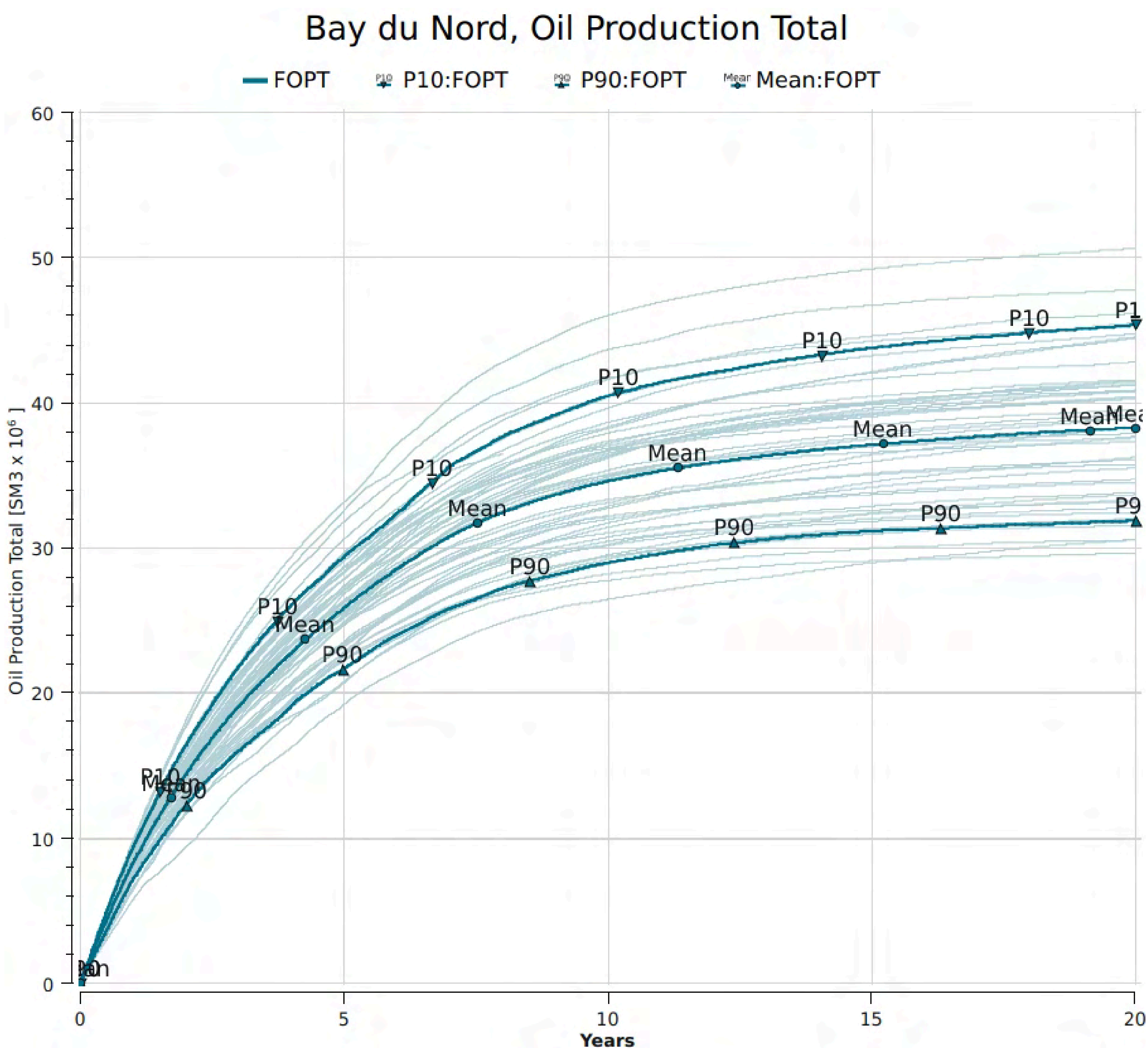


Figure 7.5 Bay du Nord Field - Uncertainty in Field Production

7.3.5 Development Scope

The resource exploitation plan for the Bay du Nord Field covers the development of the resources in the Mizzen and Bay du Nord members of the areas of Bay du Nord and Bay de Verde as shown in Figure 7.6. Within each of the Bay du Nord and Bay de Verde areas shown in Figure 7.6 there are discovered contingent and prospective resources. The exploitation of these contingent and prospective resources in these areas is considered as a continuation of the base resource exploitation plan using the same defined drainage strategy elements. The structural and geological complexity in the Bay du Nord area results in uncertainty in the reservoir connectivity, and there is also uncertainty in the quality and areal extent of the secondary reservoir targets. The development phase will permit opportunity to reduce these uncertainties and optimize the development strategy. The development wells will be placed, where possible, to define the contacts within the targeted blocks and to provide a better understanding of the controls on OWCs for the evaluation of other blocks. Seismic interpretation provides good control on the spatial distribution of incised valley deposits in the Bay du Nord member; however, to understand the extent of the high-quality reservoir in the Mizzen member well control will be more important. Wherever possible, the development wells targeting the Bay du Nord member will be optimized to define the extent of the Mizzen member. This information, along with data obtained during production operations, will be used to define additional development opportunities. Within the base resource exploitation plan, two spare slots remain to account for the exploitation of these resources. Additional wells may be drilled if opportunities are defined. In some cases, additional templates may be required and accommodation for their inclusion are made in the base subsea design.

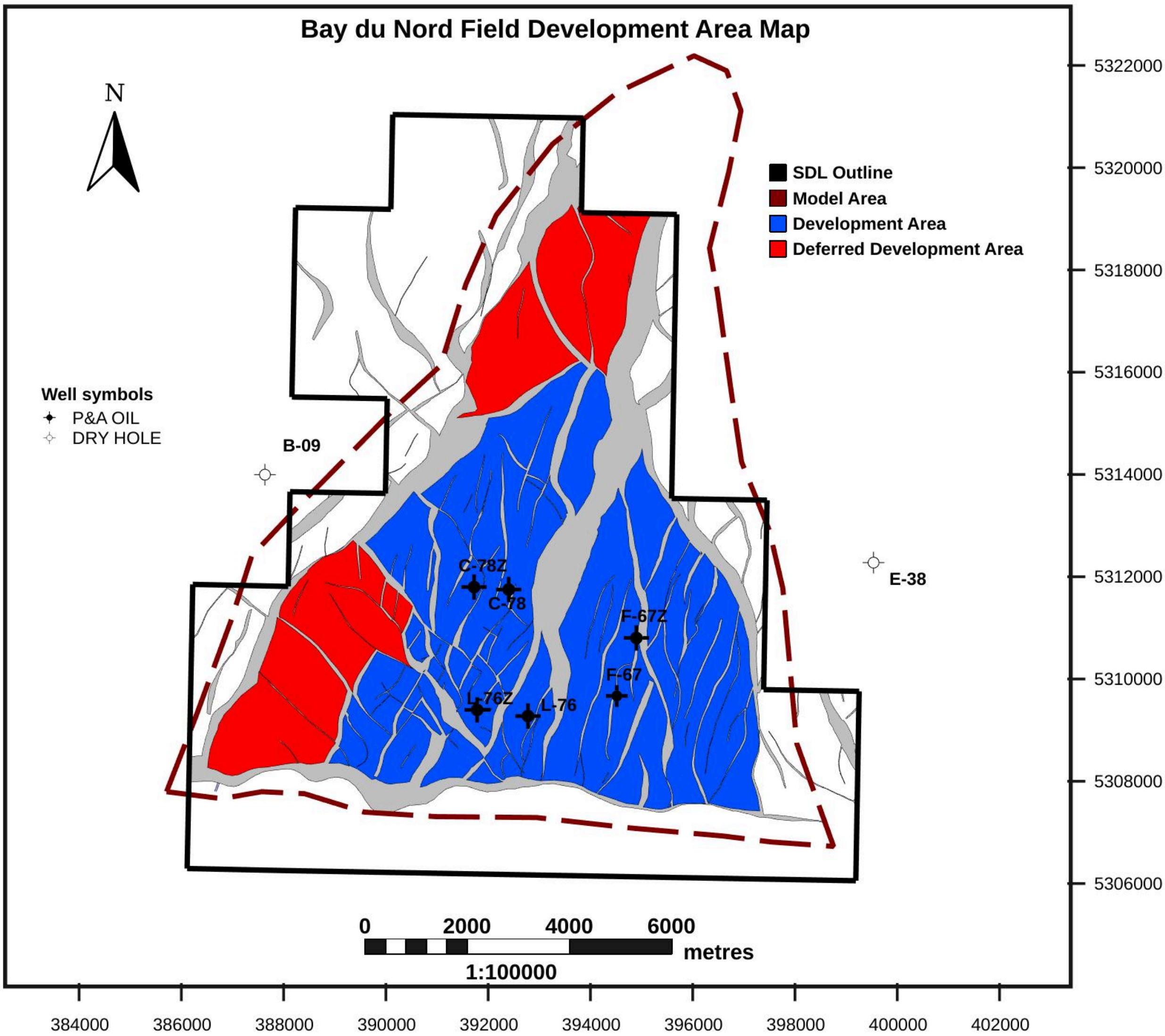


Figure 7.6 Bay du Nord Field: Development Area Map

There are three significant expected hydrocarbon accumulations included in the development area but not specifically targeted by any development wells: Bay du Nord NB region, Bay de Verde East, and the Mizzen member outside of the NC region (Figure 5.2). Both the Bay du Nord NB region and the Mizzen member are considered to be in pressure communication with areas that are targeted by the main development scope. Static and dynamic data acquired during development is expected to lead to the development of these areas. The largest expected, but undelineated, hydrocarbon-bearing area within the Bay du Nord Field is the set of blocks identified as Bay de Verde East (Figure 5.2). Development wells may be used to define the in-place hydrocarbons and ascertain any upside potential for future development, in addition to improving the understanding of the seismic inversion response to better define reservoir extent in this area. Further information related to expected upside in these (and other) areas is detailed in Section 7.7.1 Additional Development Targets.

7.4 Cambriol Field Exploitation

The main depletion plan options evaluated for the Cambriol Field are associated with the type of pressure support, the type of wells, and the type of artificial lift required for the recovery of the expected resources.

The pressure support and voidage maintenance options evaluated are:

- Primary depletion with no voidage maintenance;
- Primary depletion followed by water injection; and
- Gas injection as a gas flood or WAG flood.

The selected option is a water-flood following a period of pressure depletion.

The Cambriol Field's depletion plan considers the use of the following subsurface technology in developing the reservoir:

- MLTs;
- Multi-target wells;
- Zonal control;
- Inflow control; and
- Artificial lift.

The following sections describe the main elements of the base depletion plan along with opportunities over the life of the development. The chosen depletion plan meets the following criteria:

- Maximize the economically recoverable oil from the known and expected hydrocarbon accumulations within the field; and
- Acquire data through the drilling of development wells and operation of the field to address the known uncertainties within the field and identify additional potential for development.

7.4.1 Simulation Model

The Eclipse 100 simulation software from SLB was used in the drainage strategy and development concept evaluations for the Project. Separate modelling projects were developed for each field in the Project.

The geological model for the Cambriol Field is built in the RMS software from Roxar and exported to Eclipse for simulation with no upscaling performed. This ensures that the dynamic model honours the structural and geological concept developed by the geoscientists. The typical grid size is 100 x 100 x 1 m. The total number of cells in the model is 4,998,000 with roughly 210,000 cells active during simulation based on the area being evaluated. The Cambriol Field includes six regions, A through F, of which three are expected to contain hydrocarbons and one has the possibility of containing hydrocarbons. The reservoir model includes the four regions with possible hydrocarbon accumulations, B, C, D and F, as shown in Figure 7.7. The development evaluations are limited to regions B, C and D Figure 7.8. The model consists of a single reservoir unit, the Mizzen member.

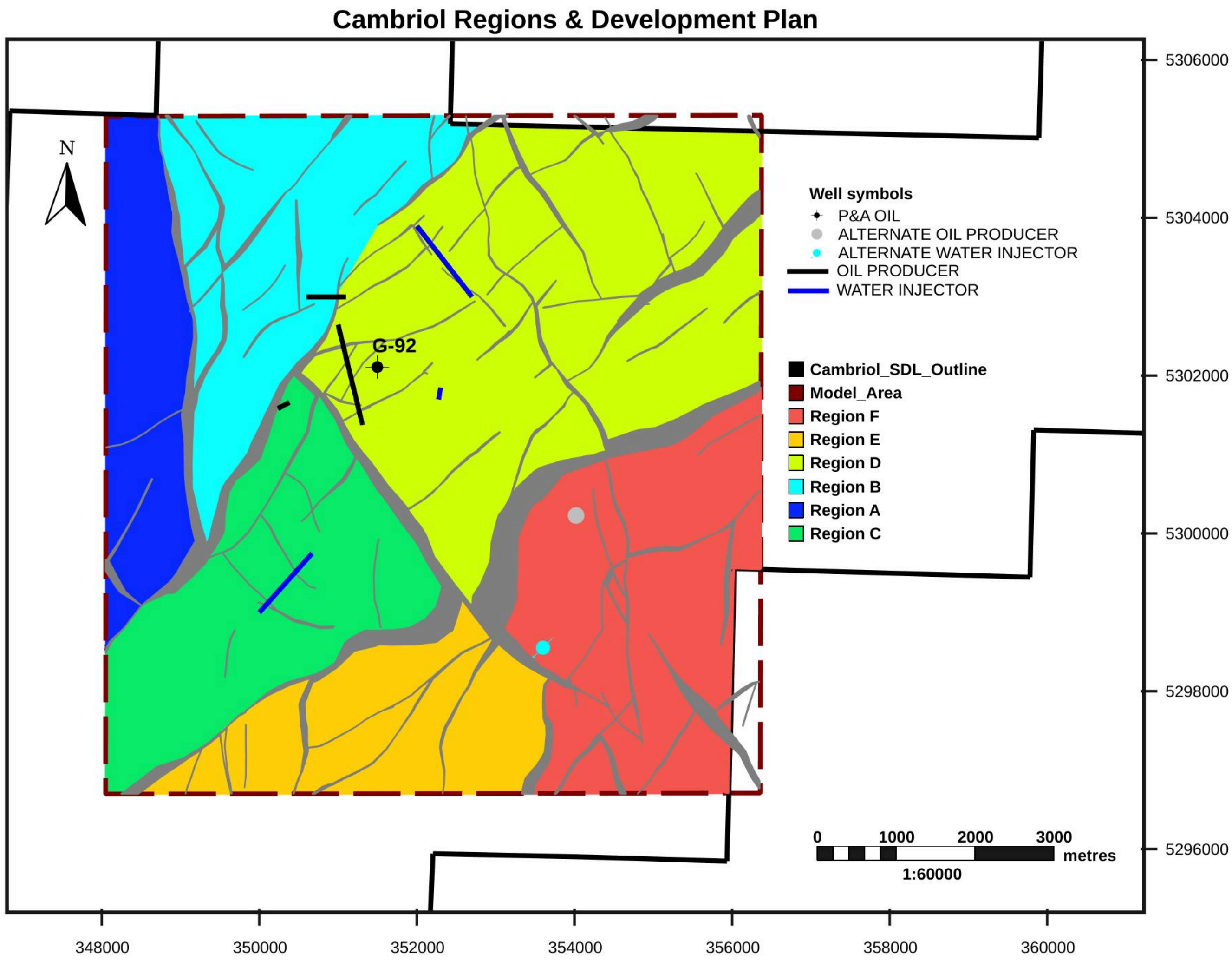


Figure 7.7 Cambriol Field - Dynamic Model

A map showing the OOIP distribution of the Mizzen member is shown for the reference case in Figure 7.8. As discussed in Section 7.2 Reservoir Modelling and Uncertainty, multiple models were generated for the field during the drainage strategy assessment. Unless otherwise noted, the cases shown are for a reference case that was chosen due to its representation of the expected OOIP and recoverable volumes.

The flow parameters model (SCAL) and fluid model (PVT) are described in Section 6.2.3.1 Relative Permeability and Section 6.2.2.1 Fluid Models. OWCs used in the reference case are described in Section 6.2.1.1 Fluid Contacts. A detailed fault seal analysis study was performed to characterize the nature of the faults and as input to the fault seal modelling work performed in RMS. The model was initialized with the base fault seal assumptions, which provide moderate restrictions to flow where high-quality reservoir facies are juxtaposed.

A summary of the OOIP distribution in the field is included in Section 9.2 Original Hydrocarbon-in-Place Estimates.

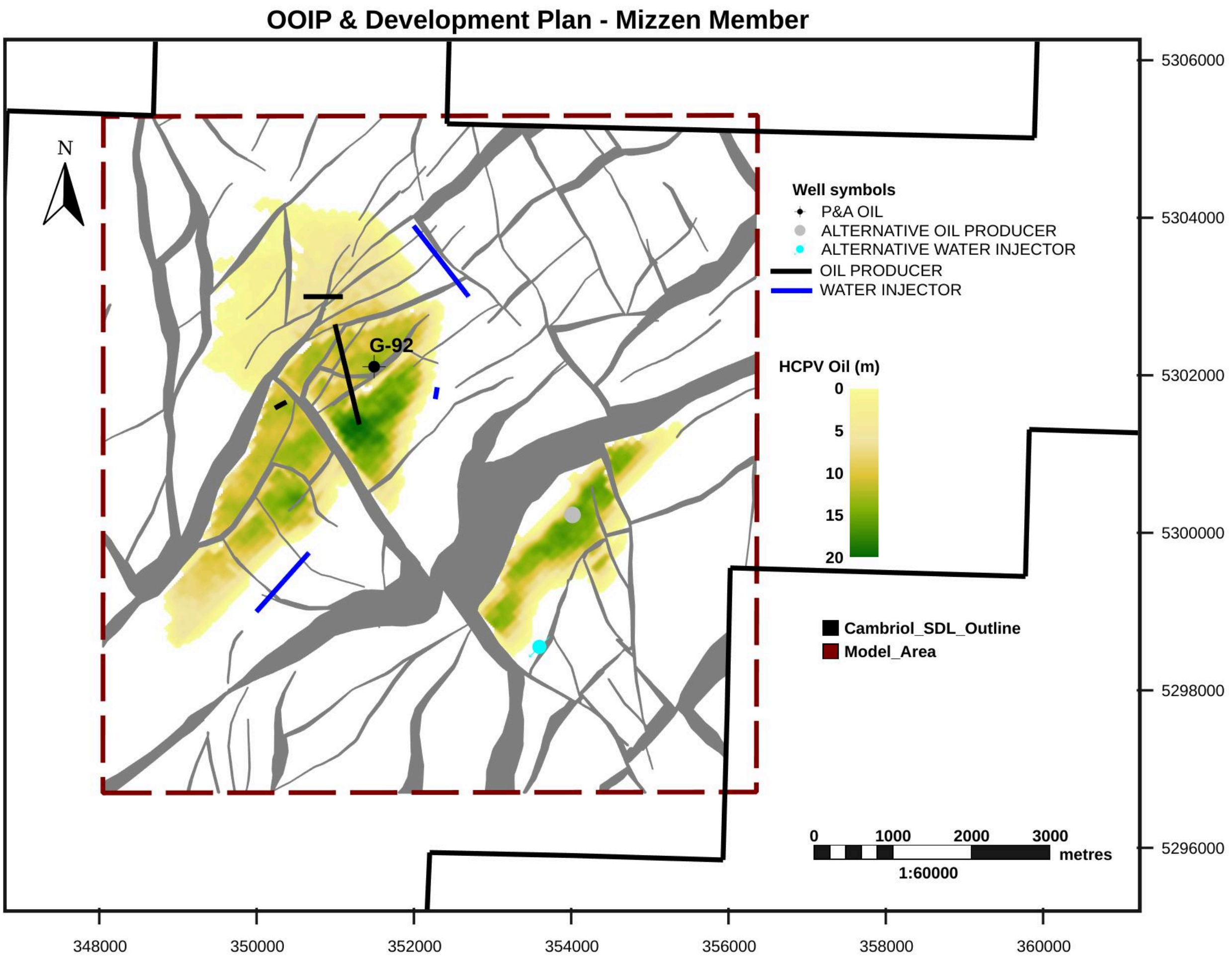


Figure 7.8 Cambriol Field - Mizzen Member

7.4.2 Base Case Depletion Plan

For the Cambriol Field, the key considerations for determining the most effective drainage strategy are:

- It is an over-pressured reservoir with high production potential.
- The primary target is the delta front sandstones within the Mizzen member. This is a high-quality reservoir, based on permeability, allowing for high deliverability wells with high recovery potential.
- The oil has a low GOR providing a limited amount of gas to manage, but also generating a low amount of energy within the reservoir.
- The light oil has a low viscosity providing a favourable mobility ratio to water injection.
- The good quality reservoir sands are well defined in the delineated D block providing good control on well placement and resource distribution within that region.
- The undelineated C block has high confidence in reservoir presence, although there is uncertainty on hydrocarbon presence and potential communication with Region D.
- The undelineated B block has a risk of reservoir presence and a high degree of structural uncertainty.
- The high degree of faulting and a large number of small faults within the development area. Combined with the uncertainty in the presence of good quality sands there is a risk of compartmentalization and bypassed oil.
- The potential for additional hydrocarbon-bearing, good quality sands, within the Mizzen member.
- The uncertainty in the behaviour of faults and sand-to-sand juxtaposition between regions.
- The low probability of aquifer support.
- The distance to the FPSO.

The base case depletion plan for the Cambriol Field is summarized as:

- Primary depletion followed by water injection to provide pressure support and displace oil within the reservoir.
- The drilling of three producers and three injectors with the optionality to adjust the total well count and well targets based on depletion plan optimization, drilling results, and subsurface learnings throughout to life of the field. The base case depletion plan assumes moderate connectivity within and between regions and wells are planned to mitigate this uncertainty. Data acquisition will be planned to reduce this uncertainty and well count and placement will be adjusted accordingly.
- Solution gas produced from the Cambriol Field will be injected into the Bay du Nord Field.

The Cambriol Field may produce for several months without water injection prior to reaching the planned operating pressure for the field, of approximately 600 bar or 180 bar below initial pressure. This pressure is considered optimal based on the data available and evaluations completed. Further work will be performed prior to and during operations to optimize operating assumptions to improve recovery. The initial period of primary production has several advantages including delaying water breakthrough and reducing water injection pressures.

A map showing the base fault interpretation along with the base well layout is shown in Figure 7.7. Well types in the field vary from deviated to near horizontal, depending on the specific requirements of the region. In general, the use of highly deviated or horizontal wells is to address reservoir compartmentalization and connectivity risks due to the combination of a structurally and geologically complex field. Extended length wells will also allow for additional data acquisition on the distribution of good quality sands and reservoir connectivity. Deviated wells, on the other hand, will allow for the delineation of OWCs and simplified data acquisition and interpretation. The developed area in the base depletion plan is constrained by the known limitations on resource distribution at this time - the interpreted structure, mapping of the extent of the Mizzen member on seismic, and information available on OWCs. As additional data is acquired and reservoir interpretations updated, the well requirements and placement will be matured.

The well placement philosophy for the field is:

- To define the OWCs and potential for down-dip cementation early so that future wells can be optimized based on the confirmed hydrocarbon extent;
- To evaluate the extent and quality of the sands away from the Cambriol G-92 exploratory well;
- To avoid the risk of compartmentalization and connectivity by using highly deviated or horizontal wells to connect reservoir sands and cross faults; and
- To manage the uncertainty in the presence of good quality sands by using highly deviated or horizontal wells with extended reservoir sections.

Individual wells will be placed based on the following information and considerations:

- Predicting reservoir sand from geophysical interpretations in certain areas is more uncertain. Well placement will be based on seismic reservoir prediction in areas of the greatest confidence, but will also leverage the geological concept and data acquired from the drilling of development wells in areas of less confidence. Directional drilling will be considered to help place wells following the penetration of good quality reservoir sands.
- The high permeability sands should allow for high initial production rates. Maintaining production rates will depend on strong injection support. It is important to place injectors in reservoir sands of sufficient thickness to meet target water injection rates. The length of injectors will be planned to ensure sufficient injectivity. The potential use of highly deviated or horizontal wells in some areas is coupled with consideration for inflow or outflow control in some of these wells to both limit the total injection demand for voidage replacement and target specific segments that require the most injection support. Careful consideration has been given to water injector placement, completion design, and well count to ensure a robust base development. This evaluation will continue through to detailed well planning.
- Reservoir connectivity associated with fault seal and sedimentological features is uncertain. Some wells are planned to improve recovery if poor connectivity is an issue. These wells will be revisited as data is acquired to update the reservoir interpretation.

The order for drilling of the wells will be governed by the following priorities, while balancing the needs for production rate and data acquisition:

- Define the OWCs;
- Address potential for down-dip cementation;
- Evaluate the extent of the Mizzen member;
- Address structural and geological uncertainty;
- Delineate the B and C regions;
- Maintain optionality to develop alternate Region F targets based on data acquisition;
- Incorporate infill and improved oil recovery opportunities; and
- Integration with other fields for data acquisition and production optimisation.

The Cambriol Field has been the subject of recent data acquisition and evaluation to ensure the implementation of a robust drainage strategy. However, two of the three regions in the base depletion plan are undrilled and have risked resources. These represent a large portion of the field's estimated recoverable resources. A map of the Cambriol Field regions is shown in Figure 7.7. This figure identifies the regions within the field, while Figure 7.8 depicts the relative distribution of hydrocarbons. The inclusion of undrilled blocks and risked resources in the base case depletion plan means that maintaining optionality throughout the development is considered a key enabler for a successful depletion plan. As such, one alternative producer and one alternative water injector in Region F are shown in Figure 7.7 and Figure 7.8. These wells may become primary targets during the development phase depending on drilling results and subsurface learnings. Some factors that may lead to the development of Region F within the base case depletion plan include:

- A lack of hydrocarbon or reservoir presence in Region C;
- Good connectivity across faults in Region D reducing the need for a second producer injector pair in the region;
- A deep OWC encountered in the initial development wells increasing the probability of a thicker oil column in Region F;
- Changes to the width, thickness, and/or extent of the Cambriol depositional system-based data acquisition in development wells; and
- Improved seismic imaging prior to development leading to improved confidence in Region F or reduced confidence in Region B or C.

To assist in the management of the multi-target wells, inflow and outflow control options will be evaluated for each well. The completion considerations for the Project are included in Section 10.4 Completion Program.

Section 10.6 Interventions and Workovers provides a brief overview of intervention and workover activities, including types of interventions that may be considered to improve reservoir performance. The base depletion plan does not require interventions to deliver on the expected production; however, opportunities may exist over the life of the development to improve well performance and recovery through interventions. Examples of possible intervention activities include zonal isolations and the stimulation of injection wells.

A detailed data acquisition strategy will be developed as the Project matures and prior to the detailed planning of development wells (refer to Section 7.5.3 Data Acquisition and Formation Evaluation Program).

OIP and recovery estimates are provided in Section 9 Reserves and Resource Estimates. Production profiles are provided in Section 7.6 Drilling Schedule and Production Forecasts.

Due to the higher pressure at the Cambriol Field, artificial lift is not required to lift fluids from the reservoir. Reservoir pressure will be decreased from initial conditions, however, it will be maintained to optimize production. It is expected that the reservoir pressure will be maintained at or near 600 bar. Riser base gas lift will be used for flow stability as outlined in Section 7.5.6 Artificial Lift.

7.4.3 Alternate Depletion Plans

Alternate drainage strategies, well concepts, well completions, and artificial lift options were evaluated for the Cambriol Field.

Three drainage strategies were evaluated prior to selecting primary depletion followed by water injection.

The Cambriol Field has a sufficient degree of overpressure to consider primary depletion as a drainage strategy, however the degree of overpressure is insufficient to offset the value of water injection. Recovery from primary depletion is limited due to the likelihood that there is no communication with a regional aquifer. The field is overpressured and highly faulted which makes it improbable that there will be an active aquifer to provide pressure support and increases the likelihood that structural and sedimentological baffles and barriers will reduce the degree of pressure support from the flanks of the field. The low GOR and lack of gas cap in Cambriol also limits the natural energy from fluid expansion in the reservoir which further reduces the effectiveness of primary depletion. The addition of artificial lift mechanisms to a primary depletion strategy were not pursued as traditional secondary drainage strategies provide for a more robust development concept.

Gas injection, as a gas flood or a water-alternating-gas flood, was considered, but screened out due to the distance from the FPSO and the benefits of gas injection in other fields. The Cambriol Field is approximately 34 km from the planned FPSO location. Gas injection would require the installation of a significantly longer gas injection line than for Bay du Nord. Measures to prevent hydrate formation and to manage flow assurance over the distance would also reduce the value of gas injection at the Cambriol Field. The Cambriol Field oil has the lowest viscosity of any of the oils in the Project indicating a more favourable displacement to water injection than the Bay du Nord Field. The incremental recovery from gas injection would also then be lower than at the Bay du Nord Field. Combining the cost, technical challenges, and recovery impacts, gas injection to the Cambriol Field was screened out as a potential depletion plan option. Thus, water flood was selected as the pressure support and voidage maintenance method.

Well options are adapted from the work performed for the Bay du Nord Field and the options considered for the Bay du Nord Field are applicable to the Cambriol Field. While deviated and near horizontal wells are planned for in the base depletion plan, well options for the field may also include MLTs. These options will be matured further during detailed well planning.

Options for artificial lift at the Cambriol Field were evaluated and are covered in Section 7.5.6 Artificial Lift.

Additional considerations on depletion plan options are presented in Section 7.7 Improved Oil Recovery and Section 7.7.2 Enhanced Oil Recovery Considerations.

7.4.4 Sensitivity Studies

The approach to evaluating and selecting a drainage strategy, depletion plan, and development concept for the Cambriol Field is based on capturing subsurface uncertainties throughout the modelling process, as described in Section 7.2 Reservoir Modelling and Uncertainty.

To assist in communicating the risks associated with some of the main subsurface uncertainties, individual sensitivities were performed using the high and low inputs for each parameter. The results of these sensitivities are shown in Figure 7.9 and are presented at 1 year, 5 years and 20 years to distinguish between parameters that have an impact on initial rate versus those that have an impact on long term recovery. As shown, the three parameters with the greatest impact on recoverable volumes are the facies definition, OWCs, and fault seal.

The facies definition impacts the widths, thicknesses, and directions of the modelled deltaic systems shifting the location and extent of hydrocarbon accumulations and impacting the efficiency of the base case depletion plan. Improving the definition around these uncertainties are integrated into the well planning and data acquisition plans for the Project.

The impact of OWCs is considered in the selection of the depletion plan for the Cambriol Field. Defining the contact and the extent of the known high-quality sands, as well as delineating the other, undrilled, regions are integrated into the well planning and data acquisition plans for the Project.

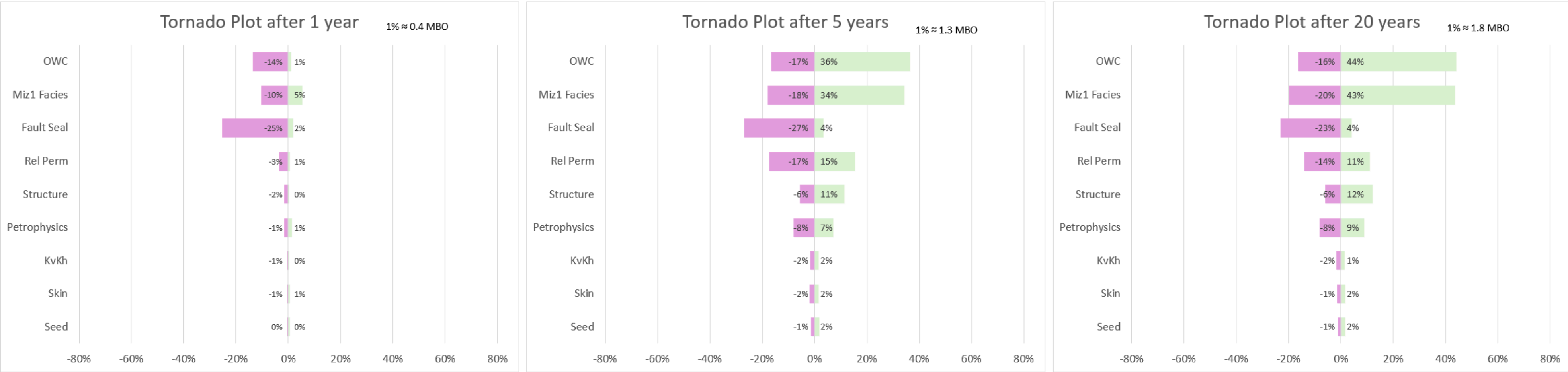


Figure 7.9 Cambriol Field - Key Uncertainty Sensitivities

The impact of fault seal is largely associated with communication within the reservoir. High fault seal assumes there is poor connectivity across faults. In this case more wells may be required than if fault seal is low, and there is good communication between the juxtaposed sands. There is also the potential to use 4D seismic monitoring to identify how fluids are behaving in the reservoir and respond early in the life of the field with changes to how wells are operated or where wells are placed. The sensitivity work does not reflect options within the field management plan to better manage fluid behaviour.

The mean recoverable volumes for the Cambriol Field are taken from simulation runs covering the full uncertainty span. In this case it is represented by 51 separate models sampling from the static and dynamic uncertainty parameters for the field but does not include any backout from combining Bay du Nord and Cambriol production at the FPSO. The result is the range in field recovery shown in Figure 7.10 and summarised in Table 7.3.

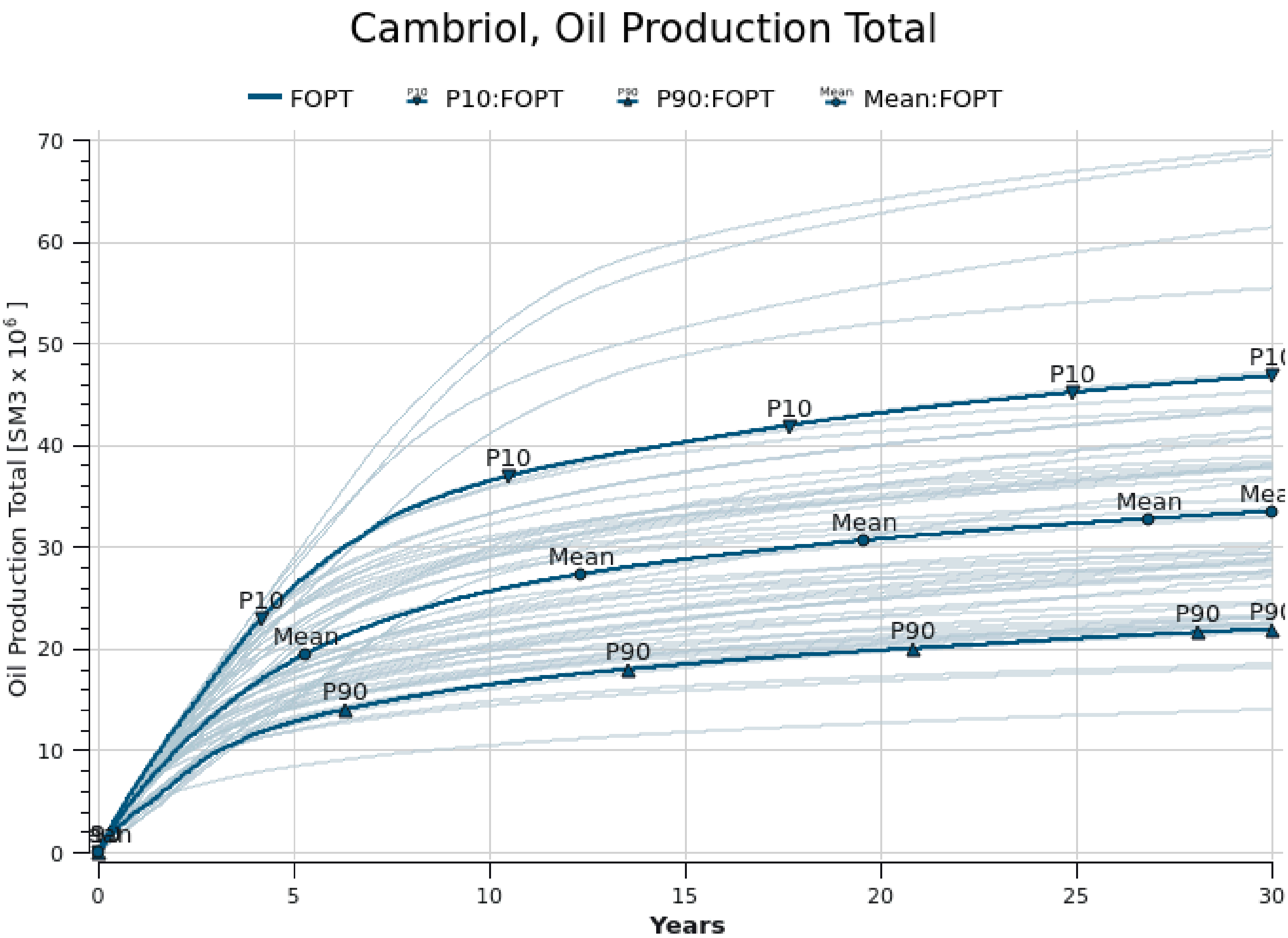


Figure 7.10 Cambriol Field - Uncertainty in Field Production

Table 7.3 Cambriol Field Recovery Range

	Field Recovery (e^6m^3)	Field Recovery (MBO)
Min	12.8	80.7
P90	20.1	126.2
Mean	31.1	195.6
P10	43.6	274.2
Max	64.7	406.9

7.4.5 Development Scope

The depletion plan and resource assessment for the Cambriol Field is based on the confirmed hydrocarbon-bearing sands of the Mizzen member. The main development area is shown in Figure 7.11. The Cambriol G-92 well has confirmed the presence of oil in the Mizzen Member (Figure 2.4 and Table 3.7).

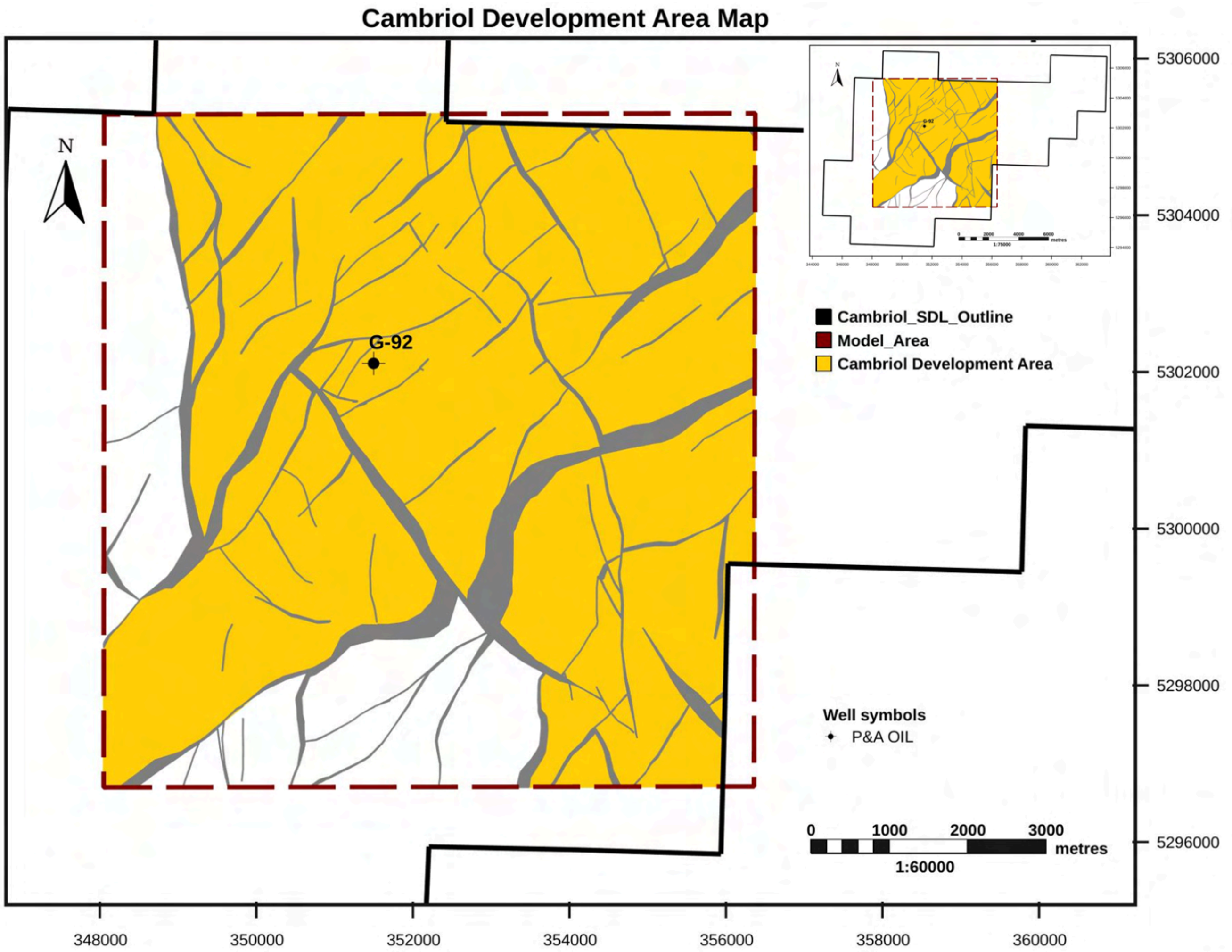


Figure 7.11 Cambriol Field: Development Area Map

The depletion plan for the Cambriol Field covers the resources within the B, C and D regions (Figure 7.7). Region D was delineated by the Cambriol G-92 well. No water was encountered in the oil-bearing sands of the Mizzen member. There is juxtaposition of the Mizzen member between Region D, and Regions B and C within the oil column. It is assumed that the three regions share a common OWC.

The F region is interpreted as a separate closure from the B, C and D regions with a potential to contain hydrocarbons. There are several interpreted spill points surrounding the F block that may control the oil-water-contact. The inclusion of Region F within the development scope as an alternative target and some factors that may lead to its development of Region F are outlined in Section 7.4.2 Base Case Depletion Plan. The volume of oil in the block is dependent on the OWC. An example of the hydrocarbon potential in the region is shown in Section 5.3 Cambriol Field. The hydrocarbon potential will be updated following data acquisition during the development phase.

The current resource assessment does not indicate the presence of hydrocarbons in the A or E regions. These blocks are down flank extensions of the B, C and D regions and contain negligible hydrocarbon volumes even in the deepest OWC scenarios.

7.5 Reservoir Management

In combination with Equinor's extensive experience in oil and gas operations, globally and in the Canada-NL offshore area, the reservoir management plan is based on the evaluation of the Flemish Pass exploration data that was conducted to assess the development potential and select an appropriate depletion plan for the Project.

The reservoir management plan outlines how the current reservoir understanding will be augmented with development drilling results, and the inclusion of data acquisition and reservoir surveillance plans. The reservoir management plan will also outline how these results, data, and interpretations will be implemented during operations to maximize recovery from the Project Area. Equinor is committed to developing a "field of the future" where information and professional experience are integrated through digitalization and analytics to deliver on the Project reservoir management plan.

The characteristics of an effective reservoir management plan are:

- **Knowledge:** expanding on what is known and challenging expectations through the continuous gathering, interpretation, and implementation of information.
- **Collaboration:** the reservoir management plan is the result of integrated technical work from all disciplines within the Project, contributing to a common goal. The operation of the fields will continue this collaboration as the wells are planned, drilled, interpreted, and operated.
- **Flexibility:** the Project has put forth robust depletion plans to deliver on the expected resources within the Project Area. However, the Project has also shown that there are a wide range of potential outcomes as the development is executed and operated. Realizing the potential of each outcome requires the Project to be flexible and adaptive in order to respond to opportunities in a timely and efficient manner.
- **Ambition:** through the reservoir management plan, the Project sets out its expectations for how the Project will be operated as a safe, responsible, and successful development. The ambition is more than delivering on the base depletion plans; it is to deliver on the maximum potential of the fields.

The Project has described the expected reservoir exploitation plans for the Bay du Nord and Cambriol fields based on the technical evaluations described throughout the Development Plan. The reservoir management plan is the integration of the subsurface technical evaluation and understanding, with the data acquisition plan and knowledge that will be gained throughout the development. The evaluation of development scenarios for each field will continue through the design and execution of the Project and into the development and operations phases of the fields. Development wells will evolve based on the outcomes of all of the technical work and learnings through to the end of the operations phase.

The Project has employed a model-based uncertainty analysis for evaluating development options, as described in Section 7.2 Reservoir Modelling and Uncertainty. This analysis will be employed throughout the development drilling and into operations, allowing quick integration of well results and production data into the static and dynamic models to improve future well planning and production forecasting.

The general principles that form the basis of the Project's reservoir management plan are:

- Data will be acquired from the development wells during drilling to address the main uncertainties within each field, optimize subsequent wells, and identify upside development opportunities.
- Wells will be drilled to create and preserve productivity and injectivity. Injectivity is a risk in all fields as production will be dictated by the ability to effectively inject water.
- Water will be managed to reduce the need for excessive cycling within the reservoir, ensuring capacity is available for development outside of the base plan.
- Water injection will be managed to ensure safe injection at all times.
- Gas will be managed to enhance recovery, and provide a reliable source of power for the life of the Project.
- Reservoir surveillance will be used to manage uncertainty within the reservoirs with a focus on ensuring good sweep efficiency and recovery enhancement. This will form the basis for well operations and future infill drilling. Reservoir surveillance is covered in detail in Section 7.5.5 Reservoir Surveillance.
- Pressure will be managed within the reservoir to benefit production over the life of each field. At the overpressured Bay du Nord and Cambriol fields, reservoir pressure will be controlled for production of

hydrocarbons and to manage fluid movement within the reservoirs.

- The injection of gas as part of the WAG drainage strategy will be managed for the enhancement of recovery from the Project, with cycle times and wells selected for injection based on the dynamic management of the fields.
- Well slots will be managed for the enhancement of recovery over the life of the Project. Opportunities for slot reclamation will be balanced with potential slot expansion based on the outcomes of development drilling and data acquisition during operations.
- Monitoring plans will be put in place to ensure the integrity of sand control measures.
- The reservoir will be managed to limit the impacts of subsurface processes on production, including reservoir souring, reservoir cooling, and the near wellbore potential for hydrates during WAG operations.

7.5.1 Gas Management Strategy

The Project fields contain highly undersaturated oils with limited amounts of solution gas. Consequently, the hydrocarbon accumulations do not contain gas caps. However, a gas management strategy is necessary to ensure conservation of the produced gas as there are no commercial options to export the gas in offshore Newfoundland and Labrador. Equinor has committed to reducing greenhouse gas emissions from all of its operations and intends to use a pilot-less flare and a closed flare system at the Bay du Nord facility. There will be no routine flaring from the FPSO with a focus on preserving gas for gas injection, artificial lift, and fuel.

The recommended gas management strategy for the Project is gas injection into the Bay du Nord Field. Gas injection may be alternated with water injection as WAG floods to increase flexibility in gas management options. All injection wells in the Bay du Nord Field will be designed for WAG functionality as described in Section 7.3 Bay du Nord Field Exploitation.

To ensure prudent gas management within the Project, the following strategies were evaluated:

1. Gas injector to aquifer(s);
2. Dedicated gas-flood(s);
3. WAG-flood(s); and
4. Water-floods with gas reinjection in the same reservoir.

Gas injection to the Cambriol Field was screened out (de-selected) due to the distance from the FPSO and the high reservoir pressure.

Gas injection to an aquifer was evaluated, but no aquifers of sufficient size and connectivity exist in the Project Area. Additionally, as an increase in oil recovery is seen from gas injection, this was seen as a less favourable option, even if the required aquifers were found. If, through future exploratory drilling, an aquifer of interest is discovered and gas compression capacity is identified as a production constraint, this could be re-evaluated.

The gas management strategy for the Project must be adaptable enough to address the unknown elements of the fields and the Project. The Cambriol Field is the main source of solution gas for reinjection as the GOR there is roughly twice that of the Bay du Nord Field. With the relatively large uncertainty in total recoverable oil in Cambriol (as described in Section 9.3 Recoverable Resource Estimates), this leads to an uncertainty in required gas storage volume. To address this while maintaining strong production from Bay du Nord Field, crestal gas injection into the area north of C-78 was selected as the primary gas management strategy. With the expected volume of produced solution gas from the Bay du Nord and Cambriol fields, this crestal gas injector is capable of flooding down from the crest of the Bay du Nord structure towards mid-dip oil producers, while WAG-enabled water injectors simultaneously flood up from the water leg. In cases where there is less gas for reinjection due to smaller in place volumes at Cambriol or slower gas movement in Bay du Nord than expected, the downdip water injectors in Bay du Nord can increase their injection rate to accommodate the reduced gas injection rate. In cases where there is more gas available for reinjection due to larger in-place volumes at Cambriol or faster gas movement in Bay du Nord than expected, these water injectors can initiate WAG cycles to enhance recovery and store gas in other areas of Bay du Nord.

Crestal gas injection as the primary gas management strategy in Bay du Nord allows for the slowest evolution of free gas production out of all of the strategies tested due to the gravity segregation of the less dense gas in the crest above the oil producers. Adding WAG to this allows for the flexibility to accommodative a wide range of produced gas volumes and behaviours.

Based on this assessment and observations, switching injectors between water and gas injection was identified as a Project requirement for prudent field management and optimal recovery of the resource. The evaluation of the current, robust WAG flood in the Bay du Nord Field evolved from this assessment. The final evaluation indicates a significant improvement in recovery with WAG of five to ten percent incremental to combined gas- and water-flood alone. The gas management strategy is intended to be flexible and to adapt to the outcomes of the Project development and operations activities. Gas will be managed to increase recovery over the life of the Project.

Based on the evaluations, the following gas management strategy is planned for the Project:

- Crestal gas injection into the Bay du Nord Field;
- All injection wells included in the base development at the Bay du Nord Field will have the functionality to be WAG injectors;
- Multiple wells will be capable of gas injection simultaneously;
- Wells chosen for gas injection will be based on the performance of each area of the field, maximizing gas utilization for enhancing recovery and conserving fuel gas for long term field operations;
- Gas produced at the Cambriol Field will be injected into the Bay du Nord Field; and
- Flexibility will be included in the subsea design to expand gas injection to other fields if required.

The selected gas management strategy has proven robust across the range of scenarios tested in the uncertainty study for the Project. Further work has been performed to evaluate the impact of additional production to the FPSO, either through improved oil recovery initiatives within the Project Area or through the tie-in of other discoveries. The gas management strategy appears robust with the capacity to adapt to a range of scenarios through the life of the Project.

In the following sections, the base assumptions for the WAG wells (wells that actively receive gas injection) and the cycle durations provided are based on a reference case. Actual WAG cycles and well selection will be based on development drilling results and additional studies.

The other use for gas within the field is for the provision of riser or template-based gas lift, which is described in Section 7.5.6 Artificial Lift.

7.5.2 Water Management Strategy

Water Injection and Pressure Maintenance

A successful water injection strategy is fundamental to maximizing the recoverable resources from the Project fields. Fluid injection is considered to be the sole reservoir pressure support mechanism for the Project, as no known active aquifer or gas cap exists within the development area. High injectivity is deemed necessary to exploit production potential, maintain pressure support, and maximize resource recovery.

The proposed development concept for the Project consists of two water injection subsea risers. One riser will distribute injected water to two subsea templates of the Bay du Nord Field while the other will deliver water to a single subsea template on the Cambriol Field. Higher pressure is required for Cambriol water injection due to its high reservoir pressures. The injection pressure determines which field is served by each riser.

Pre-drilling of development wells is planned to reach the production plateau, necessitating the suspension of initial injection wells for an extended period. Where feasible, risk-reducing measures are implemented to minimize the likelihood of poor injectivity caused by injection into thin or low-permeability reservoir sands, as well as drilling and suspension-induced formation damage. These measures include:

- The treatment and filtering of injection water;
- The inclusion of options to control fluid flow in the design of the injection wells;
- Well designs that minimize restrictions that could limit injection rates;

- Designing for the ability to flow back injection wells to the facility for clean up operations prior to injection;
- Multi-stage treatment of produced water using best treatment practices that are commercially available and economically feasible and discharge to sea; and
- Detailed fluid qualification to include formation damage tests and completion compatibility tests for well suspension.

A WAG injection scheme is proposed for the Bay du Nord Field; whereas water injection is proposed for the Cambriol Field. WAG injection cycles between wells will vary based on reservoir management requirements with the continuous injection of excess produced gas, gas not used for fuel, flare and artificial lift. The cycling between gas and water within a common wellbore requires control during production operations. Hydrate management is a risk that will require specific mitigating measures, as discussed in Section 6.3.1.4 Hydrate Evaluation. During normal operations, injection temperatures will remain above the hydrate equilibrium temperatures. Reduction in injectivity is a common issue with WAG projects, as discussed in the Society of Petroleum Engineers paper SPE-71203 [56]. The authors observed that, *"it is a common trend that while reduced injectivity of water is observed after a gas slug, the injectivity of the gas after a water slug generally is not a major problem"*.

High well injectivity is deemed necessary for reservoir pressure support and to maintain reservoir production rates in both Bay du Nord and Cambriol fields. With offshore subsea water injection, it is common for the reservoir to fracture from the combination of cold water injection and the plugging of the reservoir along the well. In general, fracturing improves reservoir injectivity compared to matrix injection; however, the fractures must be managed to maintain safe and effective injection. Plugging and fractured injection effects are important mechanisms for water injection wells and their resultant injectivity. Injection water quality can have a large effect on the degree of well and formation plugging. Retaining injectivity is necessary for the technical and economic viability of the development and for resource conservation. Good injectivity allows for high-rate injection which is necessary to optimize recovery of the fields. Understanding the relationship between injectivity and recovery has been and will continue to be a focus for the Project. The work includes data acquisition during the exploration program, technical studies and evaluations of rock properties and fracture mechanisms, modelling, and leveraging of Equinor ASA's operational experience.

Risks associated with out of zone injection fracture growth may occur through the following mechanisms:

- Leakage by failed well integrity;
- Leakage through naturally existing geological structures; and
- Leakage through fracture growth.

The Project fields are, in general, highly faulted. Water injection well placement near faults must be considered in field development planning. To ensure safe injection, injection intervals will be placed away from major bounding faults with risk of reactivation that extend out of the targeted development zone to alleviate the undesirable migration of fluids attributed to fault reactivation. The risk of fracture propagation toward faults increases considerably if produced water injection were to occur.

Produced Water Management

As committed to in the Bay du Nord EIS [4], the assessment of alternatives to the management of produced water will be addressed in the Development Application for the Project [57]. In summary, injection of produced water into a disposal reservoir is not feasible for the Project.

Bay du Nord Field

With respect to Produced Water Reinjection (PWRI), the Bay du Nord Field is unsuitable for PWRI as the thinner reservoir sands are susceptible to fractured out of zone injection. Additionally, gas injection (via WAG) combined with PWRI would produce unacceptable reservoir souring concentrations at Bay du Nord Field.

Cambriol Field

For the Cambriol Field, the current evaluation indicates that PWRI to the reservoir may have a negative impact on injectivity, thus risking recoverable volumes. Additionally, PWRI will accelerate reservoir souring leading to increased hydrogen sulphate (H_2S) in production stream with negative impact on structural integrity of flexible risers that pose challenges to safe operations and economic development. Further studies post operations are needed to determine the overall acceptability of PWRI for the Cambriol Field. Optionality for the future implementation of produced water injection will be included in the facility design.

During operations, further assessment will be completed with testing of the produced water properties, the quality of the treated water, and in-situ well injectivity for the Cambriol Field. With this operational performance data, the produced water management strategy will be re-evaluated. The Project will consider available technology and potential reservoir implications when designing for produced water management. The Produced Water Management Strategy [57] provides additional information on PWRI for the Project.

Injection modelling simulations have been performed for a number of fluid injection scenarios for the Project. The objectives of the work were to investigate the evolution of fracture growth over time. It should be noted that high-rate injection in pure matrix mode is very uncommon, regardless of water quality. As such, the modelling was not to determine if fractured injection will occur, but rather to determine the impact of varying water qualities on fractured injection. The simulations indicated that seawater injection is feasible in all scenarios. It was observed that fracture length and fracture growth increases significantly with high particle content water. This is attributed to produced water injection, highlighting the necessity for ensuring good water quality for the Project. There are risks associated with managing fracture growth to ensure that it is maintained within the targeted injection interval. Most fields require mitigation measures, in the form of particle filtering and/or injection well rate reductions, if produced water reinjection is implemented. The expected reductions in injection rates associated with PWRI may limit the economic viability of some of the development wells.

Produced Water Management Strategy

Based on the risks and uncertainties associated with PWRI, the water management strategy for the Project is to commence with treated seawater injection, and produced water treatment using best treatment practices that are commercially available and economically feasible and discharge to sea in accordance with C-NLOER guidelines.

The treatment of produced water for discharge to the sea has a focus on the reduction of oil content within the water and the reduction of particles that may be coated with oil, as referenced in the C-NLOER guidelines and Equinor ASA guidelines. Water quality for PWRI has a greater focus on the presence of particles and their relationship to the reservoir near the injection wells. PWRI typically increases the particle content of injected water into the formation, which has the potential to increase near-wellbore plugging. This reduces injectivity resulting in an increase in the size of fractures, for the same injection rates, or requires a reduction in injection rates to manage fracture growth. To maintain injection rates with PWRI, increased injection pressures are typically required to continually extend fractures, compensating for continuous increases in the amount of plugging. Options exist to reduce the particle content in the injected water; however, there are practical limitations and operational issues that may limit effectiveness. One such consideration is the requirement for continuous maintenance of the particle removal equipment. When the equipment requires cleaning, particle removal must stop requiring injection to stop or the reservoir may be damaged. Both will have negative impacts on production and recovery.

The particle loading content of seawater tends to be low and the existing particles in seawater are generally soft, consisting of micro-organisms and non-living organic matter. These particles tend to be easily split into smaller particles as the seawater is pumped and injected through the injection network. Produced water particle size and distribution is field specific and can vary overtime. The particle loading content of produced water will be a function of the injection filtering design capabilities and their operability. The design for best available filtering techniques will reduce the particle content of produced water if the filtering equipment is used for 100% of the water injected. Reductions in production efficiency and injection system downtime may occur for injection filtering maintenance and repair. If produced water injection is implemented, water discharge capability will still be required such that unfiltered water is not injected into the reservoir during injection filtering maintenance and repair. During these periods the quality of the discharged water will be treated to meet discharge limits.

Technology is continuously evolving and Equinor is committed to research and development activities that improve on all aspects of oil and gas production including safety, the environment, production and recovery. As new technologies are developed, they will be screened for potential implementation in the Project as part of the produced water management strategy.

Produced water reinjection may be possible if sufficient operational data is collected and analysed to demonstrate that it is technically and economically feasible to be implemented [57]. To ensure Project robustness and conservation of future resources, produced water discharge after treatment will be implemented at start-up. The design of the FPSO will include considerations for implementing future PWRI. If the injection risks of PWRI are deemed acceptable following further data collection and study, then PWRI may be implemented.

7.5.3 Data Acquisition and Formation Evaluation Program

The data acquisition and formation evaluation program is an important part of the reservoir management plan. The strategy is based on the reservoir understanding as detailed in Section 2 Geology, Section 3 Petrophysics, Section 4 Geophysics and Section 6 Reservoir and Production Engineering along with the proposed development scenarios detailed in Section 7.3 Bay du Nord Field Exploitation and Section 7.4 Cambriol Field Exploitation. The outlined data acquisition strategy will continue to evolve leading up to the submission of the Project Data Acquisition Program, and will have the flexibility to respond to changing evaluation needs as the development matures.

A standard data acquisition program will be implemented for each development well. However, several wells may require a more advanced program to optimize well placements and reduce reservoir uncertainties. In general, the following categories of data acquisition will be considered, with options for modifications to best meet the requirements for operations and reservoir management:

1. Standard logging program: Logging While Drilling (LWD) log suite required to drill, to stratigraphically correlate and to provide general reservoir evaluation information.
2. Extended logging program: inclusion of options from the standard program with additional data acquisition which may include check-shot and velocity surveys, fluid sampling, or well testing using the formation pressure tester associated with fluid sampling.
3. Detailed data acquisition program: in addition to options from a standard or extended program the inclusion of conventional coring, cased-hole logging, compressional, and shear sonic logging, micro-resistivity/ acoustic imaging, or ultra deep azimuthal resistivity logs may be targeted for specific areas.
4. Advanced data acquisition program: in addition to the other options provided, the inclusion of interference testing, rock strength testing, or extended well testing may be included.

The standard logging program assumes LWD while other options, including wireline and tubing conveyed operations, may be considered based on well and reservoir requirements. In addition, it is essential that the strategy include flexibility to address unknowns that may arise during the drilling of the development wells. Table 7.4 provides a more detailed overview of data acquisition options during well operations along with considerations for acquiring and using the data. Well operations may be limited to the initial drilling and completion programs with no planned interventions of the base development wells. As opportunities arise, consideration will be given to additional data acquisition.

Final decisions on data acquisition will be dependent on the specific requirements for each well, and outcomes of the preceding wells.

Additional data acquisition activities associated with reservoir surveillance are discussed in Section 7.5.5 Reservoir Surveillance.

Table 7.4 Bay du Nord Project: Data Acquisition Options

Category	Description	Considerations for Use
1: Standard	LWD and/or wireline logging	
	Gamma ray, rate of penetration, resistivity, density, thermal neutron porosity, acoustic caliper	This is the standard set of logs to be acquired in a well. They may be used to assist in drilling and completion activities, assist in reservoir characterization and for standard petrophysical interpretations. Logs and tools may be changed and augmented over time based on reservoir requirements and changes in technology.
	Formation pressure testing	Formation pressures may be used to determine fluid gradients, for use in estimating fluid contacts, and for the monitoring of depletion and communication within the reservoir.
	Cement evaluation logging	To verify hydraulic isolation.
2: Extended	Checkshot and velocity surveys	These surveys may be acquired where necessary to improve seismic velocity control in the fields.
	Fluid sampling	Sampling of both oil and water may be performed in wells that penetrate previously untested fluid systems. They may be used in fluid compatibility studies, geochemical evaluations and for reservoir characterization.
	Well testing (Mini-Drill Stem Tests [DSTs])	Mini-DSTs may be performed as part of fluid sampling operations to gain additional information on reservoir properties and connectivity.
	Nuclear Magnetic Resonance (NMR)	NMR may be run in some wells to reduce uncertainty in reservoir properties.
	Tracers	Completion and/or injection tracers may be run in some wells to determine fluid inflow along well and to determine sweep pathways between injection and production wells.
3: Detailed	Conventional core	For use in calibrating well logs and seismic to reservoir properties along with general reservoir characterization. Core may be acquired to improve the understanding of the depositional environment and extent of the reservoir sands. Coring of shale sections may be performed to further the understanding of rock properties.
	Production logging	Production logs may be considered to improve the understanding of production behaviour over the life of the field. Limitations associated with well and completion design will be evaluated along with other opportunities to acquire similar data.
	Sonic logging	May be used to improve geophysical interpretations and geomechanical models for overburden and reservoir assessments.
	Ultra deep azimuthal resistivity	May be run in select wells for geosteering.
	Micro-resistivity / Acoustic imaging logs	May be used to provide stratigraphic and facies calibration to core, seismic and standard well logs.
4: Advanced	Extended well testing	Options for well testing during the drilling of the development wells may be considered to improve on the understanding of connectivity and development potential of reservoir sands not included in the base reservoir exploitation plans. Options may include traditional drill stem tests or more modern tubing conveyed methods such as the Formation Testing While Tripping (FTWT).
	Interference testing	The monitoring of reservoir pressure during logging operations to identify communication with producing or injecting wells. This would only be considered in instances where permanent down hole gauge data is deemed insufficient.
	Extended Leak Off Tests (XLOT) and micro or mini-fracs	Options to evaluate the mechanical properties of the reservoir and the overburden may be considered if required for improved operation of the fields.

7.5.4 Impact of Rate on Recovery

The impact of oil production rates on recovery was assessed for the Project. The assessment considers whether high production rates may negatively impact ultimate recovery from the two fields. The resource estimates and production profiles provided in Section 9.3 Recoverable Resource Estimates and Section 7.6 Drilling Schedule and Production Forecasts are based on an oil production capacity of 160,000 bopd and are integrated profiles at the Project level. This assessment is performed on the independent dynamic models for each field, using the field-level approach described in Section 7.2 Reservoir Modelling and Uncertainty. As such, the reported recoverable volumes are higher than the integrated, facility constrained, recoverable volumes. In the following figures, the integrated mean recovery for each field is shown relative to the assessment rates. For all fields, potential production rates within the proposed design limits for each field are not expected to negatively impact recovery.

The method used for the evaluation of the impact of rate on recovery varies between the fields to reflect the main constraints of each field. For the Bay du Nord Field, the assessment is made based on the FPSO oil capacity. The Bay du Nord Field is likely to have both the well capacity and the flow line capacity to reach the facility design rates. Therefore, the assessment considers the FPSO oil capacity of 25,440 m^3/d (160,000 bopd) as the peak oil rate that may be reached by the proposed Bay du Nord Field development. Note that the design limit may be exceeded as a result of de-bottlenecking activities, as is common for oil fields. However, this option for increased rates is not considered here. It is unlikely to change the results of the evaluation as other fields are likely to contribute to the total oil production through the FPSO. For the Cambriol Field the assessment is made based on an assumed maximum flowline liquid capacity of 16,000 m^3/d. For each field the maximum capacity is reduced by 25% and 50% for the evaluation.

The results of the evaluation are shown in Figure 7.12 and Figure 7.13. In addition to the rates and recovery for each field from the assessment, the mean oil rate and recovery from the integrated profiles is included. For each field the integrated mean production rate is less than most of the potential rates considered in the assessment.

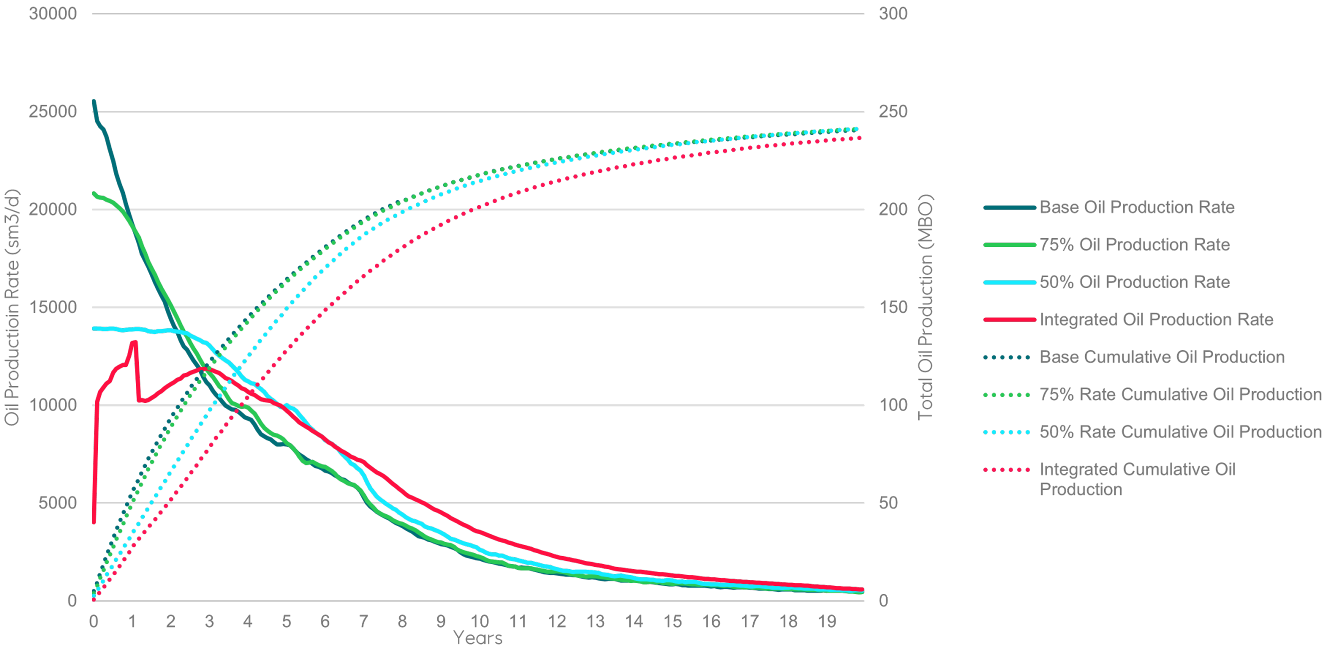


Figure 7.12 Bay du Nord Field: Impact of Oil Rate on Recovery

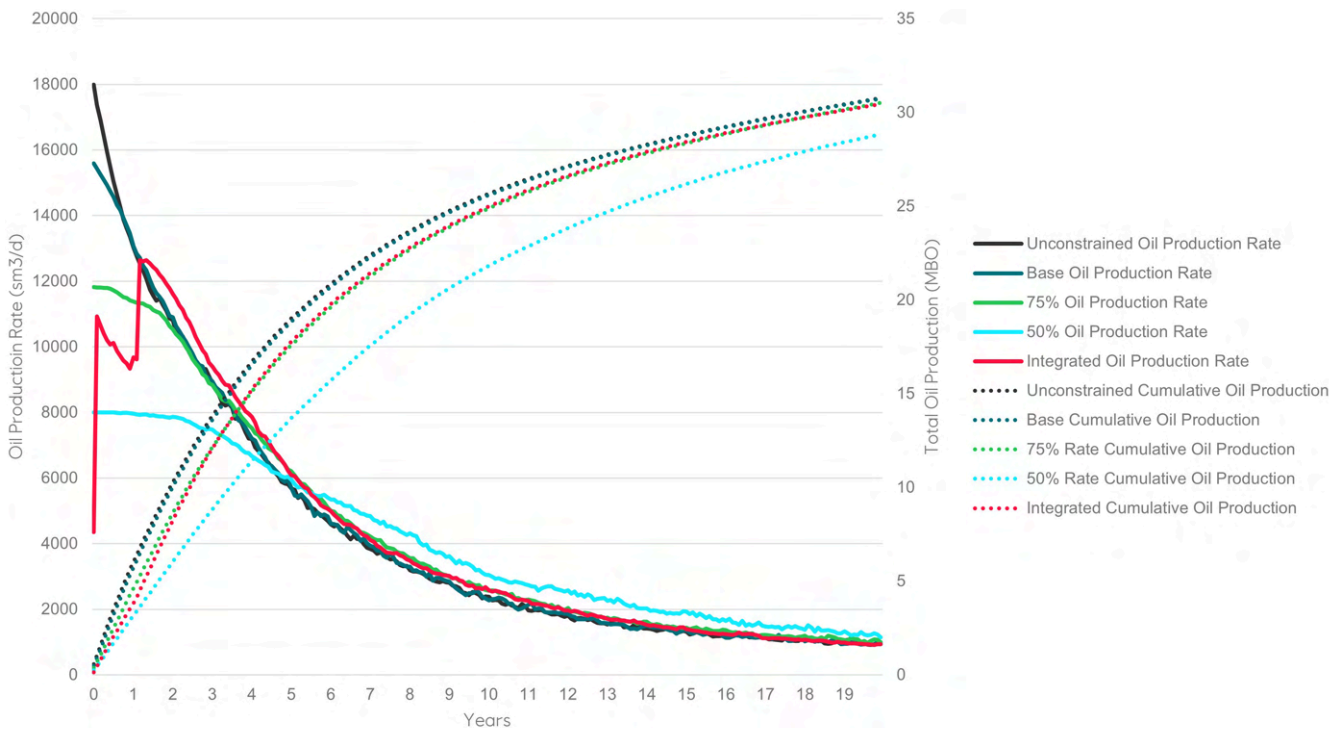


Figure 7.13 Cambriol Field: Impact of Oil Rate on Recovery

For the Bay du Nord Field, producing at lower rates typically results in a deferment of production but similar recovery at 20 years. As the integrated profile produces at rates less than 50% of what is hydraulically possible in simulation, there is some small backout that can be seen at the end of the 20-year modelling period.

For the Cambriol Field, producing at lower rates typically results in a deferment of production but similar recovery at 20 years. While the liquid capacity of the Cambriol flowline is 16,000 m^3/d, Figure 7.13 also shows an unconstrained profile which is used to demonstrate the full potential of the producers. On a field level the production deferment is logical and only the 50% flowline capacity case shows a material change in recovery at 20 years. The integrated profile produces at rates less than 75% of what is hydraulically possible in simulation initially as both fields compete for capacity before ramping up after about two years resulting in limited backout at the end of the 20-year modeling period.

Well operating rates are not expected to impact recovery. However, the interactions between wells can impact recovery. Reservoir management will involve data acquisition and production forecasting to actively manage wells and optimize production. Many factors will influence the actual rates at which each well is operated, including reservoir quality, completion design, level of injection support and fluid breakthrough. Within the fields, well rates will be managed to optimize production and improve economic recovery from the reservoirs.

7.5.5 Reservoir Surveillance

Reservoir surveillance is necessary to ensure the development of the resource is maximized through efficient operations and optimal well placement, management, and performance. The Project will have a robust reservoir surveillance plan in place during operations that is both adaptive and responsive to development drilling results. The reservoir surveillance plan will facilitate the implementation of the development strategies while addressing the subsurface uncertainties, as discussed in Section 7.3 Bay du Nord Field Exploitation and Section 7.4 Cambriol Field Exploitation. As development progresses, the employed reservoir surveillance methods will likely be dependent on the technical evaluations of preceding wells and the evolving understanding of the reservoirs.

Well Testing

Well testing is an integral part of field operations, providing valuable information for use in allocating production, managing wells, monitoring the reservoir, and collecting samples of fluids for analysis. The well testing equipment for the Project will be designed to meet the applicable requirements of the *Measurement Guidelines* [58] and Equinor's internal technical requirements. The planned well testing system may include:

- A three-phase test separator;
- Subsea multi-phase flow meters;
- Virtual flow metering software; and
- Functionality to route individual and grouped wells to the test separator.

Note that over the life of the field, it may not be possible for low productivity wells to produce independently to the test separator as water-cuts increase. Artificial lift is intended to facilitate independent well production to the test separator; however, some wells may require testing by difference methods or commingled testing in later years. This is not expected to impact allocation, as wells will produce from common reservoirs and well testing will be combined with modelling software to improve accuracy. The wells are also planned to include multi-phase flow meters for additional accuracy in well allocation.

Fluid Sampling

Surface fluid samples of oil, gas, and water will be collected from each development well during the initial production from the well. It is expected that surface samples will be collected from production wells regularly during production testing. Following water breakthrough, wells may be monitored to determine if the source of the water is formation water or seawater.

Sampling of the injection water will be performed regularly to monitor composition and the amount of dissolved solids. Additional fluid samples will be collected as necessary to aid in troubleshooting operations.

The fields are expected to sour during field operations. Fluid sampling will include monitoring for H_2S.

Pressure Surveys

Pressure surveys are an important part of field management. They are planned on wells when opportunities are presented. The surveys are valuable for managing the pressure within the reservoir and providing information on reservoir characteristics and changing reservoir properties over time. They will form an important part of understanding the nature of reservoir boundaries and baffles within the Bay du Nord and Cambriol fields. In addition to planning for initial pressure surveys in wells following the start of production, injection wells may also be tested during clean-up operations.

Production Logs

Production logs are an important tool in understanding inflow from the reservoir. Production logging for the Project may be limited based on well completion design, and drilling installation availability. Alternate options to understanding inflow along the production wells will be evaluated, including the use of tracers.

Reservoir Tracer Programs

There are several types of tracers that may be implemented at the fields to monitor fluid movement and supplement subsurface data collection over the life of the development. The following are examples of potential future tracer programs:

- Topsides tracer injection into specific injection wells for the monitoring of fluid movement within the reservoir. Tracers specific to water and gas may be implemented to evaluate the effectiveness of the WAG programs.
- Tracers applied in production wells prior to installation of the completions with the following characteristics:
  - Provide an indication of initial inflow along the well, specifically in multi-target wells, where production logging is not possible, and
  - Fluid activated tracers that will indicate when and where water or gas breaks through in a well or segment of a well.
- Tracers applied to injection wells prior to installation of the completion to provide an indication of what segments in multi-target wells are in communication with what producers.

Tracer programs may be developed over the life of the development in response to specific monitoring requirements.

Geochemical Fingerprinting

Geochemical fingerprinting can be used to allocate production from multiple zones within a single well provided each zone contains a geochemically distinguishable oil. When wells are tested, a sample of the oil can be taken, and analysis done to determine the approximate percentage of production in that sample from each zone contacted by that well. Previous independent zonal samples are required have been taken to serve as a fingerprinting baseline. Geochemical fingerprinting may be used over the life of the development in response to specific monitoring requirements.

Seismic Reservoir Monitoring

As discussed in Section 7.7 Improved Oil Recovery, seismic reservoir monitoring or 4D seismic is being evaluated for implementation at the Project fields. If implemented, and successful, 4D seismic may assist with managing flood patterns, identifying bypassed oil, and planning for sidetrack and infill drilling programs. It may also be used to identify areas where the reservoir has been thoroughly swept in multi-target wells and used as part of planning for isolating zones in production or injection wells.

7.5.6 Artificial Lift

The Project has considered several options for the implementation of artificial lift to improve production performance over the life of the Project. The artificial lift strategy for the Project, summarized below, reflects the specific challenges of the Bay du Nord and Cambriol fields.

For the Bay du Nord Field, it was determined that artificial lift is not required to improve the potential production performance. Key considerations include:

- Overpressured reservoir;
- Short ca. 5.6 to 7.1 km distance to riser base, 2.4 km distance from riser base to FPSO hang-off;
- Highly permeable reservoir with good continuity allows for high well deliverability; and
- With WAG drainage strategy, the potential for down hole artificial lift to improve production performance is limited.

For the Cambriol Field, it was determined that artificial lift is not required to improve the potential production performance. Key considerations include:

- Highly overpressured reservoir;
- Light oil with a higher GOR relative to Bay du Nord field;
- Highly permeable reservoir with good continuity allows for high well deliverability; and
- Long 34 km distance to riser base, 2.4 km distance from riser base to FPSO hang-off. This distance is overcome by sufficiently high reservoir pressure, well deliverability, and flowline sizing.

Both Cambriol and Bay du Nord's riser bases will be designed for gas lift, while only the Bay du Nord Field will be designed for template-based gas lift. This is to reduce occurrences of slugging in the riser, considering the impact of unstable flow on riser fatigue and process stability. In addition, it is expected to support start up operations, single well testing, and improve late life production at high water cuts.

Figure 7.14 from Prosper model demonstrates that BdN production wells can deliver high liquid rates with original GOR without artificial lift even at high water cuts (WHP 140 bar).

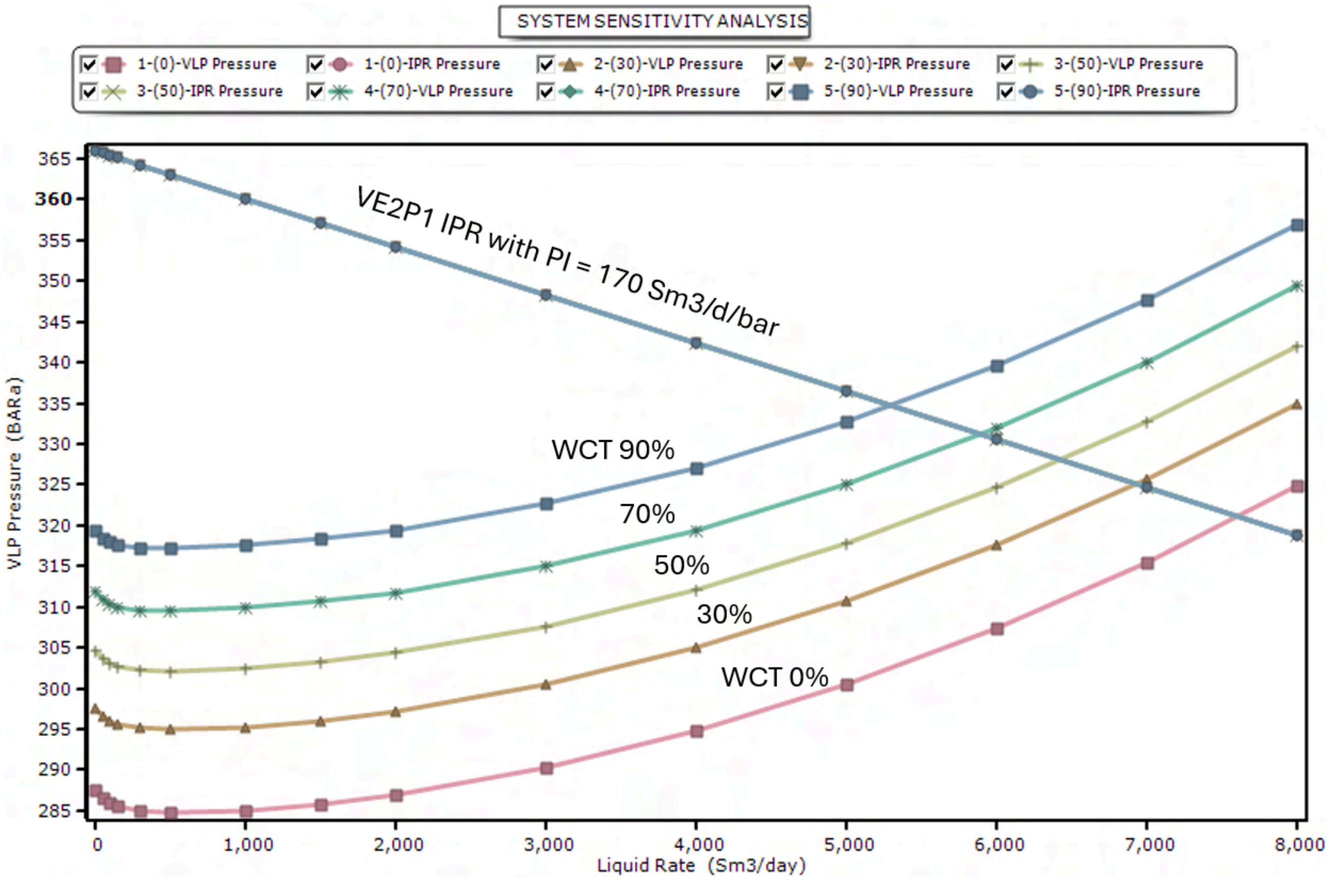


Figure 7.14 IPR and VLPs for BdN producer VE2P1

7.6 Drilling Schedule and Production Forecasts

The drilling schedule and production profiles associated with the base reservoir exploitation plan for the Project are provided below. The production profiles incorporate reservoir uncertainty, drilling order, FPSO capacities, and operational efficiency assumptions.

Pre-drilling of development wells will be used to meet the production profile requirements and achieving the production plateau. It is also assumed that drilling and completion operations will be performed in batches to best manage the efficiency of the drilling program. A tentative schedule for the delivery of the wells in the base reservoir exploitation plan is shown in Table 7.5, and was used to generate the production profiles shown in this section. This schedule assumes ten wells in the Bay du Nord Field and six wells in the Cambriol Field. The potential for future wells beyond this number is discussed in Section 7.7.1 Additional Development Targets. Additional work will be completed on well requirements and timing prior to development drilling. This schedule depends on both drilling activities and subsea infrastructure installation, and is therefore subject to change.

In the Bay du Nord Field, the reservoir pressure is maintained close to initial 380 bar which is above hydrostatic pressure reducing requirements for gas lift. In the Cambriol Field, the high initial pressure of 785 bar is depleted to approximately 600 bar in the first 6 to 12 months of production and then continuously maintained with water injection.

Production and injection profiles are provided in Table 7.6 through Table 7.10. In each table low, base, and high profiles are included on an annual basis for each of the two fields within the Project Area and for the Project itself. These are deterministic coupled cases modelled in Resolve (Base) or Eclipse (Low/High) as detailed in Section 7.2 Reservoir Modelling and Uncertainty and, while the recoverable resource totals are similar to those noted in Section 9.3 Recoverable Resource Estimates, these are not generated using the same tool.

Daily production and injection profiles are provided in Figure 7.15, Figure 7.16, Figure 7.17, Figure 7.18, Figure 7.19 and Figure 7.20 for the base case. Cumulative oil profiles assume production start in the fourth quarter of year 1.

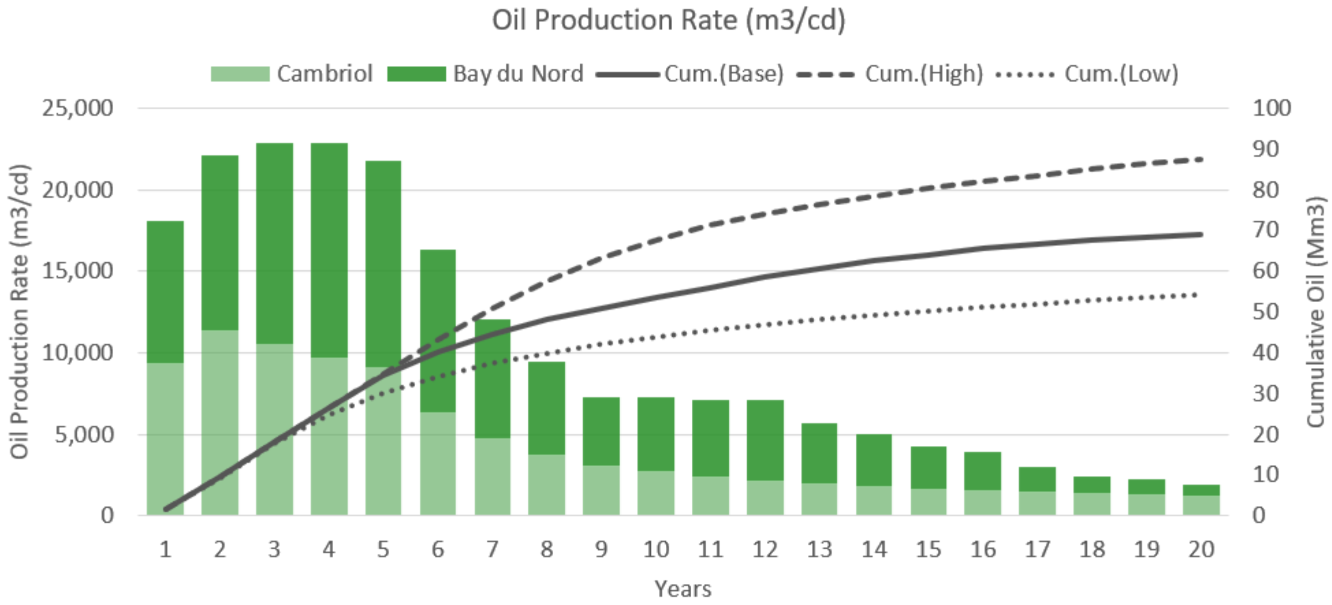


Figure 7.15 Bay du Nord Project: Oil Production Rate by Field

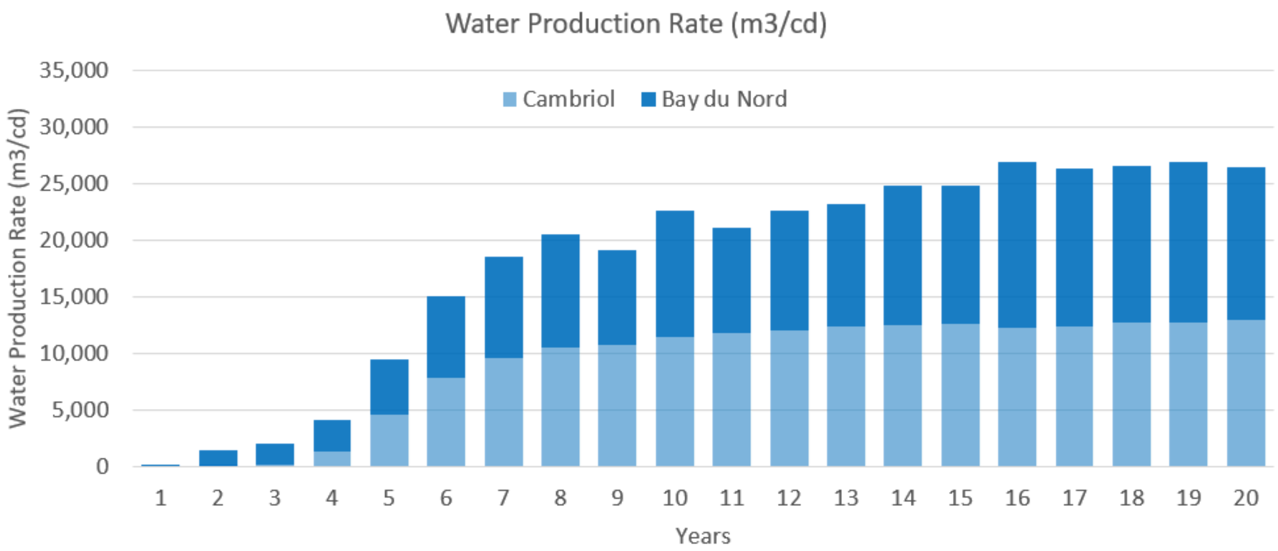


Figure 7.16 Bay du Nord Project: Water Production Rate by Field

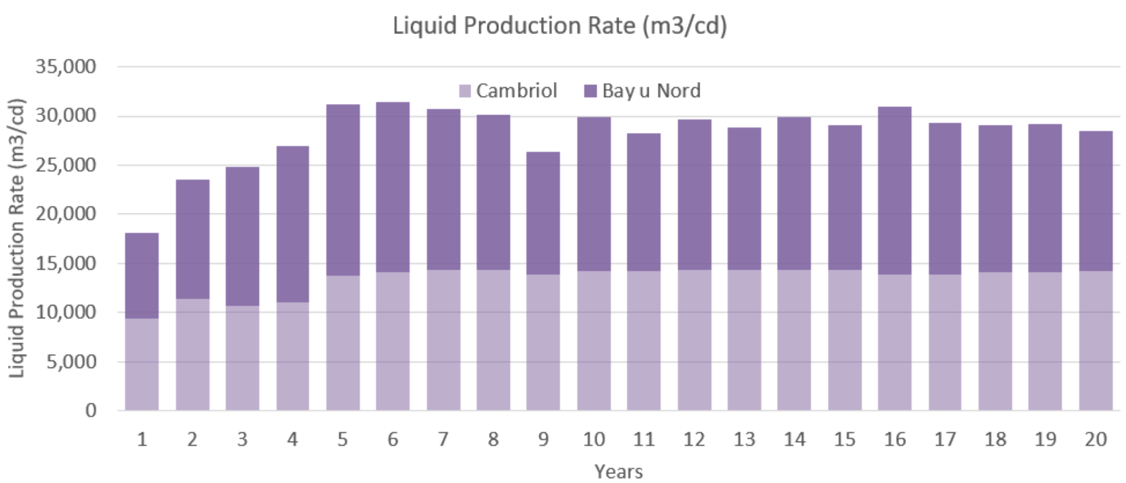


Figure 7.17 Bay du Nord Project: Liquid Production Rate by Field

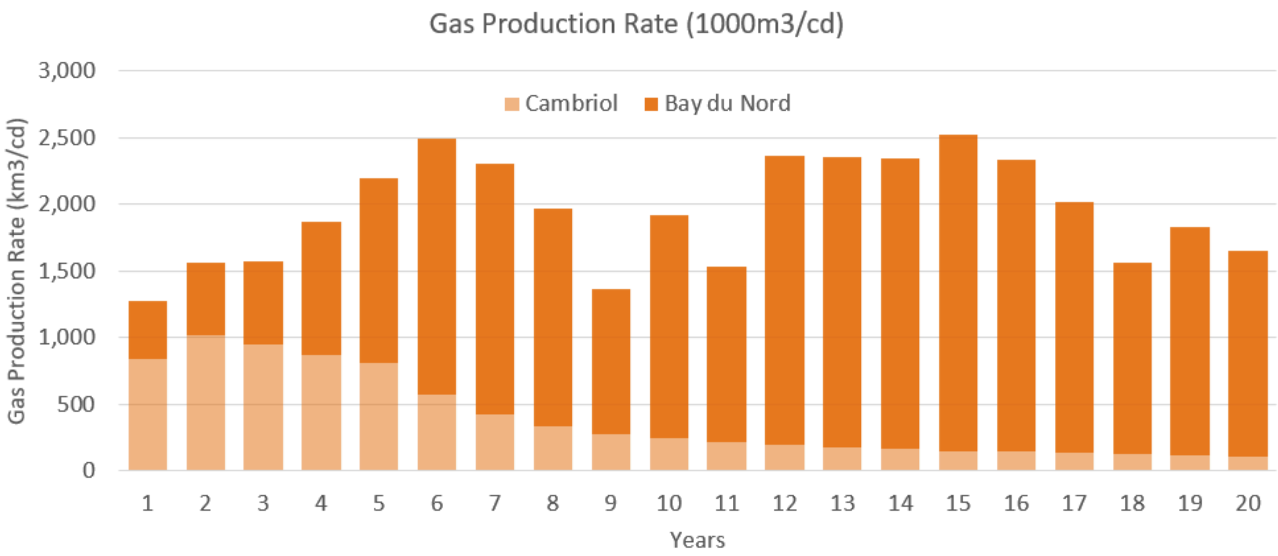


Figure 7.18 Bay du Nord Project: Gas Production Rate by Field

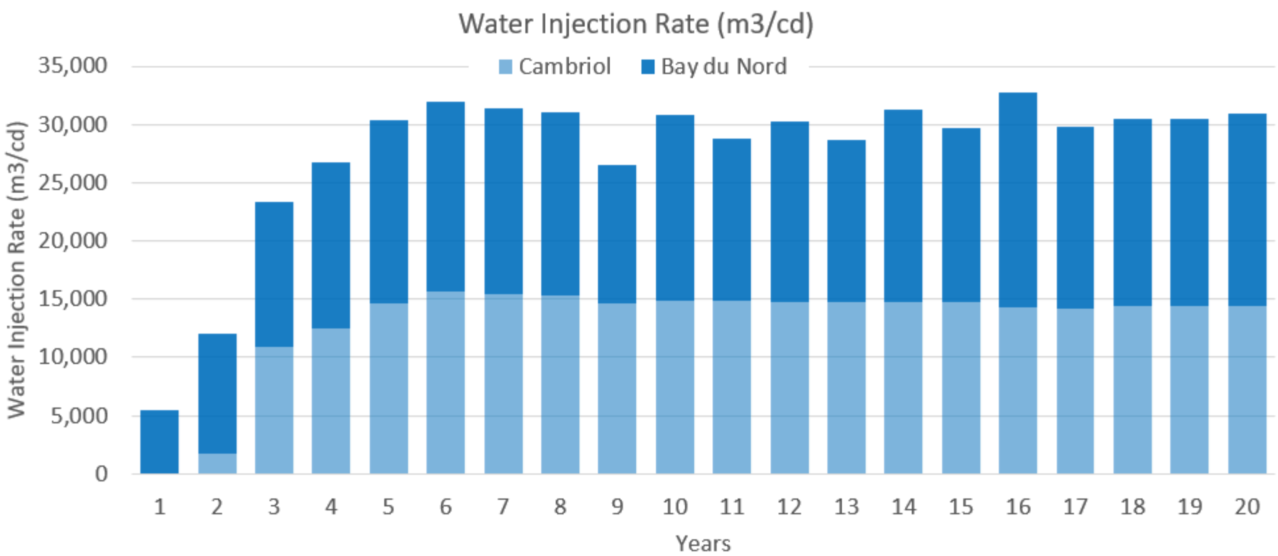


Figure 7.19 Bay du Nord Project: Water Injection Rate by Field

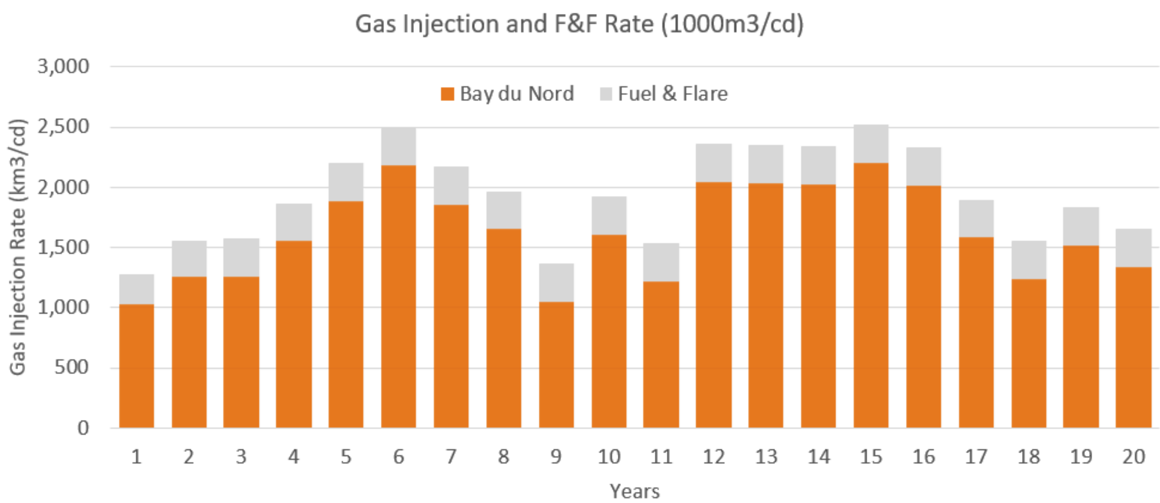


Figure 7.20 Bay du Nord Project: Gas Injection Rate by Field

Table 7.5 Bay du Nord Project - Preliminary Drilling Schedule

Well	Field	Online (months from first oil)
Bay du Nord - 1	Bay du Nord	0
Bay du Nord - 2	Bay du Nord	0
Bay du Nord - 3	Bay du Nord	0
Bay du Nord - 4	Bay du Nord	0
Bay du Nord - 5	Bay du Nord	0
Bay du Nord - 6	Bay du Nord	0
Cambriol - 1	Cambriol	0
Cambriol - 2	Cambriol	0
Cambriol - 3	Cambriol	0
Cambriol - 4	Cambriol	8
Cambriol - 5	Cambriol	8
Bay du Nord - 7	Bay du Nord	11
Bay du Nord - 8	Bay du Nord	11
Bay du Nord - 9	Bay du Nord	11
Bay du Nord - 10	Bay du Nord	11
Cambriol - 6	Cambriol	14

Table 7.6 Bay du Nord Project: Estimated Annual Oil Production

Year	Annual Oil Production (Base)			Annual Oil Production (Low)			Annual Oil Production (High)		
	Bay du Nord	Cambriol	Project	Bay du Nord	Cambriol	Project	Bay du Nord	Cambriol	Project
	(e^6m^3)	(e^6m^3)	(e^6m^3)	(e^6m^3)	(e^6m^3)	(e^6m^3)	(e^6m^3)	(e^6m^3)	(e^6m^3)
1	0.8	0.9	1.6	0.7	0.6	1.6	0.9	0.8	1.6
2	3.9	4.2	8.1	3.8	2.7	7.9	5.2	4.3	8.1
3	4.5	3.8	8.3	3.9	2.6	8.3	5.6	4.4	8.4
4	4.8	3.5	8.3	3.3	3.1	7.0	5.4	5.0	8.4
5	4.6	3.3	7.9	3.8	2.1	5.4	4.6	4.6	8.4
6	3.6	2.3	6.0	3.2	1.3	4.2	3.7	3.9	8.4
7	2.7	1.7	4.4	2.7	1.0	3.4	2.9	3.9	7.8
8	2.1	1.4	3.5	1.4	0.8	2.3	2.9	3.3	6.7
9	1.5	1.1	2.7	1.5	0.7	2.1	1.8	2.1	5.8
10	1.6	1.0	2.7	1.2	0.6	1.8	1.6	2.1	4.5
11	1.7	0.9	2.6	1.1	0.6	1.6	1.6	1.3	3.5
12	1.8	0.8	2.6	0.8	0.5	1.4	1.6	1.0	2.7
13	1.3	0.7	2.1	0.7	0.4	1.3	1.3	0.8	2.4
14	1.2	0.7	1.8	0.5	0.4	1.1	1.1	0.7	2.2
15	0.9	0.6	1.5	0.5	0.4	1.0	0.9	0.6	1.8
16	0.8	0.6	1.4	0.4	0.3	1.0	0.6	0.6	1.7
17	0.6	0.5	1.1	0.4	0.3	0.9	0.6	0.5	1.6
18	0.4	0.5	0.9	0.4	0.3	0.9	0.7	0.5	1.5
19	0.3	0.5	0.8	0.3	0.3	0.7	0.3	0.4	1.3
20	0.3	0.4	0.7	0.3	0.3	0.7	0.3	0.4	1.3
Total	39.5	29.6	69.1	30.9	19.3	54.3	43.6	41.3	87.6

Table 7.7 Bay du Nord Project: Estimated Annual Water Production

Year	Annual Water Production (Base)				Annual Water Production (Low)				Annual Water Production (High)		
	Bay du Nord	Cambriol	Project		Bay du Nord	Cambriol	Project		Bay du Nord	Cambriol	Project
	(e^6m^3)	(e^6m^3)	(e^6m^3)		(e^6m^3)	(e^6m^3)	(e^6m^3)		(e^6m^3)	(e^6m^3)	(e^6m^3)
1	0.0	0.0	0.0		0.0	0.0	0.0		0.0	0.0	0.0
2	0.5	0.0	0.5		0.0	0.0	0.0		0.3	0.2	0.5
3	0.7	0.0	0.7		0.0	0.0	0.0		1.3	0.1	1.1
4	1.0	0.5	1.5		0.1	0.0	0.2		3.0	1.1	4.2
5	1.8	1.7	3.4		0.4	0.0	0.5		3.9	2.8	5.4
6	2.7	2.8	5.5		1.4	0.1	1.7		4.8	3.5	6.7
7	3.3	3.5	6.8		3.0	0.4	3.8		5.2	3.5	7.9
8	3.7	3.9	7.5		3.1	1.2	3.9		6.0	4.0	9.4
9	3.0	3.9	7.0		2.9	1.2	4.0		6.3	4.1	9.5
10	4.1	4.2	8.2		2.2	1.4	3.6		6.7	3.5	9.6
11	3.4	4.3	7.7		2.0	1.5	6.5		6.4	3.7	9.8
12	3.8	4.4	8.2		1.8	1.9	6.7		6.8	3.6	9.3
13	3.9	4.5	8.5		3.9	2.1	7.4		6.9	3.7	9.7
14	4.5	4.6	9.1		1.6	2.3	6.2		7.1	3.3	9.9
15	4.5	4.6	9.1		1.5	3.0	6.0		7.1	4.2	9.9
16	5.4	4.5	9.9		1.4	2.6	6.4		7.2	3.7	9.9
17	5.1	4.5	9.6		1.9	2.7	5.9		7.1	3.6	9.9
18	5.1	4.7	9.7		1.6	3.3	6.9		6.9	3.3	9.8
19	5.2	4.7	9.8		1.8	3.6	6.0		6.8	3.7	9.8
20	5.0	4.7	9.7		2.7	3.7	6.3		6.6	4.3	9.8
Total	66.5	65.9	132.4		33.4	30.9	81.8		106.2	59.8	151.9

Table 7.8 Bay du Nord Project: Estimated Annual Gas Production

Year	Annual Gas Production (Base)				Annual Gas Production (Low)				Annual Gas Production (High)		
	Bay du Nord	Cambriol	Project		Bay du Nord	Cambriol	Project		Bay du Nord	Cambriol	Project
	(e^6m^3)	(e^6m^3)	(e^6m^3)		(e^6m^3)	(e^6m^3)	(e^6m^3)		(e^6m^3)	(e^6m^3)	(e^6m^3)
1	40	76	116		37	56	103		47	73	110
2	196	373	569		191	240	511		263	384	574
3	230	345	574		237	228	557		386	397	694
4	364	318	682		327	280	663		410	449	760
5	506	297	803		424	188	644		513	409	913
6	702	208	911		555	119	600		742	352	1161
7	684	156	840		436	87	607		821	351	1113
8	595	124	719		476	73	577		1087	295	1329
9	395	102	497		536	64	487		908	188	1464
10	611	91	702		462	57	555		1086	186	1482
11	480	81	560		588	50	537		1144	117	1478
12	789	72	862		481	44	634		1186	92	1470
13	792	66	858		459	39	581		1273	75	1452
14	795	60	855		544	36	570		1305	64	1386
15	864	55	919		488	33	569		1314	56	1386
16	799	52	851		360	30	583		1314	50	1425
17	686	49	735		458	29	410		1302	46	1411
18	523	45	569		336	28	319		1256	41	1402
19	626	43	669		285	27	254		1262	38	1308
20	564	40	604		268	23	184		1140	36	1313
Total	11241	2653	13895		7947	1731	9943		18760	3699	23631

Table 7.9 Bay du Nord Project: Estimated Annual Water Injection

Year	Annual Water Injection (Base)				Annual Water Injection (Low)				Annual Water Injection (High)		
	Bay du Nord	Cambriol	Project		Bay du Nord	Cambriol	Project		Bay du Nord	Cambriol	Project
	(e^6m^3)	(e^6m^3)	(e^6m^3)		(e^6m^3)	(e^6m^3)	(e^6m^3)		(e^6m^3)	(e^6m^3)	(e^6m^3)
1	0.5	0.0	0.5		0.5	0.0	0.5		0.6	0.0	0.6
2	3.8	0.0	3.8		3.1	0.0	3.3		5.0	0.7	5.1
3	4.6	0.0	4.6		3.1	0.2	4.8		6.7	4.0	9.1
4	5.2	0.5	5.7		2.8	4.3	8.4		7.1	5.5	10.1
5	5.7	1.7	7.4		3.4	5.3	9.6		7.1	4.9	12.6
6	6.0	2.8	8.8		4.5	3.7	9.0		7.3	5.8	11.9
7	5.8	3.5	9.3		5.5	3.6	10.5		7.3	5.8	12.2
8	5.7	3.9	9.6		5.0	3.1	10.9		7.5	5.5	12.6
9	4.3	3.9	8.3		4.8	3.5	10.4		7.6	5.5	12.7
10	5.8	4.2	10.0		3.3	3.6	8.8		7.6	5.5	12.3
11	5.1	4.3	9.4		3.9	3.3	8.8		7.8	5.1	11.8
12	5.7	4.4	10.1		2.9	3.3	8.4		8.0	4.7	11.8
13	5.1	4.5	9.6		3.1	3.3	9.0		7.8	4.8	11.3
14	6.0	4.6	10.6		2.7	3.3	7.8		7.5	5.0	11.3
15	5.4	4.6	10.0		2.2	3.3	7.6		7.3	4.9	11.1
16	6.7	4.5	11.2		2.4	3.3	8.1		7.6	4.6	11.1
17	5.7	4.5	10.2		3.1	3.3	7.2		7.5	5.0	11.0
18	5.9	4.7	10.5		4.0	3.3	8.3		7.2	5.0	10.9
19	5.9	4.7	10.5		3.3	3.3	7.8		7.0	4.9	10.3
20	6.0	4.7	10.7		3.0	3.3	8.6		6.7	4.8	10.3
Total	104.9	65.9	170.8		66.6	60.3	157.7		138.2	92.0	210.1

Table 7.10 Bay du Nord Project: Estimated Annual Gas Injection

Year	Annual Gas Injection (Base)			Annual Gas Injection (Low)			Annual Gas Injection (High)		
	Bay du Nord	Cambriol	Project	Bay du Nord	Cambriol	Project	Bay du Nord	Cambriol	Project
	(e^6m^3)	(e^6m^3)	(e^6m^3)	(e^6m^3)	(e^6m^3)	(e^6m^3)	(e^6m^3)	(e^6m^3)	(e^6m^3)
1	94	0	94	81	0	81	89	0	89
2	458	0	458	380	0	380	462	0	462
3	459	0	459	446	0	446	580	0	580
4	567	0	567	530	0	530	644	0	644
5	688	0	688	511	0	511	796	0	796
6	796	0	796	423	0	423	1045	0	1045
7	677	0	677	545	0	545	999	0	999
8	604	0	604	462	0	462	1210	0	1210
9	382	0	382	340	0	340	1349	0	1349
10	587	0	587	381	0	381	1367	0	1367
11	445	0	445	451	0	451	1363	0	1363
12	747	0	747	553	0	553	1348	0	1348
13	743	0	743	492	0	492	1336	0	1336
14	740	0	740	502	0	502	1249	0	1249
15	804	0	804	457	0	457	1290	0	1290
16	736	0	736	439	0	439	1307	0	1307
17	578	0	578	301	0	301	1284	0	1284
18	453	0	453	203	0	203	1235	0	1235
19	554	0	554	144	0	144	1223	0	1223
20	489	0	489	74	0	74	1060	0	1060
Total	11601	0	11601	7715	0	7715	21237	0	21237

7.7 Improved Oil Recovery

For the Project, IOR is defined as any activity that increases recovery beyond the volumes considered in the base depletion plans. This may include the drilling of additional wells, the inclusion of new or alternate technology, or the implementation of enhanced recovery methods. IOR is separated into two categories: additional development targets and Enhanced Oil Recovery (EOR).

These topics explore the opportunities within the Project Area to increase recovery beyond the expected cases presented in Section 7.3 Bay du Nord Field Exploitation and Section 7.4 Cambriol Field Exploitation. The ambition of the Project is to ensure that the resources are fully evaluated and exploited over the life of the Project. Opportunities are provided and discussed to highlight the potential within the Project Area and to demonstrate that the Project has thoroughly considered options to maximize the economically recoverable resources. Implementation of IOR opportunities will only occur where technically and economically feasible.

7.7.1 Additional Development Targets

The Project will maximize the recovery of discovered resources, but also seeks to evaluate the undelineated areas and confirm the production potential of currently marginal resources. Although a comprehensive listing of all opportunities within the scope of the reservoir exploitation plan is not practical, the Project intends to de-risk drilling opportunities within the fields and enhance upside potential through data acquisition. This section provides an overview of opportunities for additional development drilling within the development area of each field, as discussed in Section 7.3.5 Development Scope and Section 7.4.5 Development Scope. This section does not address potential development wells in deferred development areas.

Potential for Additional Development Wells within the Bay du Nord Field Development Area

OIP maps for the Bay du Nord and Mizzen members of the Bay du Nord Field are shown in Figure 7.21, Figure 7.22, Figure 7.23, Figure 7.24, Figure 7.25, and Figure 7.26. The OIP maps are provided for low, base, and high OIP scenarios for each member, and each map shows the initial wells included in the base depletion plan for that zone. The differences in the depicted resource distributions are due to the effects of shallower and deeper oil-water contacts, reduced and extended reservoir sand extents, and other parameters from the uncertainty work, Section 7.3.4 Sensitivity Studies.

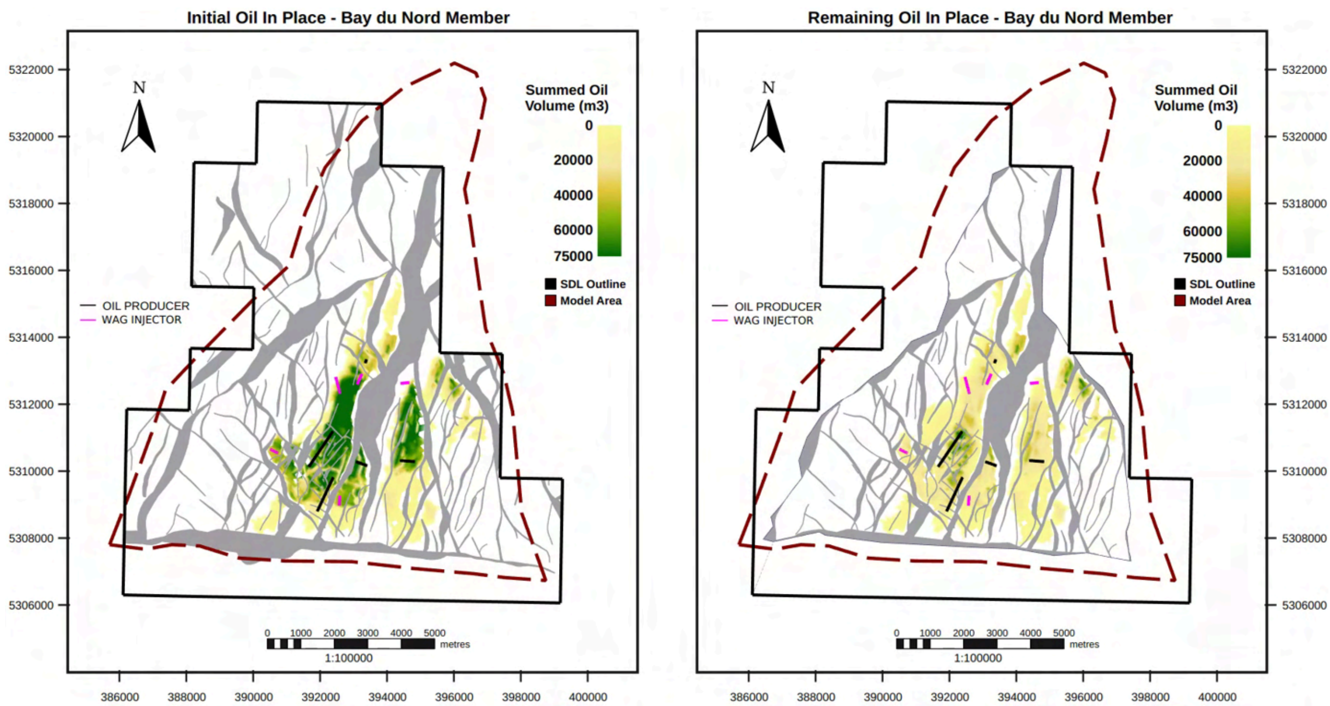


Figure 7.21 Bay du Nord Field: Bay du Nord member Low OIP

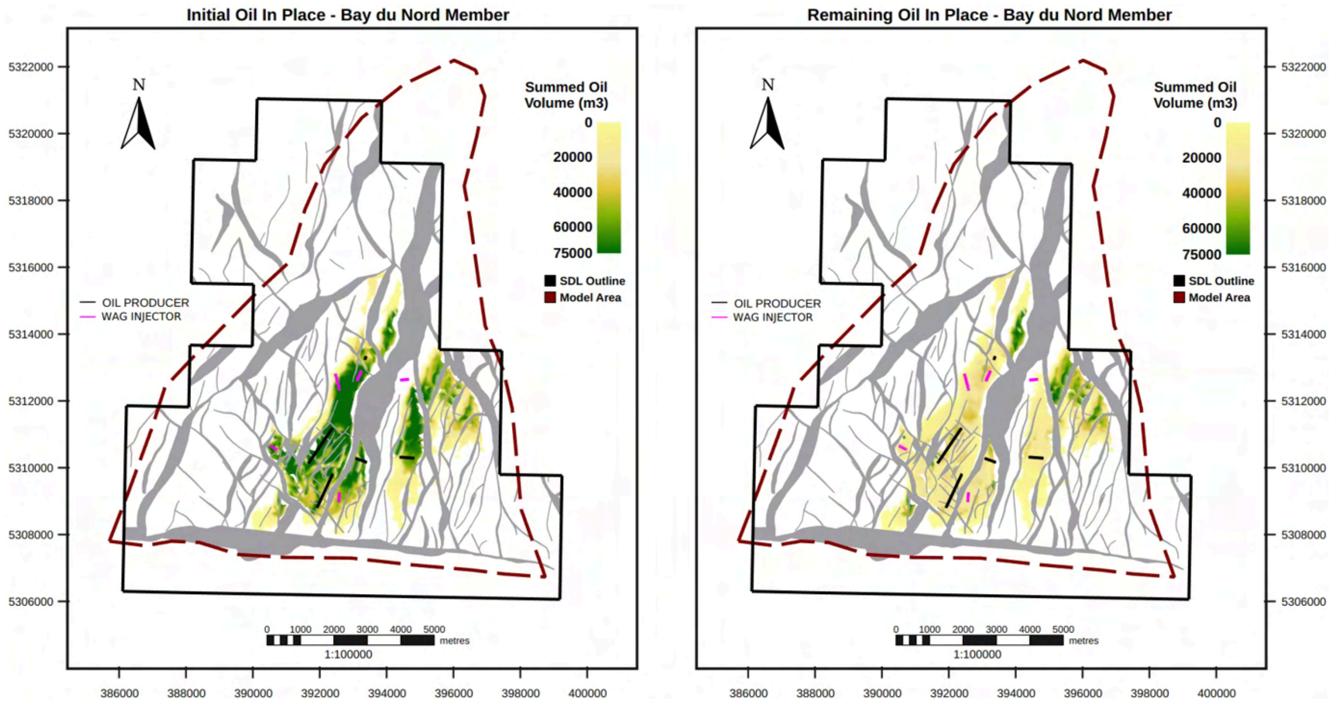


Figure 7.22 Bay du Nord Field: Bay du Nord member Base OIP

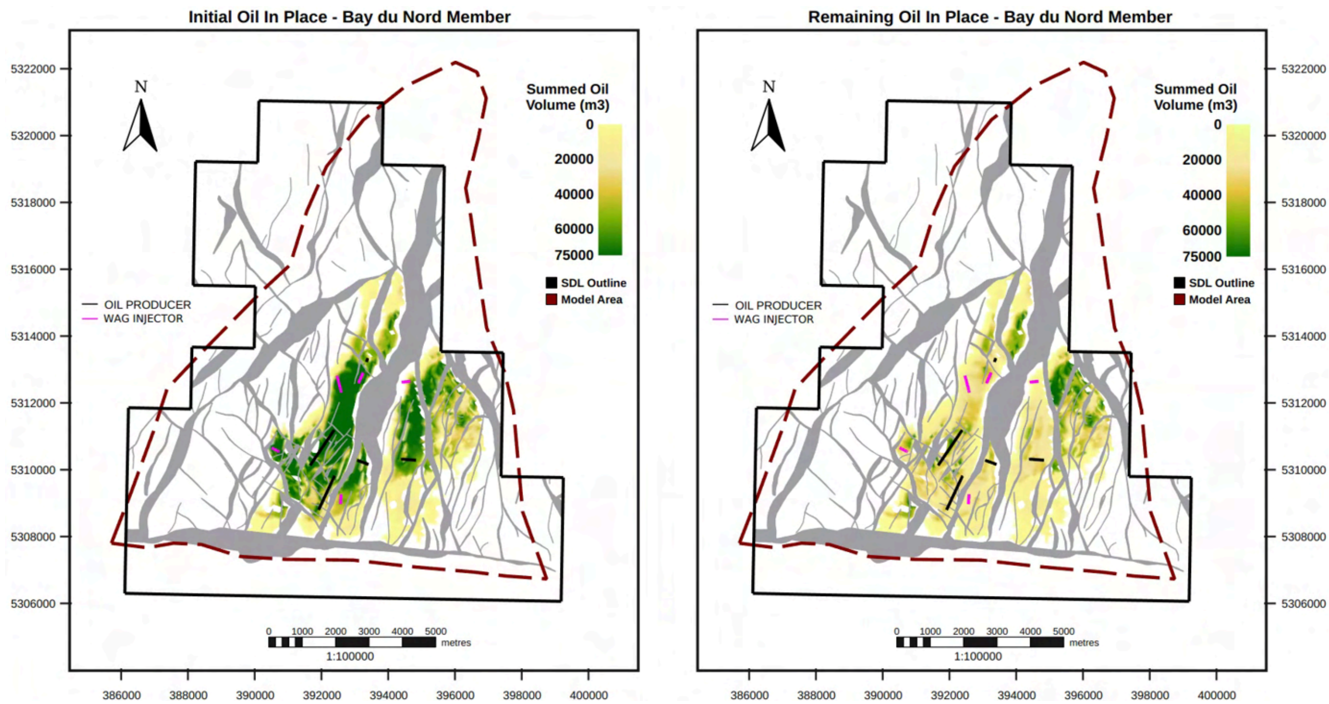


Figure 7.23 Bay du Nord Field: Bay du Nord member High OIP

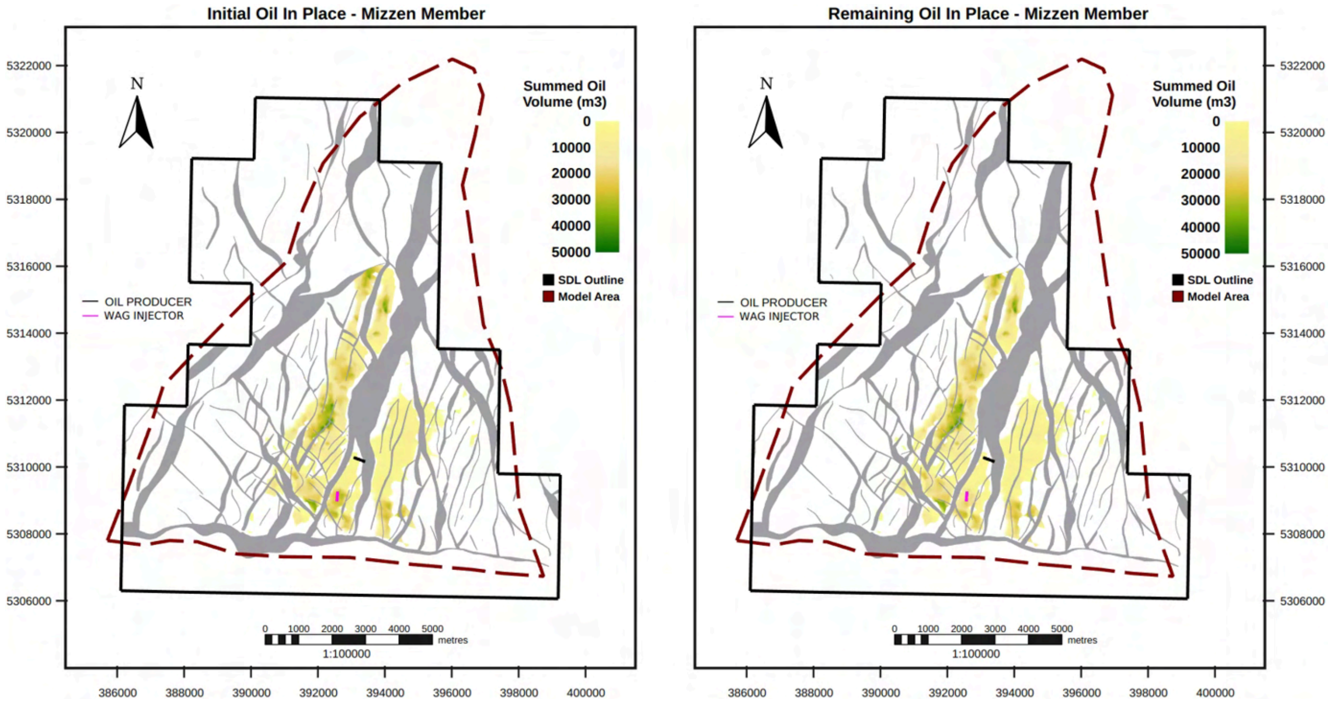


Figure 7.24 Bay du Nord Field: Mizzen member Low OIP

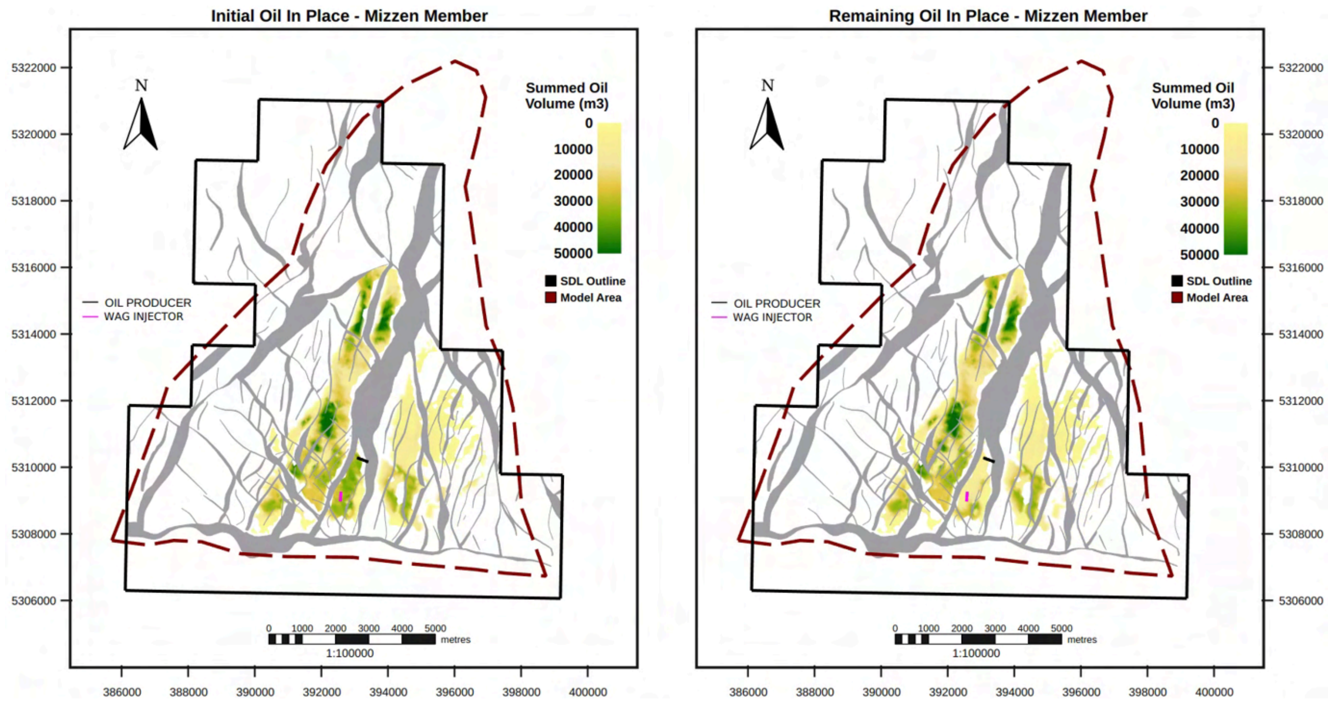


Figure 7.25 Bay du Nord Field: Mizzen member Base OIP

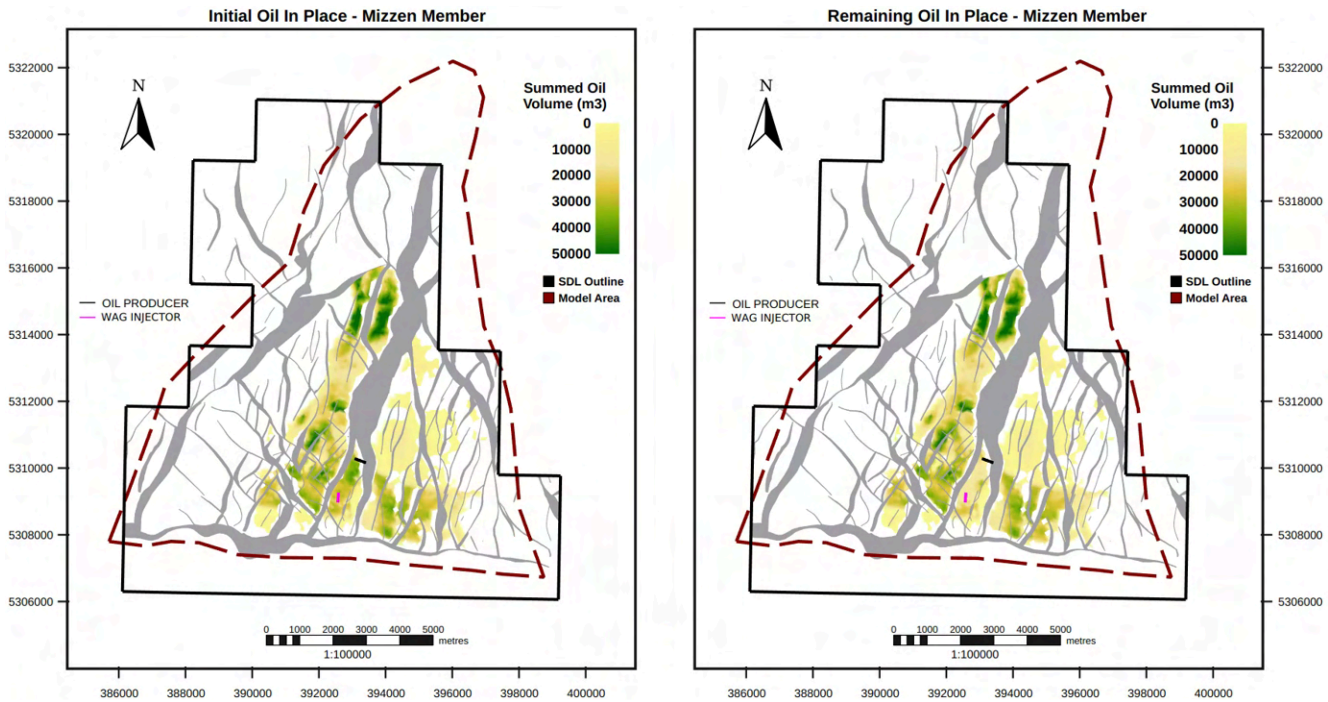


Figure 7.26 Bay du Nord Field: Mizzen member High OIP

The remaining OIP maps indicate possible remaining resources after 20 years of production, which demonstrates that there will likely be opportunities for infill drilling within the development area as part of upside potential. In both base and high OIP maps of the Bay du Nord member, accumulations of oil are notable in the NB and Bay de Verde East regions. In the low OIP map, this is not the case; with either a shallow OWC in Bay de Verde East or a narrower incised valley extent to the north, these opportunities can be much smaller than expected. These uncertainties may be reduced by data acquisition during both development drilling and operations. Wells in the area north of C-78 will be used to assess the incised valley extent and thickness towards the northern edge of the field and water injection wells will be used to assess the OWC in each of the penetrated areas within the field. Within the Bay du Nord member, additional drilling may result from the need for infill wells to address bypassed oil, the extension of economic hydrocarbons associated with deeper OWCs, or more extensive reservoirs. Wherever practical, the Bay du Nord and Mizzen members will be evaluated as co-development targets, as in the base depletion plan. In the high scenario, there are additional opportunities for development wells across the field. The base depletion plan assumes no infill wells while the actual number of infill wells will be based on the results of development drilling and production operations.

The Mizzen member is a known, but challenging development opportunity within the field. The delineated reservoir sands are separated into multiple thinner and vertically isolated sands within the member, and cannot be mapped with a high degree of confidence on the seismic data. Additionally, the switch from incised valley in the south to deltaic deposits north of L-76Z make reservoir connectivity uncertain. Through the drilling of the base development wells the Mizzen member will be assessed to determine:

- The connectivity and recovery potential of the incised valley reservoir;
- The oil-water contacts;
- The connectivity and OIP within the deltaic reservoir; and
- The requirements for additional development wells including co-development wells with other Bay du Nord member segments.

As shown in Figure 7.26, there is significant upside potential in the Mizzen member. The area between C-78 and L-76Z is where the majority of the well-defined upside sits. This area will be subject to multiple well penetrations from the base development wells and will be able to be characterized more accurately during the development drilling and operations phases. The NB region is also seen as an area of upside in the Mizzen member. Where this occurs simultaneously with the upside potential in the Bay du Nord member, co-development of both of these members will be evaluated.

Potential for Additional Development Wells within the Cambriol Field

Low, base, and high OIP scenario maps for the Mizzen member of the Cambriol Field are shown in Figure 7.27, Figure 7.28, and Figure 7.29. Each map shows the initial wells included in the base depletion plan as well as the alternative producer and injector in Region F as discussed in Section 7.4.2 Base Case Depletion Plan. The differences in the depicted resource distributions are due to the effects of shallower and deeper OWCs, reduced and extended reservoir sand extents, and other parameters from the uncertainty work, Section 7.3.4 Sensitivity Studies.

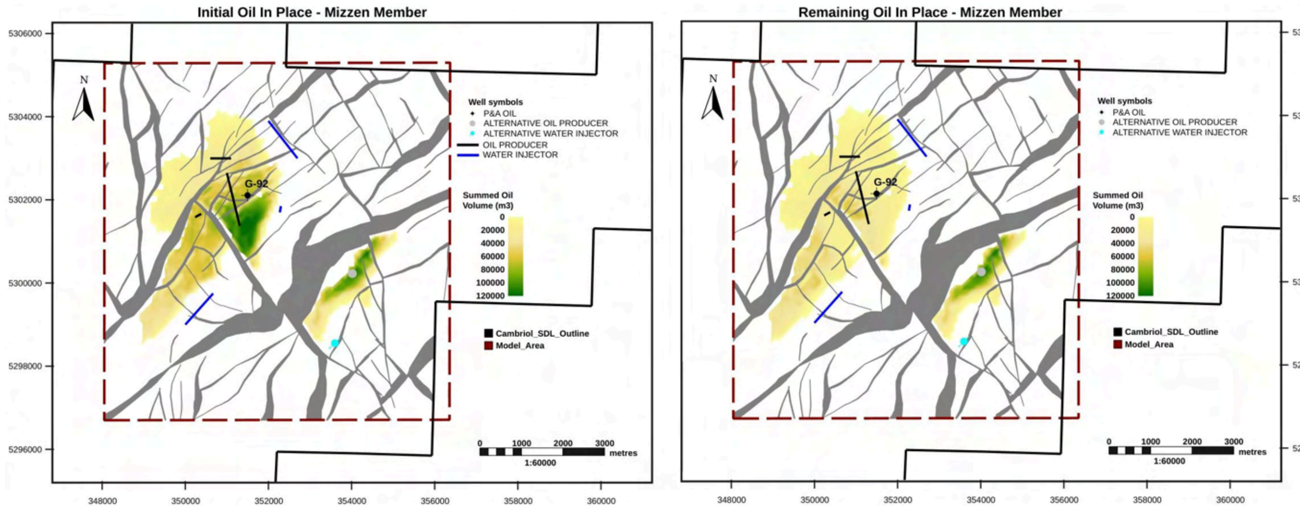


Figure 7.27 Cambriol Field: Mizzen member Low OIP

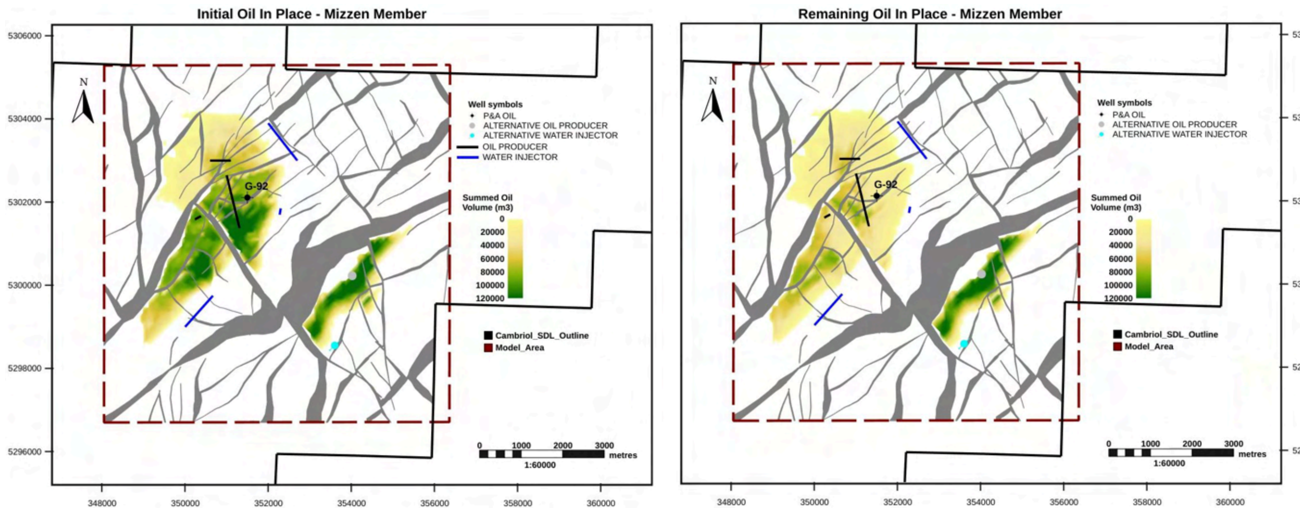


Figure 7.28 Cambriol Field: Mizzen member Base OIP

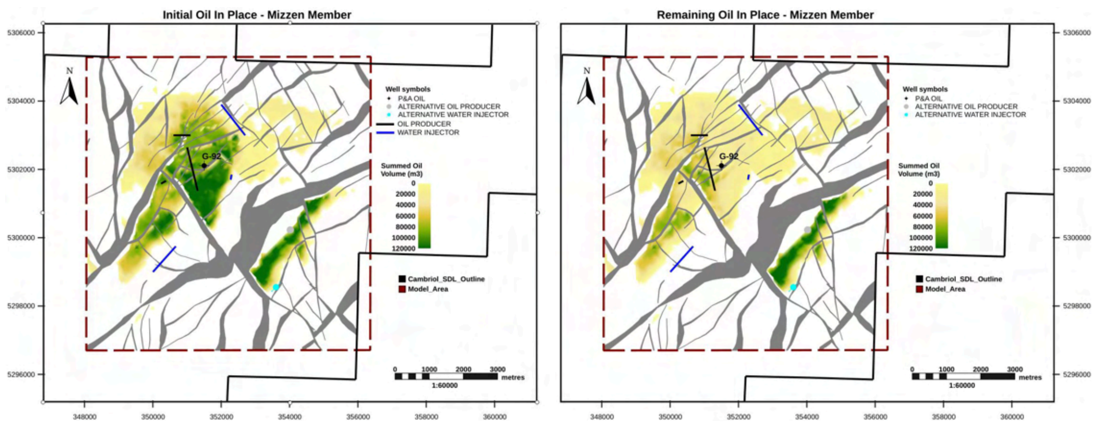


Figure 7.29 Cambriol Field: Mizzen member High OIP

The remaining OIP maps indicate possible remaining resources after 20 years of production, which demonstrates that there will likely be opportunities for infill drilling within the development area as part of upside potential.

The base case depletion plan for the Cambriol Field includes the drilling of six wells, three production wells and three water injection wells. With only one exploratory well in the field, and three of the six development wells planned to penetrate unproven prospects, there is uncertainty in the total number of wells required to develop the field and the placement of the wells. The proposed development wells address the known uncertainties but additional wells may be required if the results of development drilling differ from expected in areas such as sand distribution, reservoir connectivity and oil-water contact depths. In scenarios where oil extends beyond the planned development wells additional wells may be required. Infill wells may also be required if compartmentalization results in sufficient quantities of bypassed oil to warrant additional wells. The number of wells, and the location of those wells, will be based on detailed well planning and the results of data acquired through development drilling and production operations.

Across all OIP maps, the Region F remains a significant opportunity. As discussed in Section 7.4.2 Base Case Depletion Plan the inclusion of undrilled blocks and risked resources in the base case depletion plan means that maintaining optionality throughout the development is considered a key enabler for a successful depletion plan. Region F is considered an alternative target and may become a primary target during the development phase depending on drilling results and subsurface learnings.

In both base and high OIP maps, accumulations of oil are notable updip area of Region D and a secondary high in Region C. In the low OIP map, these accumulations are not present as the shallower OWC or alternate facies model reduce the size of the opportunities.

In the high OIP map, accumulations of oil in Region B and towards the north-east in the Mizzen 3 sand are notable. These accumulations require high side outcomes to represent viable opportunities and are either too small or not present in base and low case OIP maps. These uncertainties will be reduced by data acquisition during both development drilling and operations. Wells planned in the vicinity of expected Mizzen 3 and Region B will be used to assess the quality and extent of the facies distribution.

7.7.2 Enhanced Oil Recovery Considerations

EOR, traditionally considered a tertiary recovery method, is a subset of IOR, encompassing techniques applied after primary and secondary recovery. Primary recovery is production without injection and secondary recovery is pressure support using water or gas injection. EOR methods can be employed at any time in the life of an oil field. Traditionally many of these methods required pilot projects to determine effectiveness and impact on production and injection behaviour. Today, many EOR methods have been evaluated on large scale projects and have become readily available for implementation. Others are still under evaluation as the industry seeks to understand not only if they improve recovery but also to understand why they improve recovery.

EOR methods that have been evaluated, and/or implemented, by Equinor ASA in other fields are discussed below as they relate to the Project. The methods typically focus on one of two aspects of recovery - altering fluid properties or altering rock properties. At this time, no EOR methods have been included in the depletion plans for the Project. However, further evaluations may be required over the life of the Project based on outcomes of the development drilling program and field production performance.

Low Salinity Water Injection

- Applicable to reservoirs with wettability that are mixed to oil wet, low salinity water injection may alter the wettability of the formation towards water wet. This alteration creates a more favourable situation for the flow of water in the reservoir, reducing the timing of water breakthrough and the overall volume of water associated with oil recovery. This assists in accelerating and increasing ultimate recovery. Low salinity water injection is favourable when injection takes place in the oil zone.
- The Bay du Nord Field is interpreted as having a mixed or neutral wettability while the Cambriol Field is interpreted as being water wet to slightly water-wet. High recoveries associated with the good reservoir quality and implementation of WAG limit the value for the Bay du Nord Field. The potential increase in recovery for the field is low relative to the technical complexity of implementing low salinity water injection to a single field within the Project.

Polymer Flooding

- Polymer flooding is typically implemented in fields with high oil viscosities that result in poor mobility ratios with respect to water flooding. Poor mobility ratios result in unstable flood fronts, early water breakthrough and the potential for poor sweep efficiency. Polymer flooding may also be beneficial in reservoirs with high levels of heterogeneity where it also improves sweep efficiency in poorer quality sands.
- Polymers are problematic for production facilities and may require additional investments to manage.
- The Bay du Nord and Cambriol fields contain light oils with relatively low viscosities where stable flood fronts are expected. This results in a low likelihood of any future implementation within these fields. If other, heavier oils, are encountered during the life of the project or considered for tie-in to the FPSO this option may be revisited.

Polymer Assisted Surfactant Flood (PASF)

- PASF is a form of chemical EOR that is intended to mobilize residual or trapped oil within a reservoir. The addition of a polymer to the surfactant flood improves the stability of the flood front, reducing tendencies for fingering, and creating a more piston-like displacement.
- Polymers are problematic for production facilities and may require additional investments to manage.
- For the Project fields, the residual oil saturations are low and the benefits of PASF are considered low. PASF also requires careful screening against the mineralogy of the reservoir, with high clay contents being a particular concern. No opportunities for implementation within the current reservoir exploitation plan are identified.

Flow Diversion

- There are several forms of flow diversion technologies currently available. Two that have been implemented by Equinor ASA are polymers and silicates. The purpose of flow diversion technologies is to inject the substance into the reservoir to create plugs that permanently alter the injection pathways taken by the injected fluids. Injection of flow diversion substances may occur once or several times, depending on the performance and the objectives, but they are not part of ongoing, large scale injection programs like polymer floods. Once in the reservoir, the substances expand and block pore throats causing the injected fluids to find alternate pathways, typically containing bypassed oil. There are two favourable outcomes - reduced water production and/or increased recovery. As the substances remain in the reservoir there is no impact on processing facilities.
- There may be negative impacts associated with flow diversion including reduction in injectivity and unfavourable changes in the movement of injected fluids within the reservoir. In some cases the fluids may go around the plugs, returning to the previous behaviour.
- For the Bay du Nord and Cambriol fields the main consideration is whether the formation of plugs would alter the flow paths within the high-quality sands. If data acquisition activities identify bypassed oil, flow diversion options may be favourable to reduce water production and increase recovery.

Foam Assisted Water-Alternating-Gas Flooding (FWAG)

- FWAG is intended to improve the performance of injected gas as part of a WAG program. In situations where gas preferentially flows into high permeability zones or along the tops of the reservoir sands, the addition of foam blocks the preferential pathways and forces the gas into other areas where bypassed oil is likely present. Equinor ASA has had success with FWAG pilots; however, there are simpler, easier implementation methods for managing injection into the reservoir such as inflow control methods.
- For the Bay du Nord Field, the injected gas may be miscible with the formation oils and the gas may move through the reservoirs in the liquid phase, reducing the benefits of FWAG. The implementation of inflow control options, and the ability to move gas injection between several wells, may also provide alternate methods of managing where the gas floods the reservoir. FWAG is considered as having a low probability of being implemented in the Project.

Carbon Dioxide and Carbonated Water Injection

- There are two ways in which carbon dioxide (CO_2) may be injected into a reservoir - as CO_2 alone and as CO_2 in the water stream, typically referred to as carbonated water. Both methods are intended to increase recovery.

- As an EOR option, CO_2 floods require a local source of CO_2 to provide sufficient CO_2 to impact reservoir performance. There are no local sources to support a CO_2 flood as part of any EOR method in the Project. CO_2 injection is also challenging for the process equipment as it can create a corrosive environment if it is produced from the reservoir as it displaces the oil. CO_2 injection is not considered a viable EOR method for the Project.

7.8 Future Studies

With respect to reservoir exploitation, the appraisal of the fields within the Project are sufficient to proceed with the design and development of the Project. In combination with the data acquired through development drilling and field operations, there is no additional information required to proceed with the Project. Subsurface studies and evaluations have been completed to the necessary level to ensure a robust and effective drainage strategy is in place for the fields so that the recoverable resources can be maximized. Updates to the work completed and new studies may be initiated as new data and technology becomes available.

8 Deferred Developments

8.1 Introduction

Deferred developments in the Project Area will be considered following the initial base development of Bay du Nord and Cambriol fields. The deferred developments consist of both discovered and prospectives resources within the Project Area, as shown in Figure 1.1. These resources have been evaluated as part of the Bay du Nord Project's (the Project) initial concept development and long-term growth potential, but were ultimately not included in base reservoir exploitation plans.

8.2 Bay du Nord Field

The Bay du Nord development scope (Figure 7.6) includes the development of resources of the Bay du Nord member of Bay du Nord Main, NC, and Bay de Verde Main, as well as the Mizzen member of NC (Figure 5.2) of the field. The sole delineated resource within the field not considered for development is the Bonaventure member. The Bonaventure member was encountered in exploratory and appraisal wells, but the presence of high-quality reservoir is interpreted as having a limited extent within the field and a low Oil-In-Place (OIP). No opportunity for the economic development of the resource has been identified. Table 8.1 presents the Original Oil-In-Place (OOIP) volume for the Bonaventure member, which is considered a deferred development. As the Bonaventure member was not included in the Bay du Nord Field reservoir models, a probabilistic assessment was not available for this interval. However, a deterministic assessment was completed to capture its potential.

Outside the main Bay du Nord development area, there are a number of prospective regions in the Bay du Nord Field considered deferred developments. These are shown in Figure 5.2 and Figure 7.6 and include the Bay du Nord NA, ND, and SW regions for both the Bay du Nord and Mizzen members. OOIP volumes for these regions are included in Table 8.2. The resources for NA and SW require deeper Oil-Water-Contacts (OWCs) than the expected values for the delineated area. Both of these regions have a chance of success applied to account for the uncertainty of hydrocarbon presence. The assessed likelihood of success relies on factors such as seismic reservoir prediction and structural analysis to assess juxtaposition with neighbouring oil-bearing drilled areas. The reservoir extent in both the Mizzen member and Bay du Nord members is uncertain in the ND region and therefore the estimated resources are insufficient for current development.

All deferred development regions may be re-evaluated after data acquisition during the development drilling and operations phases to assess their future potential and viability. If learnings reduce risks in these areas, it may enable their development. Other factors influencing future development include:

- Findings from new seismic data;
- Updates to the overall technical and economic feasibility of the deferred development;
- Optimization of the drainage strategy; and
- Evaluation of new reservoir exploitation technologies.

Table 8.1 Original Oil-In-Place: Bonaventure Member

Volumes	Bay du Nord	Bay de Verde	Total
OOIP (e^6m^3)	3.7	2.2	5.9
OOIP (MBO)	23.1	14.1	37.1

Table 8.2 Original Oil-In-Place: Bay du Nord Field Deferred Developments

Zone	Region	MBO				e^6m^3			
		P90	P50	Mean	P10	P90	P50	Mean	P10
Bay du Nord member	Bay du Nord SW	0.0	0.0	11.9	50.6	0.0	0.0	1.9	8.0
	Bay du Nord NA	0.0	0.0	4.0	17.1	0.0	0.0	0.6	2.7
	Bay du Nord ND	3.7	7.1	7.9	12.7	0.6	1.1	1.3	2.0
	Total	4.3	11.8	23.8	63.7	0.7	1.9	3.8	10.1
Mizzen member	Bay du Nord SW	0.0	0.0	5.3	21.8	0.0	0.0	0.8	3.5
	Bay du Nord NA	0.0	0.0	6.3	25.1	0.0	0.0	1.0	4.0
	Bay du Nord ND	8.5	19.9	21.2	32.7	1.4	3.2	3.4	5.2
	Total	13.1	28.9	32.8	58.9	2.1	4.6	5.2	9.4
Total	Total	19.2	41.1	56.6	118.5	3.1	6.5	9.0	18.8

Note: The sum of individual region/zone P10, P50, and P90 OOIP volumes does not equal the total field P10, P50, and P90 due to the independent probabilistic nature of each region/zone's estimates. This is also applicable to other OOIP and recoverable volume tables presented within the application.

8.3 Cambriol Field

The Cambriol development scope (Figure 7.11) includes the development of resources of the Mizzen member in all of the prospective regions (B, C, D, and F) (Figure 5.3) of the field. There are currently no proposed deferred developments at the Cambriol Field. Regions A, E as well as deeper potential reservoirs such as the Bay du Nord and Bonaventure members do not show prospectivity with the current data and interpretations. The Cambriol G-92 well has confirmed the potential for hydrocarbons in the Bay du Nord and Bonaventure members (Figure 2.4 and Table 3.7). The Bay du Nord member was tight and attempts to acquire pressure and fluid samples were unsuccessful. Pressure and fluid samples were acquired in the Bonaventure member, but the fluid samples were wet and the oil shows were interpreted as residual. However, new learnings may become available from new seismic data or following data acquisition during the development drilling and operations phases. At this time, the ability to develop these regions and zones will be evaluated.

8.4 Cappahayden Field

The Cappahayden K-67 well encountered reservoir pay in the Tithonian Bonaventure, Bay du Nord and Mizzen members while the Cappahayden K-67Z well encountered reservoir pay in the Bay du Nord and Mizzen members. An overview map of the Cappahayden Field at the Cretaceous Base is shown in Figure 8.1. Cappahayden Field OIP estimates are shown in Table 8.3.

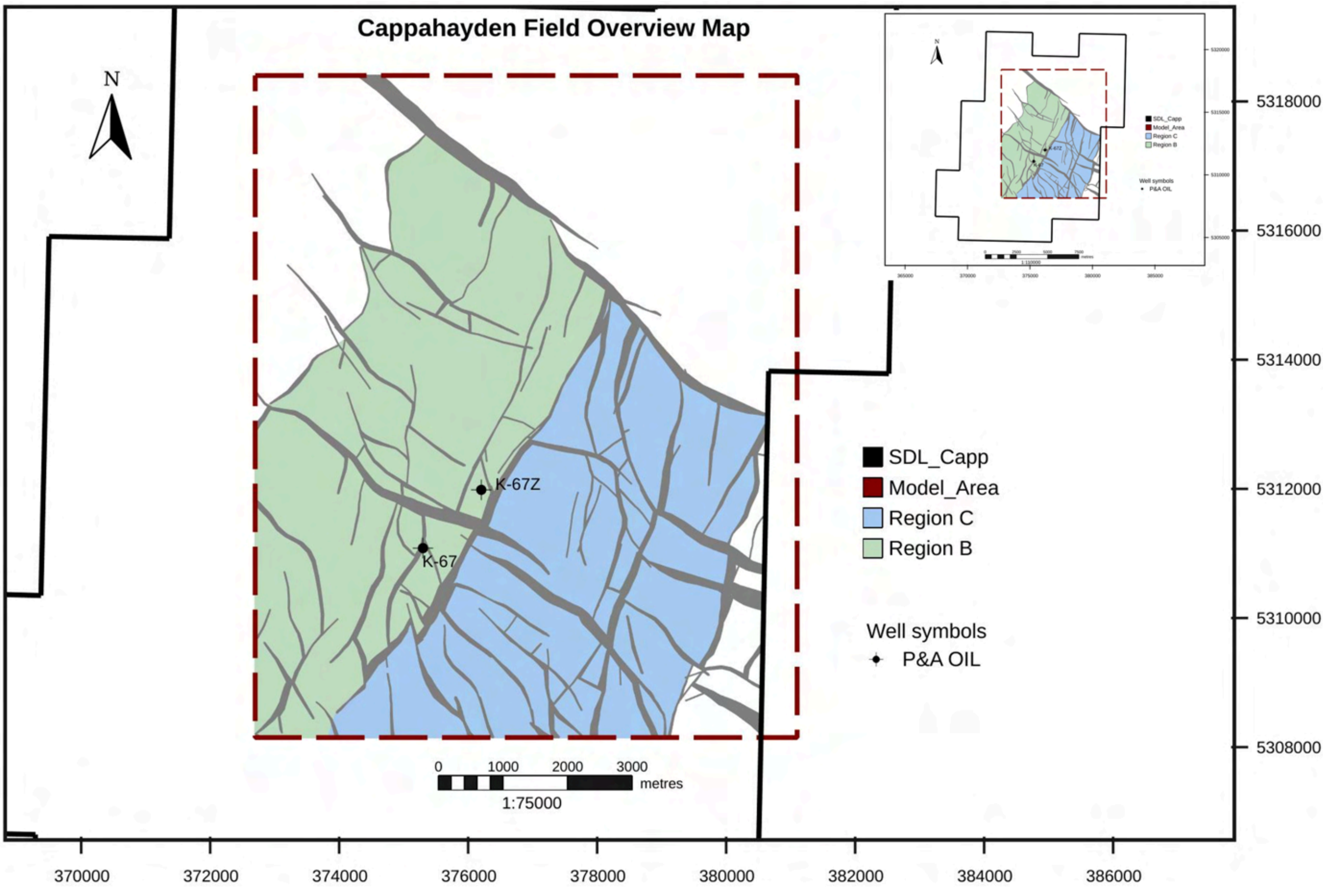


Figure 8.1 Cappahayden Field Overview Map

The main uncertainties at the Cappahayden Field are the oil-water contact, reservoir distribution and thickness, and fault transmissibility. Another important factor at the Cappahayden Field is the chance of success of the undrilled segments neighbouring the discovery. Oil is proven in the two isolated segments that were penetrated by wells (Figure 8.1); however, beyond these segments, all others have a risked probability of hydrocarbon presence and varying degrees of subsurface uncertainty.

Table 8.3 Cappahayden Field In-Place Volume Overview

Zone	Region	MBO				e^6m^3			
		P90	P50	Mean	P10	P90	P50	Mean	P10
Mizzen member	B	41.7	79.9	94.3	169.4	6.6	12.7	15.0	26.9
	C	0.0	0.0	2.1	8.5	0.0	0.0	0.3	1.4
	Total	44.1	82.8	96.4	169.7	7.0	13.2	15.3	27.0
Bay du Nord member	B	101.3	127.9	129.7	161.2	16.1	20.3	20.6	25.6
	C	0.0	95.9	90.3	177.2	0.0	15.2	14.4	28.2
	Total	126.3	219.9	220.0	313.6	20.1	35.0	35.0	49.9
Bonaventure member	B	23.8	30.3	31.4	40.5	3.8	4.8	5.0	6.4
	C	0.0	26.3	31.9	72.1	0.0	4.2	5.1	11.5
	Total	28.9	57.9	63.3	105.8	4.6	9.2	10.1	16.8
Total	B	186.0	245.1	255.4	343.5	29.6	39.0	40.6	54.6
	C	16.1	121.9	124.4	236.2	2.6	19.4	19.8	37.5
	Total	251.9	369.8	379.8	516.3	40.0	58.8	60.4	82.1

Reservoir exploitation plans may consider water injection and/or Water-Alternating-Gas (WAG) for the Cappahayden Field through a combination of injectors and producers. Estimates of recoverable oil may range from 36 MBO to 81 MBO. The subsurface interpretation and exploitation strategy will continue to be evaluated with any new information that becomes available.

Future development of the Cappahayden Field is contingent on the technical and economic viability of the development concept. Several factors may influence this outcome:

- Learnings from the recent exploration campaign and well drilled at Cappahayden South (Figure 8.2) will be integrated into the understanding of other undelineated segments at the Cappahayden Field and will help clarify the potential of other undrilled segments in the field;
- Work may focus on optimizing the drainage strategy and assessing new reservoir exploitation technologies that could improve recovery; and
- Changes in overall Capital Expenditures (CAPEX) required for field development and alleviation of current market pressures would increase the attractiveness of the Cappahayden Field tieback.

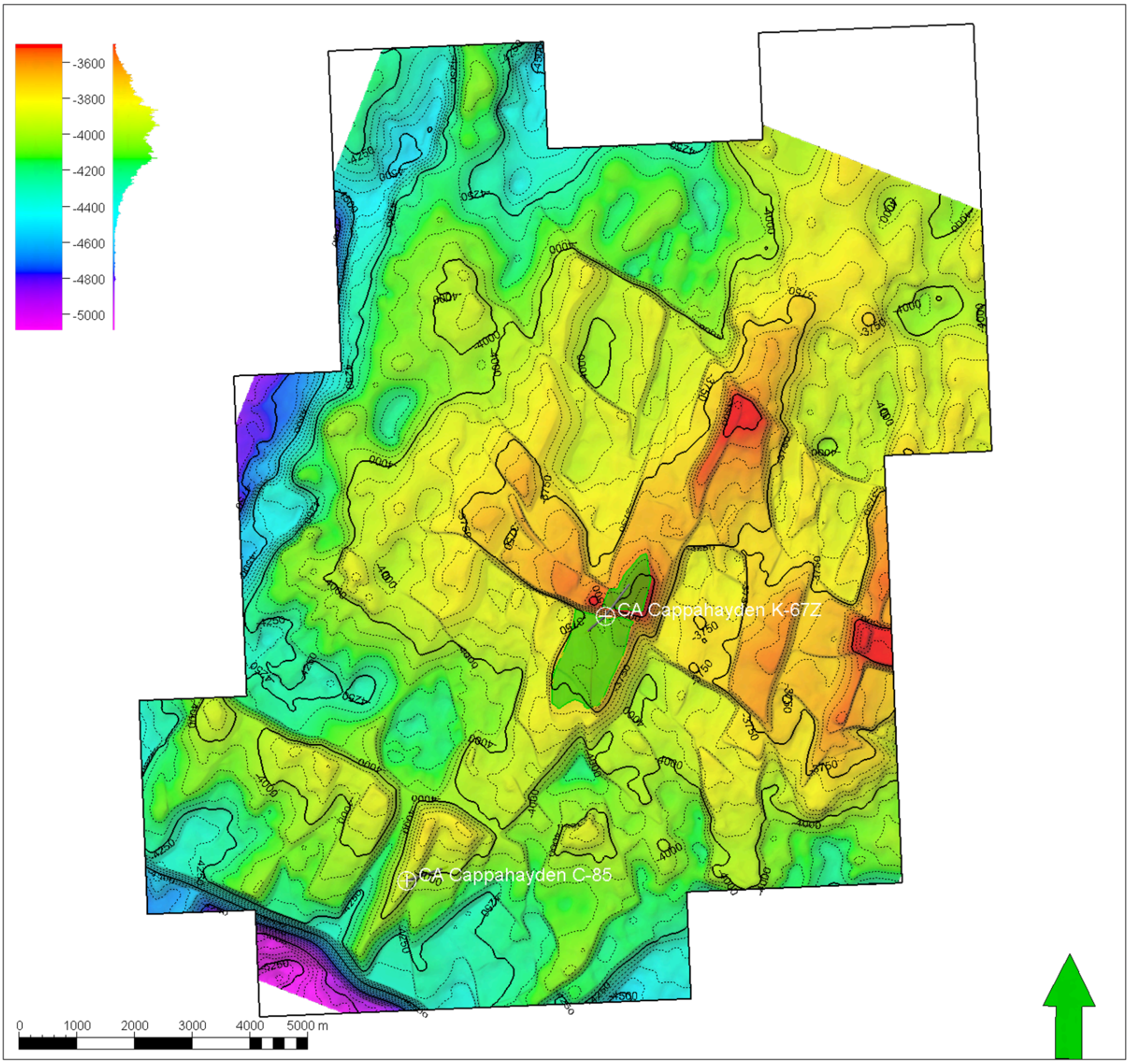


Figure 8.2 Base Bay du Nord Member Structure Map - Cappahayden Area

8.5 Harpoon Field

The Harpoon O-85 well encountered reservoir pay in the Tithonian Mizzen member sandstones. An overview map at the Cretaceous Base level of the Harpoon Field is shown in Figure 8.3. Harpoon Field OOIP estimates are shown in Table 8.4.

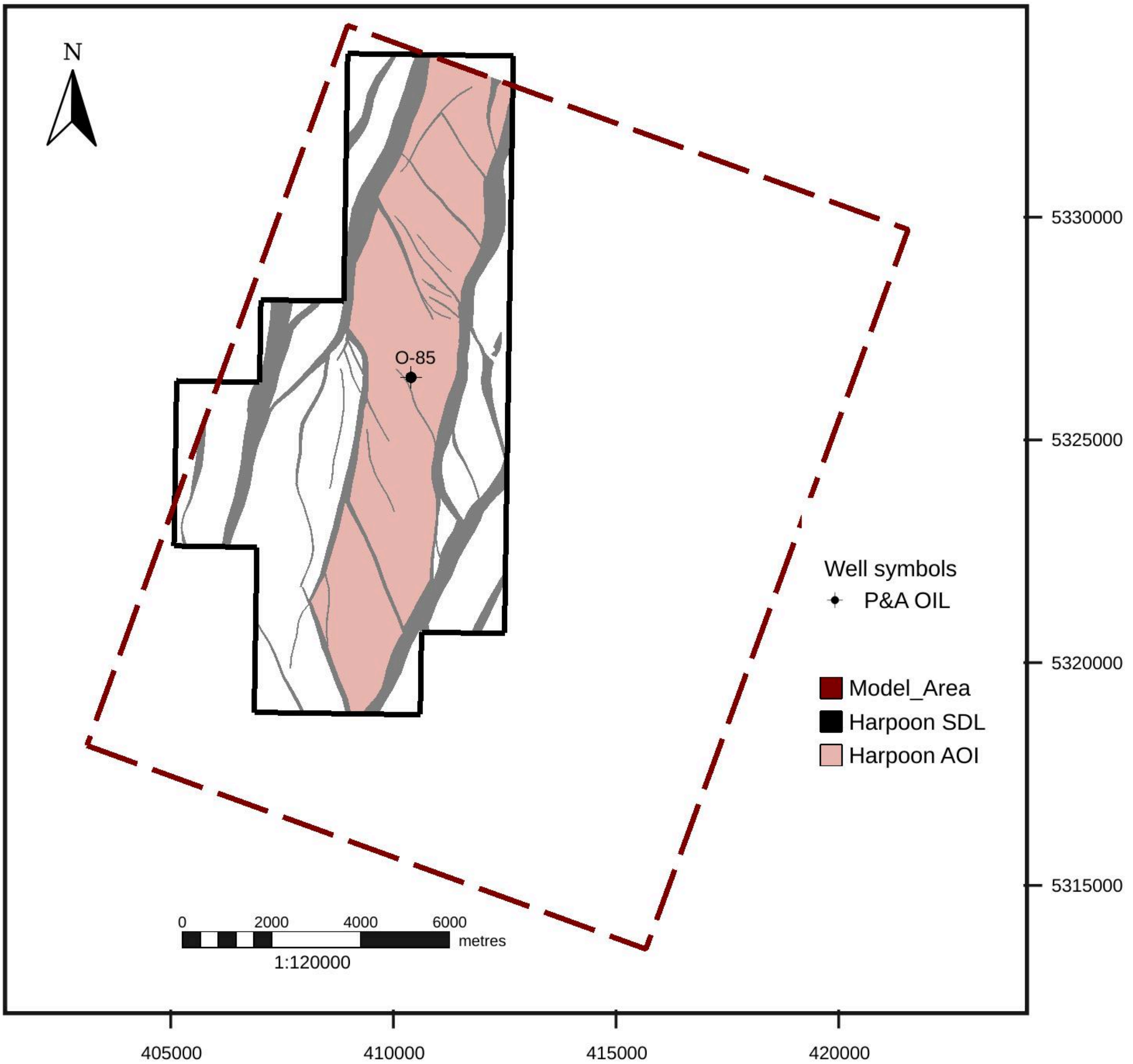


Figure 8.3 Harpoon Field Overview Map

The primary uncertainty at the Harpoon Field is the depositional environment, where two possible scenarios are considered. One is an incised valley, in which the Mizzen member sandstones are high quality and well connected. The other possibility is of a deltaic environment, where the sands are more poorly connected and lower quality. In addition to the depositional environment, the OWC is an important uncertainty at the Harpoon Field.

Reservoir exploitation plans may consider a waterflood development for the Harpoon Field with downdip water injectors and updip oil producers. Estimates of recoverable oil may range from 7 MBO to 80 MBO. The subsurface interpretation and exploitation strategy will continue to be evaluated with any new information that becomes available.

Future development of the Harpoon Field is contingent on the technical and economic viability of the development concept. Several factors might lead to this future development:

- If the business case for the Harpoon Field enhances an overall Flemish East tieback;
- There is potential for future delineation and exploratory drilling in the Harpoon area which could help make it a viable development option;
- Work will continue to optimize the drainage strategy and assess new reservoir exploitation technologies that could improve recovery; and
- Changes in overall CAPEX required for field development and alleviation of current market pressures would increase the attractiveness of the Harpoon Field tieback.

Table 8.4 Harpoon Field In-Place Volume Overview

Zone	MBO				e^6m^3			
	P90	P50	Mean	P10	P90	P50	Mean	P10
Mizzen member	78.9	138.5	141.5	236.4	12.5	22.0	22.5	37.6

8.6 Baccalieu Field

The Baccalieu F-89 well encountered reservoir pay in the Cretaceous Baccalieu member sandstones. An overview map of the Baccalieu Field at the Cretaceous Base is shown in Figure 8.4. Baccalieu Field OOIP estimates are shown in Table 8.5.

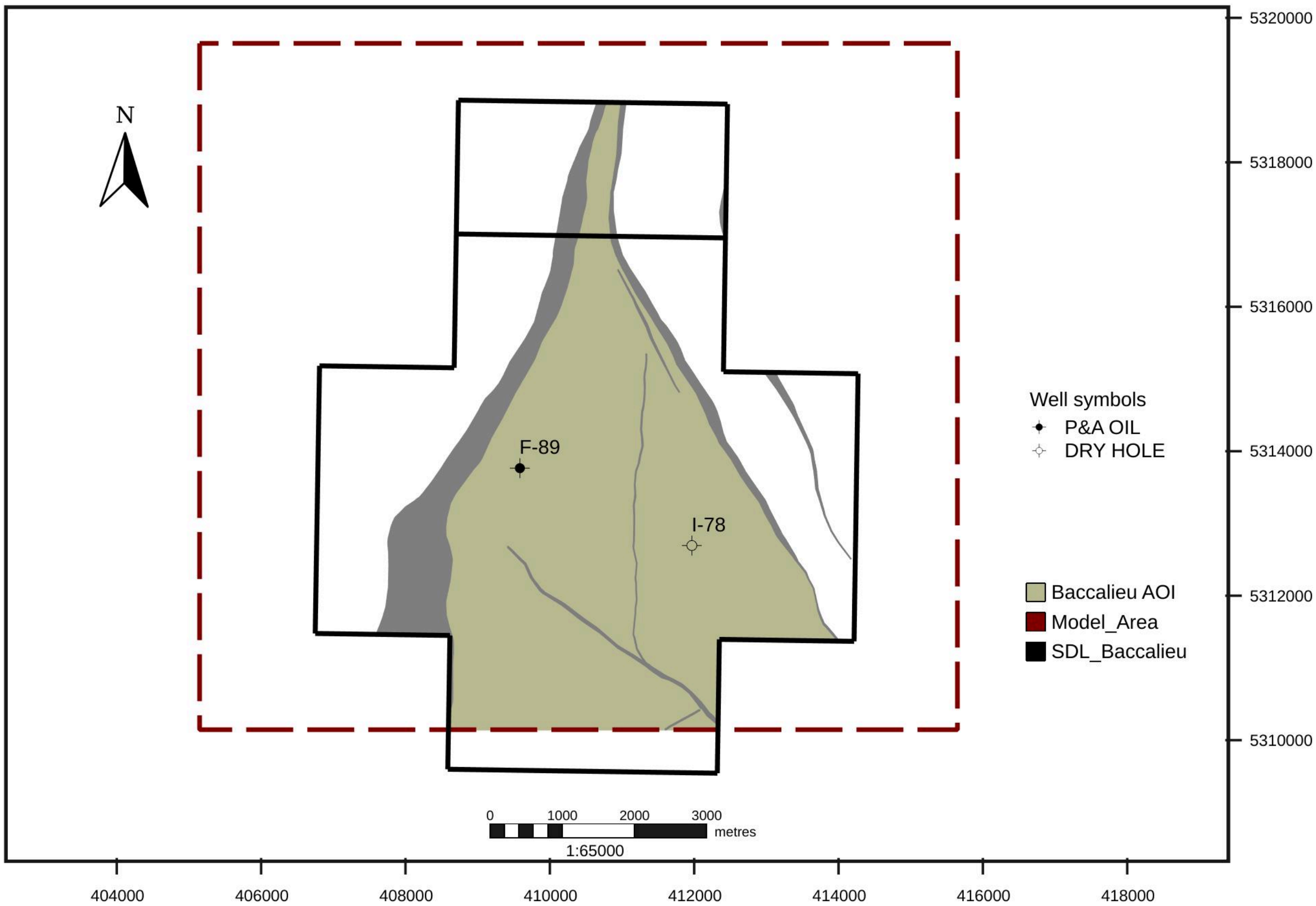


Figure 8.4 Baccalieu Field Overview Map

The greatest uncertainties at the Baccalieu Field are the structural uncertainty, OWC, and facies distribution. Reservoir exploitation plans may consider a waterflood development for the Baccalieu Field with downdip water injectors and updip oil producers. Estimates of recoverable oil may range from 28 MBO to 60 MBO. The subsurface interpretation and exploitation strategy will continue to be evaluated with any new information that becomes available.

Future development of the Baccalieu Field is contingent on the technical and economic viability of the discovery. Several factors might lead to this future development:

- If the business case for the Baccalieu Field enhances an overall Flemish East tieback (with the Harpoon Field);
- There is a possibility the Baccalieu Field could help with the overall Project gas management strategy;
- Work will continue to optimize the drainage strategy and assess new reservoir exploitation technologies that could improve recovery; and
- Changes in overall CAPEX required for field development and alleviation of current market pressures would increase the attractiveness of the Baccalieu Field tieback.

Table 8.5 Baccalieu Field In-Place Volume Overview

Zone	MBO				e^6m^3			
	P90	P50	Mean	P10	P90	P50	Mean	P10
Upper Baccalieu	60.3	84.9	87.4	116.2	9.6	13.5	13.9	18.5
Lower Baccalieu	0.0	21.1	19.8	42.6	0.0	3.4	3.1	6.8
Total	62.1	105.7	107.2	150.7	9.9	16.8	17.0	24.0

8.7 Other Opportunities

Mizzen Field

The first discovery in the Flemish Pass Basin was in the Mizzen O-16 well. The Mizzen discovery is approximately 35 km from the Bay du Nord Field and contains a heavier, biodegraded oil. The low-quality oil and long distance make the development of the Mizzen Field to the Floating Production, Storage, and Offloading (FPSO) facility technically and economically challenging. Development of the Mizzen Field may be considered if additional resources are identified nearby or between the Bay du Nord and Mizzen fields. This would allow for either a separate development of the Mizzen Field and the new discovery, or a joint development where the new resource facilitates transporting production from the Mizzen Field to the FPSO. Technology advancements may also facilitate a future Mizzen Field development. Options to increase recovery and facilitate transport of fluids to and from the Mizzen Field are necessary to make the discovery a technically and economically viable project.

Exploration in the Flemish Pass

The Project is intended to open up the Flemish Pass Basin to additional development. If new discoveries emerge in the future from future exploration or appraisal activities, the technical and economic feasibility of utilizing the FPSO as a production hub will be assessed.

9 Reserves and Resource Estimates

9.1 Introduction

The Original Oil-In-Place (OOIP) and Original Gas-In-Place (OGIP) volumes, along with estimates of recoverable resources, are provided in Section 9.2 Original Hydrocarbon-in-Place Estimates and Section 9.3 Recoverable Resource Estimates. The recoverable resources are associated with the base depletion plans, described in Section 7.3 Bay du Nord Field Exploitation, Section 7.4 Cambriol Field Exploitation and the uncertainty study, described in Section 7.2 Reservoir Modelling and Uncertainty.

The resource assessment is based on a 20-year production period. The 20-year period was used throughout field development studies and concept evaluations to provide a consistent basis for optimization and reporting. As the Bay du Nord Project (the Project) has used an uncertainty centric approach, evaluating options across a range of reservoir models, there is a range in the potential field life. The ultimate economic life of the Project will depend on many factors, including oil rates, operational costs, oil price, and technical feasibility. Recoverable resources and recovery factors are based on a 20-year production profile, with no economic cut-off for either individual wells or for the fields as a whole. With the base economic assumptions and a mean production outcome, the economic life of the Asset is anticipated to be longer than the profile shown. In downside and upside cases, the analysis did not consider early abandonment or field life extension; the profile is always reported at the 20-year mark.

9.2 Original Hydrocarbon-in-Place Estimates

The OOIP and OGIP volumes for the Project are provided in Table 9.1 to Table 9.6 at surface conditions of 15 °C and 1 bar. The mean volumes are provided along with the 90%, 50%, and 10% probability volumes based on the results of the stochastic uncertainty analysis as described in Section 7.2 Reservoir Modelling and Uncertainty.

The volumes are broken out into regions within the fields as shown in Figure 5.2 and Figure 5.3 as well as zone. The Bay de Verde East region is considered a prospect. It is assigned a geological chance of success (Pg) of 72% which represents the likelihood of the prospect containing oil. The OOIP and OGIP volumes include the Pg of 72%. The gas volumes represent the solution gas associated with the OOIP. There are no free gas volumes expected within the Project Area.

The volumes in the Cambriol Field include both the discovered D region, as well as the unpenetrated B, C, and F regions. These unpenetrated regions are assigned a Pg of 80%, 90%, and 72%, respectively. This represents the likelihood of hydrocarbon presence in those regions. The OOIP and OGIP volumes include the chance of success. The gas volumes represent the solution gas associated with the OOIP. There are no free gas volumes expected within the Project Area.

Table 9.1 Bay du Nord Field: Original Oil-In-Place

Original Oil-In-Place									
Bay du Nord Field		MBO				e^6m^3			
Zone	Region	P90	P50	Mean	P10	P90	P50	Mean	P10
Bay du Nord member	Bay du Nord Main	234.0	272.8	275.4	322.7	37.2	43.4	43.8	51.3
	Bay du Nord NC	36.3	44.5	44.6	52.2	5.8	7.1	7.1	8.3
	Bay du Nord NB	13.3	19.9	21.0	30.9	2.1	3.2	3.3	4.9
	Bay de Verde Main	56.8	68.2	72.9	96.0	9.0	10.8	11.6	15.3
	Bay de Verde East	0.0	20.4	33.4	95.6	0.0	3.2	5.3	15.2
	Total	368.3	435.1	447.4	538.6	58.6	69.2	71.1	85.6
Mizzen member	Bay du Nord Main	79.0	106.9	107.6	136.8	12.6	17.0	17.1	21.7
	Bay du Nord NC	10.5	15.8	16.0	21.5	1.7	2.5	2.5	3.4
	Bay du Nord NB	11.0	22.2	22.4	32.7	1.8	3.5	3.6	5.2
	Bay de Verde Main	12.8	20.5	23.2	37.1	2.0	3.3	3.7	5.9
	Bay de Verde East	0.0	1.9	4.4	12.0	0.0	0.3	0.7	1.9
	Total	129.4	169.8	173.6	220.0	20.6	27.0	27.6	35.0
Total	Total	517.3	603.4	621.0	739.3	82.2	95.9	98.7	117.5

Table 9.2 Cambriol Field: Original Oil-In-Place

Original-Oil In-Place									
Cambriol Field		MBO				e^6m^3			
Zone	Region	P90	P50	Mean	P10	P90	P50	Mean	P10
Mizzen member	B	0.0	40.3	54.6	123.8	0.0	6.4	8.7	19.7
	C	44.2	144.8	140.1	213.9	7.0	23.0	22.3	34.0
	D	145.5	208.8	226.5	328.7	23.1	33.2	36.0	52.3
	F	0.0	58.5	63.3	139.4	0.0	9.3	10.1	22.2
	Total	265.8	466.0	484.5	732.7	42.3	74.1	77.0	116.5

Table 9.3 Project: Original Oil-In-Place

Field	MBO				e^6m^3			
	P90	P50	Mean	P10	P90	P50	Mean	P10
Bay du Nord	517.3	603.4	621.0	739.3	82.2	95.9	98.7	117.5
Cambriol	265.8	466.0	484.5	732.7	42.3	74.1	77.0	116.5
Total	861.5	1077.3	1104.8	1380.4	137.0	171.3	175.7	219.5

Table 9.4 Bay du Nord Field: Original Gas-In-Place

Original Gas-In-Place									
Bay du Nord Field		BCF				e^9m^3			
Zone	Region	P90	P50	Mean	P10	P90	P50	Mean	P10
Bay du Nord member	Bay du Nord Main	65.3	76.2	76.9	90.1	1.8	2.2	2.2	2.6
	Bay du Nord NC	9.5	11.7	11.7	13.7	0.3	0.3	0.3	0.4
	Bay du Nord NB	3.7	5.6	5.8	8.6	0.1	0.2	0.2	0.2
	Bay de Verde Main	16.3	19.5	21.0	27.7	0.5	0.6	0.6	0.8
	Bay de Verde East	0.0	5.8	9.6	27.5	0.0	0.2	0.3	0.8
	Total	103.0	121.6	125.0	150.4	2.9	3.4	3.5	4.3
Mizzen member	Bay du Nord Main	21.4	28.9	29.1	36.9	0.6	0.8	0.8	1.0
	Bay du Nord NC	3.2	4.6	4.6	6.3	0.1	0.1	0.1	0.2
	Bay du Nord NB	3.1	6.0	6.1	8.8	0.1	0.2	0.2	0.3
	Bay de Verde Main	3.6	5.9	6.6	10.6	0.1	0.2	0.2	0.3
	Bay de Verde East	0.0	0.5	1.3	3.4	0.0	0.0	0.0	0.1
	Total	35.6	46.7	47.8	60.6	1.0	1.3	1.4	1.7
Total	Total	143.8	167.8	172.7	205.6	4.1	4.8	4.9	5.8

Table 9.5 Cambriol Field: Original Gas-In-Place

Original Gas-In-Place									
Cambriol Field		BCF				e^9m^3			
Zone	Region	P90	P50	Mean	P10	P90	P50	Mean	P10
Mizzen member	B	0.0	20.2	27.5	62.3	0.0	0.6	0.8	1.8
	C	22.1	72.8	70.6	107.6	0.6	2.1	2.0	3.0
	D	73.1	105.0	113.9	165.5	2.1	3.0	3.2	4.7
	F	0.0	29.4	32.0	70.2	0.0	0.8	0.9	2.0
	Total	133.8	234.4	243.6	368.6	3.8	6.6	6.9	10.4

Table 9.6 Project: Original Gas-In-Place

Field	BCF				e^9m^3			
	P90	P50	Mean	P10	P90	P50	Mean	P10
Bay du Nord	143.8	167.8	172.7	205.6	4.1	4.8	4.9	5.8
Cambriol	133.8	234.4	243.6	368.6	3.8	6.6	6.9	10.4
Total	324.6	405.9	416.3	520.1	9.2	11.5	11.8	14.7

9.3 Recoverable Resource Estimates

The process used to generate the statistics in this section is described in Section 7.2 Reservoir Modelling and Uncertainty. While the total recoverable resources noted here are close to those listed in Section 7.6 Drilling Schedule and Production Forecasts, it is important to note that this Base, High, and Low cases do not correspond exactly to the P10, Mean, and P90 statistics.

The recoverable resources and Recovery Factors (RFs) for the Project are outlined in Table 9.7 to Table 9.12. The volumes are taken from the integrated production profiles for the Project which combine the individual field ensembles with the Project level constraints of the system capacities, production efficiencies, and drilling schedule. As such the recovery for each field is lower than the independent field results provided in the sensitivity studies section for each field. The mean volumes are stated along with the 90%, 50%, and 10% probability volumes based on the results of the integrated project dynamic uncertainty analysis. The recovery factors are reported similarly, though the statistical recovery factors are not simply a calculation based on the oil in place and recoverable oil values, but rather an assessment of the actual 90%, 50%, and 10% probabilities for recovery factors for each field and the project. As such, simple division based on the original oil in place and recoverable oil will not yield the values in this table for any statistic outside of the mean.

Table 9.7 Bay du Nord Field: Recoverable Resource

Recoverable Oil									
Bay du Nord Field		MBO				e^6m^3			
Zone	Region	P90	P50	Mean	P10	P90	P50	Mean	P10
Bay du Nord Member	Bay du Nord Main	123.3	165.2	164.5	208.9	19.6	26.3	26.2	33.2
	Bay du Nord NC	16.5	21.3	21.6	26.1	2.6	3.4	3.4	4.2
	Bay du Nord NB	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Bay de Verde Main	36.0	45.1	47.3	60.8	5.7	7.2	7.5	9.7
	Bay de Verde East	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total	196.8	236.2	233.4	271.8	31.3	37.6	37.1	43.2
Mizzen Member	Bay du Nord Main	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Bay du Nord NC	2.8	3.6	3.7	4.5	0.4	0.6	0.6	0.7
	Bay du Nord NB	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Bay de Verde Main	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Bay de Verde East	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total	2.8	3.6	3.7	4.5	0.4	0.6	0.6	0.7
Total	Total	199.9	240.0	237.1	276.1	31.8	38.1	37.7	43.9

Table 9.8 Cambriol Field: Recoverable Resource

Recoverable Oil									
Cambriol Field		MBO				e^6m^3			
Zone	Region	P90	P50	Mean	P10	P90	P50	Mean	P10
Mizzen Member	B	6.3	11.9	13.2	22.5	1.0	1.9	2.1	3.6
	C	24.8	55.3	57.2	100.2	3.9	8.8	9.1	15.9
	D	57.8	109.8	121.6	207.6	9.2	17.4	19.3	33.0
	F	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total	123.5	171.9	192.0	263.7	19.6	27.3	30.5	41.9

Table 9.9 Project: Recoverable Resource

Field	MBO				e^6m^3			
	P90	P50	Mean	P10	P90	P50	Mean	P10
Bay du Nord	199.9	240.0	237.1	276.1	31.8	38.1	37.7	43.9
Cambriol	123.5	171.9	192.0	263.7	19.6	27.3	30.5	41.9
Total	342.6	418.3	429.1	521.1	54.5	66.5	68.2	82.8

Table 9.10 Bay du Nord Field: Recovery Factors

Recovery Factor					
Bay du Nord Field		RF (%)			
Zone	Region	P90	P50	Mean	P10
Bay du Nord Member	Bay du Nord Main	61%	64%	60%	70%
	Bay du Nord NC	42%	50%	48%	56%
	Bay du Nord NB	0%	0%	0%	0%
	Bay de Verde Main	62%	68%	65%	74%
	Bay de Verde East	0%	0%	0%	0%
	Total	44%	53%	52%	61%
Mizzen Member	Bay du Nord Main	0%	0%	0%	0%
	Bay du Nord NC	9%	21%	23%	58%
	Bay du Nord NB	0%	0%	0%	0%
	Bay de Verde Main	0%	0%	0%	0%
	Bay de Verde East	0%	0%	0%	0%
	Total	2%	2%	2%	3%
Total	Total	36%	42%	38%	46%

Table 9.11 Cambriol Field: Recovery Factors

Recovery Factor					
Cambriol Field		RF (%)			
Zone	Region	P90	P50	Mean	P10
Mizzen Member	B	0%	15%	24%	41%
	C	2%	37%	41%	51%
	D	51%	61%	54%	68%
	F	0%	0%	0%	0%
	Total	28%	38%	40%	55%

Table 9.12 Project: Recovery Factors

Field	MBO			
	P90	P50	Mean	P10
Bay du Nord	36%	42%	38%	46%
Cambriol	28%	38%	40%	55%
Total	33%	40%	39%	49%

10 Development Drilling and Completions

10.1 Introduction

The Bay du Nord Project (the Project) plans to conduct drilling programs from subsea templates using a drilling installation. Equinor has experience conducting operations from drilling installations, including the exploratory drilling programs in the Canada-NL offshore area, as described in Section 10.2 Summary of Past Activities.

Drilling programs, as part of the full field construction, are planned to take place both before and after the arrival of the Floating Production, Storage, and Offloading (FPSO) facility. There is consideration to have several wells fully drilled and completed before the FPSO arrival to allow for the early production plateau. The wells will be safely suspended with two verified well barrier envelopes. The FPSO will then start-up the wells as per the defined well objective (production or injection).

The number of wells, well objectives, locations, targets, and completion types will be defined and updated as the Project matures through the decision gates described in Section 1.1.8 Approach to Project Management. Generally, wells will have deviated or horizontal trajectories into the reservoir.

Currently, the Project consists of three main well types:

- Producers;
- Water Injectors (WI); and
- Water-Alternating-Gas (WAG) injectors.

The concepts described in Section 10.3 Proposed Drilling Program, Section 10.4 Completion Program, Section 10.5 Wellhead and Trees, Section 10.6 Interventions and Workovers, and Section 10.7 Well Control and Safety Systems are subject to change during the Front-End Engineering Design (FEED) and detailed design phases.

10.2 Summary of Past Activities

Equinor has over 16 years of experience drilling in the Canada-NL offshore area. In total, 28 exploratory wells, including six sidetracks, have been drilled. As seen in Figure 10.1, the majority of these wells have been drilled in the Project Area, which has allowed for a vast amount of operational experience to be gathered and incorporated in the proposed well operations described within the subsequent sections.

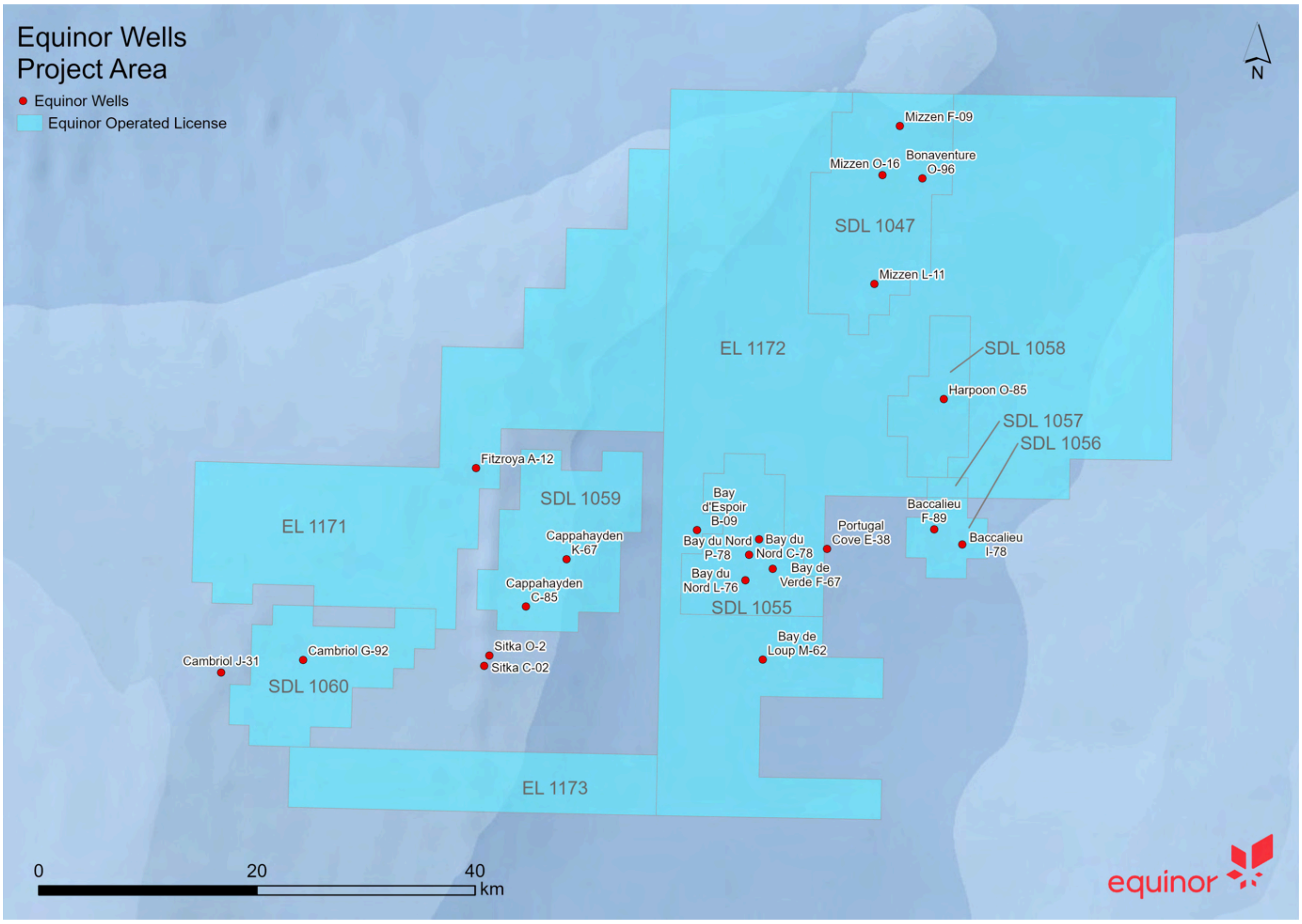


Figure 10.1 Exploratory and Appraisal Wells Drilled by Equinor in and around the Project Area

10.3 Proposed Drilling Program

The development wells are planned to be drilled from subsea templates. The current well design is a four-string, five-hole section design which may be further optimized as more operational experience is gained.

The current operational plan utilizes a batching strategy to maximize efficiency, starting with drilling the tophole sections for several wells before coming back and drilling the rest of the well to its planned total measured depth.

10.3.1 Drilling Hazards and Mitigative Measures

Experiences regarding drilling hazards have been captured from the offset exploratory wells drilled within the Flemish Pass Basin. The overburden within the Project Area is represented by the same tectonism, stratigraphy, and depositional environments experienced in the offset wells. Potential drilling hazards which may be encountered are described below. These potential drilling hazards will be assessed on an individual well basis during detailed well planning.

Boulders/Seabed

The Project Area has been surveyed, and seabed boulders mapped. Template locations have been selected to avoid boulders as much as possible. As well, a geotechnical program covering all template locations has been completed. Boulders and hard formation were encountered while drilling within the Cambriol Field. Encountering boulders, or hard formation, shallow in the well trajectory, may cause a higher-than-desired wellbore inclination. This risk is mitigated through careful review of the geotechnical data collected to optimize the template placement.

Mass Transport Zone

The Mass Transport Zone (MTZ) in the Laurentian Group consists of a chaotic mixture of inter-layered silt/sand and shale. This could lead to possible losses while drilling. If encountered, losses would be mitigated through regular drilling practices using lost circulating material. No operational issues have been experienced while drilling through the MTZ in the offset wells.

Shallow Gas and Hydrates

Seismic data acquired at the planned template locations show no clear indications of shallow gas. All locations have been internally classified as Class 0, indicating that shallow gas is not predicted. Furthermore, no shallow gas was encountered during the drilling of nearby exploratory and appraisal wells.

The geological setting—characterized by deepwater, cold temperatures, and a specific subsurface thermal gradient—places the upper section of the overburden within the theoretical Gas Hydrate Stability Zone (GHSZ). Geophysical indicators of hydrate-like features have been observed in the lower portions of the MTZ; however, these features have not resulted in operational challenges in offset wells that penetrated similar zones.

To mitigate the risk of encountering shallow gas or hydrates prior to Blowout Preventer (BOP) installation, the top-hole sections will be drilled riserless, in accordance with Equinor ASA's Well Control Manual and established drilling practices. These procedures include pre-spud drills, real-time monitoring, and conservative casing setting depths designed to reduce the likelihood of uncontrolled flow events. These measures are consistent with industry best practices and regulatory expectations for safe and environmentally responsible drilling operations.

Wellbore Stability

When drilling well trajectories with high inclination, there is a risk of wellbore instability due to unconsolidated formations. Preliminary wellbore stability plots have been created covering all fields. These plots estimate the required fluid weights to prevent any wellbore instability challenges. They have been modelled based on data obtained during the drilling of the offset exploratory wells and are planned to be reviewed and further developed in the detailed design phase.

The best way to mitigate against wellbore stability issues is through the proper selection of a drilling fluid. These specifications are planned to be future matured in the detailed design phase once the well designs have been finalized and a third-party fluids supplier has been selected. Together with the continuous monitoring and maintenance of drilling fluid properties, operational parameters such as rotating, tripping, and pumping speeds are planned to be optimized to ensure the most effective and safe well construction.

Faulting

Faults are expected to be encountered while drilling the planned development wells, both within the overburden and the reservoir section. Faults may pose a risk to drilling operations resulting in loss of drilling fluid and / or borehole instability. Wellbore instability will be mitigated with the proper drilling fluid selection as described above.

With regard to losses, these will be mitigated by ensuring an appropriate drilling fluid has been selected and enough reserve drilling fluid volume is on hand to compensate for any fluid loss. Also, fluid loss material will be readily available on the drilling installation should it be necessary. Losses will be handled in line with Equinor ASA's Well Control and Well Integrity requirements.

Hydrogen Sulphide

Hydrogen sulphide (H_2S) potential is described in Section 6.3.1.5 Hydrogen Sulphide Souring Evaluation. H_2S has not been detected in well fluid samples collected from the Project Area. However, temperature-based correlations suggest that low concentrations of H_2S may theoretically be present in the initial reservoir fluids at the Cambriol Field.

Over the life of the field, H_2S is expected to develop in all reservoirs as a result of microbial activity—specifically, the metabolism of sulphate in injected seawater by sulphate-reducing bacteria and archaea. This process, known as reservoir souring, is associated with long-term production operations.

While drill strings may theoretically encounter trace H_2S during reservoir penetration, H_2S is not anticipated to pose a risk to well construction activities. The drilling installation, including drill strings and associated components, will be selected and managed in accordance with Equinor ASA's standards and industry best practices to ensure safe operations and account for any potential exposure.

10.3.2 Casing and Cementing Program

Casing Program

The typical hole and casing sizes are outlined in Table 10.1, and is based on experience gained from the offset exploratory and appraisal wells, as well as Equinor ASA's experience from other deepwater projects.

The design criteria used for developing the casing program are based on internal requirements and local regulatory requirements, and covers the entire well lifecycle. These include, but are not limited to, the following:

- Drilling considerations such as pressure testing, available kick tolerance to drill the next hole section, and blowout loads;
- Completions considerations such as pressures and sizes required for running downhole equipment;
- Production/injection considerations such as pressures seen during wellbore clean-up, production, or injection, and late-life production/injection considerations; and
- Intervention/workover considerations such as pressure seen during bullheading operations or potential tubing leakage scenarios.

As well, the design factors used for analyzing the casing program are based on internal requirements and local regulations.

Table 10.1 Preliminary Casing Program

Hole Size	String Name	Casing Outer Diameter (OD)	String Type
42" (1069 mm)	Conductor	36" (914 mm)	Casing
26" (445 mm)	Surface	20" (508 mm)	Casing
17 1/2" (445 mm)	Intermediate	13 5/8" (346 mm) OR 14" (356 mm)	Casing
12 1/4" (311 mm)	Production	10 3/4" x 9 5/8" (273 mm x 244 mm) OR 10 3/4" x 9 7/8" (273 mm x 251 mm)	Casing, liner or liner and tieback

Materials will be selected to consider expected production and injection fluid compositions, reservoir characteristics, and operational conditions to ensure compatibility with anticipated downhole environments and support long-term integrity of well components.

The casings, hole sizes, and number of sections presented above may be further matured and optimized during the detailed design phase to accommodate for specific well trajectories, targets, and drilling constraints. Technology improvement, reservoir understanding and operational or safety improvements may also change the design.

Cement

The cementing program is based on experience gained from the offset exploratory wells and internal company experience. For each well, the following information is planned to be further matured during the detailed design phase to accommodate well-specific shoe depths and wellbore trajectories.

The main cementing objectives for the conductor and surface casings strings will be to provide structural support and isolate unconsolidated formations allowing for the drilling of the next hole section. As such, the cement tops for these sections are planned to be taken back to the seabed.

For the intermediate and production strings, the cement top will be planned high enough to provide an annulus barrier and isolate any zones with flow potential. To mitigate possible Annular Fluid Expansion (AFE) and corresponding Annular Pressure Build-up (APB), it is planned to keep the cement top below the previous casing shoe in order not to create a sealed-off annulus.

For the conductor and surface hole sections, a drill cuttings and cement disposal system is planned to be utilized to move both drill cuttings and excess cement away from the subsea templates.

10.4 Completion Program

The completion strategy will be dependent on well objectives, location, and reservoir properties. Detailed engineering and design work will be completed and updated as required on a well-by-well basis. Technology improvement, reservoir understanding, and operational or safety improvements may change the design. The Project will be planned with wells that enable the safe production of hydrocarbons and reservoir fluids and enable the safe injection of both gas and water. Completion designs will be communicated through the Approval to Drill a Well (ADW)/Notification to Complete process with any required supporting analysis and documentation.

Production and injection wells will be designed to maintain long-term production/injection while aiming to minimize or eliminate the need for planned interventions or workovers.

Wells will be constructed to:

- Provide long-term injection or production for the planned life of the well at the conditions specified during the detailed design phase;
- Provide primary and secondary barrier envelopes against defined pressures;
- Provide material strength and properties to withstand defined load cases and fluids including H_2S;
- Minimize the number of potential leak points;
- Prevent sand production;
- Provide downhole pressure and temperature monitoring;
- Allow for intervention activities to install mechanical isolation plugs in the production tubing, if required;
- Minimize complexity and increase standardization while ensuring well objectives are met;
- Take into account the potential need for sidetracking and slot recovery for increased recovery and drainage optimization; and
- Take into account the future need for permanent plug and abandonment of the well.

Some injection wells will be able to support WI or both WAG as part of the described reservoir drainage strategy in Section 7 Reservoir Exploitation. The use of the WAG wells is planned for the Bay du Nord Field, while WI is planned for the Cambriol Field.

Production wells will be able to support the production of reservoir fluids, including oil, gas, and water.

In some cases, injection or production wells may include equipment to inject into or produce from independent areas along the same wellbore within the reservoir. This equipment provides the ability to optimize reservoir drainage and production, and provides future flexibility as more information and experience are gained. Downhole mechanical equipment is typically hydraulically operated, while pressure and temperature gauges are powered electronically.

Downhole gas lift is not currently in the completion concepts but may be required in future wells. Downhole chemical injection is expected to be required across parts of the development. The requirement will be matured during the detailed design phase.

Some major components, which are subject to change and vary between wells, are listed below:

- Open hole Stand-Alone Screens (SAS);
- Production tubing of varying sizes from 2 7/8" to 7" (73 to 178 mm);
- Liner hanger/screen hanger and packer with a Polished Bore Receptacle (PBR);
- Seal stinger or mule shoe;
- Production Packer (PP);
- Downhole Pressure and Temperature Gauge(s) (DHPTG);
- Downhole Safety Valve (DHSV);
- Tubing Hanger (TH);
- Flow Control Valves (FCV);
- Inflow Control Devices (ICD)
- Downhole chemical injection;
- Isolation packers (swell-able, hydraulic set or mechanical type); and
- Temporary tubing plugs.

Figure 10.2 and Figure 10.3 give an example of a well with and without flow control valves as part of the completion.

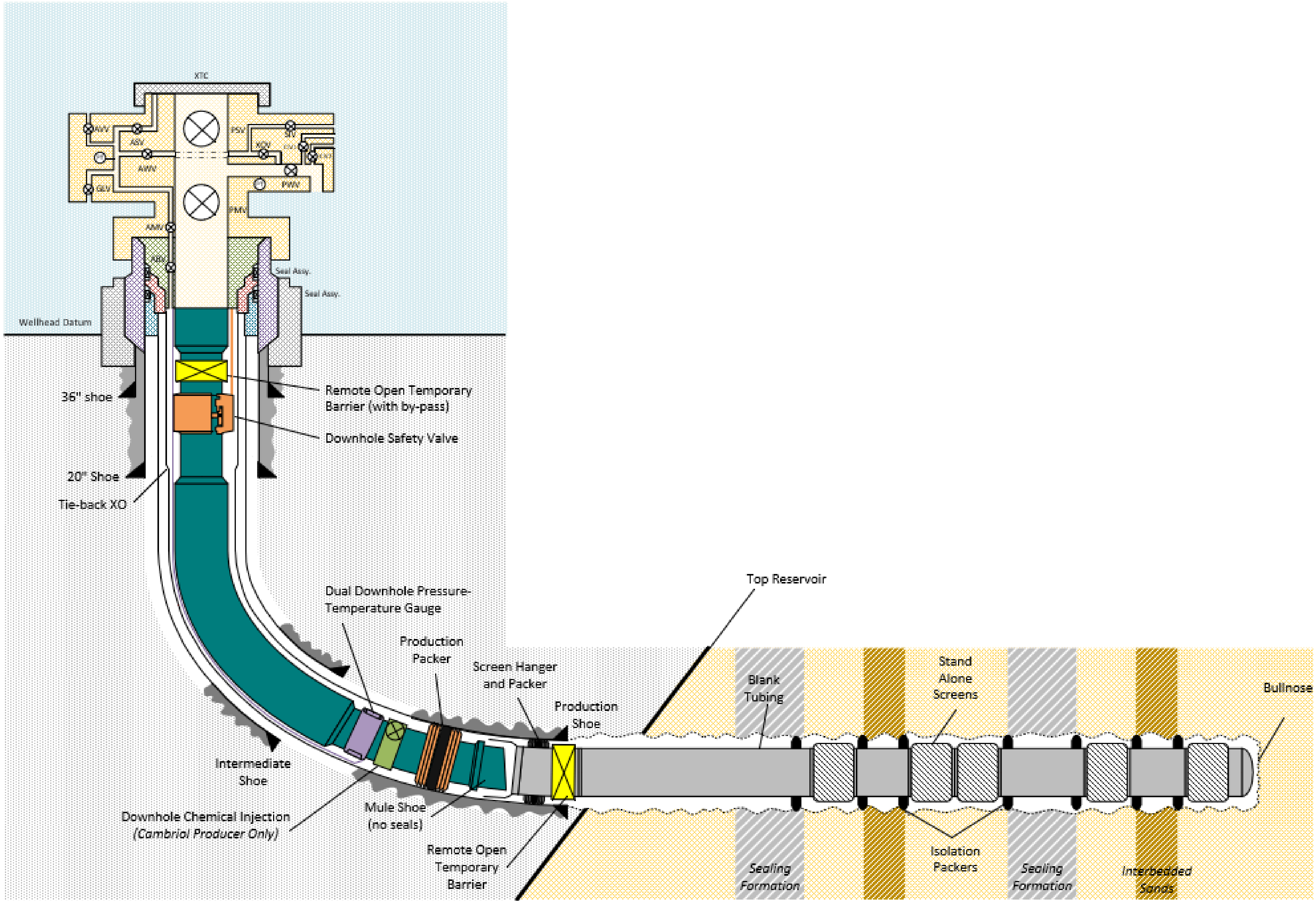


Figure 10.2 Completion Example without Flow Control Valves

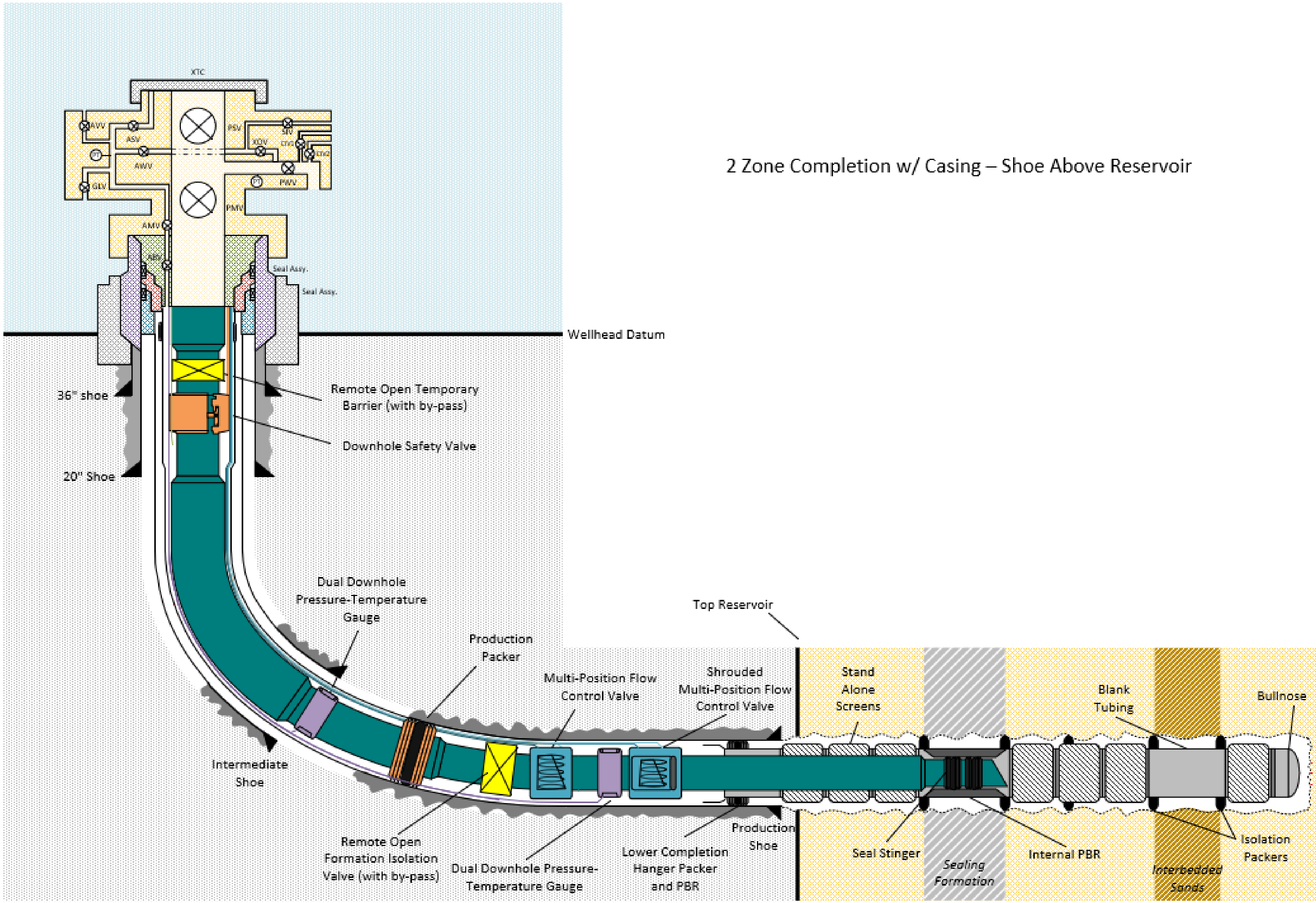


Figure 10.3 Completion Example with Flow Control

10.4.1 Completion Fluids

Completion fluids will vary depending on the reservoir properties, base fluid, clean-up considerations, and material compatibility. Both water-based and non-aqueous fluids will be considered. Completion fluids will be designed or used to:

- have compatibility between drilling, completion, and reservoir fluids;
- keep the wellbore stable while lower completion equipment is installed;
- keep the well in over-balance while equipment is installed or operated;
- keep the well in under-balance if needed;
- fulfil the objective of the well construction process while minimizing wellbore damage;
- allow for optimal clean-up of the fluid before production or injection;
- have annulus/packer fluids with the correct composition to mitigate settling, corrosion, and elastomer degradation over the life of the well;
- provide inhibition against freezing during suspension operations;
- minimize formation damage during suspension before well clean-up; and
- break down fluids and filter-cake after the well construction is complete (if a breaker system is used).

Hydraulic fluids used to operate equipment downhole and as part of the Subsea Production System (SPS) will be determined as part of the subsea design work.

10.5 Wellhead and Trees

The wellhead, Christmas Tree (XT) and TH systems will be designed to accommodate the expected wellbore temperatures, pressures, and loads that it may be exposed to over its lifetime. The systems will be designed with due consideration to the applicable requirements in the *Canada–Newfoundland and Labrador Offshore Area Petroleum Operations Framework Regulations* (the *Framework Regulations*), industry standards and guidelines.

The XT will be of a typical deepwater subsea design and will include remote operated valves and choke for control of production or injection fluids. The XT will have functionality for accepting chemical injection to the XT as required for hydrate inhibition or chemical treatment. It will also have pressure and temperature sensors for production and injection monitoring purposes. The XT will connect to the TH system. The TH system will be equipped to supply hydraulic pressure via the completion control lines for operation of downhole valves such as the surface controlled DHSV, supply downhole chemical injection as needed via control line depending on the completion concept and be equipped with electrical feed throughs for use as needed for downhole gauges. A schematic of a typical valve arrangement for a XT is illustrated in Figure 10.4.

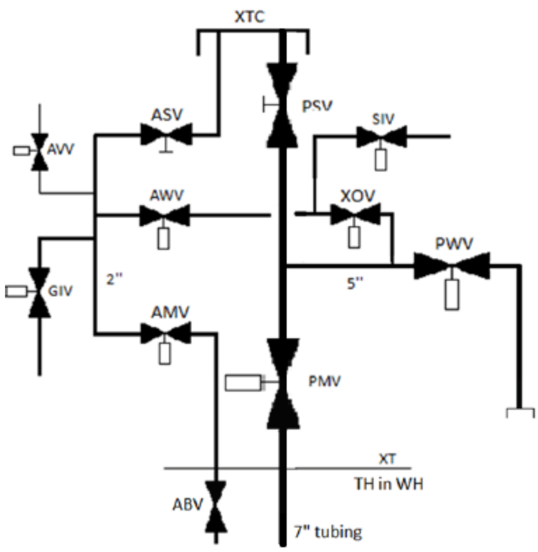


Figure 10.4 Typical Valve Arrangement, Subsea XT

The wellhead system will be installed as part of drilling operations. It will have hang-off points incorporated for installation of required casing strings. The wellhead system will have a connector at the top for connection of the subsea XT. XT installation will be via drilling installation or vessel.

10.6 Interventions and Workovers

In any instance when there is an unplanned failure or planned intervention or workover activity, a drilling installation or intervention-capable vessel will be needed to complete the work. Downhole intervention is not possible from the FPSO.

Wells will be designed to minimize the need for intervention activities throughout the production life, and workovers are not planned as part of the base case for the initial Project development. Further work will be completed before finalizing the well design to determine if any interventions will be required for reservoir management, as discussed in Section 7 Reservoir Exploitation. Based on a review of available data and in consideration of the current completion design, it is estimated there could be up to 30 interventions. The frequency of interventions will depend on the operation and the availability of drilling installations or intervention-capable vessels. Slot recoveries and sidetracks will be possible, and the potential need will be considered in the initial drilling and completion designs.

Interventions may consist of, but are not limited to: Remotely Operated Vehicle (ROV), pumping, Wireline (WL) or slickline, coiled tubing, and drill pipe operations, among others.

10.7 Well Control and Safety Systems

Well control and safety systems will be in place during well operations.

Well control equipment utilized for drilling and completion operations typically consist of a BOP, kill and choke lines, marine riser, and associated surface equipment. All equipment utilized within this system will align with Equinor ASA's well integrity and well control requirements as well as local regulatory requirements.

The BOP will be comprised of annular preventers and rams, as well as kill and choke lines. The BOP will be configured and stacked up in a way suitable for operations in the applicable Project water depths and conditions and allow for safe and efficient operations. The exact configuration, pressure ratings, and stack requirements will be further matured in the detailed design phase, once a third-party drilling unit has been selected, and the final well designs have been confirmed.

The marine riser connects to the BOP and ties it back to the drilling installation. The riser allows lowering and lifting of the BOP stack from the surface down to the seabed, and also provides a conduit for the drilling or completion fluids.

The surface equipment may consist of items such as a fluid monitoring system ensuring the fluid weights and volumes are kept within planned limits. Managed Pressure Drilling (MPD) related technologies to allow for precise control of wellbore pressures, mud gas separators helping to separate gasses from the fluid, the diverter system, and auxiliary BOP control systems such as accumulators and kill and choke manifolds. The surface equipment will be further matured once a third-party drilling installation has been selected and the final well designs have been confirmed.

An integrated part of the safety systems will be the Well Control Bridging Document between Equinor and the drilling installation contractor which will define well control roles and responsibilities during the operation. In addition, a Health, Safety, and Environment (HSE) Bridging Document will be prepared to describe the coordination and cooperation of systems for emergency response between Equinor and the rig contractor. Both of these documents will be prepared before the start of drilling activities. Contingency planning is further addressed in Section 15.14.1 Overview.

Wells will be designed to minimize the need for intervention activities throughout the production life. When intervention activities such as WL, slickline, or coiled-tubing activities are conducted, a subsea well control package, landed on top of the XT, will be utilized. The details of the stack-up including configuration, pressure rating, and additional system requirements will depend on the intervention type and method, to be matured as part of the intervention planning activities. All equipment utilized within this system will align with Equinor ASA's well integrity and well control requirements as well as local regulatory requirements.

10.7.1 Completion Safety Systems

Downhole safety systems that will be installed in the well will form part of the barrier envelope that prevents uncontrolled flow in the event of a failure. All wells will have a verified primary and secondary barrier envelope during the construction, suspension, XT installation and production periods.

The following barrier elements typically create a full cross-section that creates the barrier envelope during production. Barrier envelopes can be created or defined in multiple ways, and the following list summarizes some of the components of a typical cross-section:

- Formation strength above reservoir pressure;
- Cement in the annulus;
- Casing/liner;
- Production packer or other packer types;
- Production tubing;
- DHSV;
- Wellhead and wellhead seals; and
- Subsea XT and associated valves/seals.

The DHSV will be designed to close in the event of a failure. All other downhole completion equipment that is defined as part of the barrier envelope is verified during installation, and some elements can be periodically tested during the production phase.

11 Design Criteria

11.1 Regulatory, Certification, and Classification Basis

The production installation, including the Floating Production, Storage, and Offloading (FPSO) facility, Subsea Production System (SPS), and wells, will be designed according to applicable federal and provincial authority regulations and requirements, international standards and codes, and when required, Equinor and/or FPSO contractor requirements.

The applicable regulations, codes of practice, and guidelines for the Bay du Nord Project (the Project) are promulgated by the:

- Shelf state regulator, Canada-Newfoundland and Labrador Offshore Energy Regulator (C-NLOER); and
- Maritime flag state regulator, Transport Canada (TC).

Equinor will implement a process of classification, certification and verification to ensure that the quality and safety of the production installation meets the requirements, and when required, Equinor and/or FPSO contractor requirements.

The concepts described in the following subsections are subject to change during the Front-End Engineering Design (FEED) and detailed design phases.

11.1.1 Offshore Regulatory Requirements

The primary regulations pertaining to an offshore production installation include the following:

- *Canada–Newfoundland and Labrador Offshore Area Occupational Health and Safety Regulations* (the *OHS Regulations*); and
- *Canada–Newfoundland and Labrador Offshore Area Petroleum Operations Framework Regulations* (the *Framework Regulations*).

As prescribed in the *Framework Regulations*, a Certification Plan will be developed and will include:

- A description of the installation that will be certified, including its systems and equipment;
- A list of the standards that will apply to the installation to be certified, including its systems and equipment;
- A list of the standards to develop the risk reduction measures in the Safety Plan and the Environmental Protection Plan (EPP);
- If no standards apply, include studies or analyses that show the measures will reduce risks to a level that is As Low As Reasonably Practicable (ALARP); and
- A list of all Safety and Environmental Critical Elements (SECEs), as well as a description of how the associated performance standards will be developed.

The Certifying Authority (CA) will review and endorse the Certification Plan prior to Equinor's submission to C-NLOER in accordance with regulatory requirements. The formal CA Scope of Work issued to the C-NLOER by Det Norske Veritas (DNV) will be based upon Equinor's Certification Plan and the regulatory requirements.

11.1.2 Maritime Regulatory Requirements

During operations, the FPSO will be required to meet applicable Canadian and international maritime requirements, as outlined in the Project Description Document (PDD) that will be prepared by DNV and submitted to TC. The PDD will act as a guide to assist TC, Equinor, FPSO contractor, builders, designers, and the CS in achieving the classification and regulatory requirements applicable to the FPSO.

DNV will be the CA and the Classification Society (CS) for the Project as well as the Recognized Organization (RO) towards TC. DNV will conduct reviews of the design, construction, installation, hook-up, commissioning, and start-up of production operations to ensure compliance with rules, regulations, codes of practice, and guidelines administered by the shelf state, flag state and CS. DNV will be formally designated as RO towards TC under *TP 13585 Marine Safety Management System - Tier I - Policies* [59], and in particular, the Delegated Statutory Inspection Program (DSIP) policy.

The CS/RO will confirm compliance with the applicable regulations for those marine-related aspects of the FPSO which impact the safety and integrity of the FPSO including hull, turret, and topsides.

The FPSO will have the ability to disconnect from its moorings and sail away under its own propulsion. The vessel will be Classed by DNV and will remain in Class following installation.

11.1.3 Class Notations

The Class notations will be a fundamental part of the design requirements for the FPSO. The FPSO will be designed and constructed according to the following DNV Class notation string:

✠1A, Ship Shaped Oil Production and Storage Unit, Field (Bay du Nord), Crane-offshore, FMS(25), FAB+, HULL+, LCS, PROD(CAN), ECO, HELDK (SHF), Offloading, POSMOOR(HC), BIS, BWM(T), COAT-PSPC(B,C), Recyclable, Barrier (Custom), Cybersecure (essential), ABATE (P,F,Pr,S).

Through the FEED and detailed design phases, adjustments to the Class notations may be made, as appropriate.

11.2 Physical and Environmental Conditions

11.2.1 Introduction

The physical and environmental conditions for the Flemish Pass region are considered similar to the Grand Banks and northern North Sea. The region experiences summer and fall hurricanes as well as significant winter storms, with winds generally coming from the southwesterly and westerly directions. Reduced visibility due to fog is common, especially during the spring and summer months, caused by warm and moist air from the Gulf Stream moving North and condensing as it passes over the cold Labrador Current. The Project Area is also subject to seasonal incursions of sea ice (January through April) and icebergs (March through early August), as well as marine icing during certain wind, wave, and air temperature conditions. The most severe sea states occur in December and January originating from the northwest through southwest.

11.2.2 Environmental Data

Existing environmental data to be used for design of the Project facilities for operation are outlined in Table 11.1 to Table 11.11.

Atmospheric and oceanic environment (climatic temperatures, waves, wind, current, and tides) of the Flemish Pass area are described in the Metocean Design Basis [60] and the Environmental Impact Statement [4].

Table 11.1 Monthly and Annual Sample Distributions of Non-Exceedance [%] of Significant Wave Height (Hs) at the Bay du Nord Field

Hs [m]	**Month**												**Year**
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
< 1	0.00	0.00	0.16	0.14	0.86	2.39	5.25	4.62	0.96	0.13	0.14	0.00	**1.23**
< 2	2.21	2.86	6.21	16.64	38.97	57.69	70.89	66.13	34.88	13.73	6.91	2.88	**28.82**
< 3	18.89	22.16	34.80	57.40	80.32	90.62	96.01	93.88	76.30	52.18	35.54	23.45	**56.97**
< 4	47.93	53.41	64.57	82.09	94.42	97.85	99.39	98.33	92.03	78.48	65.63	51.49	**77.23**
< 5	71.43	75.33	82.86	92.41	98.27	99.54	99.86	99.64	97.43	91.47	83.23	73.09	**88.77**
< 6	85.11	87.10	91.94	96.93	99.28	99.88	99.99	99.96	98.86	96.64	92.29	86.62	**94.58**
< 7	92.41	93.62	96.99	98.78	99.73	99.96	100.00	100.00	99.39	98.62	96.57	93.88	**97.51**
< 8	96.51	97.21	98.78	99.48	99.92	100.00			99.75	99.35	98.57	97.10	**98.90**
< 9	98.61	98.91	99.65	99.88	100.00				99.90	99.69	98.51	98.73	**99.58**
< 10	99.46	99.55	99.82	99.95					99.97	99.87	99.76	99.36	**99.81**
< 11	99.75	99.75	99.91	100.00					100.00	99.97	99.86	99.66	**99.91**
< 12	99.91	99.87	99.95							100.00	99.92	99.85	**99.96**
< 13	99.96	99.96	99.98								100.00	99.96	**99.99**
< 14	99.99	100.00	100.00								100.00	99.98	**100.00**
< 15	99.99											99.99	**100.00**
< 16	100.00											99.99	**100.00**
< 17												100.00	**100.00**
Total	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
Mean	**4.4**	**4.2**	**3.7**	**3.1**	**2.4**	**2.0**	**1.8**	**1.9**	**2.5**	**3.2**	**3.7**	**4.2**	**3.1**
Maximum	**15.3**	**13.8**	**13.9**	**10.8**	**8.5**	**7.4**	**6.4**	**6.8**	**10.9**	**11.9**	**13.0**	**16.4**	**16.4**

Table 11.2 Monthly and Annual Sample Distribution of Non-Exceedance [%] of 1-hour Mean Wind Speed 10 masl at the Bay du Nord Field

Wind [m/s]	**Month**												**Year**
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	
< 2	0.71	0.62	1.22	2.37	3.89	4.33	4.60	3.70	2.89	1.58	0.85	0.80	**2.31**
< 4	4.23	4.26	6.47	11.30	16.16	18.14	19.80	18.98	12.78	8.11	5.67	4.85	**10.93**
< 6	11.09	11.91	16.39	26.04	35.24	39.77	43.67	42.59	29.90	21.39	15.32	12.72	**25.58**
< 8	21.62	23.03	31.14	46.16	59.03	64.56	69.65	68.05	52.80	40.88	30.06	24.57	**44.41**
< 10	35.32	36.63	47.02	62.97	76.80	81.01	86.54	83.96	70.44	57.31	45.91	39.02	**60.37**
< 12	49.18	51.30	61.80	77.17	88.60	92.07	95.25	93.75	84.08	72.09	60.99	53.43	**73.42**
< 14	62.98	65.87	75.47	87.86	95.01	97.31	98.92	97.92	92.64	83.97	74.89	67.20	**83.41**
< 16	76.27	78.23	86.08	94.02	97.89	99.25	99.76	99.25	96.87	92.43	86.01	79.64	**90.53**
< 18	86.77	88.10	93.46	97.45	99.24	99.86	99.94	99.75	98.87	97.04	93.10	89.20	**95.26**
< 20	93.92	94.32	97.31	98.94	99.76	99.99	99.99	99.94	99.63	98.69	97.22	95.11	**97.92**
< 22	97.55	97.41	98.96	99.59	99.96	99.99	99.99	99.98	99.88	99.51	98.89	98.04	**99.16**
< 24	99.18	98.97	99.62	99.89	99.99	100.00	100.00	100.00	99.93	99.76	99.53	99.16	**99.67**
< 26	99.74	99.63	99.80	99.98	100.00			100.00	99.97	99.94	99.84	99.56	**99.87**
< 28	99.91	99.88	99.88	100.00					100.00	99.98	99.96	99.77	**99.95**
< 30	99.95	99.95	99.92						100.00	99.99	100.00	99.89	**99.97**
< 32	99.99	99.98	99.98							100.00	100.00	99.96	**99.99**
< 34	100.00	99.98	100.00									99.99	**100.00**
< 36		100.00										100.00	**100.00**
Total	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
Mean	**12.2**	**12.0**	**10.7**	**8.9**	**7.6**	**7.1**	**6.6**	**6.8**	**8.2**	**9.5**	**10.8**	**11.7**	**9.3**
Maximum	**33.1**	**35.9**	**34.0**	**26.5**	**24.6**	**23.6**	**22.6**	**24.0**	**28.1**	**30.9**	**30.2**	**35.5**	**35.9**

Table 11.3 Summary Statistics for Air Temperature, Sea Temperature, and Salinity

Parameter	Unit	Minimum	Mean	Maximum
Air temperature at 2 m height	[°C]	-14.7*	5.6*	18.3*
Sea temperature, Surface	[°C]	-1.7	6.3	16.0
Sea temperature, Bottom	[°C]	2.9	3.5	4.0
Salinity, Surface	[PSU]	30.54	33.48	34.82
Salinity, Bottom	[PSU]	34.78	34.87	34.95
* From hindcast data during the period 1979-2019				

Table 11.4 Percentage Frequency of Fog for the Months of March, May, July, and September at Bay du Nord

Percentage Frequency of Fog			
Mar	May	July	Sep
10-15%	20-25%	35-40%	10-15%

Table 11.5 Summary Statistics of Current Measurements at Bay du Nord

Depth	Mean Current Speed	P90 Current Speed	Maximum Current Speed
[m]	[cm/s]	[cm/s]	[cm/s]
0	23	41	107
25	20	38	98
50	17	31	92
65	15	27	85
90	13	24	71
150	11	19	46
300	9	15	30
500	8	14	27
650	8	13	27
800	8	14	31
1000	8	14	35
5 m asb	8	14	29

Table 11.6 Direction Sample Distribution of Non-Exceedance [%] of Current Speed at the Surface at Bay du Nord

Current	**Current Direction**												**Omni**
Speed [cm/s]	**0°**	**30°**	**60°**	**90°**	**120°**	**150°**	**180°**	**210°**	**240°**	**270°**	**300°**	**330°**	
< 10	1.05	1.18	1.25	1.37	1.55	1.64	1.77	1.70	1.58	1.33	1.19	1.04	**16.65**
< 20	2.87	3.56	4.23	4.45	4.93	5.51	6.37	6.25	4.97	3.62	2.96	2.54	**52.25**
< 30	3.65	4.61	5.66	6.28	7.16	8.57	10.57	10.28	7.33	4.91	3.76	3.22	**76.00**
< 40	4.04	5.08	6.24	7.02	8.33	10.42	13.44	12.63	8.60	5.50	4.04	3.52	**88.87**
< 50	4.23	5.42	6.46	7.35	8.81	11.44	14.84	13.81	9.10	5.73	4.13	3.59	**94.92**
< 60	4.27	5.55	6.56	7.47	9.02	12.11	15.62	14.44	9.33	5.84	4.18	3.62	**98.01**
< 70	4.30	5.63	6.58	7.49	9.09	12.41	16.03	14.70	9.40	5.90	4.20	3.63	**99.36**
< 80		5.65	6.58	7.49	9.09	12.48	16.22	14.82	9.44	5.91	4.21		**99.83**
< 90				7.49	9.10	12.51	16.26	14.86	9.46	5.92	4.21		**99.96**
< 100					9.10	12.51	16.27		9.46	5.92			**99.98**
< 110						12.53	16.28						**100.00**
Total	**4.30**	**5.65**	**6.58**	**7.49**	**9.10**	**12.53**	**16.28**	**14.86**	**9.46**	**5.92**	**4.21**	**3.63**	**100.00**
Mean	**18**	**20**	**19**	**20**	**21**	**25**	**27**	**25**	**22**	**20**	**17**	**17**	**22**
Maximum	**66**	**76**	**75**	**87**	**93**	**107**	**105**	**88**	**93**	**92**	**84**	**69**	**107**

Table 11.7 Estimates of Extreme Water Levels Above Mean Sea Level

Parameter	Unit	Return period (years)	
		100	10,000
Tidal amplitude (HAT)	m	0.4	-
Storm surge	m	0.8	1.0
Wave crest height	m	19.4	26.7
Total water level	m	20.6	27.7

Table 11.8 Monthly and Annual Sample Frequency of Non-Exceedance [%] of Air Temperature at the Bay du Nord Field during the Period 1979 - 2019

Air Temperature [°C]	Month												Year
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
< -14		0.04											**0.00**
< -13		0.05	0.01										**0.00**
< -12		0.07	0.01										**0.01**
< -11		0.15	0.02										**0.01**
< -10	0.01	0.35	0.02									0.01	**0.03**
< -9	0.03	0.72	0.03									0.03	**0.06**
< -8	0.13	1.24	0.22									0.06	**0.13**
< -7	0.52	2.03	0.72									0.11	**0.27**
< -6	1.17	3.10	1.78	0.03								0.16	**0.51**
< -5	2.29	5.87	3.25	0.09								0.33	**0.96**
< -4	4.53	9.81	5.57	0.19								0.79	**1.70**
< -3	8.64	15.81	9.11	0.51							0.01	2.02	**2.94**
< -2	15.12	22.98	14.53	1.31							0.03	4.50	**4.78**
< -1	25.15	32.73	22.12	3.20	0.04						0.32	9.29	**7.62**
< 0	38.04	44.78	32.95	9.05	0.36						0.91	16.59	**11.74**
< 1	52.14	58.29	47.07	22.79	2.88					0.01	2.76	26.93	**17.56**
< 2	65.91	71.43	62.67	41.94	9.76	0.03				0.10	6.88	40.16	**24.69**
< 3	76.66	80.23	76.08	60.88	24.06	1.13				0.71	15.08	53.61	**32.15**
< 4	84.37	86.36	85.97	76.92	45.70	6.47	0.04			2.13	27.13	66.94	**39.96**
< 5	89.74	91.34	93.08	88.77	68.72	21.15	0.78			5.07	41.36	76.88	**47.86**
< 6	94.23	95.63	97.72	95.60	85.02	41.06	2.76		0.12	11.15	56.39	84.37	**55.11**
< 7	97.50	98.91	99.49	98.97	94.29	61.94	7.28	0.04	0.57	22.91	69.99	90.39	**61.62**
< 8	99.48	99.94	99.98	99.85	98.35	77.09	15.15	0.43	2.93	38.76	81.23	95.32	**67.15**
< 9	99.94	100.00	100.00	100.00	99.74	87.76	29.88	2.20	10.20	56.82	88.64	98.59	**72.62**
< 10	99.98				100.00	95.05	47.64	8.65	22.27	74.03	93.70	99.73	**78.27**
< 11	100.00					98.50	66.67	19.75	39.39	86.42	97.22	99.93	**83.87**
< 12						99.84	81.91	37.15	56.89	93.26	99.40	99.98	**88.95**
< 13						99.98	90.81	58.16	75.18	96.81	99.92	100.00	**93.35**
< 14						100.00	96.19	78.34	88.17	98.77	99.99		**96.76**
< 15							98.85	90.84	95.52	99.58	100.00		**98.72**
< 16							99.86	97.73	98.81	99.97			**99.70**
< 17							99.96	99.70	99.87	100.00			**99.96**
< 18							99.99	99.98	99.97	100.00			**100.00**
< 19							100.00	100.00	100.00				**100.00**
Total	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
Minimum	**-10.2**	**-14.7**	**-13.2**	**-6.6**	**-1.4**	**1.6**	**3.3**	**6.7**	**4.8**	**0.9**	**-4.2**	**-10.2**	**-14.7**
Mean	**0.9**	**0.3**	**1**	**2.5**	**4.2**	**6.6**	**10.1**	**12.6**	**11.6**	**8.6**	**5.7**	**2.8**	**5.6**
Maximum	**10.3**	**8.8**	**8.2**	**8.9**	**9.9**	**13.4**	**18.1**	**18.3**	**18.3**	**17.2**	**14.4**	**12.8**	**18.3**
10-year extreme	**-9**	**-10**	**-10**	**-9**	**-4**	**-1**	**2**	**4**	**2**	**-2**	**-6**	**-6**	**-11**
100-year extreme	**-12**	**-13**	**-13**	**-11**	**-8**	**-2**	**2**	**3**	**1**	**-4**	**-10**	**-9**	**-16**

Table 11.9 Monthly Mean Sea Temperature [°C] at Selected Water Depths at the Bay du Nord Field

Depth [m]	Month											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	3.2	2.4	2.5	3.3	3.4	5.4	10.5	11.9	11.8	8.7	7.0	5.5
-10	3.0	2.1	2.4	3.4	3.1	5.0	10.1	11.2	11.2	8.7	7.5	6.5
-20	3.0	2.1	2.3	3.1	2.9	4.4	8.0	8.3	10.0	8.3	7.4	6.7
-30	3.0	2.3	2.4	2.9	2.9	3.4	5.7	4.9	6.9	7.9	7.3	6.4
-40	2.9	2.0	2.3	3.0	2.3	2.3	4.1	3.2	4.8	7.2	7.0	5.9
-50	3.0	2.1	2.4	2.9	2.3	2.1	3.4	2.5	3.9	5.9	6.1	5.5
-100	3.3	2.6	2.6	3.1	2.4	2.3	3.1	2.9	3.2	3.9	4.5	4.4
-200	4.0	3.5	3.3	3.7	3.4	3.1	3.7	3.7	3.5	3.8	4.1	4.4
-300	4.1	3.9	3.6	3.8	3.7	3.4	3.8	3.8	3.4	3.7	3.9	4.2
-400	4.1	3.9	3.5	3.7	3.8	3.6	3.8	3.8	3.3	3.7	3.8	4.0
-600	3.8	3.7	3.5	3.7	3.8	3.5	3.7	3.7	3.3	3.5	3.7	3.8
-800	3.6	3.5	3.5	3.6	3.6	3.5	3.6	3.6	3.3	3.5	3.5	3.7
-1000	3.4	3.6	3.2	3.5	3.5	3.5	3.5	3.6	3.5	3.6	3.4	3.6
-1200	3.4	3.4	3.5	3.4	3.4	3.4	3.4	3.5	3.6	3.6	3.4	3.5

Table 11.10 Monthly Mean Salinity at Selected Water Depths at the Bay du Nord Field

Depth [m]	Month											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	34.27	33.96	33.94	33.94	33.55	33.30	33.06	32.47	32.76	33.45	33.76	33.32
-10	34.33	34.05	33.95	33.98	33.48	33.37	33.18	32.60	32.78	33.49	33.72	33.60
-20	34.35	34.01	33.89	33.98	33.54	33.52	33.46	33.05	33.10	33.55	33.74	33.60
-30	34.37	34.03	33.98	34.01	33.73	33.65	33.71	33.52	33.39	33.59	33.78	33.66
-40	34.38	34.26	34.01	34.12	33.86	33.74	33.90	33.83	33.89	33.75	33.85	33.74
-50	34.38	34.03	34.04	34.13	33.96	33.92	34.00	33.94	33.96	33.87	33.96	33.86
-100	34.47	34.26	34.27	34.40	34.28	34.28	34.38	34.36	34.36	34.51	34.50	34.44
-200	34.47	34.64	34.62	34.71	34.64	34.63	34.71	34.70	34.67	34.78	34.79	34.80
-300	34.81	34.77	34.81	34.82	34.78	34.76	34.82	34.80	34.79	34.85	34.84	34.87
-400	34.83	34.81	34.86	34.84	34.82	34.81	34.84	34.84	34.84	34.87	34.85	34.87
-600	34.84	34.85	34.87	34.86	34.86	34.85	34.86	34.86	34.86	34.88	34.86	34.87
-800	34.84	34.86	34.87	34.87	34.87	34.86	34.87	34.87	34.86	34.88	34.86	34.87
-1000	34.84	34.88	34.85	34.87	34.87	34.87	34.87	34.88	34.87	34.88	34.86	34.87
-1200	34.85	34.85	34.86	34.88	34.88	34.88	34.88	34.89	34.89	34.88	34.87	34.87

Table 11.11 Thickness of Marine Growth at the Bay du Nord Field - Data from NORSOK Standard N-003

Depth	Thickness	Density	Submerged weight *
[m]	**[mm]**	**[kg/m^3]**	**[kN/m^3]**
Above +2	0	-	-
-15 to +2	60	1325	2.94
-30 to -15	50	1325	2.94
-40 to -30	40	1325	2.94
-60 to -40	30	1100	0.74
-100 to -60	20	1100	0.74
Below -100	10	1300	2.70

* Submerged weight per unit volume (dry weight minus buoyancy), assuming sea water density 1025 kg/m^3.

11.2.2.1 Icebergs

The Project Area is located in the Flemish Pass where iceberg impact and ice loading are of interest. The icebergs reaching the waters offshore Newfoundland have mostly calved from glaciers of West Greenland.

Iceberg conditions of the Flemish Pass are described in the Sea Ice and Iceberg Design Basis [61]. Annual iceberg areal density at Bay du Nord is estimated to be 1.3 x 10^{-4} icebergs/km^2. Mean drift speed is 0.39 m/s. Additional information is outlined in Table 11.12 and Table 11.13.

The 10^{-4} iceberg draft in the Flemish Pass is 178 m, with no risk of contact to the seabed in the Project Area, see Section 11.4.4 Iceberg Scour.

Table 11.12 Iceberg Areal Density Centered on Bay du Nord (1998-2024 for waterline lengths >= 15 m).

Areal density	Number of icebergs per km^2
January	-
February	-
March	2.4 x 10^{-4}
April	2.9 x 10^{-4}
May	2.1 x 10^{-4}
June	3.7 x 10^{-5}
July	3.0 x 10^{-5}
August	-
September	-
October	-
November	-
December	-
Annual	6.7 x 10^{-5}

Table 11.13 Classification of Icebergs and % Occurrence in the Jeanne d'Arc / Flemish Pass

Iceberg category	Height* [m]	Waterline Length** [m]	Approximate draft [m]	Approximate Mass [tonnes]	% occurrence approximate***
Growler	< 1	< 5	< 5	< 1,000	11.0
Bergy bit	1 - 5	5 - 15	5 - 15	1,000 - 10,000	4.9
Small	5 - 15	15 - 60	30 - 50	10,000 - 100,000	32.5
Medium	15 - 45	60 - 120	55 - 75	100,000 - 2 mill	26.6
Large	44 - 75	120 - 200	80 - 100	2 - 10 mill	24.6
Very large	> 75	> 200	> 110	> 10 mill	0.6

* Iceberg height is defined as the maximum height above the waterline; Waterline length is defined as the maximum dimension of the iceberg at the water surface; and iceberg draft is defined as maximum depth below waterline
**The iceberg size (waterline length) distribution at the Bay du Nord site is expected to be similar to size distribution (exponential with a mean 59 m) used for the Grand Banks and all other relationships (i.e. mass, draft, etc.) are similar
***Occurrence recordings may be biased towards larger bergs since they are easier to detect, i.e. the population of smaller icebergs may be underestimated

11.2.2.2 Pack Ice

Pack ice (sea ice) conditions of the Flemish Pass are described in the Sea Ice and Iceberg Design Basis [61]. Pack ice does not form locally in the Project Area, but occasionally drifts from the North East Newfoundland shelf and from further north with the offshore branch of the Labrador Current. Pack ice is very infrequent at the Project Area, but is on average present once every four to five years between January and April and lingers for maximum of 3-4 weeks. In general, dominant and thickest ice are generally found to range from thin to thick first year ice, with rare occurrences of old ice.

Ice concentration is usually low (3-5/10ths), but high ice concentration (9/10ths) has been observed. The mean daily ice thickness, when sea ice is present in the Project Area, is approximately 0.23 m.

Floe sizes are moderate due to the far offshore location, with high probability of swell breaking up the larger floes, but maximum floe size up to the medium category (100 - 500 m) has been reported.

Average sea ice drift speed is 0.47 m/s and the drift direction is generally to the southeast. Traces of multi-year ice (3-10% concentration) can be present at the Project Area.

11.2.2.3 Snow and Icing

The Project Area is also susceptible to snow and icing accumulation, which can significantly affect offshore structures by adding weight and altering stability. These loads are typically formulated using established engineering equations that consider factors such as the structure's geometry, exposure conditions, and characteristic snow loads for specific return periods. Key findings regarding snow and icing loads are summarized in Table 11.14.

Table 11.14 Snow and Icing Loads

Parameter	1-Year	10-Year	100-Year	10,000-Year
Total Snow Load (tonnes)	318	519	766	1249
Sea Spray Icing Load (tonnes)	105	264	433	760
Atmospheric Icing Loads (tonnes)	-	-	464	-

11.2.2.4 Climate Change

The Environmental Impact Statement [4] provides an overview of climate change focused on the Flemish Pass, the Grand Banks and offshore NL.

Climate change may result in variations to metocean conditions relative to the present basis used for structural design and assessment. In alignment with industry standards, the design incorporates allowances for potential changes, including increases or decreases, in extreme significant wave height, wind speeds, and sea level. These allowances will be incorporated to ensure resilience against evolving climate conditions.

While the facility is designed for a 20-year production life, during which the climate is not expected to change significantly from current conditions, the design basis accounts for low-probability extreme events. This conservative approach is intended to ensure that the structure remains robust and safe throughout its intended life, even if the actual climate deviates from current projections. The combination of probabilistic extrapolation and climate allowances is expected to provide confidence that the facility can withstand both expected and unforeseen environmental changes over its operational time frame.

11.2.3 Operating Limits by Environmental Factors

The environmental factors limiting the FPSO will largely depend on the final design criteria established during the FEED phase.

Environmental factors may impose limitations on the following:

- Shuttle tanker loading;
- Ice management;
- Helicopter transport;
- Personnel transfer;
- Crane operation;
- Supply vessels;
- Subsea Inspection, Maintenance, and Repair (IMR) activities;
- FPSO evacuation; and
- Oil spill response.

11.2.4 Design Loads Methodology

The Project will be designed according to applicable federal and provincial authority regulations and requirements, international standards and codes, and when required, Equinor and/or the FPSO contractor requirements.

The effect of physical environmental loadings (wind, waves, current, sea ice, iceberg, snow, icing) on the FPSO will be analyzed using established recognized methods, and will be determined in accordance with the site's physical environmental criteria and governing design codes and standards.

The FPSO design will consider global ice actions affecting the overall integrity of the complete structure and its components, including the station keeping system as well as local ice actions for specific components or portions of the structure.

Iceberg impacts and sea ice loads will be calculated with a probabilistic procedure that accounts for the full range of environmental conditions influencing iceberg loading and offsets at the Project location.

11.3 Functional Criteria

The design parameters stated herein are based on the technical and economic evaluations carried out to date. As the Project design progresses, the flow rates and capacities will be further optimized. In addition, during the operational phase, an optimization/debottlenecking process will be in place to capture potential incremental capacity gain during the asset life.

Table 11.15 provides an overview of the current design basis [5] for the Project. Components of the design may change during FEED and detailed design phases.

Table 11.15 Overview of Current Design Basis

Concept Item	Details (subject to change during FEED and detailed design phases)
Estimated Recoverable Reserves	Approximately 429 MBO
Distance from Shore	Approximately 475 km (FPSO)
Water Depth	Bay du Nord - 1,168 m Cambriol - 621 m
Production Life	20 years
Drainage Strategy	Bay du Nord – Water-Alternating-Gas (WAG), template-based and riser base gas lift Cambriol – WI, riser base gas lift
Drilling and Well	Well count total – 16 (production, WI, WAG)[2] Standard well type concepts
Subsea Umbilicals, Risers, and Flowlines (SURF)	Number of templates: 3 x 6-slot Number of risers: 8 flexible risers, 2 dynamic umbilicals, 1 power cable, 4 spare slots in turret Flowlines: Production, WI, and Gas Injection (GI) Number of static umbilicals: 3 Subsea cooler: 1 Subsea Power Distribution Unit (SPDU): 1 Subsea Distribution Units (SDU): 2 Riser bases: 2
Main Facilities Concept	FPSO: Ship-shaped Accommodation: Up to 120 person capacity Turret: Disconnectable Offtake to shuttle tankers Oil capacity: 160 kbbl/sd design plateau production Target oil capacity (debottlenecked): 175 kbbl/sd[3] Gas handling capacity: 5.0 MSm^3/sd Liquid capacity: 40,000 Sm^3/sd[3] Water injection capacity: 40,000 Sm^3/sd[3]
Operations	Equinor is accountable for overall field operations, including SURF and Drilling & Well. FPSO contractor is responsible for FPSO operations and maintenance.

Well fluids information from the reservoir is described in Section 6.2.2 Fluid Properties and Fluid Models.

Table 11.16 summarizes the sales specification for oil.

As Project design progresses, the flow rates and capacities will be further optimized. In addition, during the operational phase, an optimization/debottlenecking process will be in place to capture potential incremental capacity gain during the asset life.

Table 11.16 Sales Specification for Oil

Parameter	Oil
C_4-	Max. C_4- content of 2.5 wt% in the stabilized crude, with an operational flexibility to increase this to 4.5 wt% within given Reid Vapour Pressure (RVP) limitations during the production phase
True Vapour Pressure (TVP) (bubble point pressure)	< 1.0 bara @ 40°C
RVP	RVP as defined and measured according to ASTM-D323 latest revision shall be less than 0.54 bara at 100° F (37.8°C) RVP requirement refers a storage temperature of maximum 40°C and an AP-42 TVP of 0.75 bara
Minimum oil storage/offloading temperature	20°C
Basic Sediments and Water (BS&W)	Max. 0.5 vol%, no stable emulsions
Salt	Max. 200 mg/l
Oxygenates (Monoethylene Glycol [MEG], Triethylene Glycol [TEG])	Max. 10 ppm wt

11.4 Geotechnical Criteria

11.4.1 Introduction

Various geotechnical site investigation programs have been conducted in the Project Area. A geotechnical site investigation was completed in summer 2025, and data collected will be used in the FEED and detailed design phases. A copy of the report will be provided to the C-NLOER, once available.

In general, the seafloor throughout the surveyed region is smooth, though punctuated on a small scale by numerous boulders, iceberg dropstone pits, pockmarks, fluid escape mounds, and fishing trawl marks. Seafloor in the Cambriol area is characterized by numerous, large intersecting iceberg scour marks. These scour marks are relics of the previous ice age and do not represent the iceberg design basis.

The soil deposits within the top few metres across the two templates areas (Bay du Nord North, Bay du Nord South) are comprised predominantly of extremely low strength to very low strength clay, with some silt and sand, and potential cobbles and boulders; though they are generally homogeneous.

Soils at the Cambriol template area exhibit a high degree of lateral variability. More than three quarters of the area to the northwest has been affected by iceberg scouring. High strength clay with some silts and sand is reported to be present at the near surface (i.e. ~1 m to 2 m).

Cambriol Area (shallower than ~640 m of water depth)

The soils at the shallower Cambriol areas consists of transition soils with high Cone Penetration Test (CPT) tip resistance and do not behave strictly as a sand or a clay.

Remaining Field (deeper than ~640 m of water depth)

The 2015 geotechnical site investigation, reported by the Norwegian Geotechnical Institute (NGI) [62], state that four soil units have been defined in the Flemish Pass and are described in Section 11.4.2 Soil Characteristics, and are outlined in Table 11.17.

Table 11.17 General Soil Description (except Cambriol)

Unit	Depth below seafloor (m)	Soil Description
I	0 - 3.0	CLAY, silty, extremely low to low strength, traces of fine to medium sand partings and few shell fragments, greenish grey. Sandy in upper 20 cm in some locations
II	3.0 - 30.0	CLAY, low to medium strength, low to medium plasticity, sand seams, few drop stones, gravel or larger and pockets of sand, greenish grey to dark grey
III	30.0 - 45.0	CLAY, medium to high strength, medium plasticity, traces of fine sub-angular to sub-rounded gravels and coarse shell fragments, dark grey, gas in solution
IV	45.0 - 61.2*	CLAY, medium to high strength, medium plasticity, drop stones, gravel or larger, possibly mass transport deposit, dark grey

* *End of borehole, not necessarily end of unit*

11.4.2 Soil Characteristics

The soil at the Project Area is characterized by extremely low to low strength clay, increasing in strength with depth.

Three geotechnical programs have been carried out in the Project Area:

- Reconnaissance program in 2015 [62];
- Location specific program in 2019 [63]; and
- Combined geophysical, geotechnical, and environmental seabed survey in 2021 [64].

Four geotechnical units have been identified (Table 11.18 and Table 11.19). Unit I is a late glacial to Holocene drape deposited in an environment with very slow deposition and is in general very soft. Unit II is layered and deposited after the latest major sliding event in the area. Unit III is very similar to Unit II but is likely to some degree affected by sliding. Unit IV contains mass transport deposits and is the most heterogeneous.

Geotechnical design will be based on the design parameters established from the 2019 geotechnical program [63]. Geophysical data from 2021 survey program should also be taken into consideration as per [64]. Site specific geotechnical site investigation program was carried out in summer 2025. Soil data from this 2025 program shall also be considered during the detailed design.

Table 11.18 General Stratigraphy - Bay du Nord

Unit	Depth Range (m)	Soil Description
I	0 – (3.29 to 3.35)	Extremely low to very low strength, silty, slightly sandy CLAY
II*	(3.29 to 3.35) - 31.80	Very low strength to high strength, silty, slightly sandy, slightly gravelly CLAY. Locally: - Laminae to medium beds of silt and sand - With traces of shell fragments - With occasional cobbles - With a thick bed of loose to medium dense sand between approximately 29.1 to 30.3 m

* *Soil Unit II may transition into Soil Unit III however such a transition was not apparent from the CPT data.*

Table 11.19 General Stratigraphy - Cambriol

Unit	Depth Range (m)	Soil Description
I*	0 - (1.34 to 2.63)	Extremely low strength to very low strength CLAY
II**	(1.34 to 2.63) - 31.94	Very low strength to high strength, silty, slightly sandy, slightly gravelly CLAY. Locally: - Laminae to medium beds of silt and sand - With traces of shell fragments - With occasional cobbles

* *Unit I applies to locations found in the South East of the Cambriol Site. Due to the high degree of variability across the Cambriol Site, Unit I has a higher content of sand and silt and may not be representative of locations in the North East.*

** *Soil Unit II may transition into Soil Unit III however such a transition was not apparent from the CPT data.*

11.4.3 Potential Geohazard Profile

The Project Area is located in a region of relative tectonic stability, as indicated by estimated return periods of 700 and 3000 years for Extreme Level Earthquake (ELE) and Abnormal Level Earthquake (ALE). A site-specific seismic hazard analysis has been carried out [65] and the calculated acceleration response spectra for both ELE and ALE earthquake are used in design.

In addition, a desktop level slope stability evaluation using limit equilibrium approaches and semi-empirical displacement estimation methodologies have been carried out as per [66]. A liquefaction study has also been performed as per [67].

Summary of main potential geohazard identified within the site are listed in Table 11.20.

Table 11.20 Summary of Main Potential Geohazard

Geohazard	Location / Distance	Potential Impact
Extremely low strength and very low strength material at seafloor	Present at all borehole locations, especially at Bay du Nord and FPSO area Extremely low strength clays at some borehole locations do include gravel or a sand layer	Sliding, uneven penetration of equipment/ structure at seafloor
High degree of variable soils at Cambriol	Present at Cambriol borehole locations Transition soil which does not behave strictly as a sand or a clay (i.e. partially drained/ undrained behaviour)	Heterogeneous and unpredictable soil conditions; uneven penetration of equipment/ structures; damage to equipment during installation
Seismicity	Site located in Seismic Zone 1	Cyclic / dynamic loading, loss of soil strength, potential liquefaction at Cambriol due to high level of sand materials
Boulders	Present at all sites, particularly Cambriol Seabed surface and sub-surface Seafloor boulder mapping is available (latest field layout is still pending due to the latest survey 2025)	Heterogeneous and unpredictable soil conditions; uneven penetration of equipment/ structures; damage to equipment during installation

11.4.4 Iceberg Scour

A combined seabed, environmental, and geotechnical survey completed in 2021 details the iceberg scouring identified within the Project Area. Iceberg scours and pits do not occur within the Bay du Nord Field due to the water depth in which it is located. The seafloor in the shallower Cambriol Field was heavily scoured [64]; however, these features are relics of the previous ice age and do not represent the iceberg design basis.

12 Production Installation

12.1 Floating Production, Storage, and Offloading Facility

The concepts described in the subsequent subsections are subject to change during the Front-End Engineering Design (FEED) and detailed design phases.

12.1.1 Hull and Oil Export

12.1.1.1 Overview

The Floating Production, Storage, and Offloading (FPSO) hull will be designed according to applicable federal and provincial authority regulations and requirements, international standards and codes, and when required, Equinor and/or the FPSO contractor requirements.

The hull will store stabilized oil, support the topsides production and utility system and turret, including future development opportunities as needed, and handle all environmental loads that may be experienced at the production site. The FPSO will offload stabilized oil to shuttle tankers via a Stern Discharge System (SDS).

The hull is designed for continuous operation at the production site without dry docking, subject to relevant regulatory approvals.

The FPSO has been designed as a passive weathervaning vessel with heading control. The FPSO is disconnectable and is therefore equipped with systems necessary to move off station under its own propulsion.

12.1.1.2 Structural Design Requirements

The hull structural design is performed in accordance to Class rules and will be approved by the Classification Society (CS) (see Section 11.1 Regulatory, Certification, and Classification Basis). With relevance to hull structural performance, the Class notation FMS(25) is applied (specifying an increased fatigue life capacity of 25 years). The structural design takes into account learnings from operations of similar installations located in areas with comparable physical and environmental conditions. Particular attention is given to structural details that are fatigue prone and structures exposed to ice.

12.1.1.3 Hull Structure and Condition Monitoring System

The hull will be arranged with permanent means of access for tank inspection, according to flag state rules.

The FPSO is built for in sea survey at the operations site according to the BIS class notation. Hull markings and hull openings are designed to allow remote inspection and remote intervention, including grabber bars for Remotely Operated Vehicle (ROV).

A sensorless hull monitoring system will be implemented for the FPSO, linked to a vessel-met ocean system and loading computer to predict hull stress levels and fatigue life within a structural digital twin. The hull monitoring system includes measurement of accelerations, loading computer interface and wind sensor.

A detailed risk-based inspection plan for monitoring hull and primary structural fatigue, coating, and corrosion conditions will be developed based on an initial detailed fatigue assessment.

The results of monitoring, periodic Ultrasonic Testing (UT), and drone-based inspections will further refine the structural inspection plans.

12.1.1.4 Design Considerations for Sea Ice and Icebergs

The FPSO design shall incorporate hull strengthening and a disconnect capability to facilitate safe operations given the sea ice and iceberg environment documented in Section 11.2 Physical and Environmental Conditions.

12.1.1.5 Marine Systems

The marine systems will be designed in accordance with the Class and flag state rules, including compliance to offshore regulations where applicable (see Section 11.1 Regulatory, Certification, and Classification Basis). The systems will secure safe and efficient operations of the FPSO, both at location and when disconnected.

Based on the current design, marine systems integrated within the hull will likely include the following:

- Cargo handling (from production/transfer/export);
- Cargo tank gauging and pressure monitoring;
- Cargo tank heating (final requirement to be determined during FEED);
- Crude oil washing system/tank cleaning;
- Inert gas and gas freeing;
- Propulsion (thrusters);
- Hull power distribution;
- Essential power;
- Hydraulic control system for remotely actuated valves;
- Diesel fuel;
- Fuel oil;
- Lube oil;
- Starting air and service air;
- Water and waste management;
- Fresh water and potable water;
- Sewage treatment;
- Ballast and bilge (including treatment);
- Cooling system for hull users;
- Safety systems (refer to Section 12.1.4 Safety Systems); and
- Navigational/conning systems.

The controls for the majority of marine systems will be located in the FPSO central control room.

The hull, turret, and topsides integration will be fully addressed with respect to Emergency Shutdown (ESD) philosophy and electrical isolation.

12.1.1.6 Accommodations Area

The accommodations area will be designed to satisfy the peak Personnel on Board (POB) requirements to facilitate daily operations, and for typical hook-up and commissioning, maintenance, and turnaround work scopes. However, if activities require higher, sustained peak POB levels, a temporary accommodations installation(s) may be considered.

Safety systems will be designed according to applicable regulatory requirements. The accommodations area will be arranged aft with a fire and blast rated front wall for the dimensioning accidental fire and blast loads. The current design has a POB capacity of 120 single bed cabins. Refer to Section 15.3 Staffing for additional information related to offshore staffing levels. The accommodations area will be arranged with a central staircase and elevator serving all accommodation decks.

Solid and food wastes will be handled according to applicable regulatory requirements.

12.1.1.7 Helicopter Facilities

The helicopter deck will be located such that a favorable combination of helideck response (e.g, motions, velocities, accelerations), turbulence, and visibility will be achieved. The helicopter traffic control centre will be arranged inside the navigational bridge on the same deck level.

In close proximity to the helicopter deck, a separate push-in parking area for unserviceable helicopters will be available.

The limiting sea state for the helicopter deck varies depending on the presence of swell, non-collinearity between wind, waves, and swell directions, as well as the peak periods of both swell and wind sea.

The Heading Control System may be utilized to improve landing conditions.

12.1.1.8 Water Supply and Discharge Facilities

Cross contamination between seawater intakes and water discharges will be minimized by ensuring sufficient separation in vertical and horizontal positioning. Sewage and grey water will be discharge overboard in accordance with applicable regulatory requirements.

Seawater used for process cooling and water injection purposes will be supplied by pumps through hull caissons going through the ballast tanks. The seawater used for process cooling will be returned to sea via a seawater discharge caisson. Separately, treated produced water will be discharged through its own dedicated caisson to prevent any mixing with the seawater stream.

There are several sources and functions of seawater supply to the FPSO, including:

- Firewater supply (see Section 12.1.4.4 Active Fire Protection);
- Cooling and water injection purposes; and
- Fresh water generation.

Fresh and potable water will be generated from seawater feed and distributed on the FPSO.

12.1.1.9 Materials Handling Equipment

The design for materials handling equipment is to eliminate personal injury and asset damage while delivering efficient work practices. The types of lifts that are expected to be performed will be identified and the associated risks highlighted. The arrangement is subject to change during FEED and detailed design phases.

The FPSO is planned to be equipped with two offshore pedestal cranes (one port and one starboard). The offshore cranes will be used for transfer of equipment and supplies from and to supply vessels, and both will be certified for personnel transfer.

A third, smaller crane will be located at the stern of the vessel, adjacent to the offloading hose reel, and will be used primarily for operation and maintenance activities associated with the reel.

A network of primary and secondary transport routes is anticipated to support the horizontal movement of equipment and supplies, potentially utilizing forklift trucks or tow trolleys for heavier loads, and pallet trolleys or other suitable equipment for lighter items.

Elevators are provided between the upper deck level and decks within the accommodation areas and from the A deck level (process deck) to the general store area located at the upper deck level.

Vertical transfer of materials from and to machinery spaces will be provided by installing a monorail at A deck level, which will be used to lift materials through a series of hatches provided at successive deck levels.

Handling materials, in the form of monorails, davits, lifting lugs etc. will be located throughout the FPSO to assist handling operations.

Loose lifting equipment will be registered and managed in compliance with governing Canadian requirements, and when not in use, will be stored in a manner that prevents exposure to weather and other conditions that could lead to degradation.

12.1.1.10 Crude Oil Storage and Export

The FPSO will be designed with approximately 18 cargo oil tanks, one tank for handling off-specification liquids, and two slop tanks. The total storage capacity will be approximately 1.2 MBO.

The current base case is that each cargo oil tank will be equipped with an individual deep well pump and all connections between cargo tanks are at main deck level, i.e., no bulkhead valves between cargo tanks.

The stabilized crude oil will be pumped through the cargo oil offloading header via a fiscal ultrasonic metering station and an SDS. From the SDS, stabilized crude oil will flow via an offloading hose to the Bow Loading System (BLS) of the shuttle tanker. Stabilized crude oil will be exported to shuttle tankers in a tandem configuration at a rate of approximately 8000 m^3/h and at a minimum temperature of 20°C. The stabilized crude oil will be fiscally measured in a compact ultrasonic oil metering unit (see Section 12.1.3.12 Fluid Measurement, Sampling, and Allocation). The offloading operation will have sea state limitations for connection of the shuttle tanker and transfer of stabilized crude oil. Automatic or manual release of the Hose End Valve (HEV) will prevent spillage of oil in case of a disconnect.

Post-transfer, the offloading hose will be displaced with nitrogen or warm water from the FPSO to the shuttle tanker. Equinor ASA requirements apply for physical and environmental conditions during the transfer of stabilized crude oil after connection and for the connection operation of shuttle tanker.

A hawser-less system will be implemented. In a hawser-less configuration, the shuttle tanker will not be connected to the FPSO via a slack bow hawser.

During normal operation, low-pressure fuel gas from topsides will be used as blanketing gas for the cargo oil tanks, which will be the primary means for tank atmosphere management during production and offloading operations. The hydrocarbon gas will be recovered by a vapour recovery unit at topsides (refer to Section 12.1.3.6 Fuel Gas and Flaring Systems for more details). In case there is no fuel gas available, a combustion-type Inert Gas (IG) system will produce IG by burning Marine Gas Oil (MGO) in a burner and will be supplied to the cargo tanks as blanketing gas.

12.1.2 Turret and Moorings System

12.1.2.1 Overview

The production installation will have a Submerged Turret Production (STP) system, which provides the following main functions:

- Position keeping and passive weathervaning;
- Transfer of fluid, power, and signals; and
- Disconnection/reconnection of buoy with its risers, umbilicals, and moorings.

12.1.2.2 Submerged Turret Production System

The STP system is divided into two main parts:

- STP Shipboard - comprising vessel structure and all components inside the STP compartment including swivel for fluid, power, and signals transfer system with pull-in arrangements; and
- STP Subsea - comprising the STP disconnectable buoy, mooring lines, and suction anchors.

There will be 15 slots in the turret. All production lines and umbilicals will be routed through the centre turret structure of the STP system. Fluid, utilities, and power/signals will be connected and distributed on the geostationary platform decks above the top of the STP disconnectable buoy. A turret local equipment room will house control and power system cabinets on an upper geostationary deck. The turret local equipment room will have a protected overpressure ventilation system and fire/blast ratings in accordance with the fire and explosion risk analysis. Figure 12.1 provides an overview of the STP system.

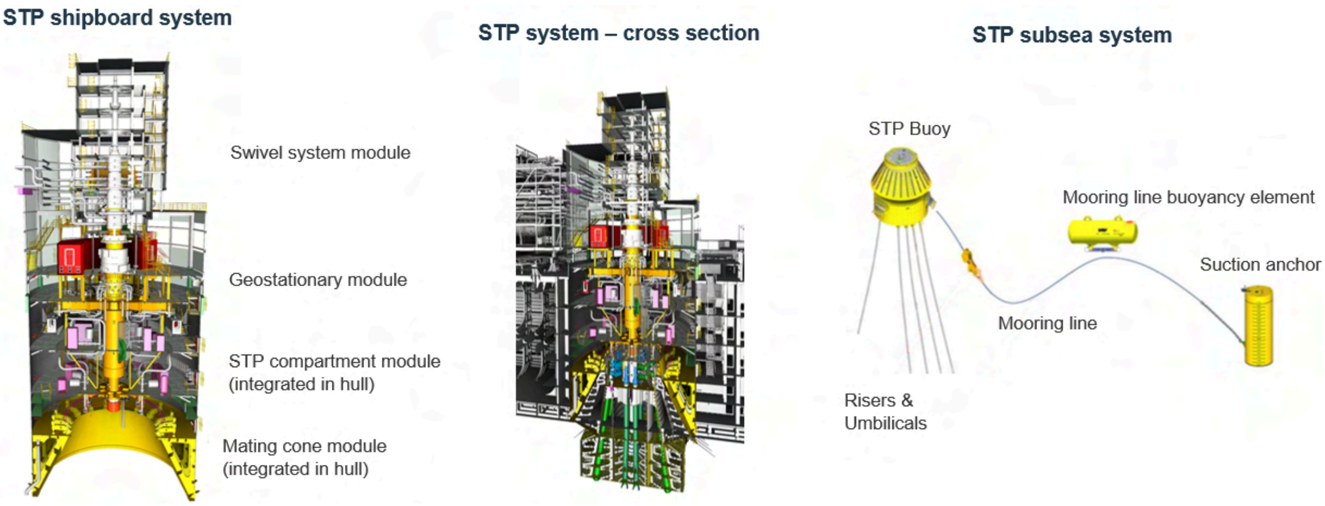


Figure 12.1 Submerged Turret Production System Overview

Mooring lines, risers, umbilicals, and power cables are connected to the STP disconnectable buoy. The STP disconnectable buoy will be locked to the FPSO by locking mechanisms which can be released simultaneously in case of disconnection, or individually during inspection testing.

12.1.2.3 Mooring System

The mooring system will provide position keeping within specified allowable offsets. The mooring system is designed according to Class rules.

The mooring system will comprise of 15 mooring lines configured in three clusters, where each cluster consists of five mooring lines. Each mooring line will consist of a lower chain segment towards the suction anchor, followed by a long polyester rope, a mooring line buoyancy element, and two polyester rope segments towards the STP buoy. These are divided by chain segments with a mooring line re-tensioner in between to adjust mooring line lengths. The mooring system will be equipped with a mooring line monitoring system.

12.1.2.4 Fluid, Power, and Signals Transfer System

The fluid transfer system provides transfer of fluids between risers/umbilicals and the topsides systems. This includes transfer of production fluids from wells, as well as injection water, injection gas and hydraulics and chemicals to subsea. Power and signals will be transferred via dedicated swivels and distributed in the turret local equipment room towards internal turret consumers and subsea. The fluid transfer system will consist of three main areas – the shipstationary piping, the swivel stack and the geostationary piping arrangement (including connectors). The geostationary piping arrangement will be connected to the top of the buoy and provide fluid transfer from the risers to the swivel section, and will include valve and pigging arrangements. The swivel stack will consist of several modules dedicated for each service.

12.1.2.5 Disconnection and Reconnection System

The disconnection system is designed to safely disconnect the FPSO from the STP disconnectable buoy. It supports both planned and emergency disconnection and can be operated fully automatically.

The disconnection and reconnection system consists of several sub-systems, including pull-in system, connectors and control system. The pull-in system will be used for the initial hookup of the STP buoy to the FPSO and for reconnecting the buoy following any future disconnection. The pull-in system will also be used for pulling in risers, umbilicals and power cables into the buoy. The pull-in system will consist of a pull-in winch including spooling device, guide sheaves for the pull-in rope and a dampener system to avoid snap loads in the pull-in rope.

Piping connectors will be provided for all piping connections on top of the isolation valves. Dedicated connectors will be provided for umbilicals and power cables. A spline connector will be provided for the connection between the installed buoy and the geostationary module. All connectors will be remotely operated.

12.1.3 Topsides Production and Utility Systems

12.1.3.1 Overview

The topsides production and utility systems consist of incoming production flowlines from the two subsea fields (Bay du Nord and Cambriol), routing the wellstream through turret swivels to topside located chokes and test and production manifolds, with further routing to the test separator or inlet separator. Oil, water, and gas will be separated with gas being reinjected in the Bay du Nord Field, as well as being used for flowline/riser gas lift. Produced water will be treated to specification and discharged to sea and/or potentially reinjected into the reservoirs, if technically and economically feasible (see Section 7.5.2 Water Management Strategy). Reservoir pressure is maintained by injecting de-aerated seawater.

A preliminary schematic of the oil and gas processing system is shown in Figure 12.2 and an overview of the current design basis [5] for the Project is provided in Table 11.15.

The topsides facilities will primarily be on a horizontal plane raised above the vessel cargo deck. The topsides will be configured in modules and pre-assembled units, the number and size of which will be determined. The pre-commissioning and functional testing of the modules/pre-assembled units will be maximized prior to installation on the FPSO.

The main topside facilities are currently planned to consist of the following:

- Production separation and crude oil treatment;
- Gas systems, including compression and dehydration;
- Fuel gas and flaring systems;
- Produced water treatment system;
- Water injection system for reservoir pressure support;
- Chemical injection system;
- Control systems for monitoring and operational automation;
- Power generation;
- Fluid measurement, sampling, and allocation systems; and
- Other supporting systems, including utilities and auxiliary infrastructure.

The crude oil will be stored in the FPSO tanks and offloaded to a tanker by a flexible hose. Refer to Section 12.1.1.10 Crude Oil Storage and Export for information related to crude oil storage and offloading.

It is expected that hydrogen sulphide (H_2S) will be formed in the reservoir as a function of seawater injection over time. The use of necessary chemicals to reduce the level of H_2S will be evaluated and included, if necessary.

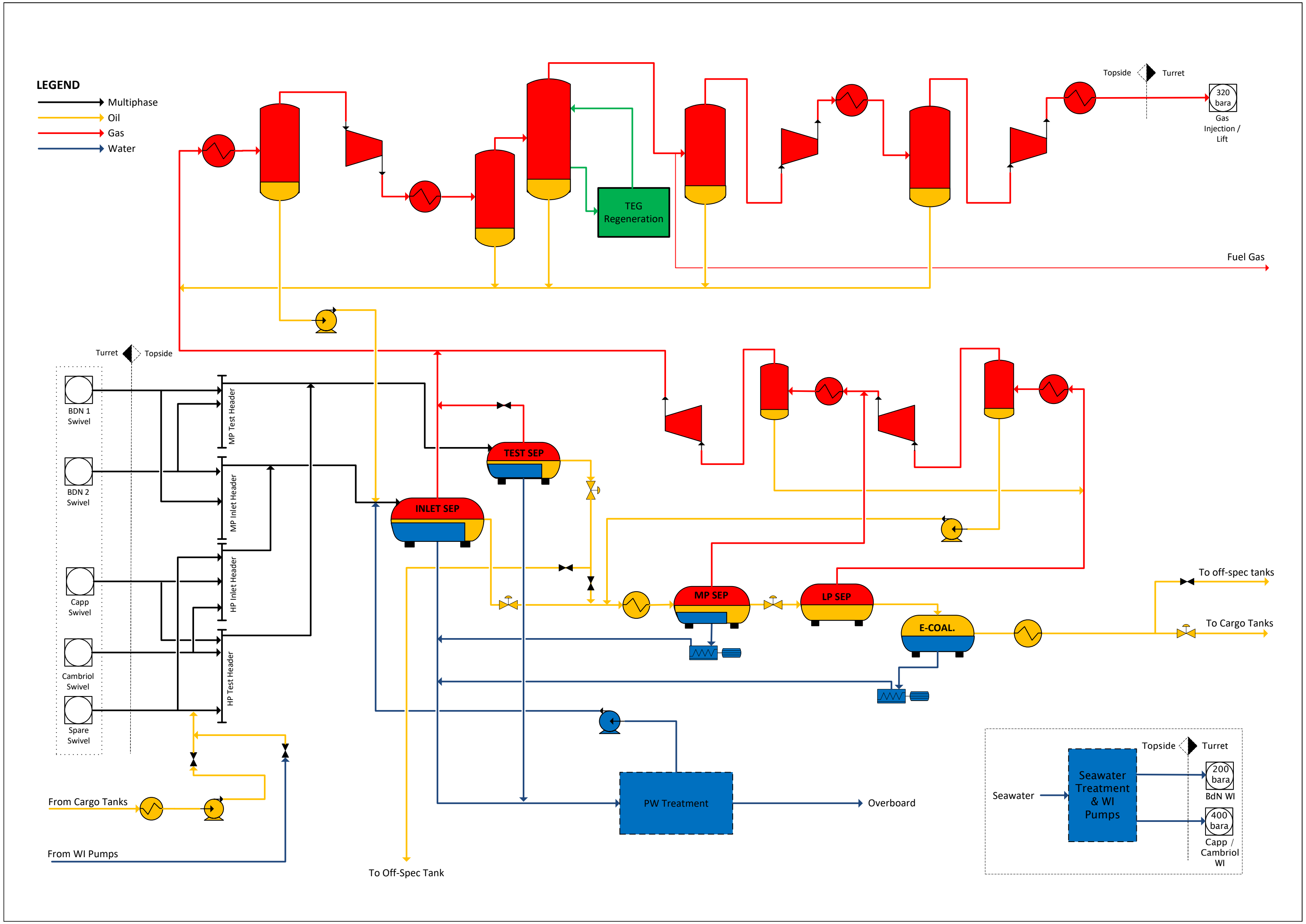


Figure 12.2 Preliminary Oil and Gas Processing System

12.1.3.2 Structural Design Requirements

Topside structures for the FPSO are designed to provide support for all equipment, process system and utilities. Topside structures consist of individual separate modules generally supported on four stools on the FPSO hull cargo deck. Elastomeric bearings are used to avoid transfer of global hull girder bending and stresses into the Topside modules.

Generally, the topside modules have three deck levels and are designed with sufficient strength, robustness and integrity to meet key design objectives and have sufficient stiffness and redundancy to limit their design deflection and any accidental deformation within required limits.

12.1.3.3 Production Separators and Crude Oil Treatment

The oil stabilization process will consist of three stages of separation, where the first stage inlet separator will operate at approximately 15 barg, the second stage will operate at approximately 4.5 barg and the last stage will operate at approximately 1.5 barg. The produced oil will be heated prior to the second stage of separation to achieve the required oil export specifications stated in Section 11.3 Functional Criteria. The Bay du Nord and Cambriol oils are expected to have good oil/water separation properties and relevant chemicals (e.g. emulsion breaker) will be used, as necessary, to enhance the oil/water separation properties. The final removal of water from oil will be done with an electrostatic coalescer before the oil is cooled and routed to storage. Any off-specification oil can be sent to dedicated cargo tanks.

In addition, a test separator will be installed to handle well clean-up fluids and for well testing. The test separator will be operated at the normal operating pressure with oil, gas, and water routed as per normal production. The test separator will be capable of handling flow from one flowline at a time and will include facilities for online sand jetting.

12.1.3.4 System Limitations

The topsides facilities will be designed to optimize system efficiency. A pre-FEED level Reliability, Availability, and Maintainability simulation (RAM Study) for the FPSO has been completed, which confirmed the selected equipment configuration should achieve a production reliability/uptime of over 94%. This RAM Study will be updated in FEED to assist selection of optimal design configurations and equipment redundancy with consideration for lifecycle cost analysis and evaluating production efficiency versus level of redundancy and sparing philosophy. Power generation will be installed as detailed in Section 12.1.3.11 Power Generation with redundancy to ensure required power is available.

12.1.3.5 Gas Systems

The associated gas from the inlet separator will be routed to the Medium Pressure (MP) compressor where the pressure is increased up to approximately 52 barg in a single stage. The gas from the MP and LP separators will be compressed in the Low Pressure (LP) compressor in two stages before it is combined with the associated gas from the inlet separator and handled by the MP compressor.

After leaving the MP compressor, the gas is dehydrated using a glycol/gas contactor, which ensures the gas is dry prior to reinjection. Following dehydration, gas enters the High Pressure (HP) compressor and is compressed further in two stages up to a pressure of approximately 325 barg. Finally, the gas is injected into the Bay du Nord field to maintain reservoir pressure, and also used for gas lift to both fields when required.

The preliminary design of the gas systems is shown in Figure 12.3.

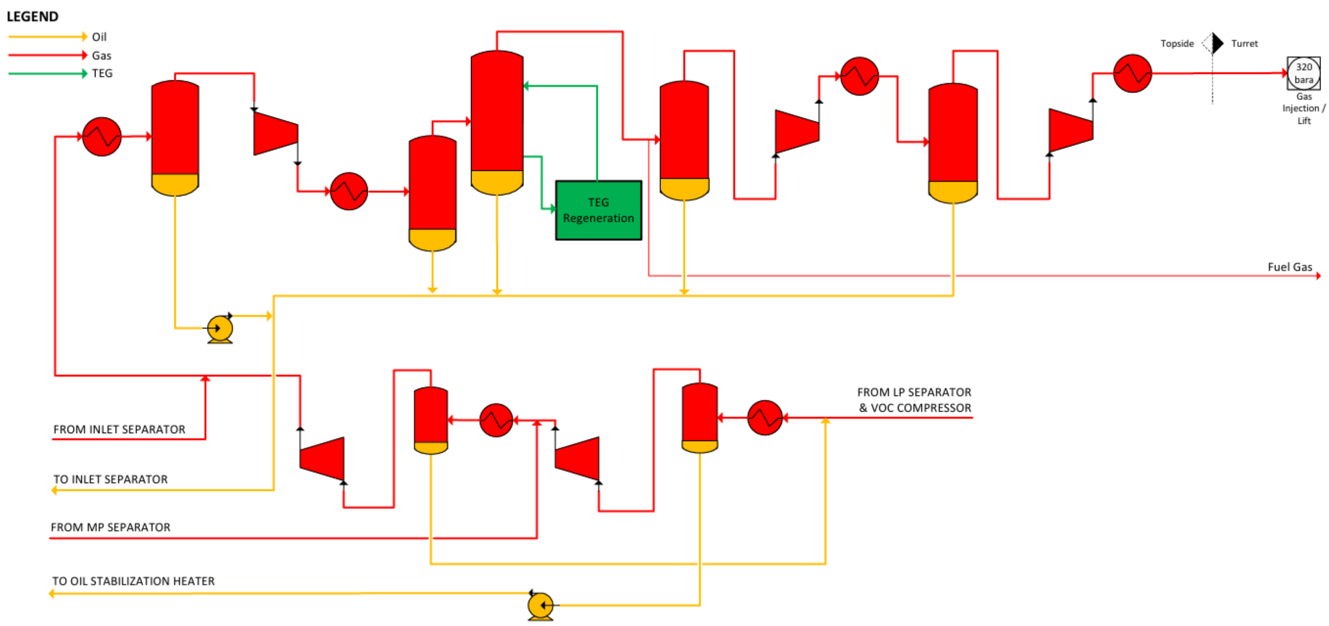


Figure 12.3 Preliminary Gas Systems

12.1.3.6 Fuel Gas and Flaring Systems

The fuel gas system provides treated gas for use as fuel by gas turbines for power generation and for other users. Fuel gas is routed from downstream the gas dehydration unit, scrubbed, and filtered to meet the turbine generator supplier specifications.

The flare and vent systems will collect and recover or safely dispose of hydrocarbon gases and liquids from the gas and oil-processing systems and produced water treatment. These gases are captured from process venting/ flaring, relief, and blow-down/de-pressurization.

The FPSO flare system consists of two sub-systems, which are independent of each other: a closed flare system and an atmospheric vent system.

The closed flare system is comprised of:

- Two flare knock-out drums (one HP and one LP);
- Flare gas metering;
- Two flare tips (one HP and one LP);
- Atmospheric vent header (from cargo system);
- Vapour recovery unit; and
- Two independent ignition systems.

It is divided into two sub-flare systems: a High Pressure (HP) flare system receiving flaring from HP sources and a Low Pressure (LP) flare system receiving flaring from LP sources. There will be no routine flaring from the production process. During start up, shutdown, well clean-up activities, and during upset process conditions, depressurization of process segments may be required for safety reasons, and gas will be sent to the flare.

In a relieving scenario, pressure in the flare drum will rise, and at a specified set point, the control valve will open to the flare tip. If the pressure continues to rise, the Fast Opening Valve (FOV) will open towards the flare tip. If the FOV fails, a parallel-installed mechanical device at a higher set point will open. The flare tip will be ignited by two different methods of ignition: a primary and a secondary system. Flare pilots are provided for flare ignition using fuel gas as a primary source, and will be lit on demand only.

The system will also include a Volatile Organic Compound (VOC) compressor package, which collects gas from the LP flare system, and increases the pressure to match that of the suction pressure of the LP compressor, where it is routed to for further processing. The VOC compressor package also recovers the low-pressure fuel gas used in the cargo oil tanks for blanketing (see Section 12.1.1.10 Crude Oil Storage and Export).

The preliminary design of the closed flare system and VOC compressor package is shown in Figure 12.4.

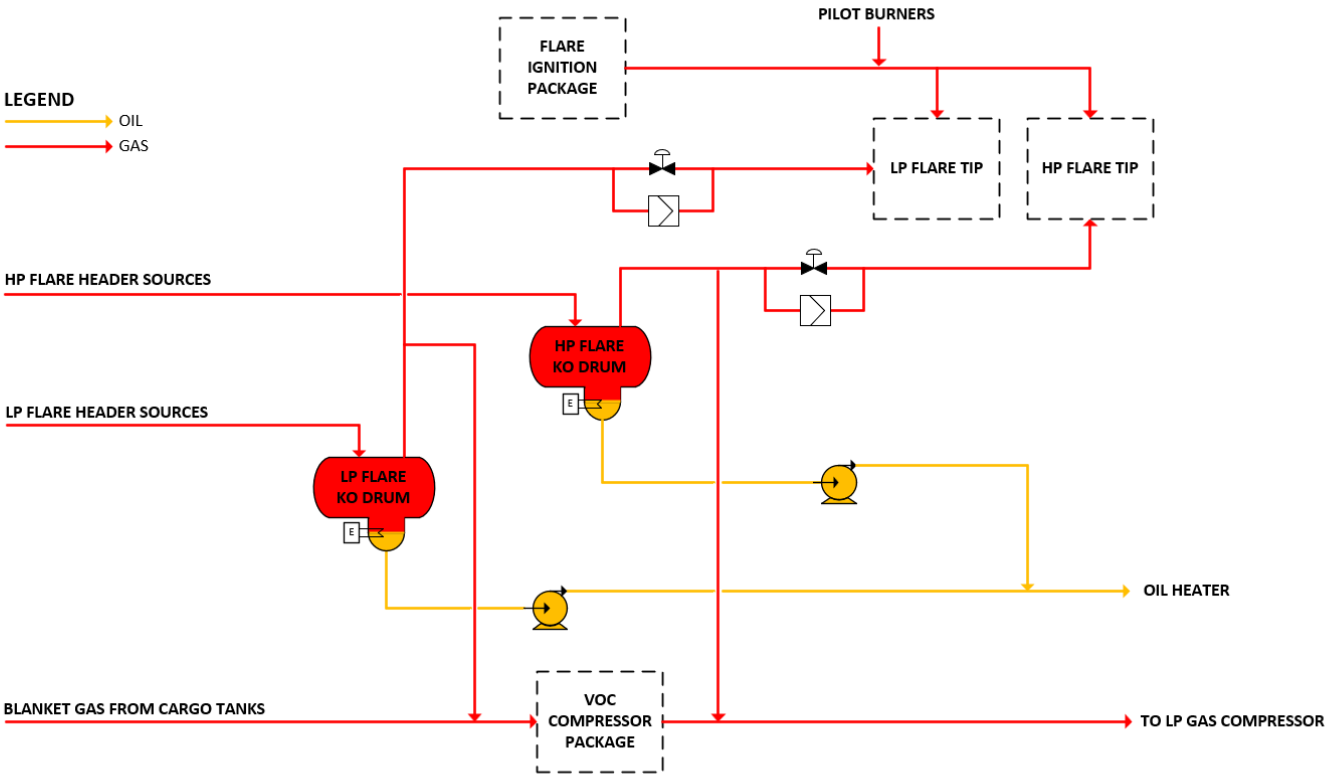


Figure 12.4 Preliminary Flaring System

The atmospheric vent system is comprised of an atmospheric vent header and a maintenance header, which are routed to a safe location and dispersed partway up the flare tower.

12.1.3.7 Produced Water Treatment System

A multi-stage water treatment process will be selected for produced water.

The current design routes produced water from the inlet separator, test separator, second stage separator, and electrostatic coalescer to a centralized produced water collection vessel. Oil separated in the vessel and flashed gas are returned to the production system. From the collection vessel, produced water is routed to hydrocyclones, which remove oil from water, and reject oil is returned to the production system via the collection vessel. The produced water is further treated using fuel gas to facilitate flotation in Compact Flotation Units (CFUs) and is then cooled prior to the treated water being discharged to sea. When produced water is discharged to sea, it will be released from below the bottom of the hull. Recovering flash gas via the VOC compressor from the discharge caisson is under evaluation. Off-specification water can be routed to designated cargo tanks for further handling/reprocessing. The preliminary design of the produced water treatment system is shown in Figure 12.5. The use of a multi-stage water treatment process will meet discharge limits. See Section 7.5.2 Water Management Strategy and the *Produced Water Management Strategy* [57] for additional information.

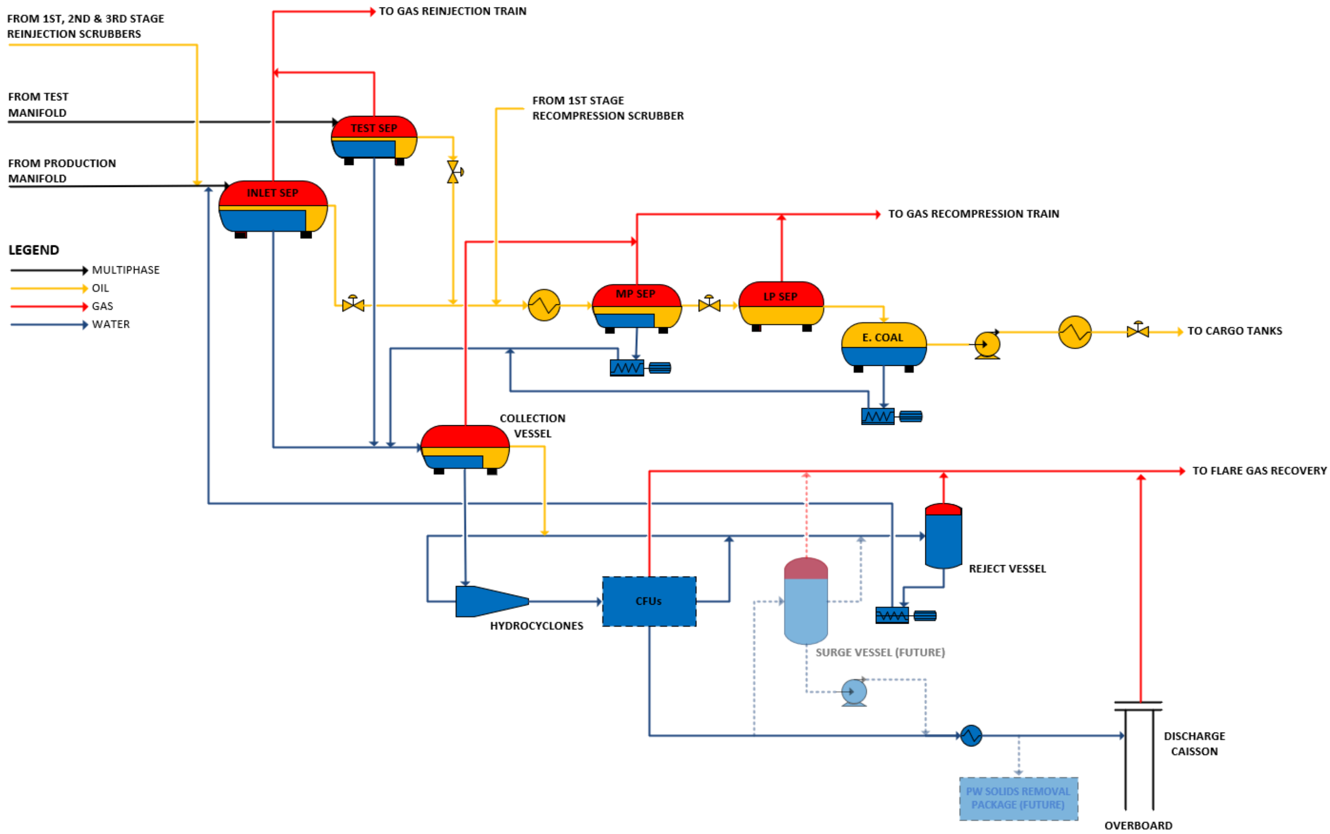


Figure 12.5 Preliminary Produced Water Treatment System

12.1.3.8 Water Injection System

The water injection system will inject de-aerated seawater to all fields to maintain reservoir pressure. The seawater used for injection will be pre-heated using waste heat from the warm cooling medium leaving the process coolers (mainly in the gas train) before being routed to the de-aerator tower, booster, and injection pumps. The de-aerator tower will operate at under-pressure conditions to enhance oxygen removal prior to injection, and oxygen scavenger will also be injected. The Cambriol field requires a higher water injection pressure than the Bay du Nord Field, hence separate injection pumps will be used for Cambriol. Heating the water prior to injection mitigates the risk of hydrate formation during WAG switchover operations.

12.1.3.9 Chemical Injection System

Chemicals will be stored on the FPSO and will be used on the topsides and subsea.

Chemicals that may be used subsea include, but are not limited to, scale inhibitor, asphaltene inhibitor, wax inhibitor, emulsion breaker and Monoethylene Glycol (MEG) (hydrate inhibitor).

Chemicals that may be used on topsides include, but are not limited to, anti-foam, emulsion breaker, scale inhibitor, biocide, clarifier/de-oiler, oxygen scavenger, H_2S scavenger, corrosion inhibitor, MEG, Triethlyene Glycol (TEG), pH regulator, hydraulic oil, and lube oil.

Chemicals that may be discharged overboard will be screened in accordance with Equinor's chemical screening and management processes, which is in accordance with the *Offshore Chemical Selection Guideline* [68].

12.1.3.10 Control Systems

The Integrated Control and Safety System (ICSS) comprises several subsystems. The process control system, which controls and monitors the production process, mechanical and electrical equipment, and utility systems within the production facility. This includes a basic process control system, which ensures safe, reliable, and efficient control and monitoring of the production process, process utility systems, and equipment. Additionally, the power distribution control system will control and monitors the electric power distribution network. The ICSS also includes a safety instrumented system, which is described in Section 12.1.4.2 Control and Shutdown Systems.

The FPSO will have one control room from where systems and equipment under control by the operators are supervised. When in disconnected mode, the status on the ICSS will be available from the bridge.

12.1.3.11 Power Generation

The current design for the main power generation system is comprised of three Gas Turbine Generators (GTGs), with Waste Heat Recovery Units (WHRUs) to supply heat to the heating medium system by extracting heat from the exhaust, located on the topsides. All three GTGs will have dual fuel capability, allowing operation on either natural gas or diesel. A schematic of the preliminary GTG and WHRU system is shown in Figure 12.6.

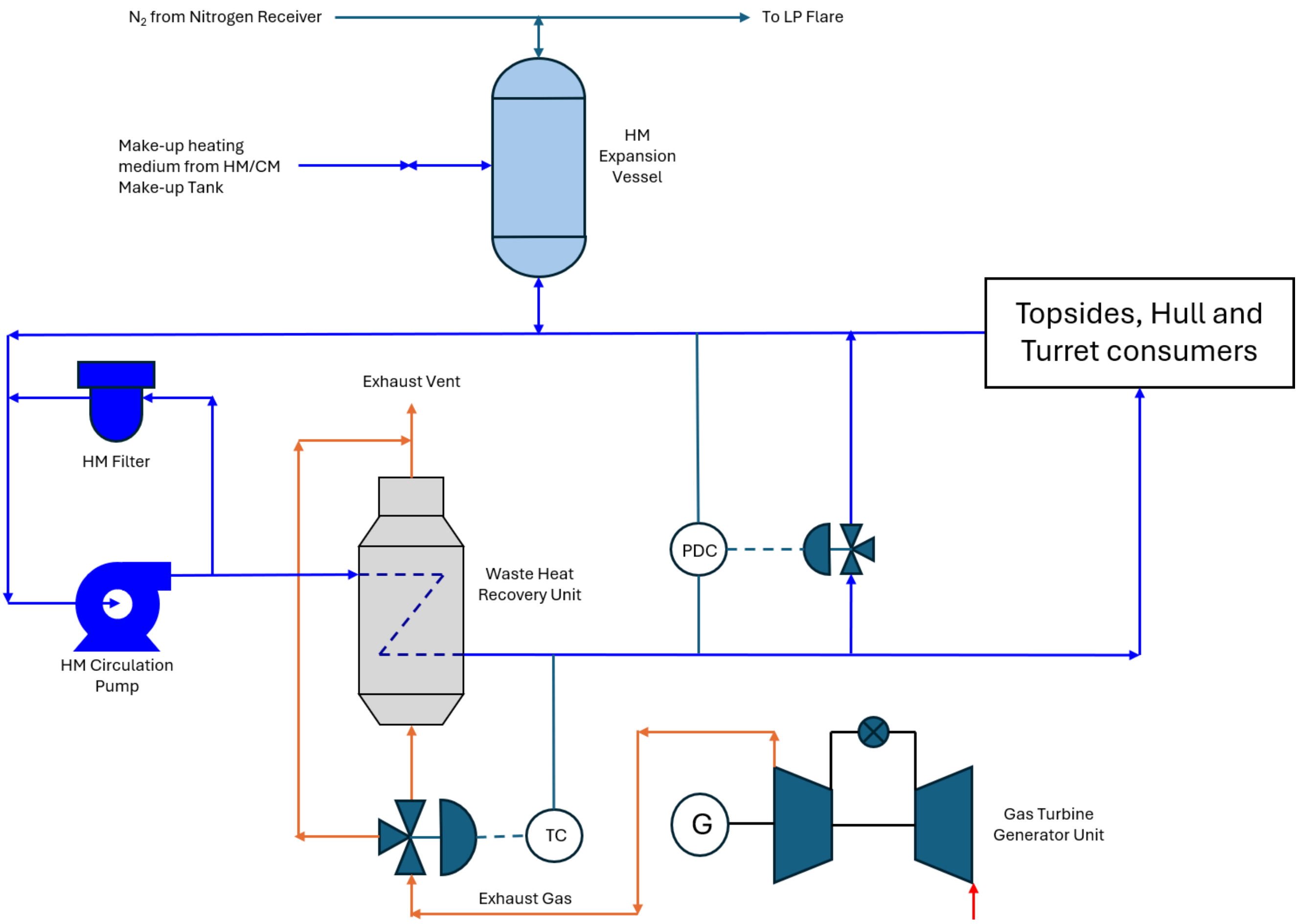


Figure 12.6 Preliminary GTG and WHRU System

In addition, the FPSO is planned to be equipped with two essential generators (reciprocating diesel engines), each capable of supplying approximately 8-9 MW of power, and one 2-2.5 MW reciprocating diesel engine as the emergency generator. The essential and emergency generators are located in the hull.

12.1.3.12 Fluid Measurement, Sampling, and Allocation

In consideration of the *Measurement Guideline* [58], separate Metering Philosophies for subsea [69] and the FPSO [70] will be issued to the C-NLOER.

Oil export, oil to storage, fuel gas, flare gas, gas to injection and gas lift, produced water, water to injection, produced water discharged to sea, test separator gas, test separator oil, and test separator water will be measured in consideration of the *Measurement Guidelines*. There is no gas export from the field.

The oil export metering system will have a planned capacity of 8000 m³/h. The system is currently planned with a single duty meter plus a single master meter configuration. The master meter will also be back-up for the duty meter in case of failure. Pressure and temperature instruments are duplicated in each of the metering runs. The master meter will be calibrated in an onshore facility at required intervals.

The design is based on the premise that the fields will be unitized. Therefore, there will not be any allocation of production between fields with different ownerships.

The following subsea measurements will be performed:

- Multiphase metering of production from each well;
- Single phase metering for individual gas lift points;
- Single phase metering for individual combined gas or water injection points; and
- Single phase metering for individual water injection points.

Each flow line for production to the FPSO can be routed to the test separator. Among other purposes, the test separator meters (oil, gas, and water) will be used for calibration of subsea multiphase meters.

There will be a subsea metering control system that takes care of Pressure-Volume-Temperature (PVT) calculations to provide input of fluid characteristics to the subsea multiphase meters and convert flow rates to standard conditions.

Allocation of production and injection to individual wells will include the use of proration factors. The proration factors will be determined by the summation of actual measured fluid streams topside divided by the sum of individual production and injection volumes measured subsea.

12.1.3.13 Other Systems

Other systems are currently anticipated to include:

- Open drain - The open drain system will collect rainwater, wash-down water, and liquid spills from deck areas, drip trays and bunded areas, routing them away to prevent the spread of flammable liquids, maintain segregation of fire areas, and separate oil from water before treated water will be discharged overboard. The higher flow rate firewater will be directed overboard without treatment.
- Closed drain - The closed drain system will collect hydrocarbon liquids from equipment and piping for safe degassing and recovery. The liquids will be drained by gravity to tanks in the hull.
- Heating medium – A heating medium system provides heating duty to the process and utility heaters (including Heating, Ventilation, and Air Conditioning [HVAC]) on the topsides, Turret and Moorings System (TMS), and hull.
- Process cooling – Cooling will be provided by direct seawater cooling and glycol/water cooling medium.
- Diesel – A diesel fuel storage system (primarily in the hull) will supply fuel for main, essential, emergency, and propulsion power generation and firewater pump drivers.
- Hydraulic power – A hydraulic storage, pumping, and distribution system provides high pressure hydraulic fluid.
- Compressed air – A compressed air system (primarily in the hull) provides utility air, instrument air and air source for nitrogen generation.
- Nitrogen – The nitrogen system will supply inert gas purging of flare and atmospheric vent headers, purging/ blanketing of vessels and atmospheric storage tanks and to utility stations.
- Aviation fuel – A storage and pumping system will provide refuelling capability for helicopters.
- Solid and food wastes – Addressed in Section 12.1.1.6 Accommodations Area.

12.1.4 Safety Systems

The FPSO will include safety systems to support Equinor's ambition of *zero harm* to people, environment, and assets. These safety systems will be developed in accordance with the applicable requirements of the legislation, international standards and codes, and Class and will take into account the results of risk analysis and safety studies.

The systems described in this section are considered safeguards and risk reducing measures and described in the Concept Safety Analysis. Refer to Section 16.2 Concept Safety Analysis and Target Levels of Safety.

12.1.4.1 Communication Systems

Public Address and General Alarm (PAGA), alarm and communication systems for use in emergency events will:

- Alert, inform, and guide personnel as quickly as possible in the event of a hazardous or emergency event;
- Provide two-way communication of information regarding emergency events to the Central Control Room (CCR) or Emergency Control Centre (ECC);
- Provide communication of requirements for emergency action to all personnel, and provide two-way communication between the On-Site Supervisor and the Emergency Response Team (ERT); and
- Allow the coordination of rescue, recovery, and emergency assistance.

Necessary equipment for internal emergency communication will be provided to enable effective coordination and communication among the ERT, and with the CCR and ECC.

External emergency communication will have necessary equipment for communication with emergency response resources such as helicopters, lifeboats, life rafts, other vessels, and shore. Telecommunication systems required to remain active in an emergency event will be in accordance with requirements related to ignition source control.

12.1.4.2 Control and Shutdown Systems

There will be an ICSS from which safety instrumented, control and monitoring functions will reside or be interfaced. The alarm system design of the ICSS will be based on the Equinor ASA Management System (EMS) requirements.

The ESD system will prevent escalation of abnormal conditions into a major accidental event and will limit the extent and duration of any such events that do occur.

The ESD system will be able to perform the intended functions independently of other systems and is in addition to system and equipment for process control. The ESD system will:

- Shut down wells and risers;
- Shut down process systems and equipment;
- Close process sectionalization valves and isolate hydrocarbon inventories;
- Shut down main power generation;
- Initiate blowdown;
- Isolate electrical ignition sources;
- Start/stop emergency generator and, for some events, essential generators; and
- Initiate PAGA, alarm, and emergency communications.

The ESD system will be provided with manual activation stations located along the escape routes and at strategic locations around the FPSO. The ESD system including sensors, logic solvers, and final elements will be designed to fail to the safe position.

The ESD functions will be arranged in a tree-structured level hierarchy, common for the whole FPSO, with several levels, such as Abandon Platform Shutdown (APS), ESD and Process Shutdown (PSD). The higher ESD levels in the hierarchy will initiate lower levels including PSD.

ESD valves will isolate and sectionalize process segments in a fast and reliable manner according to dimensioning fire and explosion scenarios.

The ESD system status will continuously be available in the CR and the system will raise alarms in the CR for operator awareness or actions.

The ESD system will be designed to comply with the applicable regulatory requirements, codes, and standards, and to, as far as reasonably practicable, remain operational in an emergency. It will also be designed so that it can be initiated both manually and automatically.

12.1.4.3 Fire and Gas Detection System

A fixed fire and gas detection system will be provided to continuously monitor for the presence of fire, flammable, or toxic gas. The system will alert personnel and enable manual or automatic control actions to minimize the probability of an explosion, fire escalation and the probability of personnel exposure.

Fire detection will be provided in all areas where fires may occur or where ingress of smoke is to be prevented.

The gas detection function will quickly and reliably identify flammable and toxic leaks before they reach dangerous concentrations that could threaten personnel and the installation.

The type and need for fire and gas detectors, along with the voting philosophy, will be determined for different FPSO areas based on a fire and explosion risk assessment. As H_2S levels are expected to rise in the production stream, detection requirements will be evaluated and incorporated into the design to mitigate risks to personnel.

Equipment activated by the fire and gas detection system during confirmed incidents will be designed to withstand Dimensioning Accidental Loads (DALs) until it fulfils its intended function.

Manual Call Points (MCPs) will be strategically placed throughout the FPSO to allow personnel to initiate a manual alarm for fires or other emergencies requiring CCR attention. MCP activation will be displayed in the CCR and trigger an alarm via the PAGA system.

Ballast tank gas detection will be installed in accordance with Class requirements and will be tied into the control and shutdown system.

12.1.4.4 Active Fire Protection

Active fire protection systems will provide a quick and reliable means for firefighting to prevent fire spread and limit damage to structures and equipment through cooling.

Active fire protection systems will fulfil the applicable requirements in the regulations, standards, and Class rules.

The active fire protection systems will be designed to:

- Control the spread of fire to adjacent areas/equipment through thermal radiation and contain larger fires until fuel is exhausted;
- Reduce fire burning rates, flame temperatures, rate of smoke, and toxic gas development;
- Provide cooling to protect structural surfaces and equipment;
- Control and extinguish pool fires and storage tank fires;
- Control and extinguish non-hydrocarbon fires;
- Protect personnel and equipment against fire exposure; and
- Reduce explosion pressure where applicable (e.g., for areas with automatic release of firewater upon gas detection).

The following active fire protection systems are being considered for the different parts of the FPSO:

- Deluge system: supplied by the firewater ring main and covering the process area (including pipe rack), turret and hull cargo deck. For the process area, the coverage is ensured by area coverage and dedicated equipment coverage when required. Areas where pool fire may occur are covered by low expansion foam distributed with the deluge system.
- Firewater monitors with low expansion foam: supplied by the firewater ring main and covering the offloading area and potentially some open parts of the hull cargo deck.
- Hose reels: supplied by the firewater ring main and covering indoor areas (e.g., accommodations area, utility areas in hull aft and forward).
- Hydrants: supplied by the firewater ring main and covering machinery spaces and outdoor areas.
- Deck Integrated Firefighting System (DIFFS) with foam supply and dual agent hose reels: supplied by the firewater ring main and covering the helideck.
- The accommodation area will be covered by a fixed fire suppression system or by portable firefighting equipment as required by the fire risk assessment.
- Total flooding system with high expansion foam is provided in the category A main machinery space aft.
- Local water mist will be used to protect high fire risk equipment in machinery spaces.
- Turbine enclosure has total compartment coverage by water mist.

- Gaseous clean agent systems may be used to cover the switchboard rooms, electrical equipment rooms, emergency generator room, paint store and chemical stores. Carbon dioxide (CO_2), halocarbons, or other noxious and poisonous gases will not be used for fixed fire suppression.

Firewater is supplied from individual and redundant pumps to a common firewater system for the FPSO. The pumps are individually driven by dedicated power source. The locations of the firewater pumps are segregated from the process plant and hydrocarbon storage areas. Pump suction is arranged as far as practicable below mean sea level, close to hull bottom.

The firewater ring main is located on the hull cargo deck level. The ring main will distribute water to the users including deluge, monitors, hydrants, and hose reels in accordance with regulatory and Class requirements.

Firefighting foam will be provided for the firefighting systems protecting areas where there is a risk for hydrocarbon liquid pool fire to occur. The type of firefighting foam to be used will be aligned with regulatory requirements.

Manual firefighting equipment (e.g., hose reels, hydrants, manual monitors, extinguishers, etc.) will mainly be used by personnel to aid escape from an area and for tasks performed by the emergency response team.

Fixed active fire protection systems (e.g. deluge/foam, water mist, gaseous agents, DIFFS) will be provided with manual releasing stations. The manual releasing push buttons will be located along the egress routes outside of the protected space.

12.1.4.5 Fire and Blast Protection

The hull will have fire divisions and protection in accordance with applicable requirements of the International Convention for the Safety of Life at Sea (SOLAS) and Class Rules, and also the *Canada–Newfoundland and Labrador Offshore Area Petroleum Operations Framework Regulations (Framework Regulations)*.

Fire and blast bulkheads will be provided to protect the Temporary Safe Refuge (TSR), main control rooms, control stations and machinery spaces facing production plant and cargo area against the risk of hydrocarbon fires.

The deck between the hull cargo area and topsides modules is a fully plated steel deck. The walls and decks of the protected escape routes along the process deck and the main bearing structures will be designed in accordance with the DAL specification.

Refer to Section 12.1.2.2 Submerged Turret Production System and Section 12.1.1.6 Accommodations Area for fire and blast protection information associated with the turret local equipment room and the accommodations area, respectively.

12.1.4.6 Escape and Temporary Safe Refuge

A network of longitudinal, transverse, and vertical escape routes will be established on the facility to enable personnel from any area to safely reach the TSR. There will be sheltered escape routes along the process deck peripheries on port and starboard side, providing a protected means of egress from the forepeak rooms, turret, and topside modules to the TSR.

Protected stair towers will connect perimeter walkways with other deck levels, and stairs will link the process and utility decks to the cargo deck on the port and starboard sides.

The TSR, located within the accommodations, will offer protection from explosions, fire, smoke, gas releases, and other hazards until evacuation is deemed necessary. The TSR will provide protection and life support to POB for the time required to ensure control of an incident and/or controlled evacuation of the FPSO. The TSR will have a minimum endurance period required to achieve a successful evacuation including sufficient ventilation powered by the emergency generator for the accommodated personnel in the applicable area.

The primary muster area is located in the TSR and will be arranged and protected to ensure the safety of personnel during the time required to prepare for the evacuation. It will be outfitted with storage for personnel survival equipment, such as immersion suits and life jackets, and with necessary emergency communications facilities.

An alternate muster area is located near the free-fall lifeboats (see Section 12.1.4.7 Life-Saving Appliances). This muster area will have facilities and protection reflecting the defined accident scenarios.

A forward muster area will be situated in the vessel forecastle area, allowing personnel trapped in the forward section due to incidents in the process, turret, or cargo areas to muster, don immersion suits, communicate with the CCR, and evacuate safely using escape chutes and life rafts on both sides.

An Escape, Evacuation, and Rescue Analysis (EERA) will be conducted to review escape routes, mustering facilities, and evacuation facilities to ensure that there are no incidents that could lead to entrapment of personnel, and to ensure that the FPSO is designed to keep the risks to personnel As Low As Reasonably Practicable (ALARP) in the event of a Major Accidental Event (MAE).

12.1.4.7 Life-Saving Appliances

The hierarchy of means of evacuation will be as follows:

- Preferred evacuation system/pre-cautionary down-staffing (e.g. helicopter or gangway to standby vessel);
- Alternative evacuation system (e.g., Totally Enclosed Motor Propelled Survival Craft [TEMPSC] - enables quick and controlled evacuation, independent of external assistance when circumstances render the primary method of evacuation unavailable); and
- Escape to sea (e.g., escape chutes with life rafts) - intended to be used only in circumstances where evacuation by other methods is not possible, and may rely considerably on the individual's own actions.

Lifeboats meeting the requirements of the offshore and maritime regulations will be located near the accommodations area, in multiple locations. The current concept includes free-fall lifeboats for maximum launch success plus davit-launched lifeboats in the event that there is sea ice. It is planned to have a combination of two free-fall lifeboats located at the stern and two davit-launched lifeboats, one on each side of the FPSO. The reason for this hybrid approach is to enable the use of lifeboats with the highest launch success probability when possible, but to also cater for the infrequent periods when sea ice may be present.

There will be one escape chute in the aft of the FPSO, on each side, with a life raft capacity of minimum 100% POB each. In addition, there will be escape chute in the forward part of the FPSO, one on each side.

The arrangement, capacity, and selection of evacuation equipment will be confirmed in the EERA, taking into consideration the MAEs.

Other life saving appliances will be installed in accordance with the regulatory and Class requirements.

12.2 Subsea Production System

The concepts described in the subsequent subsections are subject to change during the FEED and detailed design phases.

12.2.1 Overview

The Subsea Production System (SPS) covers the range of subsea structures/components required (from seabed level to FPSO connection point) to extract oil and gas from the reservoir to the FPSO. In addition, the SPS allows for the injection of gas, water, and chemicals. It also provides power to the infrastructure through various risers, flowlines, and umbilicals. The SPS will be designed in accordance with applicable requirements in the *Framework Regulations*.

The SPS comprises of the following:

- Two 6-slot template structures for the Bay du Nord Field;
- One 6-slot template structure for the Cambriol Field;
- Umbilical system with Subsea Distribution Unit (SDU) for the Bay du Nord Field;
- Umbilical system with SDU for the Cambriol Field;
- Passive subsea cooler for production fluid at the Cambriol Field;
- Power cable for Electrically Heat-Traced Flowline (EHTF) production flowlines for the Cambriol Field; and
- Flowline and riser system for production, gas injection, gas lift, water injection, and riser/template-based gas lift.

The Project fields are connected to the FPSO through rigid and flexible flowlines, and a flexible riser system, with diverless tie-ins to riser bases and manifolds installed in the templates. The proposed Project SPS layout is as illustrated in Figure 12.7.

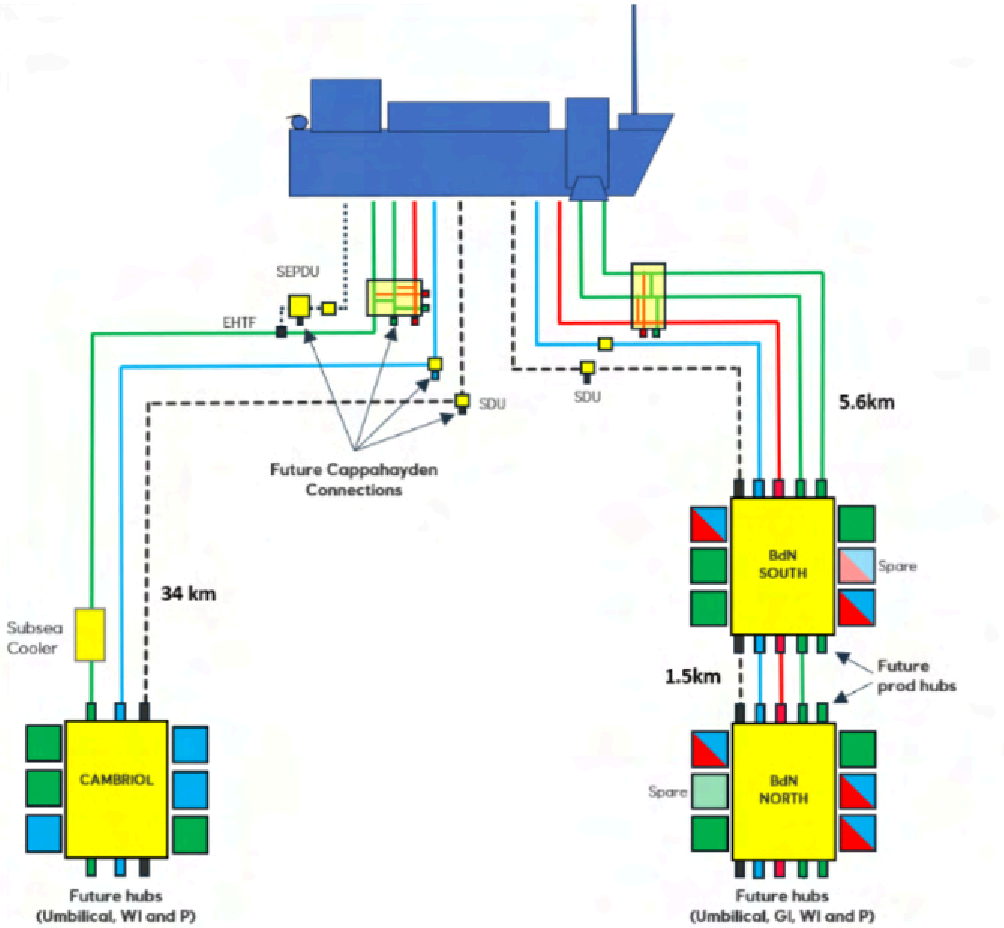


Figure 12.7 Proposed Subsea Production System Layout

The SPS will be designed to minimize the need for adhoc maintenance and repair. Thus, fault tolerance, robustness and regularity analysis will support the design with regards to redundancy. The SPS design allows for suitable Inspection, Maintenance and Repair (IMR).

The SPS design allows for simultaneous drilling and production with respect to barrier philosophy. Interface between template and the wellhead will take into consideration the expected drilling loads.

The SPS structures are designed with consideration of the anticipated installation loads as well as for the in-place operation and upset conditions.

The SPS will be installed with valves that can be remotely operated from the FPSO, this will allow for well testing of individual wells back to the FPSO while still maintaining production.

Critical components of the subsea production system are designed to be retrievable and can be recovered to surface for repair and re-installation. Typical retrievable components are: manifold, Christmas Tree (XT), choke module, flow control module, subsea control module, electrical valve actuators, and subsea cooler modules.

Iceberg scour does not occur within the Project Area. Refer to Section 11.4.4 Iceberg Scour for additional details.

12.2.2 Template and Manifold System

The proposed concept for the Bay du Nord and Cambriol fields is an Integrated Template Structure (ITS) with suction cans (or driven piles if required by soil conditions).

Key features of the ITS include:

- 6-slot configuration;
- Soft hinge well bay inserts;
- Guidewire-less module installation;
- Trawl and dropped object protection;
- Compatible with Wire Wellhead Load Relief (WLR) system; and
- Drill cuttings and cement disposal system.

Key functions of the manifold system include:

- Supports production, gas injection, and water injection;
- Dual barrier valves at each well slot;
- Remote-operated valves for flexible flow and future tie-ins;
- Multi-bore clamp connections to Vertical Christmas Trees (VXT);
- Distribution of chemicals and hydraulics via dedicated lines;
- Electrical and fiber optic jumpers for power and communication;
- High-pressure caps for spare slot protection;
- Enables pigging operations from subsea to topsides; and
- Subsea leak detection system.

The template and manifold structures are presented in Figure 12.8 and Figure 12.9.

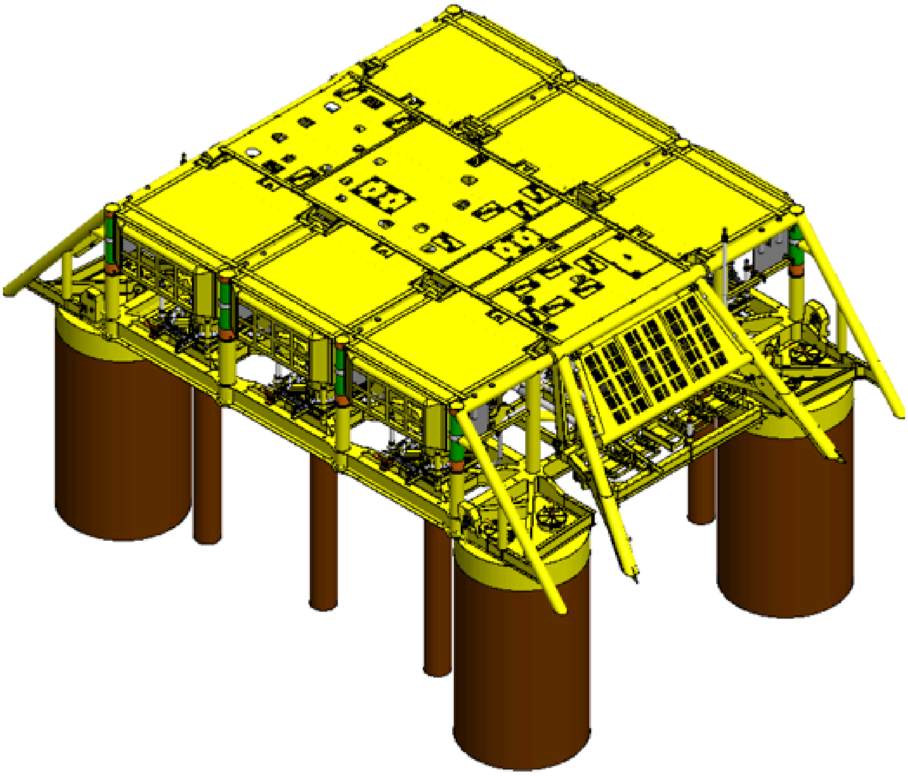


Figure 12.8 Template Structure Representation

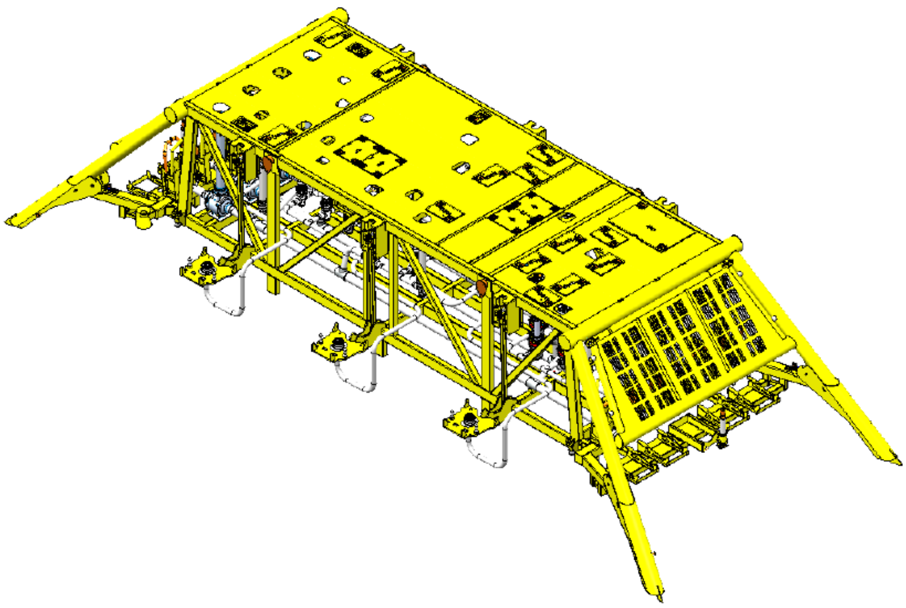


Figure 12.9 Manifold Structure Representation

12.2.3 Wellhead System

The subsea wellhead system will be a standard 15,000 psi (1,035 bar) working pressure wellhead system based on standard configuration utilized in Equinor.

The wellhead system will be designed to accommodate the expected wellbore temperatures, pressures, loads and service conditions that it may be exposed to over its lifetime. The design will take into account optimization for enhanced wellhead fatigue performance.

The wellhead system (Figure 12.10) will include a conductor housing, wellhead housing, casing hangers and packoff seal assemblies.

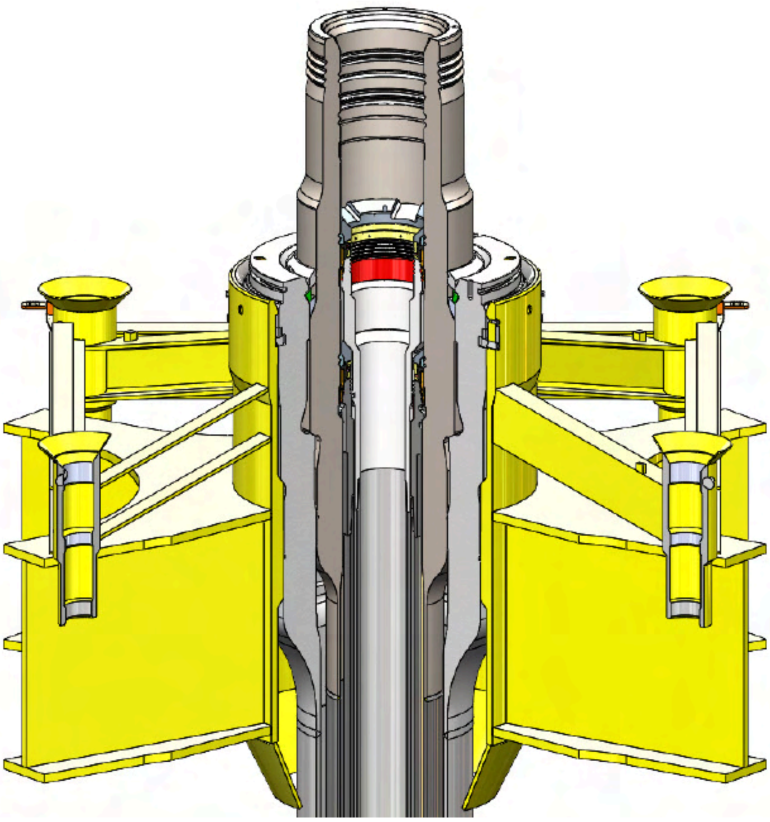


Figure 12.10 Typical Wellhead System

The conductor housing will interface with the planned conductor system to form the basic foundation for the well. It interfaces the template structure and provides a landing profile for the wellhead housing. It is designed to accommodate loads transferred from the wellhead housing for the entire life of field which includes drilling, production and workover modes.

The wellhead housing lands and locks inside the conductor housing. The wellhead housing will interface with the planned surface casing. The wellhead housing provides a landing, locking, and sealing preparations for the subsequently run casing hangers and tubing hanger. The wellhead housing includes a mandrel interface at the top for connection of the BOP or VXT, as applicable. The interface is designed with due consideration to wellhead fatigue performance.

The wellhead system is configured to accommodate two casing hangers which will interface with the associated casing strings. Each casing hanger will be locked in place by a packoff and will it provide a seal toward the relevant annulus.

12.2.4 XT System

The VXT solution will be based on the Equinor standard electric-hydraulic 7" (VXT) (Figure 12.11) with modifications as required for the Project's water depths and relevant operating temperatures. Project specific elements, including configuration (injector/producer), will be located inside the retrievable/interchangeable Flow Control Module (FCM). The VXT system will be designed to accommodate the expected temperatures, pressures, loads and service conditions that it may be exposed to over its lifetime.

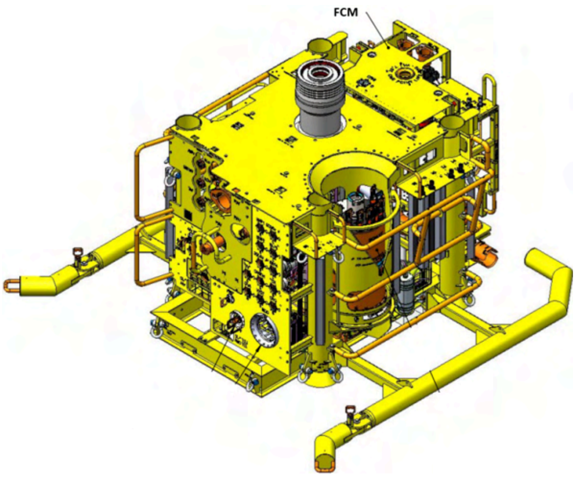


Figure 12.11 7" VXT with Retrievable FCM

The VXT features both remote operated and manual valves, isolating, and directing flow to and from the wellbore. It has a hydraulic connector to the manifold and a hydraulic connector to the wellhead. The VXT system includes a retrievable FCM which connects to the VXT through a multi-bore hub and clamp connector.

The following configurations are expected to be utilized for the development:

- Production;
- Water injection; and
- WAG injection

There will be chemical injection points both in the VXT and in the FCM. Pressure and temperature sensors will monitor tubing pressure and annulus pressure.

The FCM will typically contain components such as a flow-meter, a production or injection choke, pressure and temperature transducers, Chemical Injection Throttle Valves (CITV) and an acoustic sand detector.

Control of VXT system is achieved by means of a Subsea Control Module (SCM) and associated controls equipment. Metered chemical injection is provided into the production / injection flow and regulated by means of a retrievable CITV.

Downhole temperature and pressure monitoring will be facilitated through a retrievable downhole interface unit mounted on the VXT.

ROV access for all VXT valves is available via the panel located on the front of the VXT.

The VXT top connection (tree re-entry hub) provide a means for re-entering the well with well intervention equipment. It consists of an industry-standard mandrel, similar to the wellhead housing, and connects to the XT cap or well intervention well control equipment, as required.

The XT cap interfaces and locks to the tree re-entry hub. It provides a secondary pressure containing barrier to the production and annulus bores of the VXT. The Tubing Hanger (TH) is installed in the wellhead and interfaces with the VXT via a series of hydraulic and electrical stabs. The TH interfaces with both the production and annulus bore of the VXT.

The tubing hanger will also include an annulus isolation valve which eliminates need for wireline well intervention operation to set an annulus isolation device during the initial completion operation. The TH will be equipped to supply hydraulic pressure via the completion control lines for operation of downhole valves such as the Surface Controlled Subsurface Safety Valve (SCSSV). The TH includes a profile for a wireline installable plug in the production bore. It also includes a connection at the bottom to interface with the completion tubing.

12.2.5 Riser Base System

The riser base system includes two units, one for the Bay du Nord Field and one for the Cambriol Field, both located within the anticipated safety zones, eliminating the need for trawl protection. The riser bases serve as connection hubs for dynamic risers, flowlines, and utilities.

Each riser base is designed with flexible foundation options, including mudmat and suction anchor solutions, depending on installation requirements. They are equipped with production and gas lift headers, allowing for flushing via a crossover line. Subsea leak detection capabilities will also be integrated (see Section 12.2.11 Subsea Leak Detection).

Key functionality of the rise base system:

- Dual production headers with crossover capability;
- Gas injection header and distribution to both production headers; and
- Provisions for future production and/or gas injection tie-ins.

The riser bases are presented in Figure 12.12.

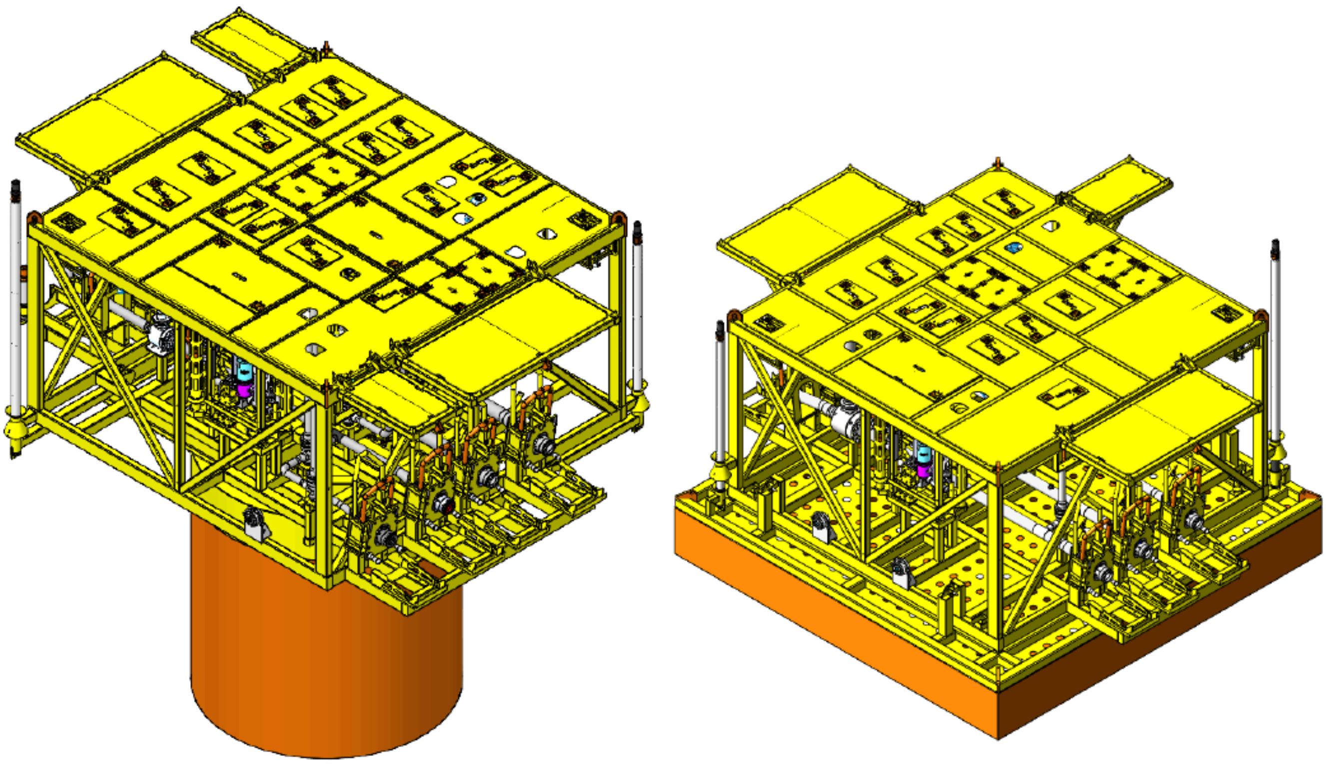


Figure 12.12 Riser Bases with Foundations

12.2.6 Subsea Cooling

Subsea cooling will be necessary for the Cambriol well fluids. A passive subsea process cooler will be installed downstream of the Cambriol template, to ensure that the temperature will be within the design limitations before entering the production flowline, riser, and turret systems.

The cooling station features two cooler modules placed in series. They are within a protective structure that includes a foundation supported by four suction anchors. Cold seawater in external contact with the cooler piping passively cools production fluids directly from the wells, eliminating the need for upstream separation or treatment. The cooler modules are retrievable for maintenance and include passive cooling capacity, instrumentation, valves, a hot-stab connection for interventions, and a control system. Small bore piping and valves allow for the injection of MEG to inhibit and displace the cooler modules. The cooling station also has a main bypass line and valve, allowing production to bypass the cooler modules when cooling is unnecessary and can help facilitate operations such as well clean-up or flowline pigging.

Figure 12.13 and presents the preliminary subsea cooler for the Cambriol Field.

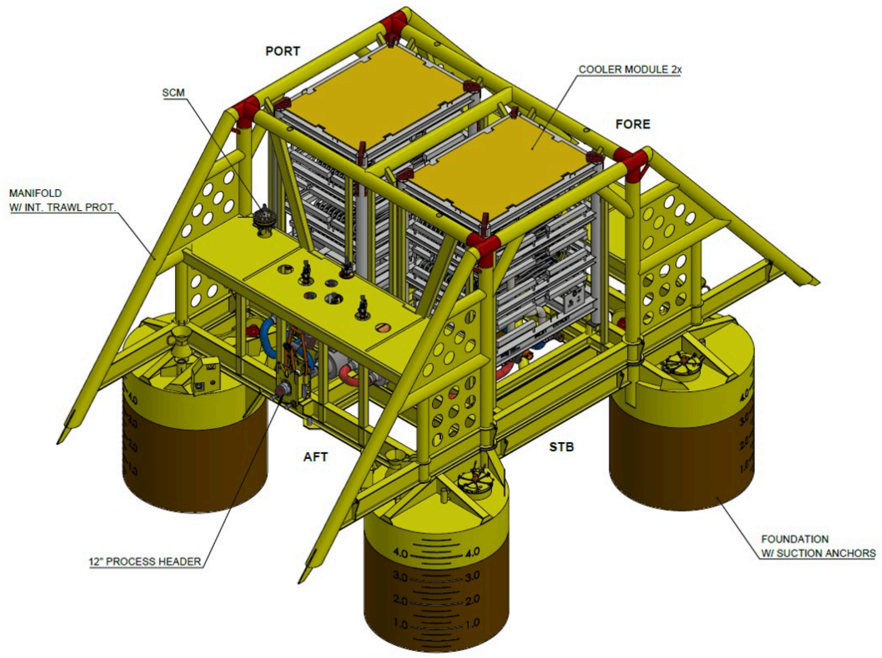


Figure 12.13 Subsea Cooler Station

12.2.7 Subsea Production Control System

The subsea production control system is based on a proven electro-hydraulic design, utilizing actuators for manifold and riser base valves in an open-loop configuration. Hydraulic fluid used in the open-loop system will be screened for use and will be reflected in the Project's Environmental Protection Plan (EPP).

The system is designed to support up to 36 wells and interfaces with the FPSO via a standardized Subsea Control Unit (SCU). Topsides control and monitoring are managed through hard-wired signals and serial communication.

Power and communication are supplied from topsides equipment and distributed via dynamic and static umbilicals. These are routed through Umbilical Termination Heads (UTHs) and connected to manifolds and riser bases using electrical and optical flying leads. Distribution continues locally or is capped for future use.

Hydraulic fluids and chemicals are delivered from the topsides Hydraulic Power Unit (HPU) through the umbilical system to the subsea infrastructure. Manifolds distribute these fluids to valves and instrumentation, and include pass-through lines for future expansion via multibore hubs.

Key topsides equipment includes:

- Electrical Power Unit (EPU);
- Subsea Gateway (SG);
- Third Party Server Unit (TPSU);
- Remote Operator Station (ROS);

- Communication Distribution Unit (CDU);
- SCU; and
- HPUs.

Two Downhole Interface Units (DIUs) are also provided to all subsea VXTs for communication with downhole instrumentation.

The control system interfaces with various subsea sensors and electrically actuated valves, including gas-lift valves, chokes, isolation valves, chemical injection valves, and pressure sensors.

A layout of the control system is shown in Figure 12.14.

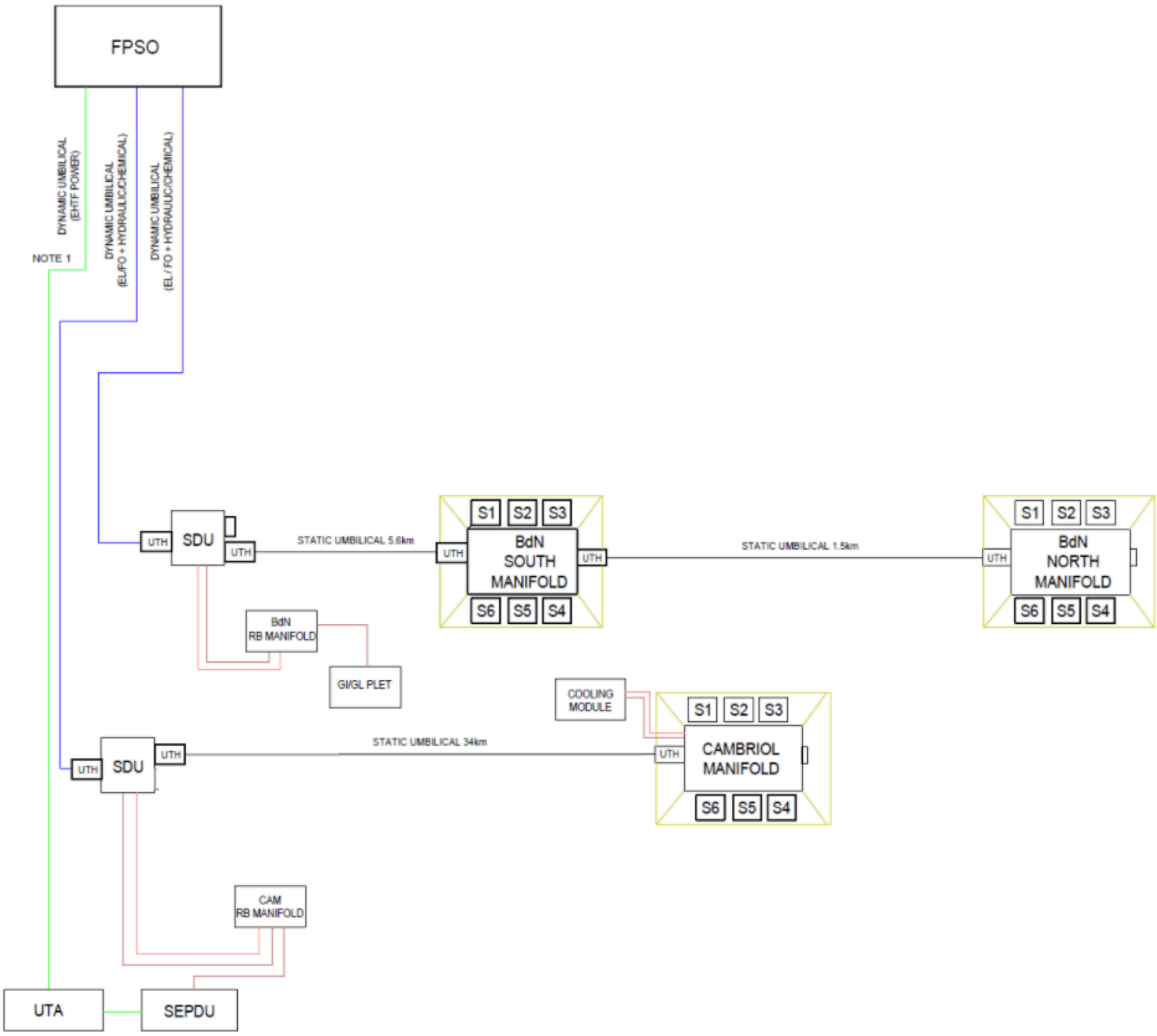


Figure 12.14 Control System Top Assembly

12.2.8 Power and Umbilical System

The base case umbilical system includes:

- Two dynamic umbilicals connecting the FPSO to the riser bases for control and chemical supply;
- Three static umbilicals connecting the riser bases to subsea templates, carrying chemicals, hydraulics, power, and communications; and
- A dynamic power cable from the FPSO to the power Umbilical Termination Assembly (UTA), with further connections to the Subsea Equipment and Production Distribution Unit (SEPDU) and EHTF flowline via electrical flying leads.

At the topsides, the dynamic riser umbilicals will be terminated with a pull-in head consisting of segmented elements to contain the end termination arrangements for electrical power, fibre optic, and hydraulic/chemical fluid lines within the umbilical.

For the Cambriol Field, the SEPDU manages power distribution, monitoring, and control of subsea equipment. It includes a subsea transformer to adapt transmission voltage for EHTF operations and a Subsea Switch Module (SSM) for control and monitoring.

12.2.9 Riser System

Eight risers are currently planned to be applied in the Project; all sizes are preliminary and will be further assessed during FEED:

- Two medium pressure production risers to Bay du Nord;
- One medium pressure gas injection/gas lift riser to Bay du Nord;
- One medium pressure water injection riser to Bay du Nord;
- Two high pressure production risers to Cambriol;
- One high pressure gas injection/gas lift riser to Cambriol; and
- One high pressure water injection riser to Cambriol.

The flexible riser concept has been developed for high pressure, deepwater, and harsh environment condition of the Project. A preliminary configuration for the flexible riser system for the Project is shown in Figure 12.15. The flexible risers will utilize tethered wave configuration with sag and hog of the riser positioned at higher elevation in order to reduce the tension at the turret. The hog and sag elevations have been checked for disconnection depth of the turret buoy.

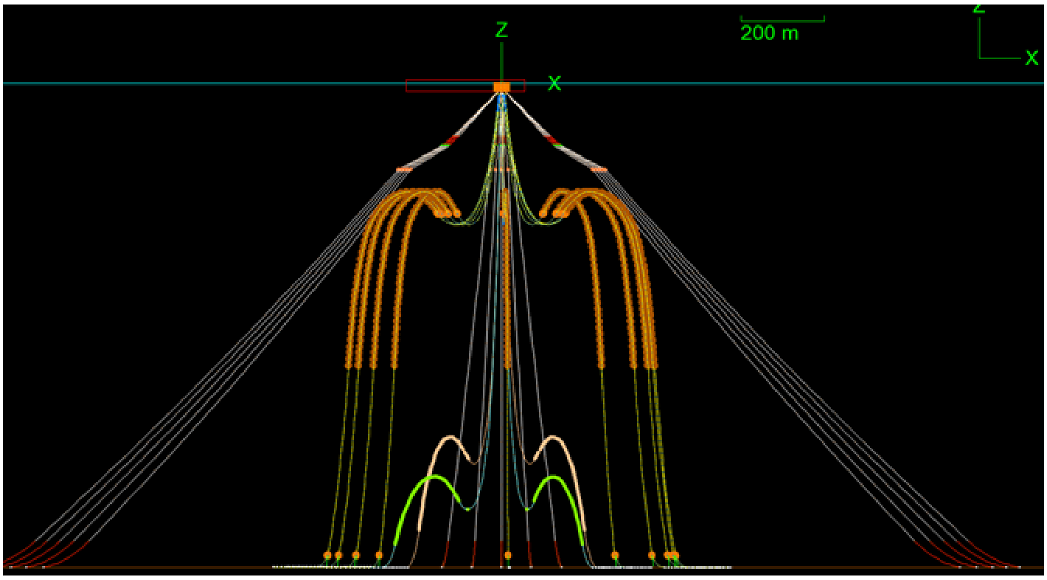


Figure 12.15 Flexible Riser System - General Configuration

The initial cross section of the flexible risers (Figure 12.16) has been defined in order to ensure sufficient fatigue life throughout the field lifetime. Each flexible riser will made up of multiple sections, and each section will be connected using mid-line connections.

Figure 12.16 Flexible Riser System - Initial Cross Section

The risers will be connected to the FPSO/turret through guide tubes with a bend stiffener connector connected at the lower part of the guide tube. Typical bend stiffener is shown in Figure 12.17.

Figure 12.17 Flexible Riser System - Bend Stiffener

Distributed buoyancy modules (Figure 12.18) are installed to achieve the desired tethered wave configuration. The modules consist of two main components, namely the clamp and the buoyancy elements. The purpose of the clamp is to axially secure the buoyancy element to the riser and will be designed to ensure that axial capacity is maintained throughout the design life of the system. The buoyancy elements will be designed as two half-shells installed over the internal clamp and will be secured in place using an external strapping system.

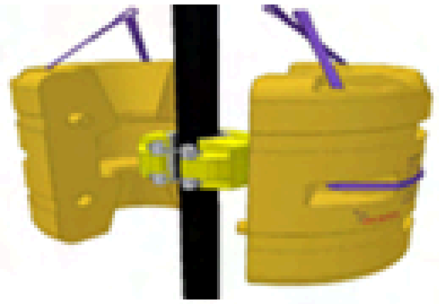


Figure 12.18 Buoyancy Module

12.2.10 Flowline System

The flowlines are part of the flowline and riser system for the Project, and are illustrated in Figure 12.7. The flowlines will provide an unobstructed flow conduit between the subsea facilities and the FPSO and will be fully compatible with the intended service duty for the entire production life. Appropriate valving will be installed subsea to control flows and to facilitate marine operations in both normal and emergency situations.

Design of the flowlines will ensure that no maintenance is required during the production life, other than external inspection using an ROV, or other suitable equipment. Hot oil flushing in Bay du Nord field production loop and Cambriol riser loop can be used for wax removal. Operational pigging for removal of wax is also feasible.

Rigid flowlines are the base case for flowline systems to Cambriol and for Bay du Nord field between riser bases and Bay du Nord South template. The short production and water injection flowline between Bay du Nord field manifolds are planned with flexible flowlines. Pipe-in-Pipe (PIP) technology is planned for all rigid production and gas injection flowlines, while single flowlines will be used for rigid water injection flowlines. PIP provides very good thermal insulation and the outer pipe provides protection against external loads. The production flowline from Cambriol will also have an Electrically Heat-Traced Flowline (EHTF) attached to the inner pipe to mitigate risk of hydrates and wax precipitation.

Rigid production flowlines will be made of carbon steel with corrosion resistant alloy as internal liner/clad to prevent corrosion from the well stream. The water injection flowlines will have an internal High-Density Polyethylene (HDPE) liner, while gas injection flowlines will be made of carbon steel with a specified corrosion allowance.

Flowlines will be connected to manifolds and riser bases using tie-in spools and flexible jumpers. All tie-ins will be conducted using diverless connectors. At end of the rigid flowlines smaller Pipeline End Termination (PLET) structures are welded in which facilitate the diverless connection towards the spools and jumpers. For the flexible flowlines, no PLETs/tie-in spools/jumpers are required as the lines are connected directly to respective manifold/ riser base.

The rigid flowlines will be designed to be stable on the seabed and to withstand trawling activities in the area. Protection measures for flexible flowlines may include rock installation, concrete mattresses, trenching, and/or protective covers typically made of Glass Reinforced Plastic (GRP), as they cannot resist trawl interaction with larger trawl gear.

12.2.11 Subsea Leak Detection

The following technical solutions will be implemented as a basis for detection of subsea leakages:

- Oil Spill Detection (OSD) radar located on the FPSO;
- Local subsea leak detectors;
- Pressure/process monitoring;
- Visual observations (from vessels and aircrafts and in limited periods from platforms, but very dependent on prevailing weather conditions and time of year); and
- ROV inspections.

The success of using OSD radar is highly dependent on the weather conditions and size and location of release. This affects the probability of detection and/or time before detection.

A separate study of alternative leak detection technologies has been conducted to support the selection of local subsea detectors. Leak detection by local passive acoustic leak detectors have been selected, and will be installed on each template manifold, riser base and the subsea cooler.

Operational aspects related to subsea leak detection elements will be developed and included in the shutdown and isolation philosophy as it is matured.

12.3 Provisions for Potential Future Expansion

The design of the production installation considers potential future expansion, including, but not limited to, the following:

- The STP buoy will be designed with additional spare slots;
- A spare umbilical slot in the STP buoy allows for further expansion of an additional 18 wells, for a total of 54 wells;
- Subsea control system infrastructure is designed to accommodate tieback of future templates with a maximum distance of 5 km from the farthest template within each of the umbilical legs;
- Additional spare well slots throughout the field which will be capable of WAG and/or production service;
- Well slots can be reclaimed, if required, to allow for re-purposing of existing non-productive, plugged or abandoned slots;
- Additional hubs for future connections at the Bay du Nord and Cambriol templates (Figure 12.7);
- The FPSO end of the Cambriol water injection line end termination structure will be configured with an additional branch connection for future expansion of the water injection system;
- Cappahayden template has been considered as a real option for future development, with flexibility maintained for the production line and water injection to be tied-back to the existing Cambriol development infrastructures; and
- The FPSO will have additional topside weight allowance that can accommodate future expansion.

These provisions are subject to change during the FEED and detailed design phases.

12.4 Operations Involvement in Development Phase

Asset Operating Model

The Asset Operating Model (AOM) (Section 15 Asset Operating Model) defines the desired operational modes, processes, and organizational relationships envisaged during the operations phase. It highlights the primary operational outcomes for the Asset infrastructure development.

Operations Participation in Asset Development

Equinor operations personnel will be engaged throughout the development phases and provide continuous support to both internal and contractors project delivery teams. Specifically, Equinor operations personnel will collaborate with the FPSO contractor's design, construction, commissioning, and pre-operations organizations to support the common objective of a seamless hand over of the FPSO facility to the FPSO contractor's Operations & Maintenance (O&M) organization in accordance with the technical and operational requirements and in compliance with applicable regulations. The Equinor pre-Operations team will facilitate a seamless hand-over of Subsea Umbilicals, Risers, and Flowlines (SURF) and wells to the Equinor field authority (or Operations).

The FPSO contractor pre-operations team will be integrated into the FPSO contractor's project delivery organization. The pre-operations team will provide operations input and verification follow up during the design, construction, and commissioning phases and facilitate the handover of systems from the project to the FPSO contractor's O&M organization.

Operations personnel will contribute to the Asset development through activities such as, but not limited to:

- Stakeholder communication of the AOM;
- Hazard Identification (HAZID), Environmental Hazard Identification (ENVID), Hazard and Operability (HAZOP) workshops;
- System design review workshops;
- Concept Safety Analysis and Major Accidental Event (MAE) register development;
- Maintenance engineering and Computerized Maintenance Management System (CMMS) workshops and reviews;
- Logistics planning workshops;

- Value improvement initiatives;
- Request for Proposal (RFP) reviews;
- Factory Acceptance Tests (FATs), System Integration Tests (SITs) etc.;
- Commissioning manuals, vendor operating manuals, equipment package specifications reviews etc.;
- Area, system, and equipment mechanical completion and commissioning reviews;
- Development of the Functional and Design Requirements (FDR);
- Management of Change (MoC); and
- Experience transfer and lessons learned from operations in the Canada-NL offshore area.

13 Construction, Installation, and Commissioning

13.1 FPSO, Subsea, and Marine Operations

The construction, installation, and commissioning methods and approaches outlined below may change during the Front-End Engineering Design (FEED) and detailed design phases.

Construction, Installation, and Commissioning of the Production Installation

The Bay du Nord Project (the Project) will begin with the construction, installation, and commissioning of a Floating Production, Storage, and Offloading (FPSO) facility, which will include an ice-strengthened hull, topsides modules, and a disconnectable turret. These components, along with those of the Subsea Production System (SPS), will be constructed, installed, and commissioned at an international yard before transiting to the operations site in the Canada-NL offshore area. The FPSO contractor will be responsible for activities occurring at the international shipyard.

Offshore Seabed Preparation

Seabed geotechnical and pre-clearance surveys will be required prior to installation of the SPS to identify any seabed or subsurface obstructions. These surveys generally use Remote Operated Vehicles (ROVs) and/or Autonomous Underwater Vehicles (AUVs), along with geotechnical equipment designed to assess soil strength and detect subsurface features such as boulders.

Offshore Installation of Subsea Infrastructure

Subsea infrastructure will be installed offshore using specialized marine installation vessels, supported by ROVs, during optimal marine installation windows. Rigid flowlines will be installed using the reeling method, while flexible flowlines will be deployed from construction vessels equipped with flex-lay systems.

The subsea infrastructure to be installed include those listed in Section 12.1.2.3 Mooring System and Section 12.2 Subsea Production System. Select infrastructure, such as templates, riser bases, and mooring lines, will be permanently connected to the seafloor using suction anchors.

Flowlines, power cables, and umbilicals will be laid directly on the seabed and/or installed in a trench. Protection measures may include rock installation, concrete mattresses, trenching, and/or protective covers typically made of Glass Reinforced Plastic (GRP). Flowlines, risers, cables, and umbilicals will be tied into the subsea production systems using ROVs.

Due to the water depth, excavated drill centres are not required. The subsea infrastructure will be protected from potential damage caused by dropped objects or trawling activities.

FPSO Transit

The FPSO will transit to the operations site. Continuous weather monitoring and forecasting will be conducted throughout the transit to ensure safe and efficient operations.

Offshore Installation and Commissioning of the Production Installation

Pre-installation surveys, wet storage of equipment, and site preparation may occur. Additional key activities include riser buoy pull-in, Turret and Mooring System (TMS) hook-up and final commissioning, subsea infrastructure installation and commissioning, and start-up preparations.

After the riser buoy is pulled into the FPSO, tasks such as mooring line re-tensioning, permanent TMS hang-off installation, leak testing, flowline dewatering, and commissioning of subsea infrastructure, including risers, umbilicals, manifolds, and Christmas Trees (XTs), will be completed. Emergency Shutdown System (ESD) testing and final start-up preparations will follow.

Subsea infrastructure may be tied into the buoy either before or after it is connected to the FPSO, depending on operational sequencing.

A variety of construction, pipe-laying, and support vessels will be used, with ROVs and/or AUVs supporting subsea operations. Activities will be planned primarily during the optimal weather window from May to September, with flexibility to start earlier or extend later if needed. Temporary equipment may be required for installation, with final requirements confirmed during detailed planning. If activities require higher, sustained peak Personnel on Board (POB) levels, a temporary accommodations installation(s) may be considered.

13.2 Drilling Services

Wells will be drilled and completed using one or more drilling installations suitable for year-round execution. Due to the water depth at the planned template locations, the drilling installation is planned to use Dynamic Positioning (DP) to stay on location, with an option to moor using anchors, if necessary.

Goods and services are grouped into the following categories: drilling installation procurement, drilling and logistics support services, and long lead items.

Drilling installations will comply with applicable regulatory requirements.

Drilling and logistics support services will be required for including, but not limited to:

- Directional drilling, Logging While Drilling (LWD), Measurement While Drilling (MWD), mudlogging and bits;
- Cementing;
- Wireline (WL);
- Drilling fluids;
- Coring services;
- Liner hanger services;
- Whipstock/slot recovery/fishing services;
- Completions equipment and services;
- Downhole mechanical isolation;
- Supply of Oil Country Tubular Goods (OCTG);
- Tubular management;
- Rig positioning;
- Helicopter passenger and Search and Rescue (SAR) services;
- Vessel services;
- Supply bases services;
- Customs/freight forwarding services;
- Fuel;
- Waste management services;
- Weather forecasting services;
- Ice reconnaissance;
- Personal Protective Equipment (PPE);
- Helicopter passenger suits;
- Medical services and medical evacuation;
- Accommodation services; and
- Telecommunications.

13.3 Environmental Considerations

The Environmental Impact Statement (EIS) [4] addresses the environmental effects of all Project activities in marine waters, including offshore construction and installation, hook-up and commissioning, drilling, and production operations. Mitigations identified in the EIS and Environmental Assessment (EA) conditions [3] will be implemented during construction, installation and commissioning, as applicable. As discussed in Section 17.3.2 Environmental Protection Plan, an Environmental Protection Plan (EPP) will be submitted with the Operations Authorization (OA) application. As indicated in the EIS and the EA conditions, follow-up monitoring programs will be developed for the Project. Refer to Section 17.4.1 Environmental Effects Monitoring Development Methodology for additional information.

14 Management System

14.1 Overview of the Equinor ASA Management System

The purpose of the Equinor ASA Management System (EMS) is to:

- Enable operations to be performed in a safe, reliable, compliant, and efficient manner in a variety of value chains, operating models and countries;
- Help to incorporate our values, "Who we are" and "How we work" in everything we do; and
- Enhances business performance through quality decision-making, efficient, and precise execution, continuous learning, and assurance.

A unified EMS establishes a consistent framework that promotes standardization and differentiation in our business, ensuring a trusted and controlled approach that secures our license to operate in all locations. The EMS framework is adaptable to meet varying country-specific legislative requirements, industries, and / or operating models.

The EMS framework is structured in three levels (Figure 14.1): (1) Equinor Book, (2) Directives, and (3) Governing Documents and Work Processes.

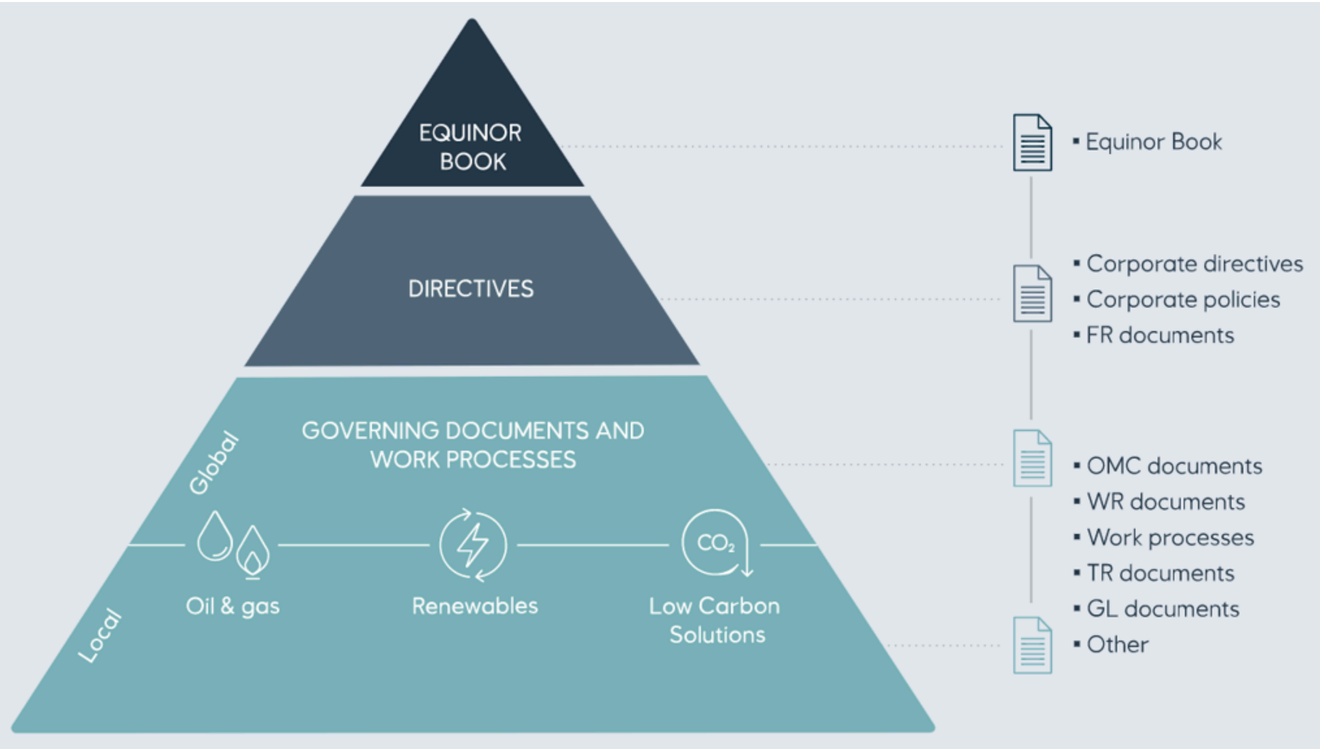


Figure 14.1 Equinor ASA Management System Hierarchy

Equinor Book

The Equinor Book is the core of the EMS. It summarizes important aspects of our identity. It describes "Who we are" and "How we work" by setting standards for our behaviour, our performance and our leadership.

Directives

Directives are mandatory across the organization and support structured risk management. The directives include Function Requirement (FR) documents, corporate policies, and corporate directive documents for organization, management, and control purposes.

Governing Documents and Work Processes

Global governing documents and work processes drive performance and standardization across the organization while supporting a variety of business needs.

Local governing documents and work processes are established to comply with local laws and regulations, and to support specific local context, risk, conditions, and operating models.

14.2 Proposed Management System Strategy for the Project

The information related to the management system strategy is under development. Elements of the management system requiring coordination with the Floating Production, Storage, and Offloading (FPSO) contractor will be developed collaboratively as the Project matures. Content in this section and subsequent sub-sections may change accordingly.

Within Equinor ASA, management system entities (e.g., office, asset, etc.). are used to enable differentiation of the EMS to meet business context, risks, and regulatory requirements.

The Equinor Book and Directives, as explained in Section 14.1 Overview of the Equinor ASA Management System, are mandatory governing documentation and will be incorporated into the Project management system, including those related to safety, security, and environment. These Equinor ASA fundamentals will form the foundation of the management system for the Project.

Applicable and appropriate global governing documents and work processes are selected. Local governing documents and work processes are developed to enable regulatory compliance, and to support specific local context, risks, conditions, and operating model.

Equinor will work closely with contractors to incorporate and bridge management systems, as illustrated in Figure 14.2. Local governing documents and work processes will be developed to reflect specific risks, conditions, operating model, and regulatory requirements. The management system will be developed in accordance with applicable requirements in the *Canada-Newfoundland and Labrador Offshore Petroleum Operations Framework Regulations* (the *Framework Regulations*).

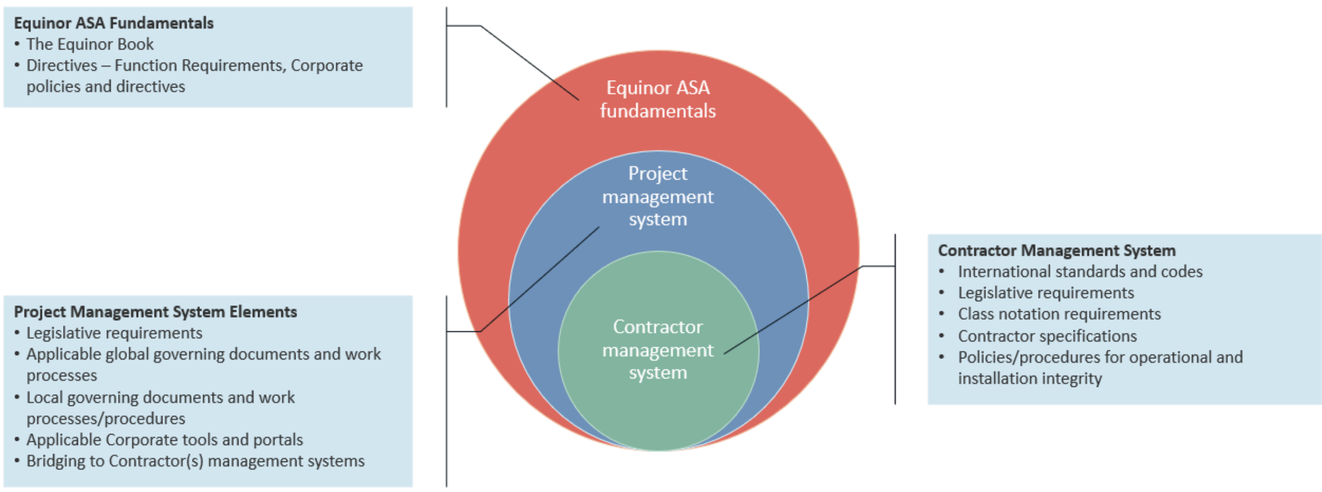


Figure 14.2 Proposed Project Management System Structure

14.2.1 Accountability

The Senior Vice President (SVP) of Exploration and Production International (EPI) Canada serves as the Country Manager, and is accountable for adopting and implementing governing documentation that complies with local laws, regulations, and internal fundamentals. In addition, the Country Manager is responsible for ensuring that governing documents are validated and adjusted to reflect local operational needs.

14.2.2 Organizational Principles

Organizational principles are outlined in the Equinor Book, and set out the guiding considerations for assigning roles and responsibilities within the organization. The potential roles and responsibilities for Project operations are discussed in Section 15.3 Staffing.

14.2.3 Management System Tools

Architecture of Integrated Information Systems

The EMS documentation is available in the Architecture of Integrated Information Systems (ARIS). ARIS is a web-based system that allows users to view documents such as, but not limited to, Equinor Book, corporate directives and policies, Function Requirement documents, and global governing documents and work processes.

A-Standard

The A-Standard is Equinor ASA's method to ensure that we collaborate and deliver the desired result safely with efficiency and quality on our tasks (Figure 14.3). It is both a mindset and an action pattern. The method enhances leadership and communication and drives a proactive safety culture. Equinor will use the A-Standard, or any future tools or methods, for the Project when appropriate.

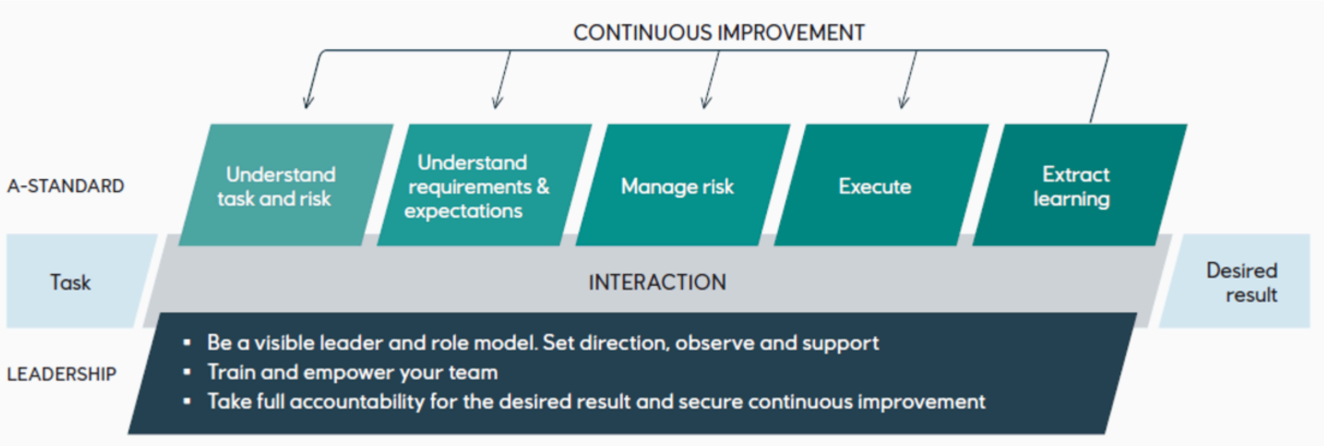


Figure 14.3 A-Standard Model

Incident Reporting and Case Handling System

Equinor will utilize a system for reporting and following up of incidents. This system records and manages incidents, investigation reports, non-conformances, internal and external audits, and safety, security, and environmental data.

14.2.4 Assurance

Assurance is about providing confidence and confirmation that we understand and manage risk, achieve our objectives, and are compliant with internal and external requirements and expectations.

At Equinor, we systematically identify, assess, and manage our risks. We monitor and execute assurance activities to ensure that processes and corresponding actions are effective to safeguard and continuously improve our operations.

Our assurance model is operationalized through accountable business areas that own and manage own risks, corporate functions that oversee risks within their functional area and corporate audit that conducts independent and objective internal audits and investigations.

A risk-based assurance framework will be established for the Project and may consist of self-assessments, verifications, and/or audits (Figure 14.4). The Project will document results, findings, actions, and learning associated with assurance activities. Contractors will also be responsible for conducting assurance activities in accordance with their management system requirements.

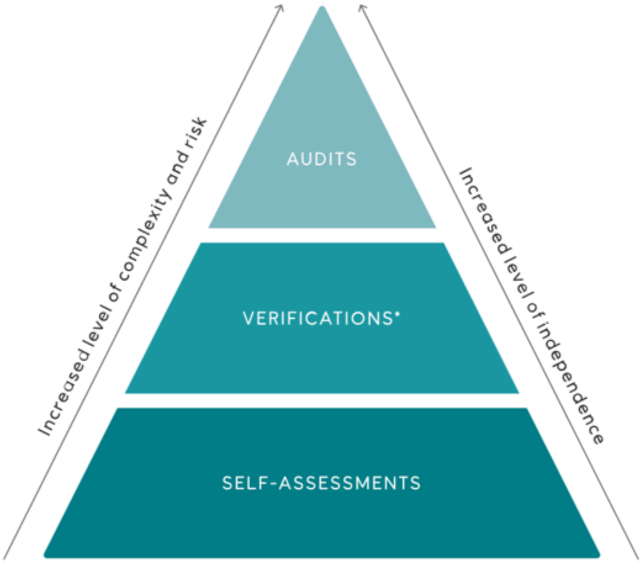


Figure 14.4 Equinor ASA Management System Assurance Hierarchy

Self-Assessment

Self-assessments are conducted at all levels, from operational to management, to demonstrate business and operational control and to identify ways to reduce risk and improve performance. The line management decides on the level, scope, frequency, and requirements for documentation of self-assessment activities based on risk and performance history.

Self-assessments at an operational level focus on critical operational and technical barriers and key controls. Self-assessments at a management level are holistic and look at the wider risk picture within the designated area of responsibility.

Verification (Internal Audit)

Within Equinor, internal auditing is referred to as verification. Verifications are a management tool used to assess areas of high-impact risk. Each business area is responsible for identifying the need for verification, to demonstrate the necessary additional conformity to control.

The need for verification is based on the business areas' identified risks (downside and upside). The need for verification of suppliers is based on information from the company representative. Proposed safety, security, and environmental verification for the Project may consist of a planned verification programme to ensure compliance with requirements, coupled with specific risk-based verification, carried out as needed.

The selection of scope and frequency is based on the activity programme and its risks. Assurance activities are carried out using Equinor ASA processes, appropriate software tools, and techniques.

Examples of typical internal verification carried out include:

- Pre-start-up verification;
- Drilling pre-start-up verification;
- Environmental verification;
- Area inspections;
- Simultaneous or combined operations verification; and
- Facility safety, security, and environmental verification.

Audit

Within Equinor, audit refers to either third-party audits or corporate audits. Audits are independent assessments to evaluate and improve the efficiency and effectiveness of the group's performance, management system, and governance. The corporate audit team perform internal audits based on a formal mandate from the Board of Directors. The mandate is in accordance with international standards and based on an evaluation of risk and materiality. Internal audits are subject to the Board Audit Committee approval.

Audits may be conducted to ensure that the safety, security, and environmental requirements are effectively implemented and continually improved. Auditing and audit findings are prioritized by the level of risk arising from the audited processes. The audit process highlights good practice and is proactive to ensure that any areas for improvement in the implementation of the safety, security, and environmental requirements can be identified to prevent potential incidents or accidents. The process ensures that the monitoring team have the necessary qualifications to conduct the monitoring task as well as knowledge of the topic or subject to be monitored. For audit and verification, the composition of the monitoring team must enable an objective evaluation of the monitored activity.

Audit findings are documented in the Equinor audit management system, reviewed, and agreed with relevant managers, process owners and personnel to establish an agreed time-scale for developing and implementing corrective and/or preventative actions.

External (third-party) audits and verification activities associated with the Project may include, but are not limited to:

- Preventative maintenance routines;
- Independent verifier;
- Drilling and intervention; and
- Management system.

15 Asset Operating Model

15.1 Introduction

The Asset, including the Floating Production Storage and Offloading (FPSO) facility, Subsea Production System (SPS), and wells, will be operated in alignment with a structured safety and environmental management approach (Section 16 Safety Management and Section 17 Environmental Management). The Asset will utilize the proposed management system strategy outlined in Section 14 Management System, leveraging the extensive local and global project expertise as well as operations experience from Equinor, its partners, and contractors. The Asset will be designed, constructed, installed, commissioned, operated, maintained, modified, and decommissioned in compliance with applicable regulatory requirements.

The Asset Operating Model (AOM) described herein will continue to be matured in subsequent Project phases.

The FPSO will be delivered and executed under a lease and operate model, with the FPSO contractor responsible for design, construction, installation, operation, and decommissioning of the FPSO. The SPS and wells are the responsibility of Equinor. Equinor will serve as the field operator throughout all phases. An integrated field Asset Integrity Management (AIM) Plan will be developed by Equinor and the FPSO contractor that will ensure all equipment and systems, including Safety and Environmental Critical Elements (SECEs), are operated as intended and maintained appropriately, in consideration of established industry practices, recognized standards, and in compliance with applicable regulatory requirements.

Proposed Field Operational Boundaries and Responsibilities

The proposed field operational boundaries are illustrated in Figure 15.1.

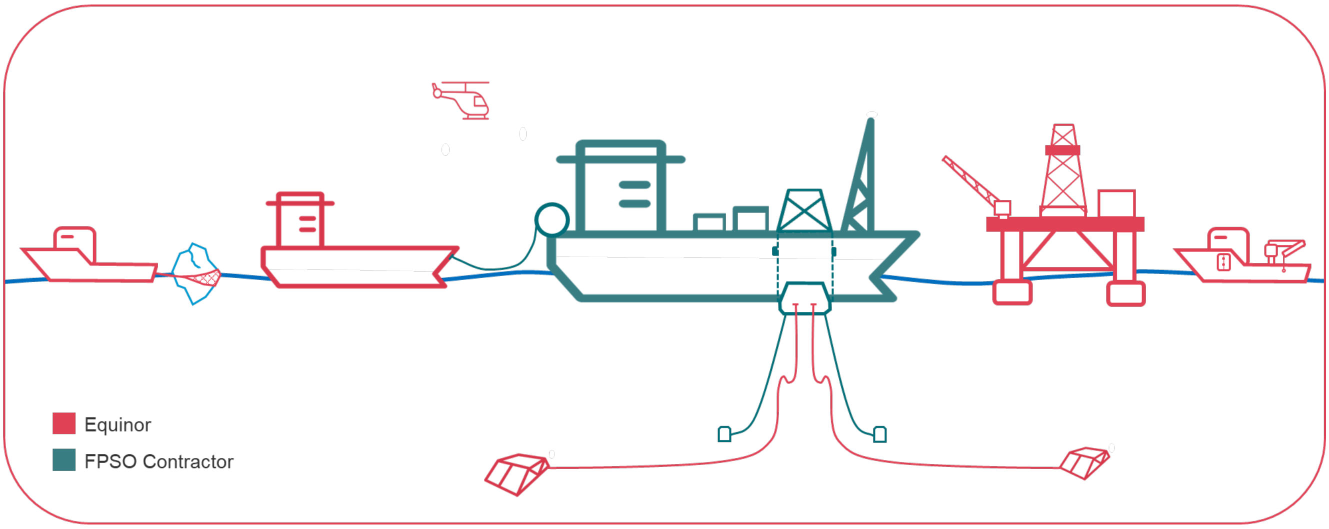


Figure 15.1 Proposed Field Operational Boundaries

Key responsibilities include, but are not limited to:

- FPSO contractor
  - Design, delivery, and operations for life of field, and decommissioning;
  - Maintenance of the FPSO (including turret and mooring system);
  - Day-to-day control of SPS;
  - Day-to-day control of field operations including tactical ice management, planned and emergency disconnect, and tactical emergency response (i.e., Emergency Response Team [ERT]);
  - Use of their management system to ensure safe and efficient operations with bridging to Equinor's management system;
  - Marine activities (e.g., shuttle tanker operations, supply vessels, etc.) within the safety zone; and

- Control and coordination of Simultaneous Operations (SIMOPs) across the full field. Planning of SIMOPs will be coordinated between FPSO contractor and Equinor.

- Equinor
  - Design, ownership, and maintenance of SPS;
  - Drilling and well programs and operations, including interventions;
  - Arranging shuttle tankers for offloading/transporting crude to market;
  - Logistics related to personnel and supply;
  - Operational and strategic emergency response (i.e., Incident Management Team [IMT] and Crisis Management Team [CMT]);
  - Management of the local Research and Development (R&D) and Education and Training (E&T) commitments under the *Accord Acts* and governed by the C-NLOER as defined in the Operations Authorization(s) (OAs); and
  - Decommissioning of SPS and wells.

15.2 Operating Philosophy

The main principles and objectives of the AOM are as follows:

Always safe – vision is zero harm for people, the environment, and assets

- Enhance asset integrity, process safety, and personal safety through use of As Low As Reasonably Practicable (ALARP) and best available technology principles;
- Create a working environment that fosters psychological safety and applies Human and Organizational Performance (HOP) principles;
- Promote energy efficiency and pursue opportunities to reduce emissions; and
- Ensure robust emergency preparedness and response capabilities suited for a remote, harsh environment.

Reliability, availability, and maintainability of equipment and systems

- Achieve production targets with high consistency;
- Use best industry practice of minimum intervention and Reliability Centred Maintenance (RCM); and
- Optimized staffing, sparing, and scheduling.

Collaborative optimization and continuous improvement in operations

- Develop integrated "One Team" operations approach between Equinor and contractors;
- Ensure high speed data accessibility and data availability – FPSO, SPS, and wells;
- Monitoring and optimization from an integrated operations centre (and global support centres); and
- Integrated technical integrity model with continuous field-wide barrier status.

15.3 Staffing

Drilling & Well Operations

The Equinor Drilling & Well operations team is anticipated to consist of up to 15 individuals, supporting safe and efficient execution of drilling activities. The preliminary onshore and offshore organizations have been defined conceptually and remain subject to change during the development phase to ensure flexibility as Project requirements evolve.

Offshore staffing levels will depend upon drilling installation selection but is anticipated to range from 120 to 160 Personnel on Board (POB). The drilling installation and drilling installation contractor will be determined during the future phases of the Project.

It is anticipated that Project development drilling and well operations will follow the standard rotation in the Canada-NL offshore area (e.g., three weeks on and three weeks off). Exploration and appraisal drilling activities performed by drilling installations during shorter seasonal campaigns may seek an alternate rotation schedule from the NL Department of Employment and Labour and C-NLOER.

FPSO Operations

The preliminary onshore and offshore organizations for FPSO operations is shown in Figure 15.2, and subject to change during the development phase.

Onshore Staffing Levels

Depending on the phase of operations, the onshore operations support organization (Equinor and FPSO contractor combined) is anticipated to have between 50 and 100 people. Onshore support will be fit for purpose for the operating model and will maintain sufficient local capacity for subsea Inspection, Maintenance and Repair (IMR), emergency response, and fulfilling responsibilities towards the C-NLOER, and other applicable authorities.

Offshore Staffing Levels and Rotational Schedule

The Asset will retain a traditional staffing model aligned with offshore assets following a seasonal campaign maintenance strategy. Staffing is based on approximately +/-80 personnel during regular operations, with a total capacity for 120 POB to accommodate activities such as, but not limited to, installation, hook-up and commissioning, maintenance, and turnarounds [71].

Offshore staffing levels shall be optimized by utilizing key productivity enablers such as a cross-trained workforce, reliability-centred maintenance practices, and conducting monitoring and verification activities from onshore, where feasible.

It is anticipated the FPSO will follow the standard rotation in the Canada-NL offshore area (e.g., three weeks on and three weeks off).

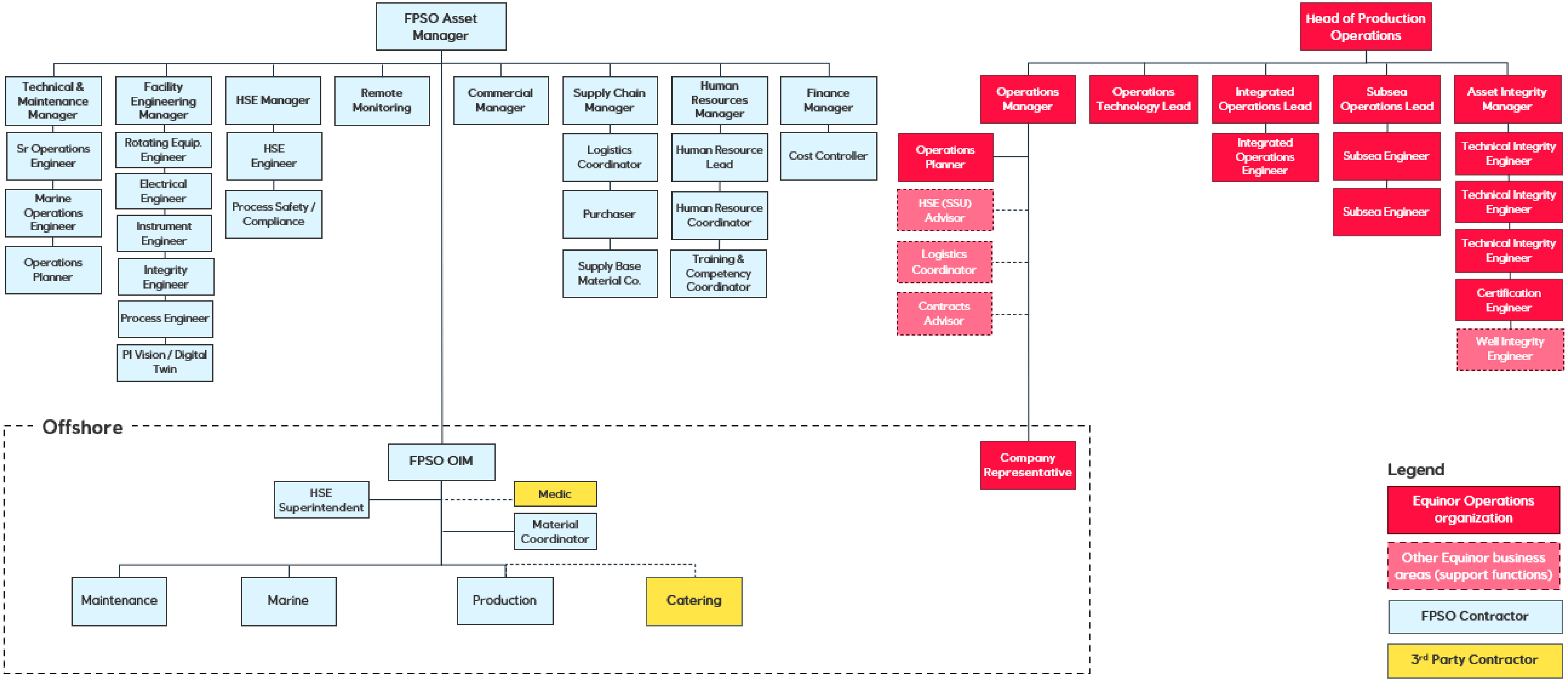


Figure 15.2 Preliminary FPSO Operations Organizational Structure

15.4 Training and Competency

The operations Training and Competence Management Plan will be aligned with the Competency Management System (CMS) framework, which will enable compliance with applicable regulatory and Equinor requirements.

Equinor assesses implementation and follow up of contractor training and competency through the contractor selection and procurement process. Subsequently, periodic verification activities will be conducted to evaluate contractors training and competency performance.

Equinor's Training and Competence Management Plan will include elements such as, but not limited to:

- Competence profiles for each discrete role;
- Collation of role requirements into a competency matrix and population into the CMS;
- Inclusion of individual training courses and certificates in the CMS/Learning Management System (LMS) for follow up;
- Assurance of competence; and
- Verification of competence assessment.

Additional training for offshore and onshore personnel, as required by the *Code of Practice - Atlantic Canada Offshore Petroleum Code of Practice for the Training and Qualifications of Offshore Personnel* [72], Transport Canada, other regulatory and Equinor requirements, will be documented in the training and competency matrix and verified through the CMS by the FPSO contractor and/or Equinor.

15.4.1 Position Classification Descriptions

Specific position classification descriptions will be developed for the safety, emergency response, environmental, business critical, and normal operational and maintenance tasks that an individual may be required to carry out to ensure compliance provided within applicable regulatory requirements.

It is anticipated that offshore staff will be cross-trained where feasible, enabling personnel to fulfil offshore FPSO management, operations or maintenance roles, with necessary certificates according to Transport Canada and other regulatory requirements. Examples of high-level qualifications for offshore positions are provided in Table 15.1 and will be further developed.

Table 15.1 Example of Offshore Operations Position Qualifications

Roles	Maritime/Offshore Qualifications	Other
▪ Offshore Installation Manager (OIM) ▪ Control room operator ▪ Marine control room operator ▪ Deck foreperson ▪ Production technician ▪ Maintenance area operator ▪ Medic ▪ Health, Safety and Environment (HSE) ▪ Mechanical technician ▪ Electrical technician ▪ Instrumentation technician ▪ Crane operator ▪ Catering	▪ Certificates according to Transport Canada and other regulatory requirements ▪ Other training as required by Transport Canada, Certifying Authority (CA), other regulatory and Equinor requirements ▪ Relevant certificates for work experience within oil and gas maintenance and/or process ▪ Relevant industrial certificates	▪ Experience from maritime/FPSO/ shuttle tanker operations, upstream oil and gas production/classified industrial/maintenance environment

The offshore organization will be supported by the Equinor and FPSO contractor onshore organizations. Both will be represented in the Integrated Operations Centre (IOC) in the St. John's, NL area. The typical groups located within the IOC are anticipated to be production, subsurface, maintenance, engineering, logistics, administration/

business support, safety, and environment. Supporting onshore functions will have the relevant certifications, experience and knowledge of the regulatory requirements, codes, and industry best practices. Examples of high-level qualifications for onshore positions are provided in Table 15.2 and will be further developed.

Table 15.2 Example of Onshore Operations Position Qualifications

Roles	Qualifications
Leader Positions ▪ Operations manager ▪ Maintenance lead ▪ Logistic lead ▪ Production lead ▪ Safety and sustainability manager	▪ Relevant technologist, industry or maritime certificate ▪ Demonstrated and relevant experience from upstream and/or midstream oil and gas
Support Functions ▪ Coordinators (e.g., operations technology, production, maintenance, logistics) ▪ Planning	▪ Relevant certification and experience
Asset Integrity ▪ Asset integrity manager ▪ Asset integrity engineers	▪ Asset integrity knowledge and experience of technical safety barriers within asset integrity management program ▪ Exposure to Major Accidental Event (MAE) management and industry standard risk analysis and assessment through practical application ▪ Experience within petroleum refining or offshore production industries with a technical knowledge of the performance standards required for major accident technical safety barriers ▪ Knowledge of regulatory and CA including regulations, codes and industry best practices ▪ Professional Engineers and Geoscientists of Newfoundland & Labrador (PEGNL) registration, where applicable

15.5 Integrated Operations

The operation of the Asset will be in accordance with Equinor's Integrated Operations (IO) concept, with the ambition of seamless integration between the offshore and onshore parts of the organization. The layered operations support model comprises of an offshore operations and maintenance organization and an IOC.

Integrated Operations Centre

The IOC, including IMT incident command post, will be established in the St. John's area. The IOC will support the offshore hook-up and commissioning activities prior to first oil.

Equinor and the FPSO contractor will be represented in the IOC to deliver integrated and collaborative operational planning in areas such as, but not limited to, production optimization, Asset integrity, HSE, and logistics. The IOC will also have representation from Equinor Subsea Operations, Equinor Drilling & Well, and key in-house contractors for these disciplines to further enhance onshore collaboration.

The IOC will be equipped for continuous field monitoring and will provide scalable support across all operational domains. The anticipated core functions include, but are not limited to:

<u>Technical and Safety Leadership</u>

- Support for all technical disciplines;
- Oversight of HSE activities; and
- Application of HOP principles.

<u>Operational Optimization</u>

- Guidance on production efficiency and system performance;
- Collaboration with contractors and internal teams, including SIMOPS coordination;

- Maintenance planning and execution support; and
- Coordination of turnarounds and campaigns.

Logistics and Supply Chain Coordination

- End-to-end logistics management for personnel, goods, and services;
- Shuttle tanker scheduling and marine coordination; and
- Procurement and supply chain integration.

Digital and Data Enablement

- Information Technology (IT) and digital systems support;
- Real-time data access and monitoring across the Asset; and
- Integration with global support centres.

Asset Integrity and Lifecycle Management

- Facilities engineering;
- Asset Integrity engineering, barrier status monitoring and support;
- Subsea operations and inspection coordination; and
- Lifecycle information services.

Global Support

It's anticipated that the FPSO contractor will utilize their corporate support centre to implement continuous improvement, monitor critical equipment performance, and analyze failures. Similarly, it's anticipated that Equinor will utilize global networks for support, when required.

IT and Telecommunications

It's anticipated that the IOC will utilize near real-time data transfer between the FPSO and onshore locations. The proposed high-capacity data connection will support high-definition video streaming, comprehensive production and maintenance monitoring, remote testing of systems and equipment, and virtual inspection methods. Remote control of facilities from onshore is not contemplated.

Integrated Activities

Production Engineering and Optimization

Production engineering and optimization will be led by Equinor in close collaboration with the FPSO contractor. Equinor will be responsible for the modelling, production planning, and reporting to the C-NLOER. The FPSO contractor will implement the production plan offshore and will meter and monitor/sample oil quality to ensure it meets specifications. Surveillance using sensors and analytics will be performed from the IOC to detect flow assurance issues such as wax, hydrates, or scale in flowlines and to optimize choke settings, well routing, and well performance.

Emergency Response

Refer to Section 15.14 Contingency Planning for an overview of the integrated emergency response activities.

15.6 Operations Manual

An Operations Manual will be developed in accordance with the applicable requirements in the *Canada–Newfoundland and Labrador Offshore Area Petroleum Operations Framework Regulations* (the *Framework Regulations*), and will draw upon the *Guideline for Framework Regulations* [73] for additional guidance and best practices. As required by the *Framework Regulations*, the Operations Manual is required to be reviewed and accepted by the CA.

15.7 Automation and Control

Control of the Asset's process, utility, safety, shutdown, marine, subsea, and well systems will be facilitated by the FPSO's Integrated Control and Safety System (ICSS), operated within the offshore Central Control Room (CCR). Direct onshore control of the Asset is not contemplated; however, remote monitoring and testing of the systems will be available from the IOC.

Production Operations Automation

Production processes and supporting utility systems will be monitored and controlled from the offshore CCR, covering the full value chain from wells to offloading. Operational data will be transmitted to the IOC to enable remote monitoring, testing, and production operations support.

Production operations optimization will be supported through advanced applications and simulation tools to enhance efficiency, stability, and performance across the Asset lifecycle.

Subsea and Well Operations Automation

Subsea infrastructure and wells will be fully integrated and operated from the ICSS in the offshore CCR. Operational data will be transmitted to the IOC to enable remote monitoring and testing and subsea and well operations support.

Process instrumentation will support automated flow control and ramp-up, contributing to optimized performance during start-up, shutdowns, and process upsets. Simulation tools will be used to evaluate system scenarios and continuously improve subsea and well performance.

Marine Operations Automation

Marine systems controls are integrated into the ICSS and may be monitored and controlled from the offshore CCR. Marine data will be transmitted to the IOC to support remote monitoring and marine operations support.

Safety and Shutdown Automation

Refer to Section 12.1.3.10 Control Systems and Section 12.1.4.2 Control and Shutdown Systems.

Cybersecurity

Equinor and the FPSO contractor will implement measures to identify, protect against, detect, respond to, and recover from cybersecurity risks. A Security Plan, including cybersecurity, will be developed (refer to Section 16.5 Security Plan).

15.8 Reliability and Maintenance

15.8.1 FPSO Maintenance

The FPSO contractor will be responsible for maintenance and asset integrity management including engineering, planning, execution, and documentation, for both routine operations and outages.

Management and Engineering

FPSO maintenance strategies will be tailored to equipment type and criticality, incorporating Condition-Based Monitoring (CBM), RCM, and Risk-Based Inspection (RBI).

Maintenance activities will be managed using a Computerized Maintenance Management System (CMMS) designed for scalability and integration with emerging technologies. The CMMS will support planning, performance tracking, inventory management, and documentation, using a structured Asset hierarchy and standardized data protocols.

Management of Change (MoC) processes will be overseen by the FPSO contractor for all asset modifications, with joint risk assessments conducted for subsea infrastructure in collaboration with Equinor.

Planning

The FPSO is expected to remain on location and connected to the Submerged Turret Production (STP) buoy throughout the 20-year production life.

Maintenance will be scheduled and executed using performance and condition-based approaches to reduce interventions and minimize breakdowns. Opportunistic maintenance will be optimized during planned and unplanned outages through effective planning and spare parts management.

Major activities requiring extended preparation or shutdowns will be coordinated through an integrated activity plan, aligning field-wide operations such as drilling, subsea inspection, and workovers. Planned turnarounds are expected to occur periodically.

Execution

All FPSO maintenance operations will be coordinated through a digital permit-to-work system. A core team will manage routine maintenance year-round, while campaign teams, supported by specialized vendors and contractors, will be mobilized during seasonal windows to execute larger, planned scopes of work.

Sparing and Tooling

Spare parts requirements will be determined using RCM, considering lifecycle costs, replacement times, and equipment criticality to support uptime and operational continuity. Inventory levels will be periodically reviewed and adjusted to reflect changes in consumption patterns, lead times, and operating conditions.

15.8.2 Subsea Maintenance

Equinor will be responsible for engineering, planning, execution, and documentation of subsea infrastructure, as well as subsea maintenance, and subsea asset integrity activities as part of the IMR program.

Management and Engineering

Subsea maintenance and operations will be managed by the Subsea Operations & Maintenance (O&M) function within Equinor. The SPS will be designed with built-in robustness and redundancy to support continued operation. Retrievable modules will enable efficient recovery and replacement using Remote Operated Vehicles (ROVs).

A routine inspection, testing, and maintenance program will be developed to support safe and reliable operations. Maintenance engineering activities will include defining SECEs, establishing technical hierarchies, conducting criticality assessments, and implementing maintenance strategies within the CMMS. Spare parts volumes for subsea and topside control systems will be defined in alignment with operational requirements and reliability targets.

Planning

Equinor will lead the IMR strategy for subsea infrastructure. The approach emphasizes system redundancy, enabling corrective maintenance to be planned and executed in seasonal campaigns. These campaigns typically occur during spring and summer, when weather conditions are more favourable for marine operations.

Critical or emergency maintenance of business, safety, and/or environmental critical subsea equipment is possible year-round. However, these activities are subject to weather-related delays and depend on the availability of IMR vessels and subsea spares.

To ensure timely and efficient subsea maintenance and repair, the Project is considering acquiring a dedicated IMR vessel. This vessel may be shared with logistics and would potentially support multiple functions (e.g., supply, standby, personnel transfer, ice management, etc.). There is also the potential that it provides services to Drilling & Well operations, such as Christmas Tree (XT) installation, well access, and subsea chemical injection.

The IMR strategy will continue to be matured in subsequent Project phases.

Execution

Corrective maintenance will focus on replacing and refurbishing subsea infrastructure and equipment using readily available spares. Scheduled maintenance will include routine inspections and testing of Emergency Shutdown

(ESD) functions and barrier integrity; all performed from the offshore CCR. These activities will be executed without vessel support and with minimal production impact. Strict handover protocols and barrier management principles will be maintained throughout all operational phases to ensure safety and continuity.

A CBM approach will be adopted. Technical integrity will be monitored continuously, and the assessed consequence of failure will guide decisions on preventive maintenance and redundancy restoration.

While no well interventions are planned, contingency interventions may be required during well construction (e.g., mechanical access to remote barriers) or during field operations to address well barrier failures or to enhance productivity.

As a base case, workovers will be conducted using a drilling installation and an open water workover system. Mechanical well interventions may be carried out using a Riserless Light Well Intervention (RLWI) vessel.

Sparing and Tooling

Preservation, storage, and maintenance of equipment and spares will be managed onshore at the SPS contractor's facilities, which will be established prior to operations. Critical spares and intervention tooling will be stored locally to ensure timely access when required.

Spares inventory will be structured to support maintenance campaigns, with both primary and backup components readily available. Non-retrievable subsea infrastructure, such as flowlines, risers, and umbilicals, will be evaluated to determine appropriate contingency measures.

Tooling availability may be supplemented through participation in a deepwater tool-pool sharing agreement, which remains under evaluation.

15.8.3 Asset Integrity

The AIM program will ensure the integrity of all equipment, systems, and structures throughout the Asset's lifecycle. The program will align with the overarching requirements for asset integrity and safety management, as outlined in the *Framework Regulations* and the *Canada–Newfoundland and Labrador Offshore Area Occupational Health and Safety Regulations* (the *OHS Regulations*). These regulatory requirements will guide the ongoing assurance of technical integrity and operational safety.

Objectives

The AIM program will ensure that the integrity of all systems, equipment, and structures remains aligned with their original design intent and are preserved throughout the Asset's operational life. Any deficiencies will be systematically identified and effectively addressed.

Key objectives of the AIM program will include:

- Optimizing scope and frequency of integrity activities through risk-based assessments, industry best practices, and precedents from existing operations in the Canada-NL offshore area;
- Applying comprehensive operational performance standards to SECEs;
- Using standardized, documented processes to inspect, verify, assess, and report integrity in alignment with the management system;
- Integrating integrity data and assessments from all sources into a dynamic, asset-wide dashboard that communicates the status of barriers and their underlying SECEs;
- Leveraging a customizable integrity information management platform that connects engineering, inspection, maintenance, and other data sources (e.g., digital twin);
- Implementing an assurance process to evaluate performance and drive continuous improvement; and
- Minimizing manual data processing to enhance accuracy, efficiency, and quality through computerized data capture and processing technologies.

Integrated Model

As operator, Equinor will remain accountable for the performance of the AIM program and compliance with applicable requirements. To support this accountability, Equinor will collaborate with the FPSO contractor to manage a unified AIM program encompassing the FPSO, SPS, and wells.

The FPSO contractor will implement an FPSO-specific AIM Plan, leveraging their corporate management systems and operational experience. This plan will cover all FPSO elements, including the hull, topsides, turret, and moorings, which the contractor is responsible for operating and maintaining. In parallel, Equinor will deploy a Subsea and Well AIM Plan built on its corporate frameworks, such as the Well Integrity Management System, supported by performance standards, technical requirements, and global expertise.

Both AIM Plans will be interconnected, forming an integrated Asset integrity model that delivers a comprehensive, continuously updated view of barriers and SECEs. Shared dashboards will be accessible to both Equinor and the FPSO contractor, offshore and onshore, ensuring a common understanding of the Asset's integrity status.

Dedicated, local AIM engineers from both Equinor and the FPSO contractor will deliver their respective plans. These teams will collaborate closely to execute the overall AIM program, supported by corporate integrity resources, as needed, to share best practices and lessons learned from the broader operations portfolio.

Assurance

Equinor will implement a robust AIM program assurance process with two key dimensions: a continuous monitoring process using AIM dashboards to track performance and compliance, and a periodic audit process to evaluate both Equinor's and the FPSO contractor's AIM plans, driving continuous improvement.

The FPSO contractor will conduct internal assessments of its AIM Plan performance and share findings with Equinor.

DNV as CA will approve the overall AIM program, performance and compliance as part of its certification responsibilities.

Equinor will use an internal platform to communicate the Asset's integrity status within the organization.

15.8.4 Regulatory, Certification and Classification

Refer to Section 11.1 Regulatory, Certification, and Classification Basis for additional information.

15.9 Logistics

15.9.1 Overview

Equinor is actively developing a comprehensive logistics strategy aimed at maximizing the use of existing infrastructure and fostering collaboration with other offshore operators in the Canada-NL offshore region. This strategy is designed to support both current and future operations, including the Project, and aligns with Equinor's broader AOM and regulatory commitments.

Logistics operations will require a combination of Offshore Support Vessels (OSVs) and long-range helicopters. These assets will be secured through contracts that may include provisions for asset sharing across operators in the basin, promoting efficiency and reducing duplication of services.

All logistics assets, whether marine or aviation, will operate between the East Coast of Newfoundland and the Project Area, and will be fully compliant with applicable regulations, including those set by Transport Canada and the C-NLOER.

The logistics strategy also includes:

- Implementation of digital logistics tools for tracking, manifesting, and compliance; and

- Integration of ice management, weather forecasting, and emergency response capabilities into the logistics framework.

This approach ensures that Equinor's logistics are robust, scalable, and adaptable to the evolving regulatory landscape and operational needs of the project.

The criteria for operations in the Canada-NL offshore area include weather, installation type, shore base distance, and supply base facility.

The logistics and procurement teams will ensure the provision and management of onshore warehousing, transportation and shore base activities in support of Equinor's offshore activities. The team will work in conjunction with both onshore and offshore suppliers to ensure safe and timely receipt, transportation, delivery, storage and return of facilities, equipment, materials and supplies, as well as transportation of personnel. Due to the remote location offshore, and relatively limited storage space available on offshore installations, regular replenishments via vessel and personnel movements by helicopter are necessary. A concentrated effort has been made to include current best practices and lessons learned from similar Equinor ASA operations, as well as input from other operations in the Canada-NL offshore area.

Logistics Roles and Responsibilities

Oversight and planning for the logistics and warehouse requirements for operations reside with the operations team working closely with the procurement teams. Key responsibilities include, but are not limited to:

- Ensure aviation and marine resources and shore-based facilities are adequate and are managed in a safe and environmentally prudent manner;
- Ensure compliance to Equinor's company management system;
- Ensure digital personnel tracking and cargo logistics tools are updated and maintained regularly for accurate tracking and manifesting;
- Provide advice and support to onshore suppliers and the broader Project team in matters relating to logistics and materials control;
- Interface with aviation, marine and shore-based contractors and government authorities to ensure compliance with applicable regulatory requirements, including those relating to health, safety and environmental protection;
- Support Equinor's onshore IMT as required;
- Attend and participate in group safety meetings during site visits to support vessels and shore-based facilities; and
- Assist, as required, in the investigation of incidents and other high potential events involving aviation, marine and shore-based facilities.

The logistics function will be staffed appropriately to support all operational requirements, including drilling, production and subsea activities. This team will be responsible for managing marine, aviation, and shore base services, ensuring alignment with Equinor's logistics strategy and operational processes.

The logistics discipline is part of the Supply Chain group and reports to the Operations organization as the designated task owner. The team will serve as the primary interface for day-to-day coordination of vessel and aviation movements, cargo prioritization, and shore base activities.

Movement of Personnel and Materials

Movement of personnel is a key requirement within the logistics process. All operational and support personnel will crew change on a regular rotational basis.

The primary means of personnel movement to and from the offshore installations will be via helicopter and carried out in accordance with local regulatory requirements and industry best practices as outlined in the Equinor Canada Ltd. Offshore Newfoundland Helicopter Operations Manual. There may be times during adverse weather or due to helicopter unavailability that movement of personnel via OSV may be required. Local regulatory requirements and industry best practices apply.

In addition to personnel movements, there will be a limited need to transport freight by air. Carriage of freight can normally be accommodated on crew-change flights if permitted, but additional dedicated freight flights may be required.

The primary means of materials and equipment movement to and from the offshore installations will be via OSVs and carried out in accordance with local regulatory requirements and industry best practices as outlined in the Equinor Canada Ltd. Offshore Newfoundland Marine Operations Manual.

Coordination with FPSO and Drilling Contractors

Equinor will maintain close coordination with the FPSO and drilling contractors to ensure seamless integration of personnel and material logistics. This includes aligning schedules for crew changes, cargo transfers, and supply runs to optimize vessel and helicopter utilization. The logistics strategy will incorporate shared planning tools and communication protocols to facilitate real-time updates and minimize operational disruptions.

15.9.2 Support Craft Functional Specifications

Vessel Fleet

All marine operations in the Canada-NL offshore area will be conducted in accordance with the Equinor Canada Ltd. Offshore Newfoundland Marine Operations Manual. An appropriate number of vessels will be utilized to support operations, in alignment with regulatory requirements and Project needs.

Marine Gas Oil (MGO), a type of diesel fuel, is available at several locations along the East Coast of Newfoundland. The loading process involves transferring MGO directly from onshore bulk storage tanks to supply vessels, which then transport the fuel to the Project Area for bunkering to the FPSO and/or drilling installation.

These functional specifications may change during Project development, or due to regulatory updates. Equinor will ensure any changes will be included in the OA application.

General Requirements

- OSVs shall be capable of supporting logistics and resupply operations for offshore installations, including transport of deck cargo, bulk materials, fuel, potable water, and waste, and shuttle tanker escort;
- Vessels must be equipped for safe operations in harsh marine environments typical of the Canada-NL offshore area;
- Station capability to support station-keeping during cargo transfer operations;
- Accommodation and lifesaving equipment must be sufficient for the vessel's crew and any additional personnel required for offshore operations;
- Vessel design should consider ice-class capabilities or seasonal operating constraints, depending on deployment timing and location; and
- An IMR vessel may also be mobilized.

Compliance and Certification

- All vessels must comply with applicable Transport Canada, International Maritime Organization (IMO), and Classification Society standards;
- Certification must include Safety Management Certificate (*International Safety Management [ISM] Code*), International Ship Security Certificate (*International Ship and Port Facility Security [ISPS] Code*), International Oil Pollution Prevention (IOPP) Certificate (Annex I of the *International Convention for the Prevention of Pollution from Ships [MARPOL]*), and Dynamic Positioning System Certification (if applicable); and
- All support vessels must comply with the *Standby Vessel Guideline* [74] and applicable sections of the *Framework Regulations* and the *OHS Regulations*.

Operational Interfaces

- Vessels must be compatible with offshore installation layouts, including crane reach, deck loading, and hose connections for fuel and bulk transfer;
- Communication systems must support integration with offshore control centres and marine coordination teams;

- Cargo handling systems should be designed for efficient loading/unloading and include provisions for hazardous materials if required; and
- Interfaces for waste management, backload handling, and emergency response support must be clearly defined.

Standby Vessel

Equinor will utilize fully compliant Standby Vessels for all offshore drilling and production operations.

The following requirements will be reviewed and taken into account when selecting the standby vessel:

- Atlantic Canada Standby Vessel Document of Compliance (AC-SBV DOC);
- Fitted with Radar Early Warning System (REWS) to monitor field and subsea assets from fishing and other activities;
- Daughter craft(s) and Fast Rescue Craft (FRC) to be fitted with equipment for person overboard monitoring;
- Survivor rescue equipment;
- Treatment room (hospital) and facilities;
- Emergency radio station;
- Firefighting capability;
- Oil spill contingency equipment, including radar;
- Inter-field cargo transfer capability (deck space);
- Potable water and diesel storage on-board the standby vessel for resupply of the FPSO; and
- Minimum crew as specified by Transport Canada Minimum Safe Manning Certificate.

Sailing

Table 15.3 outlines ports that are commonly used for operations. Final port selections have not yet been determined and are subject to change based on evolving Project requirements, availability, and regulatory considerations. This list is intended to provide a general reference and not reflect the final configuration.

Table 15.3 Approximate Distances and Times

Port	Distance (NM)	Sailing Time (Hours)
St. John's	~256	~ 24 Hours

Use of Supply Vessel for Crew Change and Walk-to-Work Solution

Movement of passengers via supply vessel will be utilized in situations where helicopter flights are unable to transfer passengers to the installation for any reason. This service is coordinated by the helicopter operator.

In addition to the traditional FROG transfer device used in the Canada-NL offshore area, the Project is evaluating a Walk-to-Work (W2W) solution to be installed on one of the supply vessels for mobilization and demobilization of personnel for high offshore activity, routine passenger transfers, and demobilization, as required, and a decision will be made during the next phase of the Project. The *Transportation by Vessel to or from a Workplace in the Atlantic Canada Offshore Petroleum Industry: Code of Practice* [75] will be utilized during all passenger transfers.

15.9.3 Aircraft Functional Specifications

The proposed aircraft for Project operations will be a twin-engine, multi-role helicopter designed for offshore transport and Search and Rescue (SAR) in harsh marine environments such as the Project Area. The chosen aircraft will have to meet stringent safety, regulatory, performance, and operational requirements, including flight in known icing conditions and extended overwater missions.

This specification outlines the high-level functional and regulatory requirements for helicopters supporting offshore crew change and SAR operations in the Canada-NL offshore area.

These functional specifications may change during Project development, or due to regulatory updates. Equinor will ensure any changes will be included in the OA application.

General Requirements

- The helicopter shall be capable of safe and efficient transport of personnel to and from offshore installations, including the FPSO and drilling installations, under varying environmental conditions; and
- SAR helicopters shall be equipped for 24-hour operations, including variable-speed rescue hoist, signalling and marking appliances, life raft systems for air deployment, and equipment for retrieving single and multiple persons from the water.

Compliance and Certification

- All helicopter operations shall comply with applicable requirements of the Transport Canada aviation regulations, *OHS Regulations*, *Accord Acts*, and Equinor Canada Ltd. Helicopter Operations Manual and associated Canadian Association of Petroleum Producers (CAPP) Codes of Practice; and
- Helicopter operators must provide certified aircraft and qualified crew, maintain aircraft in accordance with manufacturer and regulatory requirements, and operate under a management system accepted by Equinor and regulatory authorities.

Operational Interfaces

- Helicopters must be able to land on certified helidecks or perform hoisting operations from vessels or installations;
- Vessels must be capable of establishing communications and orienting appropriately for safe helicopter approach and departure; and
- Alternate crew change methods (e.g., W2W systems or supply vessels) shall be available when helicopter operations are not feasible.

15.10 Process Design Characteristics

The process characteristics in the operation phase will be aligned with the parameters and specifications described in Section 12.1 Floating Production, Storage, and Offloading Facility and Section 12.2 Subsea Production System, and their relevant subsections.

15.11 Ice Management

Equinor and its contractors will establish an integrated Ice Management Plan. The primary focus will be on the safety of offshore personnel, the environment and the facilities, encompassing drilling, installation, production and other simultaneous field operations to satisfy operational requirements in accordance with the *Framework Regulations.* The plan will outline responsibilities for ice surveillance, monitoring and reporting, as well as necessary steps to manage ice hazards that may lead to unacceptable risk exposure.

The Ice Management Plan will draw on the cooperation of existing ice surveillance/management efforts in the area and will incorporate all available information.

15.11.1 General Program Overview

The FPSO is designed as an ice strengthened -and disconnectable facility. An Ice Management System (IMS) will be established which will consist of all activities carried out with the objective to mitigate ice situations by reducing or avoiding actions from any kind of ice (sea ice or icebergs), and may include:

- Ice surveillance system, including detection, tracking and forecasting of ice features;
- Ice situational assessment and alerting system;
- Physical iceberg management by the supporting ice management vessels;
- Procedures associated with the safe avoidance of hazardous ice;
- Documentation of ice management performance to ensure continuous improvement;
- Relevant procedures associated with the safe shut-down of production (refer to Section 15.13 Disconnection); and

- A system for communicating a "common operating picture" in order to manage assets and ensure situational awareness across installations/shore.

An integrated Ice Management Plan addressing all aspects of the Project, including drilling, installation and production activities, will be developed in accordance with the applicable requirements in the *Framework Regulations*, and will draw upon the *Contingency Plan Guideline* for additional guidance and best practices. As required by the *Framework Regulations*, the Project Ice Management Plan will be submitted as part of the OA application.

Assessment and alerting will involve the assessment of potential consequences from incoming sea ice and icebergs (with and without physical management) and communication of the alert level to the OIM.

Physical iceberg management will be used to deflect icebergs off their drift course using field proven techniques such as, towing with lines or nets, water cannons, or propeller wash, among others. Such techniques have been extensively used in open water in the Canada-NL offshore area. Vessels will have the necessary equipment to manage icebergs (tow cables, iceberg nets, water cannons) and additional vessels can be mobilized in case of arrival of icebergs.

Operation specific (e.g., drilling installation, production installation, etc.) Ice Management Plans will be established based on the general ice management plan for FPSO Operations, revised based on accepted sea ice and iceberg risk criteria.

15.11.2 Limitations of Ice Management Plan

The Ice Management Plan will be based on years of operational experience obtained offshore NL and internationally.

A surveillance protocol will be developed using multiple techniques that will ensure situational awareness is maintained and to reduce the limitations of the overall surveillance system.

Physical iceberg management utilizes proven techniques and equipment, such as iceberg ropes and nets. Limitations are associated with sea state and visibility that hinder safe deployment and recovery of equipment. Early detection of ice hazards and mitigation in addition to introduction of new technology (see Section 19.3 Innovation) will increase management success.

15.12 Physical and Environmental Conditions Monitoring

Monitoring of atmospheric, oceanographic and ice parameters will be established at the drilling and production installations to satisfy operational information requirements in adherence with the *Framework Regulations*.

Per the *Framework Regulations*, a Physical and Environmental Conditions Monitoring Program will be developed that details the weather, oceanographic and ice observing, forecasting, and reporting programs to be employed for the Project. A program description, including associated plans, such as the ice management plan, will be provided to the C-NLOER as supporting information for an OA. The program description will include information on physical environment monitoring equipment to be used, frequency of monitoring, forecasting and reporting to be undertaken. The program will be developed, implemented, and maintained by Equinor and the FPSO contractor working with local contractors experienced in the provision of physical and environmental conditions monitoring services.

Components of the physical and environmental conditions monitoring may include, but not necessarily limited to the following:

- Meteorological and oceanographic monitoring;
- Sea ice and iceberg forecasting, monitoring and tracking;
- Aviation weather monitoring, observing, forecasting and reporting;
- Marine weather and sea state monitoring, observing, and reporting;
- Weather forecasting;

- Oceanographic forecasting;
- Data management; and
- Annual physical environmental regulatory reporting.

Observational data will be shared with federal government agencies, which use the data to improve national forecasting and observational programs and provide improved situational awareness to government and private-sector meteorologists for marine and aviation forecasting.

Data that will be shared with federal government organizations may include the following:

- Meteorological data - shared with Environment and Climate Change Canada (ECCC);
- Oceanographic data - shared with Fisheries and Oceans Canada and ECCC; and
- Ice and iceberg data - shared with Canadian Ice Services.

15.12.1 Forecasting

Equinor and the FPSO contractor will develop and implement meteorological and oceanographic forecasting program(s) for all marine phases of the Project. The forecasting program shall meet the requirements specified in the *Framework Regulations*. Forecasting program(s) will be developed for site-specific marine weather and sea state forecasting, aviation forecasting and ice and iceberg forecasting.

Types of forecasts to be included in the program may include the following:

- Site specific forecasts;
- Aviation forecasts; and
- Ice and iceberg forecasting.

Site-Specific Weather Forecasting

Regular site-specific forecasts will be issued to facilities operating in the Project Area. Parameters may include:

- Location;
- Time of forecast;
- General synoptic condition;
- Wind speed/direction;
- Wind gust/direction;
- Total sea state height/period/direction;
- Wind sea height/period/direction;
- Swell height/period/direction;
- Vessel motion (heave, pitch, and roll);
- Weather conditions;
- Precipitation and obstructions to vision;
- Visibility;
- Air temperature; and
- Extended outlook.

Aviation Forecasts

Regular aviation forecasts will be provided and may include the following parameters:

- Helicopter route sea state forecasts;
- Helicopter route flight level winds and temperatures; and
- Site specific forecasts of visibility, ceiling (or vertical visibility), winds, freezing precipitation, obstructions to visibility, and other.

Ice and Iceberg Forecasting

During the ice season, forecasts of ice and iceberg trajectories will be provided to the drilling and production installations and all project vessels using standard sea ice and iceberg forecasting models. The frequency of ice forecasts will depend on local ice conditions. Parameters may include:

- Sea ice - type, thickness, floe size, concentration, other; and
- Icebergs - size, shape, length, width, height, drift speed, direction.

Multiple observation sources may be used to provide ice and iceberg forecasting including Canadian Ice Service, International Ice Patrol, dedicated fixed wing aerial reconnaissance, installation radar system, satellite images, support vessel ice reconnaissance operations, among others. Drift modelling will use drift models from the National Research Council and Canadian Ice Service. The Ice Management Plan (Section 15.11 Ice Management) will provide information on ice forecasting and drift modelling.

15.12.2 Environmental Conditions Monitoring Systems

Environmental conditions monitoring system will be designed in accordance with the *Framework Regulations*. The system will monitor physical and environmental conditions, including sea states and ice movements. This information will be used to assist in the transfer of personnel, supplies and offloading to the shuttle tanker. In addition, the information will be used to assist with emergency response actions.

Environmental conditions monitoring may include the following:

- Waterline elevation;
- Wave height;
- Barometric pressure;
- Wind speed/direction;
- Current speed/direction; and
- Visibility.

15.13 Disconnection

The disconnection system is designed to safely disconnect the FPSO from the STP disconnectable buoy, and is described in Section 12.1.2.5 Disconnection and Reconnection System. The need for disconnection capability arises primarily from the risks posed by icebergs and sea ice (refer to Section 15.11 Ice Management). There are two modes of disconnection that the FPSO is designed for: planned and emergency. Table 15.4 outlines the preliminary measures to be implemented in preparation of a disconnection.

Table 15.4 Preliminary Disconnection Measures

	Emergency disconnection	Planned disconnection
Stop production and secure wells	X	X
Depressurize production and gas injection lines		X
Flush risers		X
Isolate risers	X	X
Flush flowlines - Bay du Nord (South)		X
Flush flowlines - Bay du Nord (North)		X*
Flush flowlines - Cambriol		
Depressurize topsides	X	X
Isolate flowlines	X	X
Prepare to sail away under own propulsion	X	X
Disconnect FPSO	X	X

* *Bay du Nord (North) flowline to be swept with hydrocarbon gas and MEG for planned disconnection.*

15.14 Contingency Planning

15.14.1 Overview

One principle of Equinor's emergency management philosophy is to prevent emergencies. In the unlikely event an emergency occurs, the primary objectives are to reduce the impact of an emergency on people, environment, and the integrity of offshore assets. An emergency is defined by Equinor as any unexpected occurrence resulting in or having the potential to result in:

- Death or serious injury / illness requiring hospitalization;
- Environmental impact;
- Major or significant damage to Equinor or contractor property; and/or
- Concern for the integrity of Equinor operations in the eyes of the public or regulatory agencies.

Equinor will develop interrelated contingency plan documents in accordance with the applicable requirements in the *Framework Regulations*, and will draw upon the *Contingency Plan Guideline* for additional guidance and best practices. As required by the *Framework Regulations*, the contingency plans will be submitted to the C-NLOER as part of the OA application. Potential emergencies will be identified in operations-specific hazard and risk analyses. The plans will outline the necessary procedures, personnel, equipment, and logistics support required to respond to an emergency event in a safe, prompt, coordinated manner. The plans will be distributed to designated personnel who will be responsible for emergency response actions. The content of the plans will contain sufficient detail to enable personnel to respond in a coordinated and effective manner.

Examples of contingency plans that will be developed for the Project to address emergency events, and are aligned with those outlined in the Environmental Impact Statement (EIS) [4], and listed below (plan titles are subject to change):

1. Offshore Emergency Response Plan – provides very specific role descriptions for personnel for a number of potential emergencies and provides a link between offshore operations and onshore responders.
2. Vessel Collision Avoidance Plan – identifies potential collision situations involving the drilling installation, FPSO and other Project vessels, describes communications with the threatening vessel and lists actions to be taken on the drilling installation and FPSO in the event the threatening vessel does not respond.
3. Ice Management Plan – defines roles, responsibilities, and procedures necessary for mitigation including surveillance, physical management, preparation for disconnection, and relocation (refer to Section 15.11 Ice Management for additional details).
4. Oil Spill Response Plan – defines procedures for first response to spills originating at the production and drilling installations, and tankers during offloading, and includes consideration of various spill response tactics within the context of a Spill Impact Mitigation Assessment (SIMA) and includes a Wildlife Response Plan.
5. Well Control and Containment Plan – describes the procedures and operations associated with subsea source control and containment and includes a Well Capping Plan and a Relief Well Contingency Plan.

15.14.2 Response Organization and Processes

An Emergency Response Plan (ERP) will be developed in accordance with Equinor ASA, its contractors, and local regulatory requirements. The process of establishing the ERP is based on the identification and management of risks as outlined in Section 16.3 Risk Identification and Analysis. The ERP will address all major hazards, based on Defined Situations of Hazards and Accidents (DSHA), and will be updated as necessary throughout the life of the Project.

While the number of OAs required for the various Project phases (e.g., construction, installation, commissioning, drilling, production, etc.) has not yet been determined, each OA will be supported by a dedicated ERP tailored to its scope and activities and applicable contractors. If it is determined that a single OA will be pursued, then a comprehensive Project ERP will be prepared and updated, when required, to reflect changes throughout the Project lifecycle.

Priorities in managing the response are based on the PEAR principle:

- **P**rotection of Personnel;
- Minimize impact on the **E**nvironment;
- Minimize impact on **A**ssets (as it may affect human or environmental safety); and
- Protection of company **R**eputation.

The objective of emergency preparedness and response is to prevent or reduce the consequence of loss or damage based on PEAR priorities. The Project's emergency response systems and plans will have appropriate performance standards and associated verifications schemes. Personnel identified as part of the emergency response organization, as outlined below, will complete emergency preparedness training as required. Equinor Canada and its contractors' emergency preparedness organizations will be equipped to handle hazards, accidents and significant security-related incidents.

When an emergency response is implemented, the organization for emergency response, including Equinor contractors, consists of three levels of authority and responsibility:

1. Emergency Response Team (ERT) - Tactical Level

- On-scene command and management (e.g., rescue, response, evacuation), on-scene combating and cooperation with local rescue services, and
- Request for support from IMT.

2. Incident Management Team (IMT) - Operational Level - St. John's, NL

- Incident command;
- Guidance/coordination with ERT and local and national authorities; and
- Request support from CMT, as required.

3. Crisis Management Team (CMT) - Strategic Function - Emergency Response Centre - Stavanger, Norway

- Implementation of strategic actions to minimise consequences for the company;
- Maintains contact with corporate management, customers and stakeholders; and
- Coordination with Equinor ASA Global Incident Management Assist Team (GIMAT).

There are specific requirements for each level where plans for ERT and IMT must be developed to site-specific requirements (including local laws and regulations) in addition to Equinor ASA requirements. The chain of command to be maintained during an emergency flows from ERT to IMT to CMT.

The Project ERP may include the following:

- Equinor and contractors' organization, roles and responsibilities, and procedures for emergency response and control of incidents and accidents; will include any requirement for bridging of ERP between Equinor Canada and its contractors;
- Procedures and systems for the provision of Temporary Safe Refuge (TSR), evacuation, rescue, recovery, and medical treatment (including telemedicine) of personnel on the installation;
- Procedures and systems to control communication between Project installations/vessels and the IMT in the Equinor offices in St. John's, and with local and national authorities;
- Procedures for internal and external communication;
- Control of Project-specific emergency events, including integration with emergency procedures on any interfacing installations within the established safety zone(s) for the FPSO and with any drilling installations and/or construction vessels that may be operating on the field from time to time; and
- Arrangements for emergency response training and testing of emergency systems and procedures.

15.14.3 Vessel Collision Avoidance

Vessels transiting in close proximity to the operations site pose a potential threat to the FPSO, drilling installation, and shuttle tanker during offloading operations. Equinor will have vessel surveillance and collision avoidance procedures in place to protect personnel, installations, and Project support vessels working in the area. Equinor and/or the contractors (e.g., FPSO, drilling) will notify marine users via the Navigational Warnings (NAVWARNs) notification system regarding the location of the FPSO and subsea infrastructure and drilling installation. The coordinates of the FPSO and subsea infrastructure will be provided to Canadian Hydrographic Services (CHS) for inclusion on marine charts.

Equinor will establish safety zones in the Project Area in accordance with applicable regulatory requirements.

A radar watch for the FPSO, drilling installation and standby vessel will be maintained at all times to monitor vessel movements in the vicinity and be prepared to react accordingly should the possibility of collision develop. The radar watch may be conducted on-board each installation or remotely.

Any approaching vessel will be alerted by radio as early as possible to take avoiding action. In the event that this is unsuccessful, the standby vessel will attempt to intercept the approaching vessel and make further efforts to attract its attention including but not limited to the use of radio, lights, water cannon, foghorn, and pyrotechnics.

A Project Vessel Collision Avoidance Plan will be developed in accordance with the applicable requirements in the *Framework Regulations*, and will draw upon the *Contingency Plan Guideline* for additional guidance and best practices. As required by the *Framework Regulations*, the Project Collision Avoidance Plan will be submitted as part of the OA application.

15.14.4 Environmental Contingency Planning

The list of proposed contingency plans in Section 15.14.1 Overview considers environmental contingency planning aspects. The list of proposed contingency plans is aligned with those listed in the EIS [4]. Equinor will develop interrelated contingency plan documents in accordance with the applicable requirements in the *Framework Regulations*, and will draw upon the *Contingency Plan Guideline* for additional guidance and best practices. As required by the *Framework Regulations*, the contingency plans will be submitted to the C-NLOER as part of the OA application.

As required by the Environmental Assessment (EA), in the event of an oil spill or unplanned release of other pollution that may cause adverse environmental effects, Equinor may have to conduct environmental monitoring. This will be determined by the C-NLOER and potentially other regulatory departments.

Equinor will comply with applicable EA conditions in the Accidents and Malfunctions section of the Decision Statement [3].

16 Safety Management

16.1 Introduction

Safety, security, and risk management are integrated (Figure 16.1) into the Equinor ASA Management System (EMS) as described in Section 14 Management System. They are also reflected in The Equinor Book, policies, Function Requirement documents, and global governing documents and work processes. This framework provides the basis under which Equinor incorporates health, safety, risk management, and security throughout the value chain and will develop the Bay du Nord Project (the Project).

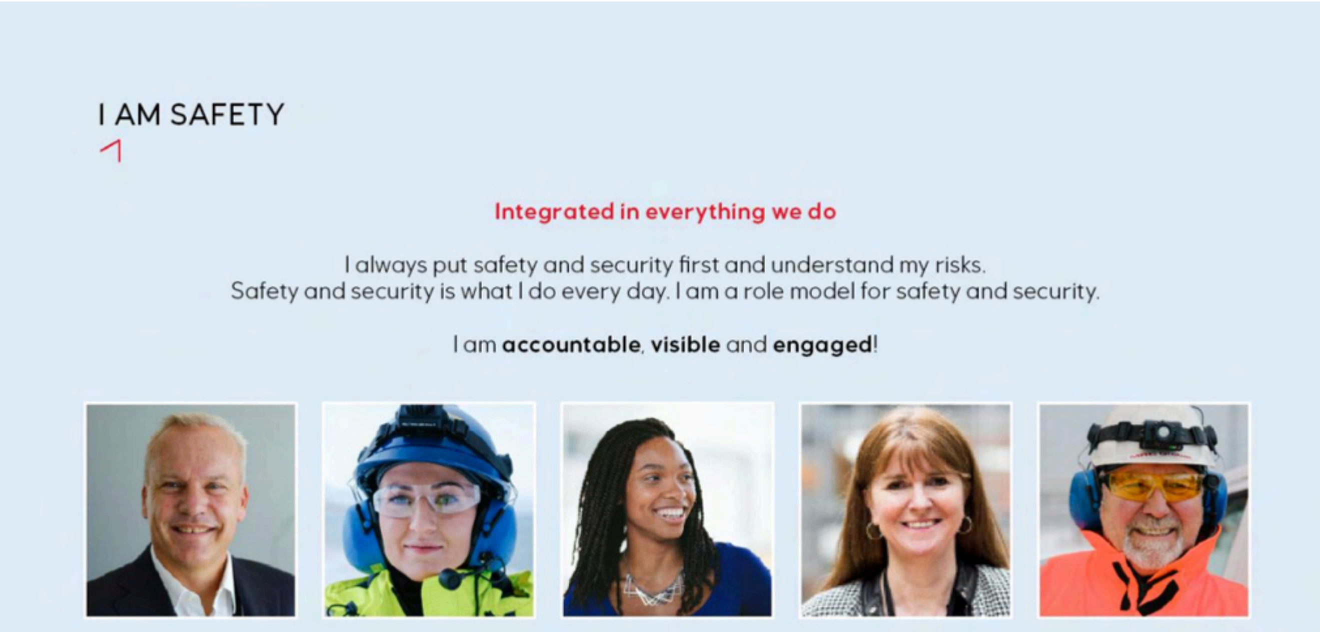


Figure 16.1 I Am Safety

Equinor's safety and security vision is zero harm. We are committed to providing a safe, healthy, and secure environment for all personnel at our facilities and job sites, preventing accidents and incidents from affecting people, environment, and assets. To build a culture that is "Always Safe" will require consistent use of "I am Safety" expectations, security rules, Life-Saving Rules[4], and a continued focus on building a proactive safety culture applying Human and Organizational Performance (HOP) Principles.

Refer to the following sections for additional information applicable to safety and security management:

- Section 14.2 Proposed Management System Strategy for the Project; and
- Section 15.4 Training and Competency.

The objective of risk management is to establish a systematic approach to identify, assess, manage, and communicate potential risks. It furthermore provides a common platform to ensure identification, ownership, and follow-up of risks in all Decision Gate (DG) phases (refer to Section 1.1.8 Approach to Project Management). The risk management process covers all activities from design through to operations and incident investigation. It is a continuous process that plays a vital role in safety, security, and environmental management. The risk management process within the EMS provides a structured approach to Major Accidental Hazards (MAHs) and the potential resulting Major Accidental Events (MAEs) that may arise from unintentional incidents or planned operations. The risk management process ensures compliance with the applicable regulatory requirements and demonstrates that risks are As Low As Reasonably Practicable (ALARP).

16.2 Concept Safety Analysis and Target Levels of Safety

A Project Concept Safety Analysis (CSA) [9] has been developed in accordance with the applicable requirements in the *Canada–Newfoundland and Labrador Offshore Area Petroleum Operations Framework Regulations* (the *Framework Regulations*). The following paragraphs and sub-sections provide a description of its contents and summarize the findings of the study.

The CSA considers all activities associated with each phase in the lifecycle of the development. This includes offshore construction, installation, operations, and decommissioning, as well as all installations, facilities, equipment, and systems that are proposed as part of the development concept. The operational phase has been reviewed and assessed quantitatively, whereas the other phases of operation are addressed qualitatively.

The scope of the CSA covers all systems that are potentially subject to major hazards to life or the environment, including the Floating Production, Storage, and Offloading (FPSO) facility, Turret and Mooring System (TMS) and offloading facilities; the Subsea Production System (SPS) and wells; and personnel transport to and from the FPSO. The scope does not include drilling installations, supply and standby vessels, or tankers.

16.2.1 Identification of Major Accidental Events

MAE is defined in the *Framework Regulations* as *"an unexpected or unplanned event or circumstance or series of unexpected or unplanned events or circumstances that may lead to the loss of more than one life or uncontrolled pollution"*.

The CSA [9] identifies all hazards having the potential to cause a MAE. It includes a detailed and systematic assessment of the unmitigated risks associated with each of those hazards, including the likelihood and consequences of each potential MAE.

Hydrocarbon releases from the production installation, including the FPSO, SPS, and wells, can lead to a variety of different consequences including:

- Loss of Containment (LOC) of hydrocarbon containing systems that have the potential to result in fires and explosions on the FPSO;
- Releases subsea and in the vicinity of the FPSO from the risers and flowlines that have the potential to result in fires or pollution; and
- Releases from the subsea wells or blowouts that are remote from the FPSO but may impact on drilling installations or vessels that are operating in the area.

Refer to the Environmental Impact Statement (EIS) [4] for pollution related risks.

A number of non-hydrocarbon or non-process related events were identified that have the potential to cause human injury/loss or damage to assets. Some of these events may be significant risk contributors, and therefore required consideration, while others were screened out as not having the potential to lead to fatalities. A brief description of these latter hazards are provided in the CSA.

The first step in the CSA was a formal Hazard Identification (HAZID) session that allowed the identification and the qualitative assessment of the following MAEs associated with the production installation:

- MAE1 - LOC of hydrocarbon gas (including 2-phase, hydrocarbon liquid/gas mixtures);
- MAE2 - LOC of hydrocarbon liquid;
- MAE3 - Hull tank fire/explosion;
- MAE4 - Non-process fires;
- MAE5 - Accommodation fire;
- MAE6 - Helicopter accident;
- MAE7 - Ship collision;
- MAE8 - Structural failure;
- MAE9 - Dropped/swinging objects;

- MAE10 - Loss of mooring;
- MAE11 - Loss of stability and buoyancy;
- MAE12 - Iceberg collision; and
- MAE13 - Hydrocarbon release risers and flowlines subsea.

The pre-Front-End Engineering Design (pre-FEED) HAZID exercises for the FPSO and SPS scopes were completed as formal workshop sessions, involving the relevant Project members of the hull, turret and moorings, topsides, and subsea design teams, and the operations team. A HAZID had been completed in the previous phase, using the same TMS concept, to evaluate the buoy disconnection/reconnection process involving the relevant members of the FPSO and SPS teams. In all cases, the HAZIDs also included previous experience, knowledge, and lessons learned from the existing facilities in the Canada-NL offshore area.

The key hazards that were identified, as well as safeguards in place to prevent, control, mitigate, and provide emergency response against the hazards, have been carried into the CSA to assess the risks to personnel, the Temporary Safe Refuge (TSR), escape and evacuation provisions. The primary focus of the HAZIDs was on the operational phase of the FPSO. The construction, installation, and decommissioning phases were discussed during the HAZID only at a high level given limited information at this early stage of the Project.

Following assessment of the risk levels at the concept stage, a qualitative ALARP workshop was completed to determine if any additional measures should be considered to reduce the risks further. This process is described further in Section 16.2.4 Risk Reduction Measures.

16.2.2 Target Levels of Safety

Target Levels of Safety (TLS) for the risk to life and the risk to the environment are established in the CSA [9] and related assessments. The TLS are based on assessments that are quantitative, where appropriate input data are available, and qualitative, where quantitative assessment methods are inappropriate or not suitable.

16.2.2.1 Risks to Life

Risk of fatalities can be expressed in terms of Individual Risk Per Annum (IRPA), which is a quantitative measure of the fatality rate per individual per annum. Such a measure can also be expressed as a function of the amount of time that an individual spends on the FPSO. The TLS stipulated for Equinor contain both risk-based and impairment-based criteria. The risk-based criteria are further sub-divided into the following categories:

- Individual Risk (IR); and
- Group Risk.

The IR criteria are the overriding criteria and must be met by the final design. FPSO staffing levels and an assumed personnel distribution [71] are required in order to quantitatively assess the IRPA associated with a facility. The remaining criteria, Group Risk and impairment-based criteria (see Section 16.2.2.3 Impairment-Based Criteria), are provided to allow the assessment of the design when staffing levels have not been defined or are uncertain, or when the overall risk assessment is still at a preliminary stage. Such criteria are used for design guidance only, specified to allow design of the facility to proceed as the Project progresses.

The risk criteria applied to the Project design are consistent with Equinor's technical requirement. The criteria for personnel are based on the definition of 1st persons (i.e., an individual or group who are involved in work at Equinor's installation).

The average IRPA, expressed by Fatal Accident Rate (FAR), is calculated for people at work. For offshore facilities, "at work" means all the time a person is on the installation as well as during transport to and from an installation or between installations. FAR is the number of fatalities per 100 million exposed hours (approximately 1,000 worker lifetimes).

The risk shall meet the following criteria:

- A FAR of less than 10, calculated as an average for all personnel on the installation, which is equivalent to an IRPA of 4.4E-04 for a worker who spends 50% of their time offshore (i.e., (10 / 1E+08) x 8760 x 0.5); and
- A FAR of less than 25 for particularly exposed groups on the installation, which corresponds to an IRPA of 1E-03 for a worker who spends 50% of their time offshore (i.e., (25 / 1E+08) x 8760 x 0.5).

Group risk has been presented as Potential Loss of Life (PLL), based on the number of fatalities per annum. There are no specified criteria or TLS for PLL, with the primary risk target being IR.

16.2.2.2 Risks to the Environment

Probability analyses of offshore spills and blowouts were conducted in support of the EIS [4]. The analyses considered the probability of both continuous, larger scale blowouts, as well as smaller scale, instantaneous, batch spills. The probability of various kinds of potential spill releases and well blowouts and their respective volumes were analyzed. Refer to Section 16.3 of the EIS for additional details on spill risk and probabilities.

Oil spill trajectory modelling was required for the EIS [4]. Based on Project activities and potential environmental risk, the following spill scenarios were selected for detailed spill fate and behaviour modelling, and effects assessment: subsurface blowouts, batch crude oil spills, and batch diesel spill. Refer to Section 16.4 and 16.7 of the EIS for additional details on fate and behaviour of potential spills and effects assessment, respectively.

16.2.2.3 Impairment-Based Criteria

Impairment-based criteria can be used during the concept development and design phase to determine which possible MAEs have the potential to cause multiple-fatality accidents. When the impairment-based criteria are not exceeded, the accident can be considered to have low potential for preventing the escape of personnel away from the accident; or for threatening the integrity of the installation, the safe refuge, or the means of evacuation within a time period that is long enough to safely evacuate personnel. Meeting impairment-based criteria may not guarantee that the IR criteria are met, but it will, however, make it more likely.

The impairment-based criteria are stipulated for the following installation safety functions:

- Installation's primary structure;
- TSR;
- Escape routes back to the TSR; and
- Availability of the evacuation systems from the FPSO to a place of safety.

For the above functions, the impairment-based criterion that has been applied is that the frequency for loss of integrity to the installation's key safety functions from any single MAE should not exceed 1E-04 per annum.

16.2.3 Results of the Risk Assessment

The CSA [9] includes a quantitative assessment of the MAEs listed in Section 16.2.1 Identification of Major Accidental Events.

Risk to life estimates are dependent on the personnel distributions that are used in the analysis, with two separate staffing scenarios being assessed:

- Maximum Staffing – a Personnel on Board (POB) of 120 represents the maximum staffing level, which occurs during commissioning and start-up operations; and
- Minimum Staffing – a POB of 79 has been used in this analysis, based on a preliminary assessment of the steady state crew of 60 for the FPSO and 19 visitors.

Further analysis will be carried out by Equinor and contractors during the design phase to determine the necessary operations, maintenance, and emergency response organization. This will be based upon equipment selection, simultaneous operations, and the operating model. An updated risk analysis for the selected minimum POB case will be performed in the Quantitative Risk Assessment during detailed design.

Occupational risks are also considered. The occupational risks relate to the hazards associated with performing work offshore (e.g., hazards such as falls, crushing mechanical impacts, electrocution, etc.). The FARs used in the CSA are based on information published by the United Kingdom Health and Safety Executive (UK HSE) over a period from 1991 to 2024. The FAR values are converted to IR per annum by taking into account the actual time each year that members of each employment category are exposed to the hazards at the workplace. Conversion of the FARs into IR values is based upon the work pattern for the representative individual within each employment category. For all employment categories, it is assumed that each individual spends 50% of their time at the workplace.

Four representative employment categories are used for the IR calculation, with the offshore occupancy for each worker category based on the typical shift pattern of three weeks on and three weeks off:

- **Administrative personnel** spend the majority of their on-shift time in the accommodations area, but spend some of their time in the process and utilities modules. They will be exposed to the immediate threats of releases within the modules they are working. These personnel typically have a low occupational risk as they spend their time taking readings and checking equipment.
- **Maintenance personnel** perform maintenance throughout the installation. They will spend time in all areas and will be exposed to the immediate threats from releases within the area in which they are working. Maintenance personnel typically have a high occupational risk as they spend their time working with tools, scaffolding, access at height, among others.
- **Operations personnel** spend the majority of their on-shift time in the process and utilities modules. They will be exposed to the immediate threats of releases within the modules they are working. These personnel typically have a low occupational risk as they spend their time taking readings and checking equipment.
- **Catering/Accommodations personnel** work within the accommodations area of the FPSO (e.g. food preparation, accommodations support). These personnel typically have a very low occupational risk as they are not considered to spend any time in the process and utilities areas, so are not exposed to the immediate effects of any hydrocarbon events.

The consequences of each MAE are also assessed to determine the probability of:

- Immediate fatalities;
- Mustering fatalities (unable to access the TSR);
- Fatalities in the TSR due to its potential impairment; and
- Fatalities during evacuation.

The detailed risk assessment results are tabulated in the CSA, including risk results summarized by worker category and by fatality classification against the list of MAEs.

The overall average FAR of 3.97 is well below the TLS of 10 set by Equinor. The highest FAR per worker group (the Maintenance Crew, at 5.45) is predominantly a result of their higher historical occupational risks. It is also well below the Equinor TLS of 25. Therefore the current design meets Equinor's TLS, and the results are considered to be in the ALARP region. The highest contributors to the FAR in descending order are (1) occupational hazards associated with slips, trips, falls, electrocution, etc., (2) transportation, either by helicopter or vessel, and (3) MAEs related to hydrocarbon releases. These are based on historical industry data and are typically high contributors to offshore operations.

The impairment of main safety functions has also been assessed, which includes TSR, escape routes, evacuation, and other identified barriers around the FPSO. A detailed description of each mechanism that can impair the main safety functions, and the results of the analysis, can be found in the CSA. The assessment of main safety functions demonstrated that the current design meets the Project-specific TLS.

The Project is currently in the pre-FEED phase, therefore, there are uncertainties and conservatisms in some of the data used within the risk assessment. In addition, a number of assumptions have been made in order to develop a full risk profile. Details of assumptions, conservatisms, and uncertainties can be found in the CSA. None of the uncertainties are considered likely to change the results significantly or to result in targets not being met, even after more detailed analysis is conducted in later Project phases.

16.2.4 Risk Reduction Measures

The results presented in Section 16.2.3 Results of the Risk Assessment indicate that the current risk levels assessed for the Project fall into the ALARP region, when reviewed against the Project-specific TLS. In order to further review the measures that are included within the design, or additional measures that may reasonably help to reduce the risks further, a facilitated ALARP workshop was held with the design team.

The team reviewed the causes and consequences of the MAEs, then reviewed the safety features that are currently in place to protect the personnel, the environment, and the asset. These were organized into the following categories of safeguard, which are presented in order of preference based on the established hierarchy or risk reduction:

- Inherent Safety;
- Prevention (P);
- Detection (D);
- Control (C);
- Mitigation (M); and
- Escape, Evacuation, and Rescue (E);

A preliminary set of Performance Standards (PSs) have been developed by the contractors and Equinor. Where appropriate, the safety features were mapped against the relevant PSs, provided in Table 16.1.

Table 16.1 Preliminary List of Performance Standards

PS	PS Title
P-01	Structural Integrity Hull
P-02	Structural Integrity Turret, Topsides, Marine Structures
P-03	Hydrocarbon Containment Topsides and Turret
P-04	Hydrocarbon Containment Hull
P-06	Submerged Turret Production (STP) Buoy and Mooring System
P-08	Inert Gas, Vapour Recovery and Purge Gas Systems
P-09	Collision Prevention and Navigation Aids (Marine/Aviation)
P-10	Lifting Appliances and Dropped/Swinging Object Protection
P-12	Electrical Protection
P-14	Cyber Security
P-TBD	Hydrocarbon Containment Subsea and Pipeline - to be developed in the next phase by Equinor and the FPSO/SURF contractors
D-01	Fire and Gas Detection System
C-01	Ignition Source Control
C-02	Emergency Shutdown System
C-03	Flare and Blowdown
C-04	Bilge and Ballast Systems
C-05	Human Machine Interface and Alarm Management
M-01	Open Drains
M-02	Heating, Ventilation, and Air Conditioning (HVAC) Systems
M-03	Passive Fire Protection
M-04	Layout and Explosion Mitigation
M-05	Active Fire Protection
M-06	Helideck Facilities
E-01	Temporary Refuge and Muster
E-02	Escape Routes
E-03	Lifeboats
E-04	Escape to Sea Systems

PS	PS Title
E-06	Rescue and Personal Safety Equipment
E-07	Public Address and General Alarm (PAGA) and Emergency Communication
E-08	Central Battery System (Lighting)
E-09	Emergency Power

Note: *The numbering system is based on the FPSO contractor's corporate PS structure for offshore units. Any PS numbers missing in this table were deemed not relevant for the Project.*

Any additional measures that may provide a benefit were then reviewed by the workshop team and either accepted, actioned for further review, or rejected with the reasons for rejection clearly stated. The findings of the review were subsequently compared to the topsides designs being assessed by Equinor through the pre-FEED phase. The resulting report forms the basis for an ALARP Register that can be expanded in the FEED phase.

During the detailed design phase, the results of the HAZID, CSA, and ALARP Workshop analyses described above will be considered, along with their recommendations, and further analyzed in the studies described in Section 16.3 Risk Identification and Analysis. The detailed PSs for the safety systems and barriers described above will be prepared by Equinor and the contractors. These PSs will be verified by the Certifying Authority (CA).

16.3 Risk Identification and Analysis

In order to systematically identify, evaluate, and mitigate the possible MAHs/MAEs associated with Project activities and to confirm the selection and suitability of appropriate risk reduction measures, Equinor and the contractors may employ engineering and risk assessment techniques, such as:

- HAZID Studies;
- Hazard and Operability (HAZOP) Studies;
- Bowtie Reviews;
- Safety Critical Task Analysis (operational barrier elements);
- Quantitative Risk Assessment;
- Safety Integrity Level (SIL) Analysis and Functional Safety Assessment;
- Smoke and Gas Ingress Study;
- Fire, Explosion and Hazardous Gas Risk Assessment;
- Natural Ventilation Study;
- Vent, Plume, and Exhaust Dispersion Studies;
- Escape, Evacuation, and Rescue Analysis (EERA);
- Ship Collision Analysis;
- Iceberg Collision Analysis;
- Transport and Crash Risk Analysis;
- Human Factors Engineering;
- Working Environment Hazard Risk Analysis;
- Failure Modes, Effects, and Criticality Analysis; and
- Cybersecurity Risk Assessment.

A detailed safety studies program will be developed in the FEED phase, with formal assessments of the FPSO and subsea infrastructure conducted during the detailed design phase. These studies will be reflected in a Quantitative Risk Assessment (QRA), which supersedes the CSA and provides a more substantive assessment of risks and safety, being based on more detailed design information. The QRA and associated studies will also be primary inputs into the Safety Case for the FPSO that will be included as part of the Safety Plan.

Equinor and the contractor will maintain the QRA, the associated safety studies, and the Basis of Safe Operations throughout the life of the FPSO, and these documents will be reviewed to reflect any proposed operational changes or FPSO equipment modifications that are considered to be substantial.

The Equinor ASA Management System (EMS) details the requirements for risk and Emergency Preparedness Analysis (EPA), and gives the requirements for conducting technical risk assessments and EPA. Equinor uses Defined Situations of Hazards and Accidents (DSHAs) for the dimensioning of emergency response on the installations. DSHAs are established through the EPA along with MAHs and Major Environmental Incidents (MEIs), Dimensioning Accidental Events (DAEs), and PSs for emergency preparedness. DSHAs represent possible hazards and accidental events for the installation and activities, and includes DAEs, which are accidental events that are used as the basis of dimensioning, involving the use of the installation and activity in order to meet defined risk acceptance criteria. A preliminary list of DSHAs has been developed in the CSA [9].

Operational line management is responsible for ensuring that procedures are in place for identifying the risks and managing all activities carried out for the Project (e.g., drilling, construction, survey, logistics, installation, hook-up and commissioning, operations and maintenance, etc.). A common management tool used is A-Standard, which helps manage risks effectively and ensure safe and efficient operations (see Section 14.2.3 Management System Tools for additional information).

16.4 Safety Plan

A Project Safety Plan will be developed in accordance with the applicable requirements in the *Framework Regulations*, and will draw upon the *Safety Plan Guideline* [76] for additional guidance and best practices. As required by the *Framework Regulations*, the Project Safety Plan will be submitted as part of the Operations Authorization (OA) application. While the number of OAs required for the various Project phases (e.g., construction, installation, commissioning, drilling, production, etc.) has not yet been determined, each OA will be supported by a dedicated Safety Plan tailored to its scope and activities. If it is determined that a single OA will be pursued, then a comprehensive Project Safety Plan will be prepared and updated, when required, to reflect changes throughout the Project lifecycle.

16.5 Security Plan

A Security Plan, including cybersecurity, will be developed for the FPSO in accordance with applicable requirements from the following:

- *Requirements Respecting the Security of Offshore Facilities* [77];
- International Maritime Organization's (IMO's) *International Ships and Ports Security (ISPS) Code*, as directed by the Canadian *Marine Transportation Security Regulations*; and
- Equinor and/or FPSO contractor requirements.

17 Environmental Management

17.1 Introduction

Environmental management is integrated into the Equinor ASA Management System (EMS) as described in Section 14 Management System, and is reflected in The Equinor Book, Environmental Policy, Function Requirement (FR) document, and global governing documents and work processes. This framework provides as the foundation for Equinor to integrate environmental considerations throughout the value chain and develop the Bay du Nord Project (the Project). The Project's approach to environmental management focuses on the following:

1. Comply with applicable laws, regulations, company policies and requirements;
2. Apply a risk-based due diligence approach to manage relevant environmental aspects;
3. Apply a precautionary approach and the mitigation hierarchy in accordance with international practices and principles;
4. Identify and manage technical and non-technical barriers with the aim of avoiding incidents with a negative impact on the environment. Should such incidents occur, emergency response measures will be activated immediately to mitigate negative environmental consequences. We will work to remedy direct negative environmental consequences in the affected areas; and
5. Monitor and routinely disclose our material environmental impacts, risks, opportunities and performance.

Refer to the following sections for additional information applicable to environmental management: Section 14.2 Proposed Management System Strategy for the Project and Section 15.4 Training and Competency.

17.2 Environmental Planning

Pursuant to the *Impact Assessment Act* (formerly the *Canadian Environmental Assessment Act, 2012* [*CEAA 2012*]), an offshore oil and gas development project must undergo an impact assessment (Environmental Assessment [EA] as per *CEAA 2012*) before its Development Plan can be approved under the *Accord Acts*.

Equinor initiated the EA process for the Project in 2018, making it subject to *CEAA 2012*. A Memorandum of Understanding (MOU) [2] between the Impact Assessment Agency of Canada (IAAC) and the C-NLOER established a joint review process to meet both *CEAA 2012* and *Accord Acts* requirements. Under this MOU, IAAC led the EA process, which lasted approximately three years and included the preparation of a detailed Environmental Impact Statement (EIS) outlining potential environmental effects.

The EA process involved multiple stages of engagement with Indigenous groups and stakeholders, including the general public, fish harvesters/processors, environmental non-governmental organizations, among others. IAAC defined the scope and requirements of the EA in the *Bay du Nord Development Project EIS Guidelines* [78]. The EIS, developed in accordance with these guidelines and the MOU, was designed to satisfy both *CEAA 2012* and *Accord Acts* requirements.

On April 6, 2022, the Minister of Environment and Climate Change Canada (ECCC) issued a Decision Statement [3] concluding that the *"Designated Project is not likely to cause significant adverse environmental effects"*. The Decision Statement established over 150 conditions that the Project must meet in order for Project activities to proceed. The mitigations and conditions will be integrated into the design and operations of the Project.

Section 17.3.1 Environmental Mitigation, Section 17.3.2 Environmental Protection Plan, and Section 17.4 Environmental Effects Monitoring and Wildlife Observations provide an overview of the environmental protection and environmental monitoring processes and plans to be developed for the Project. These plans and processes will address applicable EIS commitments, conditions from the Decision Statement, and other regulatory requirements.

17.3 Environmental Protection

17.3.1 Environmental Mitigation

As outlined in the EIS [4], environmental mitigations will be applied throughout all phases to reduce potential direct Project effects on the receiving environment.

Table 18.2 in the EIS outlines all commitments and mitigations, while the Decision Statement [3] lists a number of EA conditions related to design and operations. These measures will be integrated into the Project to prevent or reduce potential environmental effects.

Key mitigations from the EIS and/or EA conditions include, but are not limited to:

- Adherence to, or compliance with, applicable regulatory requirements (EIS commitment and EA condition);
- Reduction of greenhouse gas emissions (EIS commitment and EA condition);
- Evaluation of lighting design options to reduce seabird attraction, and implementation of those that are economically and technically feasible and do not pose a risk to safety of personnel on the installations (EA condition);
- Adherence to applicable regulatory requirements for marine discharges (EIS commitment and EA condition);
- Use of best available technology, where technically and economically feasible, for treating produced water and drill cuttings (EIS commitment and EA condition);
- Assessment of Produced Water Reinjection (PWRI) (see Section 7.5.2 Water Management Strategy) (EIS commitment); and
- Implementation of mitigation measures, including those that may be required under a Fisheries Act Authorization (if applicable), to reduce direct Project impacts on aggregations of corals and sponges (EIS commitment and EA condition).

The assessment of Best Available Techniques (BAT) is a core principle within Equinor ASA to identify optimal environmental solutions in project development and operation. The BAT assessment process includes:

1. Identifying relevant techniques/system;
2. Screening alternatives;
3. Assessing the alternatives; and
4. Selecting the best solution.

The BAT assessment process is an integrated part of the Project, and began in early engineering and will continue through design and operations, as applicable.

17.3.2 Environmental Protection Plan

A Project Environmental Protection Plan (EPP) will be developed in accordance with the applicable requirements in the *Canada–Newfoundland and Labrador Offshore Area Petroleum Operations Framework Regulations* (the *Framework Regulations*), and will draw upon the *Environmental Protection Plan Guideline [79]* for additional guidance and best practices. As required by the *Framework Regulations*, the Project EPP will be submitted as part of the Operations Authorization (OA) application. While the number of OAs required for the various Project phases (e.g., construction, installation, commissioning, drilling, production, etc.) has not yet been determined, each OA will be supported by a dedicated EPP tailored to its scope and activities. If it is determined that a single OA will be pursued, then a comprehensive Project EPP will be prepared and updated, when required, to reflect changes throughout the Project lifecycle. The EPP will include compliance monitoring, when applicable, to address operational marine discharges noted in EIS commitments and EA conditions, and in accordance with the *Framework Regulations*.

17.4 Environmental Effects Monitoring and Wildlife Observations

17.4.1 Environmental Effects Monitoring Development Methodology

Section 18.4 of the EIS [4] provides an overview of the Project's Environmental Effects Monitoring (EEM) program, and the EA Decision Statement [3] includes additional conditions for follow-up monitoring and wildlife observational programs. Project-specific EEM Plans, addressing EIS commitments and EA conditions, will be submitted in support of the applicable OA applications. Where baseline sampling may be required to inform the design of the monitoring program, any required sampling will be carried out prior to the commencement of offshore construction.

The follow-up monitoring programs will be guided by the principles and objectives outlined in the EIS and the EA Conditions. They will be tailored to specific Project activities and timeframes, using technologies suited to offshore conditions at Project water depths. For example, this may include monitoring the effect of drill cuttings on fish and fish habitat, or underwater sound emissions on marine mammals. These programs will also draw on Equinor ASA's global experience, as well as ongoing research and emerging technologies. Designed with flexibility in mind, the programs will incorporate adaptive management principles, allowing monitoring parameters to be adjusted or phased out over time based on results and evolving conditions.

17.4.2 Wildlife Observational Programs

As outlined in the EIS [4] and EA Decision Statement [3], the Project will implement applicable wildlife observational programs across all phases, as appropriate. These will be developed in consideration of standard protocols and in consultation with the appropriate regulatory agencies. As noted in the EIS, the Project will investigate technologies and equipment suited for collecting observational data on seabirds and/or marine mammals.

Wildlife observational programs may include monitoring for:

- Seabird presence and strandings on marine installations; and
- Marine mammals and sea turtles present during active geophysical programs.

17.5 Financial Security and Compensation

Fisheries Act Authorization

Under the *Fisheries Act*, the Project may require a Fisheries Act Authorization for potential effects from installing subsea infrastructure on fish and fish habitat. Whether a Fisheries Act Authorization is needed is determined by DFO through its review process. If a Fisheries Act Authorization is required, and offsetting is a requirement, the Project must provide a financial guarantee to DFO. Based on current legislation, it can be an irrevocable letter of credit from a recognized Canadian financial institution or an equivalent, such as a performance bond. The financial guarantee must cover the full cost of implementing the offshore plan and monitoring program required by the Fisheries Act Authorization.

Compensation Respecting Damages Relating to Offshore Petroleum Activities

As outlined in the *Compensation Guidelines Respecting Damages Relating to Offshore Petroleum Activity* [80], Equinor is required under the *Accord Acts* to compensate for any damages to fishing gear directly attributable to Project activities. To meet these requirements, Equinor will develop a Project compensation plan.

Financial Requirements Respecting Pollution Incidents

Under the *Accord Acts*, Equinor must demonstrate both financial responsibility and financial resources to obtain an OA. The *Guidelines Respecting Financial Responsibility Requirements* [81] outline the required amounts based on the nature of the activity. Equinor will provide the C-NLOER with the necessary financial assurances for the Project.

18 Decommissioning and Abandonment

18.1 Introduction

At the end of field life, the Bay du Nord Project (the Project) will be decommissioned in accordance with applicable regulatory requirements at the time of decommissioning. A Decommissioning and Abandonment Plan, including applicable requirements in the *Canada-Newfoundland and Labrador Offshore Area Petroleum Operations Framework Regulations* (the *Framework Regulations*), will be provided to the C-NLOER as supporting information for the Operations Authorization (OA) process. The Decommissioning and Abandonment Plan will be updated, as necessary, throughout the life of the Project. It is anticipated that decommissioning will be carried out over multiple seasons and will require significant resources, including, but not limited to, drilling installations, Riserless Light Well Intervention (RLWI) vessels, construction vessels, and heavy lift vessels.

Decommissioning and abandonment components will change during Front-End Engineering Design (FEED) and detailed design phases, and will be further refined when the Decommissioning and Abandonment Plan is developed.

18.2 FPSO and Subsea Infrastructure

As a base case, the Floating Production, Storage and Offloading (FPSO) facility will be decommissioned and removed from the Project location. Process equipment, tanks, and piping will be purged and cleaned. All equipment within the water column (e.g., turret buoy, mooring lines, risers, dynamic umbilicals and power cables) will be flushed if required, disconnected and removed, then disposed of accordingly.

Subsea infrastructure (e.g., flowlines, jumpers, rigid spools, riser bases, integrated template structures) and associated protection measures (e.g., rock, concrete mattresses) may be removed or left in place. These options will be further examined at the time of decommissioning in consultation with the C-NLOER and other regulatory authorities (e.g., Fisheries and Oceans Canada [DFO]). Additionally, over time, subsea infrastructure may have become fish habitat, and the effects of removing it will have to be assessed.

Potential alternatives to decommissioning will be examined with the C-NLOER and other regulatory authorities and include, but are not limited to:

- The flowlines may be emptied, flushed, disconnected, and covered with rock over the ends and in-line structures;
- Suction anchors and structures with suction anchors may either be removed above the mud line, covered by rock, or a combination thereof; and
- If the mooring system suction anchors are not removed, the bottom chains may be cut at the mudline as close as possible to the suction anchors, covered by rock, or a combination thereof.

Removable components such as, but not limited to, Christmas Trees (XTs), subsea power distribution, and subsea cooler, if applicable, will be flushed, disconnected, and lifted to surface via construction vessel. They will then be transported to an onshore disposal facility.

Subsea wells will be decommissioned and abandoned as per Section 18.3 Well Suspension, Decommissioning and Abandonment.

Decommissioning will be conducted in accordance with applicable regulatory requirements at the time of decommissioning. Decommissioning and abandonment components may change during FEED and detailed design phases, and further refined when the Decommissioning and Abandonment Plan is developed as part of the OA process.

18.3 Well Suspension, Decommissioning and Abandonment

Well Suspension

There may be instances when it is necessary to re-enter a wellbore such as, but not limited to, additional testing, to collect data, and/or to further progress a temporarily suspended well operation. A well may also be temporarily suspended after a well operation is completed before starting or resuming production or injection. In such circumstances, the well is not abandoned but suspended. In this case, elements which prevent any formation fluid from flowing through or escaping from the wellbore such as plugs, valves, or cement will be utilized. Additionally, a temporary debris cap may be installed to protect the wellhead connector, if applicable. Based on historic data, wells are typically suspended for up to two to three years. However, well suspension will adhere to the applicable regulatory requirements, including notification requirements, at the time of suspension.

Monitoring of suspended wells may consist of completing surveys, using Remotely Operated Vehicles (ROVs) or other appropriate methods, to ensure the areas are free of leaks, damage, equipment, and obstructions. Confirmation of location coordinates may also be completed during surveys. Well monitoring plans will adhere to the applicable regulatory requirements.

Well Decommissioning and Abandonment

Well decommissioning and abandonment involves the isolation of the wellbore by placing cement and/or mechanical plugs at required depths in the wellbore, thereby separating and isolating subsurface zones to prevent subsurface fluids from escaping. Abandonment is designed to be permanent/indefinite. Well abandonment will adhere to the applicable regulatory requirements.

The wellhead housing locks inside the conductor housing which in turn has a lock ring interface to the subsea template. As such, assessment of removal of the wellhead system when a well is decommissioned and abandoned will be connected to the decommissioning and abandonment of the subsea infrastructure as described in Section 18.2 FPSO and Subsea Infrastructure.

20 Acronyms and Abbreviations

Table 20.1 Acronyms and Abbreviations

Acronyms and Abbreviations	Definition
"	inches
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional
°	degrees
°C	degrees Celsius
°F	degrees Fahrenheit
µm	microns
Accord Acts	*Canada–Newfoundland and Labrador Atlantic Accord Implementation and Offshore Renewable Energy Management Act* and *Canada-Newfoundland and Labrador Atlantic Accord Implementation and Offshore Renewable Energy Management Newfoundland and Labrador Act*
AC-SBV DOC	Atlantic Canada Standby Vessel Document of Compliance
ADW	Approval to Drill a Well
AFE	Annular Fluid Expansion
AI	Acoustic Impedance
AIM	Asset Integrity Management
ALARP	As Low As Reasonably Practicable
ALE	Abnormal Level Earthquake
AOM	Asset Operating Model
AOP	Asphaltene Onset Pressure
APB	Annular Pressure Build-up
API	American Petroleum Institute
APS	Abandon Platform Shutdown
APSDM	Anisotropic Pre-Stack Depth Migration
APSTM	Anisotropic Pre-Stack Time Migration
ARIS	Architecture of Integrated Information Systems
AUV	Autonomous Underwater Vehicle
AVO	Amplitude Versus Offset
bar	unit of pressure measurement
bara	bar absolute - unit of pressure measurement that includes atmospheric pressure
barg	bar gauge - unit pressure relative to atmospheric pressure
BAT	Best Available Techniques
BCF	billion cubic feet
BHA	Bottom Hole Assembly
BLS	Bow Loading System
BOP	Blowout Preventer
bopd	barrels of oil per day
bp	BP Canada Energy Group ULC
BS&W	Basic Sediment and Water
CA	Certifying Authority
CAPEX	Capital Expenditures
CAPP	Canadian Association of Petroleum Producers
CBM	Condition-Based Monitoring
CCE	Constant Composition Expansion

Acronyms and Abbreviations	Definition
CCR	Central Control Room
CDP	Common Depth Point
CDU	Communication Distribution Unit
CEAA 2012	*Canadian Environmental Assessment Act, 2012*
CFU	Compact Flotation Unit
CHS	Canadian Hydrographic Services
CITV	Chemical Injection Throttle Valves
cm	centimetres
cm/s	centimetres per second
CMMS	Computerized Maintenance Management System
CMR	Combinable Magnetic Resonance
CMS	Competency Management System
CMT	Crisis Management Team
C-NLOER	Canada-Newfoundland and Labrador Offshore Energy Regulator
C-NLOPB	Canada-Newfoundland and Labrador Offshore Petroleum Board
CO_2	carbon dioxide
CPP	Canadian Pension Plan
CPT	Cone Penetration Test
CS	Classification Society
CSA	Concept Safety Analysis
CSRS	Canadian Spatial Reference System
CVP	Capital Value Process
DAE	Dimensioning Accidental Event
DAL	Dimensioning Accidental Load
D&I	Diversity and Inclusion
dB	decibel(s)
DLE	Differential Liberation Experiment
DFO	Fisheries and Oceans Canada
DG	Decision Gate
DHPTG	Downhole Pressure and Temperature Gauge
DHSV	Downhole Safety Valve
DIFFS	Deck Integrated Firefighting System
DIU	Downhole Interface Unit
DNV	Det Norske Veritas
DP	Dynamic Positioning
DSE	Depositional Sub-Environment
DSHA	Defined Situations of Hazards and Accidents
DSIP	Delegated Statutory Inspection Program
DST	Drill Stem Test
e^6m^3	million cubic metres
e^9m^3	billion cubic metres
E&T	Education and Training
EA	Environmental Assessment
ECC	Emergency Control Centre
ECCC	Environment and Climate Change Canada
EDP	Emergency Disconnect Package
EEM	Environmental Effects Monitoring

Acronyms and Abbreviations	Definition
EERA	Escape, Evacuation, and Rescue Analysis
EEZ	Exclusive Economic Zone
EHTF	Electrically Heat-Traced Flowline
EI	Employment Insurance
EIS	Environmental Impact Statement
EL	Exploration Licence
ELE	Extreme Level Earthquake
EMS	Equinor ASA Management System
ENVID	Environmental Hazard Identification
EOR	Enhanced Oil Recovery
EOS	Equation of State
EPA	Emergency Preparedness Analysis
EPI	Exploration and Production International
EPP	Environmental Protection Plan
EPU	Electrical Power Unit
Equinor ASA	Equinor ASA is a multinational energy company headquartered in Stavanger, Norway
Equinor	Equinor Canada Ltd.
ERP	Emergency Response Plan
ERT	Emergency Response Team
ESD	Emergency Shutdown
f	frequency
FAR	Fatal Accident Rate
FAT	Factory Accept Test
FCM	Flow Control Module
FCV	Flow Control Valve
FDR	Functional and Design Requirements
FEED	Front-End Engineering Design
FID	Final Investment Decision
FMU	Fast Model Update
FOV	Fast Opening Valve
FPSO	Floating, Production, Storage, and Offloading facility
Framework Regulations	*Canada-Newfoundland and Labrador Offshore Petroleum Operations Framework Regulations*
FR	Function Requirement
FRC	Fast Rescue Craft
FTWT	Formation Testing While Tripping
FWAG	Foam Assisted Water-Alternating-Gas
FWL	Free Water Level
GBS	Gravity Based Structure
GDP	Gross Domestic Product
GI	Gas Injection
GIMAT	Global Incident Management Assist Team
GHSZ	Gas Hydrate Stability Zone
GL	Guideline
GOR	Gas-Oil Ratio
GR	Gamma Ray
GRP	Glass Reinforced Plastic
GTG	Gas Turbine Generator

Acronyms and Abbreviations	Definition
H_2S	hydrogen sulphide
HAZID	Hazard Identification
HAZOP	Hazard and Operability
HDPE	High-Density Polyethylene
HET	Hydrate Equilibrium Temperature
HEV	Hose End Valve
HOP	Human and Organizational Performance
HP	High Pressure
HPU	Hydraulic Power Unit
HSE	Health, Safety, and Environment
HUM	Horizon Uncertainty Modelling
HVAC	Heating, Ventilation, and Air Conditioning
Hz	Hertz
IAAC	Impact Assessment Agency of Canada
ICD	Inflow Control Device
ICSS	Integrated Control and Safety System
IG	Inert Gas
IIoT	Industrial Internet of Things
IMO	International Maritime Organization
IMR	Inspection, Maintenance, and Repair
IMS	Ice Management System
IMT	Incident Management Team
IR	Individual Risk
IRPA	Individual Risk Per Annum
IO	Integrated Operations
IOC	Integrated Operations Centre
IOGP	International Association of Oil & Gas Producers
IOPP	International Oil Pollution Prevention
ITS	Integrated Template Structure
IOR	Improved Oil Recovery
ISM	International Safety Management
ISPS	International Ships and Port Security
IT	Information Technology
kbbl/sd	thousand barrels per standard day
km	kilometres
km^2	square kilometres
kPa/m	kilopascals per metre
k_h	horizontal permeability
k_v	vertical permeability
LBC	Lohrenz-Bray-Clark
LF	Lithofacies
LMR	lambda-mu-rho
LMS	Learning Management System
LOC	Loss of Containment
LP	Low Pressure
LR	lambda-rho
LRP	Lower Riser Package

Acronyms and Abbreviations	Definition
LST	Lowstand Systems Tract
LWD	Logging (Logged) While Drilling
m	metres
Mm^3	million cubic metres
m^3	cubic metres
m^3/cd	cubic metres per calendar day
m^3/d	cubic metres per day
m^3/h	cubic metres per hour
md/cp	millidarcies per centipoise
MAE	Major Accidental Event
MAH	Major Accidental Hazard
MARPOL	International Convention for the Prevention of Pollution from Ships
MAZ	multi-azimuth
MBO	million barrels of oil
MCP	Manual Call Point
MD	Measured Depth
mD	millidarcy
MDT	Modular Formation Dynamics Testing
MEG	Monoethylene Glycol (prevents fluid from freezing)
MEI	Major Environmental Incident
mg/l	milligrams per litre
MGO	Marine Gas Oil
MICP	Mercury Injection Saturation Data
MLT	Multi-Lateral Well
mm	millimetres
mm/d	millimetres per day
mMD RKB	depth in metres measured from the Rotary Kelly Bushing
m/s	metres per second
m TVD RT	depth in metres measured as True Vertical Depth from the Rotary Table
MoC	Management of Change
MOU	Memorandum of Understanding
MP	Medium Pressure
MPD	Managed Pressure Drilling
MR	mu-rho
ms	milliseconds
MSI	Musculoskeletal Injury
MSm^3/sd	million standard cubic metres per standard day
MTZ	Mass Transport Zone
MW	megawattt
MWD	Measurement While Drilling
NAD83	North American Datum of 1983
NAVWARN	Navigational Warning
NCS	Norwegian Continental Shelf
NGI	Norwegian Geotechnical Institute
NL	Newfoundland and Labrador
NM	nautical miles
NMO	Normal Moveout

Acronyms and Abbreviations	Definition
NMR	Nuclear Magnetic Resonance
NRMS	Normalized Root Mean Square
O&M	Operations and Maintenance
OA	Operations Authorization
OBM	Oil-Based Mud
OCTG	Oil Country Tubular Goods
OD	Outer Diameter
ODT	Oil-Down-To
OGIP	Original Gas-In-Place
OHGP	Open Hole Gravel Packing
OHS Regulations	*Canada-Newfoundland and Labrador Offshore Area Occupational Health and Safety Regulations*
OIM	Offshore Installation Manager
OIP	Oil-In-Place
OMC	Organization, Management and Control
OOIP	Original Oil-In-Place
OSD	Oil Spill Detection
OSV	Offshore Support Vessel
OWC	Oil-Water Contact
PAGA	Public Address and General Alarm
PASF	Polymer Assisted Surfactant Flooding
PBR	Polished Bore Receptacle
PDD	Project Description Document
PDP	Projects, Drilling, and Procurement
PE	Production Efficiency
PEAR	People, Environment, Assets, and Reputation
PEGNL	Professional Engineers and Geoscientists of Newfoundland & Labrador
Pg	geological chance of success
PIP	Pipe-In-Pipe
PL	Production Licence
PLET	Pipeline End Termination
PLL	Potential Loss of Life
PMT	Project Management Team
POB	Personnel on Board
PP	Production Packer
PPE	Personal Protective Equipment
ppm	parts per million
Project	Bay du Nord Project
PS	Performance Standard
PSD	Process Shutdown
PSDM	Pre-Stack Depth Migration
PSM	Petroleum Systems Model
PVT	Pressure-Volume-Temperature
PWRI	Produced Water Reinjection
QFL	Quartz-Feldspar-Lithic
QRA	Quantitative Risk Assessment
R	resolution

Acronyms and Abbreviations	Definition
RAM	Reliability, Availability, and Maintainability
R&D	Research and Development
RBI	Risk-Based Inspection
RCM	Reliability Centred Maintenance
REWS	Radar Early Warning System
RF	Recovery Factor
RLWI	Riserless Light Well Intervention
RMS	Root Mean Square
RO	Recognized Organization
ROS	Remote Operator Station
RPT	Rock Physics Template
ROV	Remotely Operated Vehicle
RSWC	Rotary Sidewall Core
RVP	Reid Vapour Pressure
s	seconds
SAR	Search and Rescue
SAS	Stand-Alone Screens
SCAL	Special Core Analysis
SCM	Subsea Control Module
SCSSV	Surface Controlled Subsurface Safety Valve
SCU	Subsea Control Unit
SDL	Significant Discovery Licence
SDS	Stern Discharge System
SDU	Subsea Distribution Unit
SECE	Safety and Environmental Critical Element
SEIS	Socio-Economic Impact Statement
SEPDU	Subsea Electrical Power Distribution System
SG	Subsea Gateway
SGR	Shale Gouge Ratio
SI	Shear Impedance
SIL	Safety Integrity Level
SIT	System Integration Test
SIMA	Spill Impact Mitigation Assessment
SIMOPS	Simultaneous Operations
Sm^3/sd	standard cubic metres per standard day
SOLAS	International Convention for the Safety of Life at Sea
SPS	Subsea Production System
SRD	Seismic Reference Datum
SSM	Subsea Switch Module
SSMD	Subsea Mechanical Dispersion
STP	Submerged Turret Production
SURF	Subsea Umbilicals, Risers, and Flowlines
SVP	Senior Vice President
SWC	Sidewall Core (Coring)
TC	Transport Canada
TD	Total Depth
TEG	Triethylene Glycol (removes water vapour from natural gas to prevent corrosion)

Acronyms and Abbreviations	Definition
TEMPSC	Totally Enclosed Motor Propelled Survival Craft
TH	Tubing Hanger
THI	Thermodynamic Hydrate Inhibitor
TLP	Tension-Leg Platform
TLS	Target Level of Safety
TMS	Turret and Mooring System
TPSU	Third Party Server Unit
TQP	Technical Qualification Process
TR	Technical Requirement
TSR	Temporary Safe Refuge
TTI	Tilted Transverse Isotropic
TVD	True Vertical Depth
TVP	True Vapour Pressure
TWT	Two-Way Travel Time
UK HSE	United Kingdom Health and Safety Executive
UT	Ultrasonic Testing
UTH	Umbilical Termination Head
v	velocity
Vo	constant velocity
VAMS	Video Assisted Multiple Sampler
VOC	Volatile Organic Compound
Vp	compressional-velocity
Vs	shear-velocity
VSh	Shale Volume
VSP	Vertical Seismic Profile
VXT	Vertical Christmas Tree
W2W	Walk-to-Work
WAG	Water-Alternating-Gas
WAT	Wax Appearance Temperature
WI	Water Injection
WHRU	Waste Heat Recovery Unit
WL	Wireline
WLR	Wellhead Load Relief
WR	Work Requirement
wt%	weight percent
WUT	Water-Up-To
XL	Crossline
XLOT	Extended Leak Off Test
XPT	Express Pressure Tool
XT	Christmas Tree
Zp	P-impedance
Zs	S-impedance

21 Select Terminology

Table 21.1 Select Terminology

Terminology	Meaning
Accommodations area	The area of an installation or vessel that contains the sleeping quarters, dining areas, food preparation areas, general recreation areas, offices and medical rooms and includes all washrooms in that area (taken from the *Framework Regulations*)
Accommodations installation	An installation that is used to accommodate persons at a production site, drill site or dive site and that functions independently of a production installation, drilling installation or diving installation (taken from the *Framework Regulations*)
Asset	FPSO, subsea production system, and wells
Barrier element	A physical element that on its own does not prevent the flow of fluids but that in combination with other physical elements forms a well barrier (taken from the *Framework Regulations*)
Barrier envelope	An envelope consisting of a set of barrier elements that prevents any unintended flow of fluids from the formation into the well-bore, another formation or the environment (taken from the *Framework Regulations*)
Benefits Plan	Benefits plan means a plan for the employment of Canadians and, in particular, members of the labour force of the Province and, subject to paragraph (3)(d), for providing manufacturers, consultants, contractors and service companies in the Province and other parts of Canada with a full and fair opportunity to participate on a competitive basis in the supply of goods and services used in any proposed work or activity referred to in the benefits plan (taken from the *Accord Acts*)
Canada-NL offshore area	Those submarine areas lying seaward of the low water mark of the province and extending, at any location, as far as (i) any prescribed line, or (ii) if no line is prescribed at that location, the outer edge of the continental margin or a distance of two hundred nautical miles from the baselines from which the breadth of the territorial sea of Canada is measured, whichever is the greater (adapted from the *Accord Acts*)
Central control room	Core functional entity, and its associated physical structure, where operators are stationed to carry out centralized control, monitoring, and administrative responsibilities on Bay du Nord FPSO (adapted from ISO 11064-1: Ergonomic Design of Control Centres)
Certifying authority	The American Bureau of Shipping, Bureau Veritas, Det Norske Veritas or Lloyd's Register (taken from the *Framework Regulations*)
Classification society	A member of the International Association of Classification Societies that has recognized and relevant competence and experience in, and established rules and procedures for, the classification of fixed and floating structures, including vessels, that are used in oil or gas activities in locations with physical and environmental conditions similar to those of the offshore area (taken from the *Framework Regulations*)
Commingled production	The production of petroleum from more than one pool or zone through a common well where the production from each pool or zone is not measured separately (taken from the *Framework Regulations*)
Decommissioning and abandonment	The carrying out of the following processes in accordance with any applicable Act of Parliament, any applicable regulation made under an Act of Parliament, the applicable authorization and any approved development plans: (a) the cessation of operations; (b) the controlled abandonment of all wells; (c) the retirement from service and abandonment or removal of all installations, including their systems and equipment; and (d) the retirement from service and abandonment or removal of all pipelines and materials (taken from the *Framework Regulations*)
Deferred development	Where hydrocarbons have been identified in a portion of the development area for which development is not proposed, including zones deeper and shallower than the producing zone, a discussion of the reasons for not proceeding with development in those portions of the development area should be provided. This should include: resource estimates; factors that might lead to future development and the possible timing of such development; and steps planned to obtain additional information concerning the hydrocarbon accumulation, if applicable (taken from *Development Plan Guideline*)
Delineation well	A well that is so located in relation to another well penetrating an accumulation of petroleum that there is a reasonable expectation that another portion of that accumulation will be penetrated by the first-mentioned well and that the drilling is necessary in order to determine the commercial value of the accumulation (taken from the *Accord Acts*)
Development Application	An application for the approval of a Development Project which includes the proposed Development Plan and the proposed Benefits Plan (taken from the *Development Plan Guideline*)
Development Plan	A plan submitted pursuant to subsection 139(2) for the purpose of obtaining approval of the general approach of developing a pool or field as proposed in the plan (taken from the *Accord Acts*)
Development well	A well that is so located in relation to another well penetrating an accumulation of petroleum that it is considered to be a well or part of a well drilled for the purpose of production or observation or for the injection or disposal of fluid into or from the accumulation (taken from the *Accords Act*)

Terminology	Meaning
Drilling installation	A drilling unit or a drilling rig, and the stable foundation on which it is installed - including an artificial island, an ice platform, a floating platform, a platform fixed to the seabed, and any other foundation specifically used for drilling - and any associated accommodations area (taken from the *Framework Regulations*)
Drilling program	A program for the drilling of one or more wells within a specified time and within specified areas through the use of one or more drilling installations and includes any work or activity related to the program (taken from the *Framework Regulations*)
Exploration licences	An exploration licence confers, with respect to the portions of the offshore area to which the licence applies, (a) the right to explore for, and the exclusive right to drill and test for, petroleum; (b) the exclusive right to develop those portions of the offshore area in order to produce petroleum; and (c) the exclusive right, subject to compliance with the other provisions of this Part to obtain a production licence (taken from the *Accord Acts*)
Exploratory well	A well drilled on a geological feature on which a significant discovery has not been made (taken from the *Accords Act*)
Flowline	Any line, other than a pipeline, that is used to transport fluids between a well and equipment used for the production of petroleum that is located at a production site or to transport fluids between a well and any systems or equipment that are used in support of that production and between those systems or equipment and the production equipment (taken from the *Framework Regulations*)
Formation flow test	An operation (a) to induce the flow of formation fluids to procure reservoir fluid samples and determine reservoir flow characteristics; or (b) to inject fluids into a formation to evaluate injectivity (taken from the *Framework Regulations*)
Integrated operations centre	Located in the St. John's area and provides integrated operational and business support for offshore activities including remote monitoring of the Bay du Nord Asset
Life-saving appliances	Includes lifebuoys, survival craft, launching and embarkation appliances, marine evacuation systems and visual signals (taken from the *Framework Regulations*)
Major accidental event	An unexpected or unplanned event or circumstance or series of unexpected or unplanned events or circumstances that may lead to the loss of more than one life or uncontrolled pollution (taken from the *Framework Regulations*)
Materials handling equipment	Equipment, other than an elevator or personnel lift, that is used to transport, lift, move or position things or persons and includes gear and devices used in conjunction with other equipment in carrying out those functions.
Offshore area	(a) In the case of petroleum, those submarine areas lying seaward of the low water mark of the Province and extending, at any location, as far as (i) any prescribed line, or (ii) if no line is prescribed at that location, the outer edge of the continental margin or a distance of two hundred nautical miles from the baselines from which the breadth of the territorial sea of Canada is measured, whichever is the greater (taken from the *Accord Acts*)
Operations site	A site where an authorized work or activity is carried out (taken from the *Framework Regulations*)
Operator	A person that holds an operating licence issued by the Board under paragraph 138(1)(a) of the Act and applies for or has been granted an authorization (taken from the *Framework Regulations*) Equinor is the operator
Physical and environmental conditions	The physical, geotechnical, seismic, oceanographic, meteorological or ice conditions that might affect an authorized work or activity (taken from the *Framework Regulations*)
Production installation	(a) The systems and equipment used for or in support of the production of petroleum, including those that are used for separation, treatment and processing; (b) the systems and equipment used to conduct well operations; (c) any systems and equipment related to marine activities; (d) any associated aircraft landing areas, storage areas or tanks and accommodations areas; and (e) any associated platforms, artificial islands, subsea production systems and offshore loading systems (taken from the *Framework Regulations*)
Production licence	A production licence confers, with respect to the portions of the offshore area to which the licence applies, (a) the right to explore for, and the exclusive right to drill and test for, petroleum; (b) the exclusive right to develop those portions of the offshore area in order to produce petroleum; (c) the exclusive right to produce petroleum from those portions of the offshore area; and (d) title to the petroleum so produced (taken from the *Accord Acts*)
Production site	A site where a production installation is or is proposed to be installed (taken from *Framework Regulations*)
Project Area	The area defined in the Environmental Impact Statement and illustrated in Figure 1.1
Significant discovery licence	A significant discovery licence confers, with respect to the portions of the offshore area to which the licence applies, (a) the right to explore for, and the exclusive right to drill and test for, petroleum; (b) the exclusive right to develop those portions of the offshore area in order to produce petroleum; and (c) the exclusive right, subject to compliance with the other provisions of this Part, to obtain a production licence (taken from the *Accord Acts*)

Terminology	Meaning
Safety and environmental critical element	Any system or equipment, including software and temporary or portable equipment, that is critical to the safety or integrity of an installation or to preventing the installation from polluting, including (a) any system or equipment (i) that is intended to prevent or limit the effects of a hazard that could cause a major accidental event, or (ii) whose failure could (A) cause a hazard that could cause a major accidental event, or (B) worsen the effects on the installation of a major accidental event; and (b) any software or temporary or portable equipment that affects any system or equipment referred to in paragraph (a). (taken from *Framework Regulations*)
Subsea production system	Equipment and structures that are located on or below the seabed for the production of petroleum from, or for the injection of fluids into, a field under a production site and includes production risers, flowlines and associated control systems that are located upstream of the isolation valve (taken from *Framework Regulations*)
Support craft	A vessel, vehicle, aircraft or other craft used to provide transportation or assistance to persons at an operations site (taken from the *Framework Regulations*)
Well control	The control of the movement of fluids into or from a well (taken from the *Framework Regulations*)
Well operation	An operation related to the drilling, completion, recompletion, re-entry, intervention, workover, suspension, or abandonment of a well (taken from the *Framework Regulations*)
Workover	An operation on a completed well that requires removal of the tree or the tubing (taken from the *Framework Regulations*)

Endnotes

1 St. John's Office: Equinor Canada Ltd., 2 Steers Cove, St. John's, NL, A1C 6J5, +1 709-726-9091.

2 The total well count may be greater than 16 due to potential additional development wells within the Bay du Nord and/or Cambriol fields as described in Section 7.7.1 Additional Development Targets.

3 Equinor will consider further debottlenecking potential as a part of FEED and detailed design. Oil capacity up to 200 kbbl/sd and liquid capacity up to 50,000 Sm^3/sd may be considered.

4 Adopted from the global industry standard set by the International Association of Oil & Gas Producers (IOGP).

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