A Natural Gas Resource Assessment of the Jeanne d'Arc Basin

Newfoundland & Labrador
CANADA

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Summary

Natural gas is considered a transition fuel during the energy transition to net-zero emissions. The development of Newfoundland and Labrador's (NL) offshore natural gas can potentially support the transition, extend the life of the Newfoundland and Labrador offshore (NL offshore), and provide significant benefit to the NL economy.

In Budget 2023, the Government of Newfoundland and Labrador included $4.7 million to conduct a Natural Gas Resource Assessment in the offshore to define further and understand the range of estimated recoverable natural gas and natural gas liquids (NGLs) within the Jeanne d'Arc Basin. This is important to better understand the potential of NL offshore natural gas as a contributor to the province's future economic growth while offering part of the solution to the global path toward net-zero emissions. The work is also intended to provide greater certainty for investors to support the development of the resource.

Work began in the Fall of 2023, and focused on evaluating 18 areas within the Basin where there are proven discoveries within the Significant Discovery Licenses (SDLs) or Production Licenses (PLs) in the currently producing fields of Hibernia, Hebron, White Rose, North Amethyst, and Terra Nova.

The scope of the assessment entailed evaluating recoverable gas resources on all lands held under licence (SDLs and PLs) and identifying the upside potential in adjacent lands that are held by the Crown and available for posting. This assessment has determined that the natural gas resource base within the SDLs and PLs in the Jeanne d'Arc Basin ranges from 8.1 to 11.3 trillion cubic feet (Tcf), with a best estimate of 9.7 Tcf.

Additional proven natural gas resources adjacent to or residing on the SDLs and PLs were identified while completing the assessment. Applying industry-standard methods based on historically discovered resources, a projection of 20 identified prospects to be evaluated indicated potential for an additional 7.4 to 30.6 Tcf of natural gas.

Global Natural Gas Outlook

Natural gas produces significantly lower downstream emissions compared to other fossil fuels. It plays a crucial role as an energy source in the world's efforts to achieve net zero emissions while meeting global energy demand. This is particularly relevant in the context of natural gas replacing coal, which still accounts for over a third of the world's electricity production. When burned in a modern, efficient natural gas power plant, natural gas emits 50 to 60 per cent less greenhouse gas emissions than a typical modern coal plant.

Most credible net-zero scenarios, including the latest projections from the International Energy Agency, predict a robust demand for natural gas, primarily Liquefied Natural Gas (LNG), until 2050, with increasing trade linked to emerging markets like Asia. LNG is natural gas that has been cooled to a liquid state, allowing it to be transported by LNG tanker ships to markets, where it is offloaded, stored, and re-gasified for consumption.

According to the Statistical Review of World Energy, 2024, published by the Energy Institute, natural gas accounts for approximately 29 per cent of global fossil fuel consumption, with four trillion cubic metres consumed globally in 2023. Global natural gas consumption has increased by approximately 19 per cent since 2013. LNG demand globally grew by nearly two per cent in 2023 compared to 2022. The largest natural gas consumers are the United States, the Asia-Pacific region, Europe, and Russia, with Asia-Pacific and Europe being the largest LNG importers.

While the overall share of hydrocarbons in the global energy mix is expected to decline significantly by 2050, demand for natural gas is anticipated to remain close to current levels.

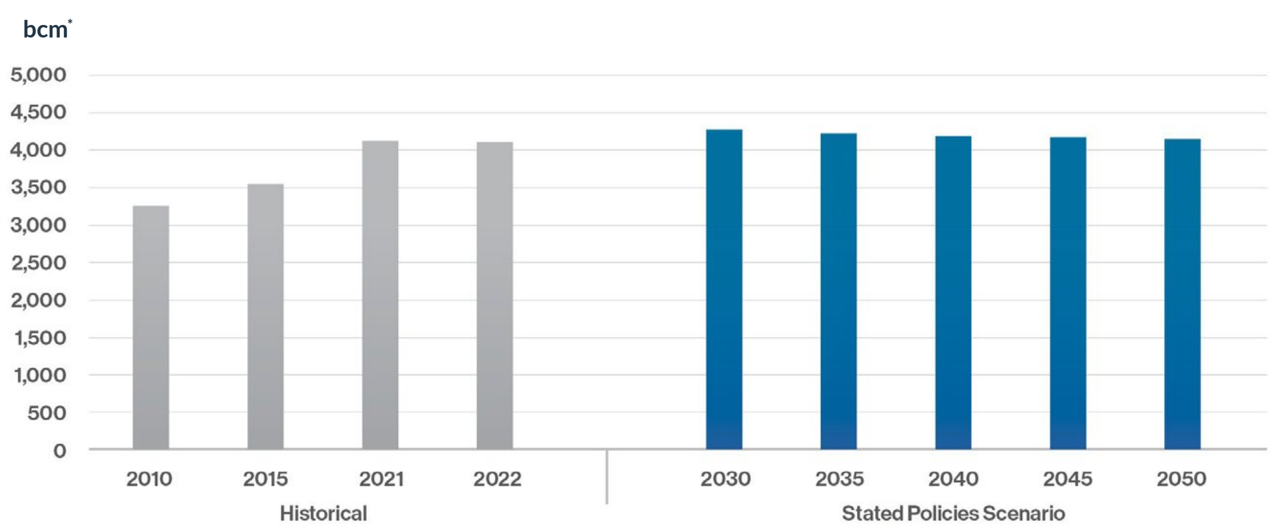


Figure 1: Global Natural Gas Production
Source: International Energy Agency 2023

*bcm - billion cubic metres

Natural Gas Resource Assessment Approach and Methodology

Newfoundland and Labrador, located on the east coast of North America, is Canada's only offshore oil-producing region. Since the discovery of oil in the Jeanne d'Arc Basin in 1979 with the exploration well Hibernia P-15, five oil fields have started production in the Basin: Hibernia, Terra Nova, White Rose, North Amethyst and Hebron. Activities within the Basin have been focused on oil production, with more than 2.4 billion barrels of oil produced to date and remaining recoverable reserves/resources totaling 3.0 billion barrels of oil.

The NL offshore region remains significantly underexplored, particularly for natural gas, as exploration efforts have primarily focused on oil. The gas discoveries within the SDLs and PLs were not the objectives of the drilling programs; therefore, the operators did not undertake further appraisal activities for each discovery.

The geoscience team within the Petroleum Geoscience Division of the Department of Industry, Energy and Technology conducted the natural gas resource assessment of the Jeanne d'Arc Basin. The assessment evaluated 18 areas within the Basin where proven discoveries exist within SDLs or PLs in the currently producing fields.

The assessment employed a data-driven scientific approach, integrating various geoscience datasets, including seismic data, well logs, core samples, and other geological reports. This ground-up methodology is independent of assessments conducted by multiple entities, including the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB).

The natural gas resource assessment is based on a comprehensive open-access database that includes all geological data, model interpretations, and assessment methods employed to estimate the range of natural gas resources within the SDLs and PLs of the Jeanne d'Arc Basin.

The assessment capitalizes on the substantial investments made by industry and government in acquiring geoscience expertise and the knowledge gained from the dynamic production of fields that have yielded more than 2.4 billion barrels of oil. The land areas that formed the basis of the assessment have relevant discovery wells that have been flow-tested to demonstrate the potential for sustainable production needed to meet the requirements for the issuance of the SDL. These flow tests help better quantify the range of discovered gas in place.

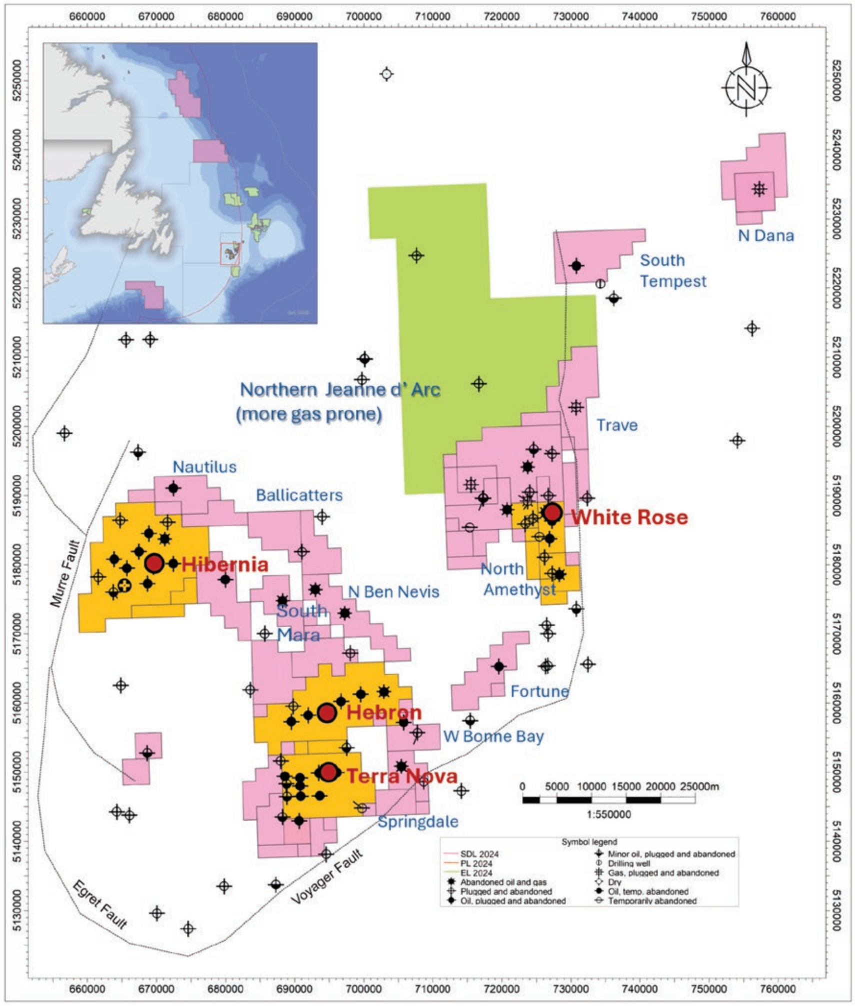


Figure 2: Producing Oilfields and Prospects
Source: Department of Industry, Energy and Technology 2025

The Jeanne d'Arc Basin is home to all four major oil-producing projects: Hibernia, Hebron, White Rose, and Terra Nova, as well as their associated infrastructure. The assessment focused on the primary formation on the SDLs and PLs within the Jeanne d'Arc Basin. This analysis provides a more comprehensive examination of defining and quantifying a potentially valuable asset compared to previous assessments.

The natural gas resource assessment will facilitate developing and commercializing Newfoundland and Labrador's natural gas sector. Expanding the natural gas assessment in 2025-2026 will further define the opportunity for development in the Jeanne d'Arc Basin.

Fostering a Clearer Understanding of Newfoundland and Labrador's Natural Gas Resource

Newfoundland and Labrador has significant natural gas resources in its offshore region. The natural gas resource assessment provides a comprehensive and current technical understanding of the potential discovered gas resource in the Jeanne d'Arc Basin.

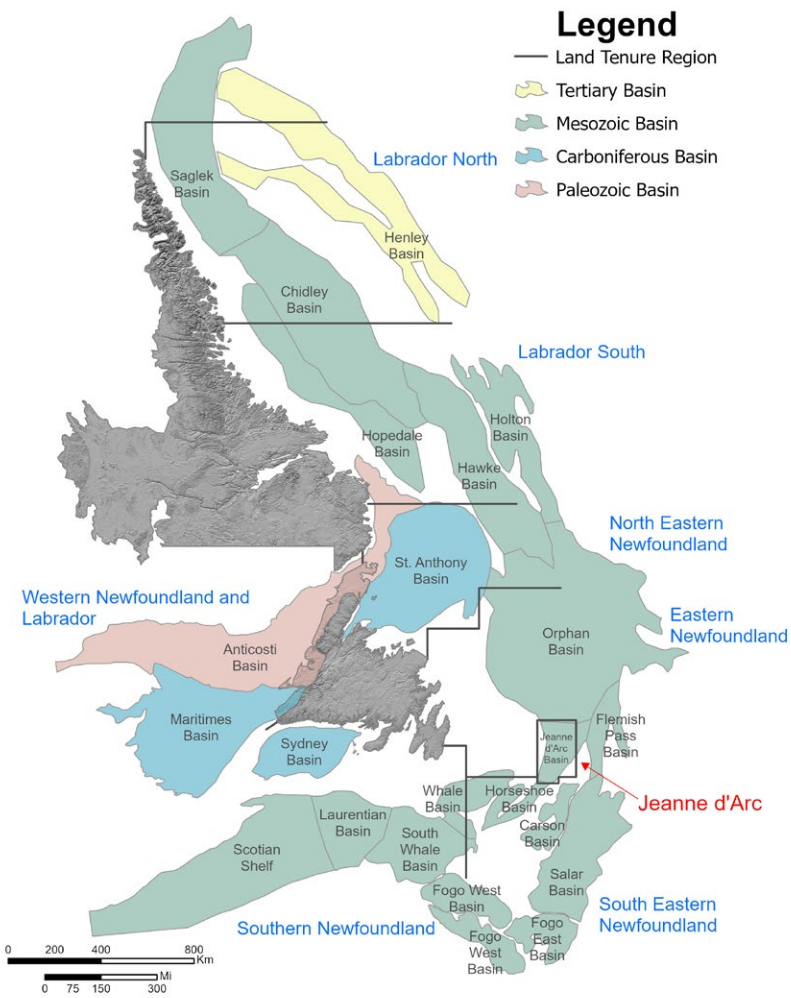


Figure 3: NL Offshore Basins
Source: Department of Industry, Energy and Technology 2025

Natural gas discoveries have occurred primarily in the Jeanne d'Arc Basin off the coast of Newfoundland and in the Hopedale Basin off the coast of Labrador. The C-NLOPB estimates these Hopedale Basin resources in coastal Labrador to hold a total 4.2 Tcf of natural gas and 123 million barrels (Mbbls) of NGLs from five discoveries. This assessment focused on the Jeanne d'Arc Basin, given the shallow waters, the existing producing infrastructure, and the supply and service community available to service any developments. This assessment of natural gas resources represents the first comprehensive analysis of the province's gas potential in the Jeanne d'Arc Basin, utilizing all the current subsurface geological data and methodologies to estimate resources. The complete assessment report: **Technical Report - 2025 Offshore Natural Gas Assessment of the Jeanne d'Arc Basin** - is attached as an annex.

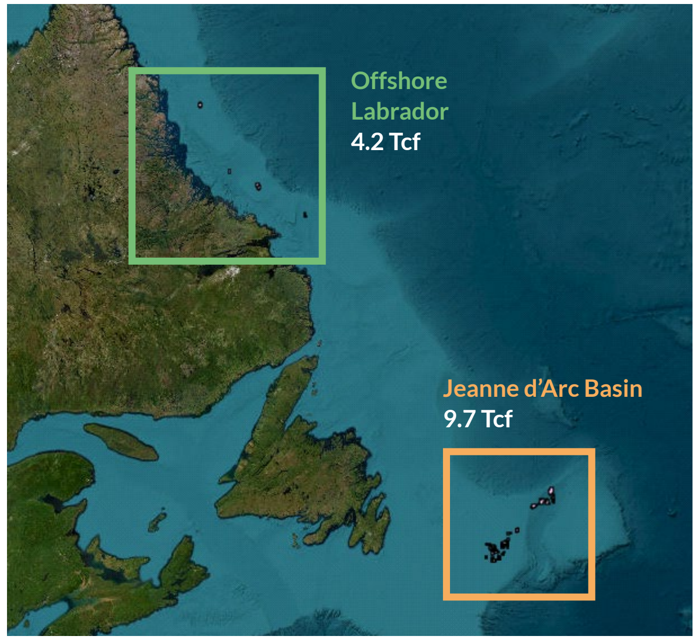


Figure 4: Gas Prone Regions NL Offshore
Source: Department of Industry, Energy and Technology 2025

The assessment determined that the natural gas resource base within the SDLs and PLs in the Jeanne d'Arc Basin ranges from 8.1 to 11.3 Tcf, with a best estimate of 9.7 Tcf. Additionally, NGLs on the SDLs and PLs were assessed at a best estimate of 372 Mbbls. For comparison, Canada's first offshore natural gas project, the Sable Offshore Energy Project in Nova Scotia, had an estimated 3.0 Tcf of recoverable gas at the development stage and produced 2.0 Tcf from five offshore fields over nearly 20 years. The Aphrodite gas field, located in the Mediterranean Sea off the southern coast of Cyprus, is an offshore natural gas field. It is estimated to hold between 3.6 and 6.0 Tcf of natural gas. The field was discovered in 2011 and is being developed by a consortium led by Chevron.

While completing the assessment, the Department identified additional proven natural gas resources adjacent to or residing on the SDLs and PLs. Applying commonly used industry-standard methods based on historically discovered resources, a projection of 20 identified prospects to be evaluated indicates an additional 7.4 to 30.6 Tcf of natural gas and 159 to 657 Mbbls of NGLs would likely be present. Figure 5 illustrates this. As a result, funds have been committed in Budget 2025 to expand the assessment and evaluate the adjacent resources.

Figure 5 is illustrative and based on current C-NLOPB estimates of discovered gas and NGL resources. Additionally, based on energy equivalence, 1 Tcf equals 0.17 billion barrels. Therefore, one incremental billion barrels of oil equivalent would equate to 1*87.4%/0.17 = 5.14 Tcf of natural gas and 126 million barrels of NGLs.

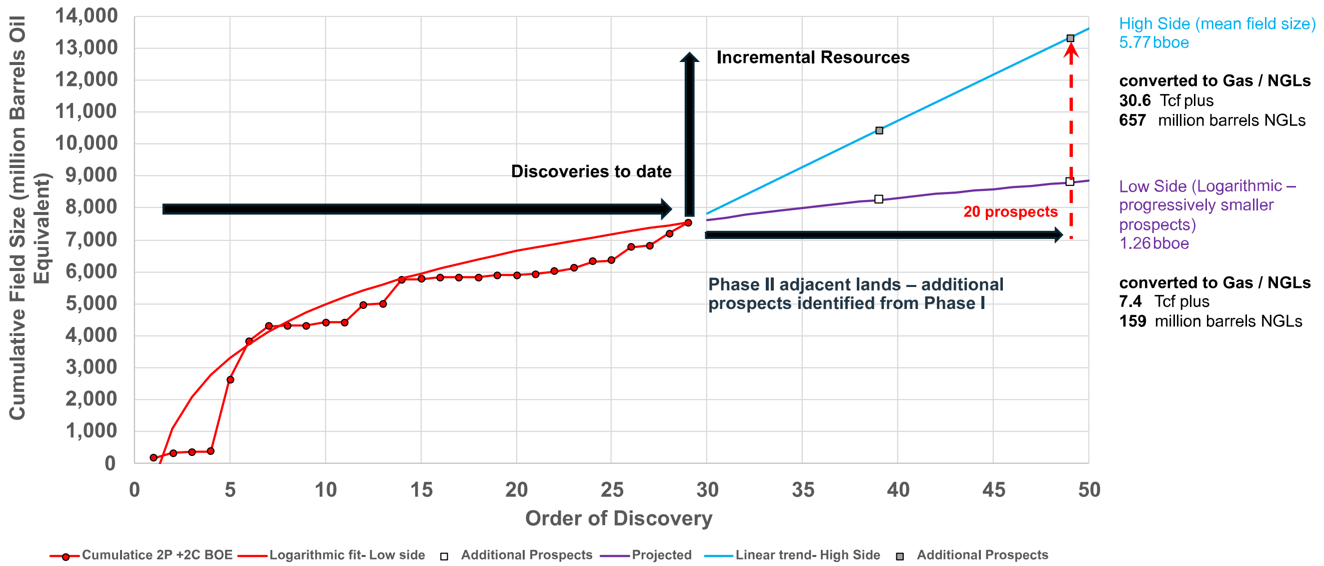


Figure 5: Recoverable Gas Potential
Source: Department of Industry, Energy and Technology 2025

Newfoundland and Labrador's Competitive Advantage in Oil Extends to Natural Gas

Newfoundland and Labrador is internationally recognized for the low carbon intensity of oil produced from its offshore facilities at the upstream level. This differentiator in the global marketplace would also apply to the province's natural gas production.

Like its oil production, future natural gas production in Newfoundland and Labrador is expected to produce significantly lower emissions at the upstream production stage compared to many other regions. It would be sourced through conventional methods not involving fracking, resulting in reduced methane emissions. High methane emissions during the upstream stage pose a significant drawback for many natural gas development projects worldwide.

Canada's oil and gas sector is recognized globally for its robust environmental, social, and governance (ESG) practices, which is a competitive advantage. Newfoundland and Labrador, which has lower oil emissions per barrel than the rest of Canada, would rank very high on a global ESG scale. The province is well-positioned to provide a responsible, ethical, and sustainable low-carbon supply of LNG from conventional offshore sources.

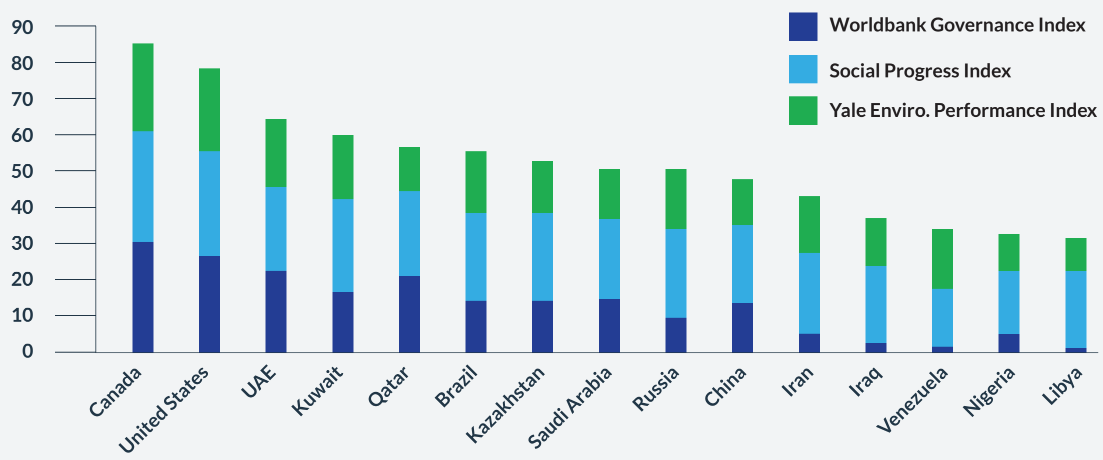


Figure 6: Canada's ESG Position
Source: Yale Environmental Performance Index (EPI); Social Progress Imperative; World Bank Governance Indicators, BMO Capital Markets (published 2021)

The world will continue to depend on oil and gas as primary energy sources for several decades while transitioning to a lower-carbon economy. Given Newfoundland and Labrador's current and projected ESG performance in the oil and gas sector, a compelling ESG argument exists for the province to remain one of the last regions to produce both oil and gas as renewable energy sources increasingly replace hydrocarbons as a fuel and heat source.

The Potential Value of Natural Gas to Newfoundland and Labrador's Economy

Newfoundland and Labrador's offshore oil and gas industry contributes to the provincial economy while providing secure, low-carbon access to a vital energy resource during the transition period.

The development of NL offshore natural gas could provide significant social and economic benefits and an opportunity to extend the commercial life of the province's offshore resources. In the future, as global oil production declines, natural gas production may play a crucial role in ensuring that the oil and gas sector continues to support the province's economy and revenue streams.

Offshore oil royalty revenues remain a critical component of the province's revenue, accounting for 15 per cent of revenues to the Provincial Government in 2024.

Natural gas production can significantly boost the offshore sector's substantial contribution to the provincial economy and treasury. Models incorporating various scenarios indicate that natural gas production could generate billions of dollars for the Newfoundland and Labrador Government in the upcoming decades.

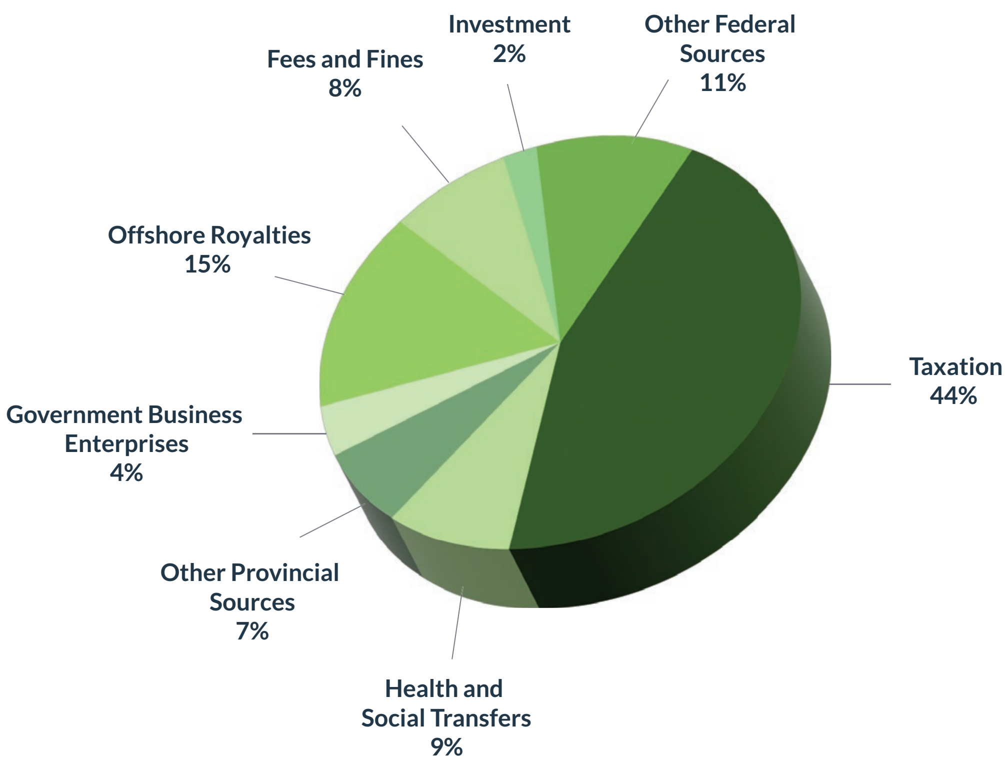


Figure 7: Government of Newfoundland and Labrador Revenue
Source: Government of Newfoundland and Labrador Budget Overview 2025

The Long-term Potential of Natural Gas for Newfoundland and Labrador

More broadly, the opportunities for NL's offshore natural gas and the offshore basins to support the dual objectives of contributing to the global transition and promoting the province's economic development are multi-faceted. Natural gas can directly support the energy transition and facilitate other developments.

Natural gas can be used to produce hydrogen through steam methane reforming. Hydrogen produced in this way is known as blue hydrogen, which can also contribute to the energy mix on the path to net zero emissions. In the short term, blue hydrogen could be delivered at a lower cost than green hydrogen (which is produced using renewable energy) and the share of blue hydrogen in the global energy market is projected to grow significantly. Blue hydrogen is considered a crucial transitional fuel, while the capacity to produce more green hydrogen from renewable energy sources is anticipated to increase over the coming decades.

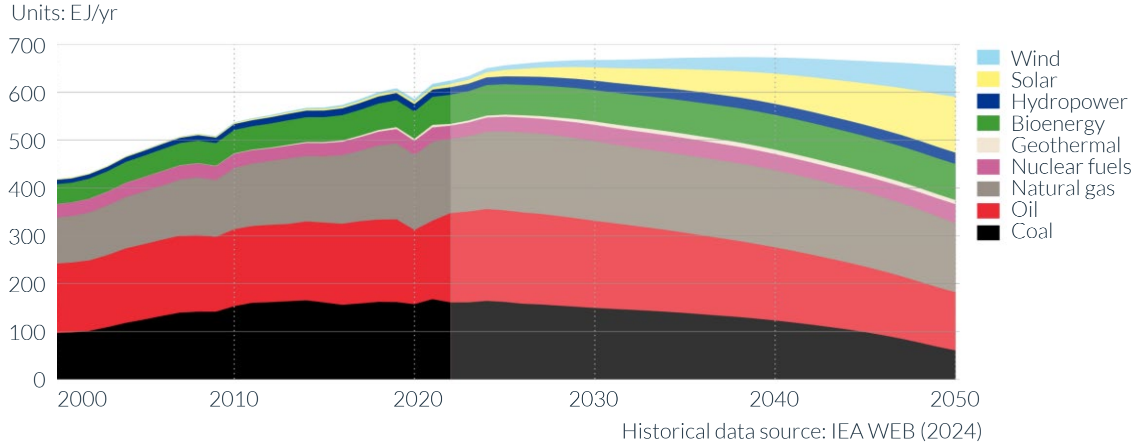
A blue hydrogen project in NL offshore, fueled by natural gas, could help initiate a Carbon Capture, Utilization and Storage (CCUS) sector. CCUS presents an opportunity for the province, as the offshore geology of Newfoundland and Labrador is well-suited for storing large volumes of CO_2 from various Canadian and international jurisdictions. CCUS is a critical element in achieving global net-zero emissions, and jurisdictions with geological formations suitable for safely storing CO_2 will play a role in the worldwide effort to combat climate change.

Concurrent with these opportunities, the abundant renewable energy of Newfoundland and Labrador can potentially power offshore oil and gas installations, further reducing operational emissions. This will position the province's hydrocarbon production as one of the most attractive globally, as consumers increasingly demand responsible oil and gas.

The Long-term Potential of Natural Gas for Newfoundland and Labrador (continued)

The province's abundant energy resources, synergies, and strong ESG rating position the province as a true energy hub. This strategic positioning enables the province to become a key integrated supplier of renewable and non-renewable energy while transitioning to a lower-carbon future and contributing to the fulfillment of the world's growing energy demands.

There is no single solution on the pathway to net-zero emissions. Instead, as illustrated in Figure 8, a wide range of energy sources and technologies will be integral to the solution. Natural gas will be one of those key sources. Newfoundland and Labrador must fully understand the opportunities associated with each energy source to promote and develop them effectively. The natural gas resource assessment is critical in this regard.



DNV's forecast of the change in the energy mix through 2050.

Figure 8: World Primary Energy Supply by Source
Source: DNV Energy Transition Outlook 2024

Conclusion

Budget 2025 includes almost $1 million for the second phase of the natural gas resource assessment to evaluate the additional prospects identified in the initial assessment. Phase II will continue building an inventory of proven and prospective gas resources across the Basin.

An assessment of these additional resources adjacent to or residing on the SDLs and PLs has never been conducted. Through 2025 and into 2026, the province will continue its initiative to better understand the volume of recoverable gas in the Jeanne d'Arc Basin by completing an assessment of these incremental resources. The same team in the Department of Industry, Energy and Technology that completed the initial report will conduct the assessment, with a final report to be released in 2026. Completing this next phase of the natural gas resource assessment will give potential developers the essential data necessary to evaluate the economic viability of commercial development, along with insights into the upside value and tie-back opportunities. It will also improve the understanding of gas availability timing and allow the province to promote its gas development opportunities.

These natural gas resources have significant economic potential and are in waters with depths of less than 200 metres. These assessments are crucial steps toward commercializing natural gas.

Another important step will be to finalize a provincial natural gas royalty regime. This regime is being developed with input from international experts to ensure that the fiscal framework is competitive with other jurisdictions while providing a fair return to the people of Newfoundland and Labrador. Establishing a natural gas royalty will provide clarity and transparency to interested exploration and development companies, allowing them to assess natural gas resource investment opportunities and make decisions related to the NL offshore. A draft royalty regime will be released in 2026.

The combined natural gas resource assessments and royalty framework will assist potential developers in better understanding the business case for developing natural gas in Newfoundland and Labrador's Jeanne d'Arc Basin.

Annex

Technical Report — 2025 Offshore Natural Gas Assessment of the Jeanne d'Arc Basin

The Natural Gas Assessment

- This study aims to quantify the probabilistic range of discovered in-place gas volumes within the offshore Jeanne d'Arc Basin.
- While exploration for offshore oil has been ongoing for over 50 years, no focused effort has yet been undertaken to find and develop natural gas. The current natural gas volumetric estimates, as noted by the Canadian Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB), is approximately 10.7 Tcf / 303 10^9 m^3 of recoverable resources across the entire East Coast offshore (C-NLOPB$_1$).
- The natural gas discoveries are primarily associated gas ("free" gas capping an oil column) found as a result of oil exploration drilling. Most discoveries currently reside on Significant Discovery Licenses (SDLs) or Production Licenses (PLs) of the current oil fields: Hibernia, Hebron, White Rose, North Amethyst and Terra Nova (Figure 1).
- Recent focus on natural gas as a preferred source of energy, emphasis on energy security on a global scale and the clear need to develop in jurisdictions like Newfoundland and Labrador offshore with upstream low emissions, has brought natural gas to the forefront of stakeholders minds.

Executive Summary

- A natural gas scientific data driven analysis was undertaken to understand the range of discovered gas in-place, recoverable gas volumes and natural gas liquid yields held within the Jeanne d'Arc Basin SDLs.
- The study focused primarily on the main gas bearing formation on all SDLs and PLs within the Jeanne d'Arc Basin (Figure 1).
- Probabilistic range of original gas in-place (OGIP), recoverable gas (REC) and recoverable Natural Gas Liquids (NGLs) on SDLs and PLs were calculated using all available modern data at the time of this study. The combined probabilistic total for prospects included in this analysis is shown in Table 1.

Probabilistic Volumes in Jeanne d'Arc Basin (primary formation)	P90	P50	P10
SDL OGIP (BCF)	8279	9905	11892
SDL REC / NGL (BCF/MMBBLS)	5291 / 116	6438 / 228	7843 / 339
PL REC ASSOC GAS / NGL (BCF/MMBBLS)	2208 / 112	3169 / 145	4129 / 178
TOTAL REC GAS (SDL+PL) (BCF)	8151	9730	11314
TOTAL REC NGL (MMBBLS)	258	372	488

Table 1: Probabilistic estimates of combined total volumes of OGIP and REC of the primary gas prospects on the SDLs/PLs in the Jeanne d'Arc Basin. Statistical volumes can not be added together for an overall summed total.

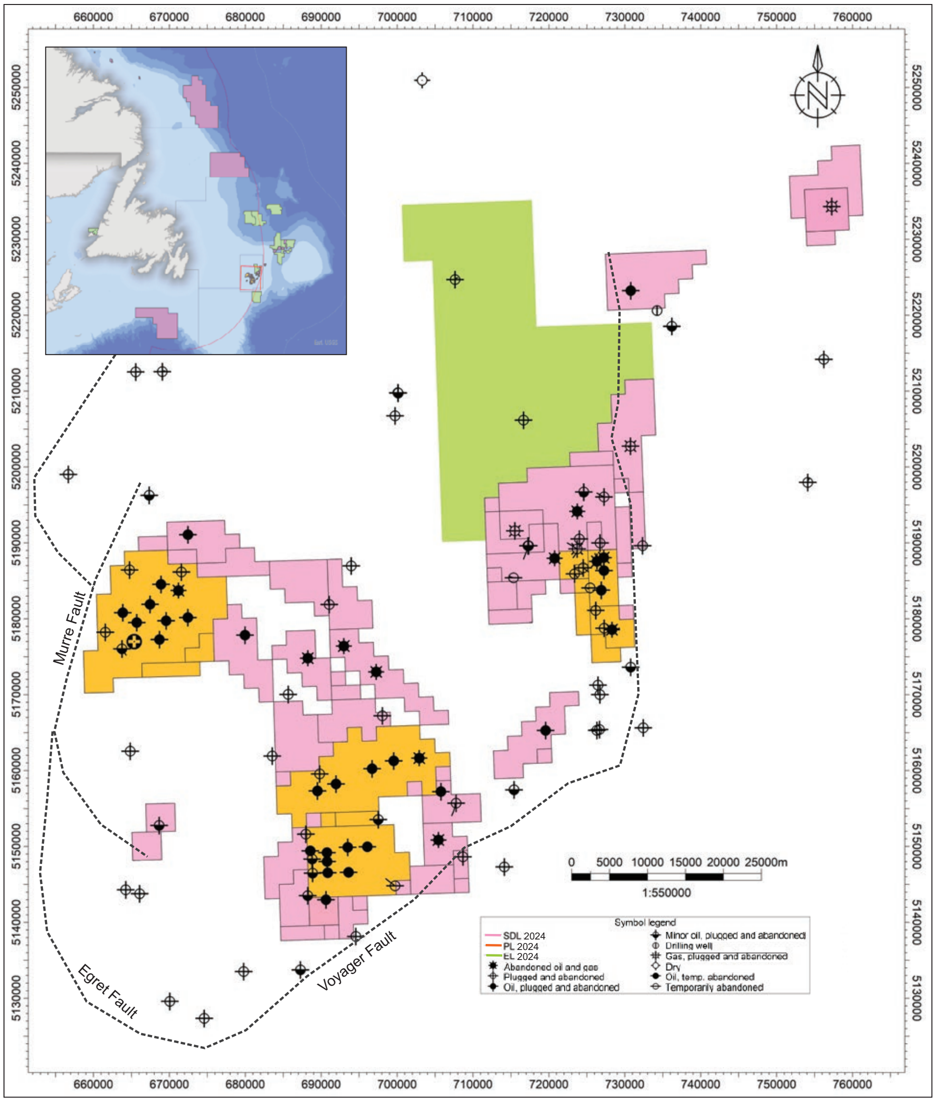


Figure 1. Land map of the Jeanne d'Arc Basin showing the study areas SDLs (pink) and PLs (orange). Basin bounding faults defined by black dashed lines.
Source: Department of Industry, Energy and Technology 2025

Study Area and Methodology

- Each of the SDL land areas have relevant discovery wells with flow tested volumes of natural gas in their respective wellbores. The range of discovered OGIP and REC volumes were calculated in the main gas bearing formation, often the one used to award the SDL. Additional upside OGIP encountered in other formations in the wellbores were noted but not fully assessed at this time.
- The Geoscience Petroleum Division utilized multiple time and depth seismic datasets over the study area. A workflow was developed to integrate interpreted time horizons, well tops, well ties, sonic and density logs to generate velocity models and convert time seismic datasets to the depth domain.
- Detailed interpretations were mapped on high resolution 3D seismic surveys to evaluate the structural - stratigraphic traps used to calculate the bulk rock volume (BRV) for this assessment.
- Analyzed curves for volume of shale, porosity and water saturation were generated by a third party petrophysical consultant (SLB) in order to define appropriate ranges for the assessment.
- @risk software was utilized to generate the stochastic original gas in place range.

Current Oil and Gas Industry

- The Province of Newfoundland and Labrador, located on the east coast of North America, is Canada's only offshore oil producing region. Since the discovery of oil in the Jeanne d'Arc Basin in 1979 with the exploration well Hibernia P-15, five oil fields have started production in the Jeanne d'Arc Basin: Hibernia, Terra Nova, White Rose, North Amethyst, and Hebron (Figure 1).
- To date, oil production is in excess of 2.4 billion barrels of oil with remaining recoverable reserves/resources totaling 3.0 billion barrels of oil, 10.96 Tcf of natural gas and 267 million barrels natural gas liquids in East Coast Newfoundland and Labrador offshore (noted by C-NLOPB as of January 2025).

Regional Geology of the Atlantic Margin

- In eastern Canada, a series of interconnected sedimentary Mesozoic rift Basins developed (green areas on map; Figure 2).
- This network of Basins stretch from offshore Nova Scotia to Newfoundland. The Scotian Basin extends between Cape Breton Island and Southern Newfoundland. The offshore Newfoundland area contains; Laurentian, South Whale, Whale, Horse Shoe, Jeanne d'Arc, Flemish Pass and Orphan Basins (green areas on map; Figure 2).
- The Mesozoic extensional Jeanne d'Arc Basin (9000 km^2) formed over hyper-stretched Precambrian and Paleozoic basement on the Canadian Atlantic Margin.

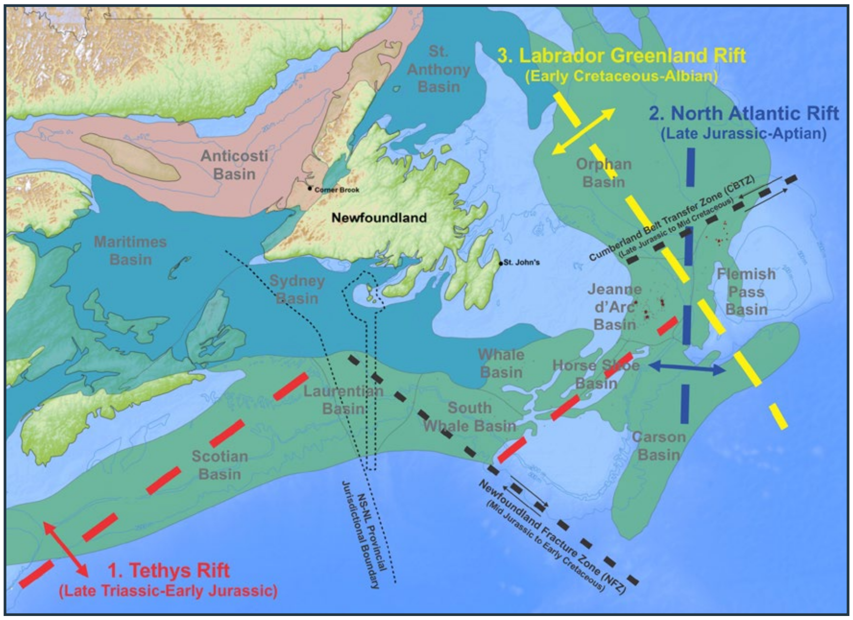


Figure 2: Regional geology of the Canadian Atlantic Margin showing main structural elements that define the basins including three phases of rift extension and transfer zones. Source: Modified from Enachescu 2020

Jeanne d'Arc Basin Geology

- Jeanne d'Arc Basin is host to most of the significant petroleum discoveries in the Newfoundland offshore area. This Basin forms an elongate NE-SW trending large half-graben structure, hinged on the East side by the Voyager Fault, the Murre Fault to the West, the Egret Fault to the South and the Cumberland Belt Transfer Zone (CBTZ) delineating the Basin to the North (Figures 1 & 2).
- Three main extensional rift phases influenced the final structural shapes of the Basins expressed today (Figure 2):
  1. Tethys Phase (Red), during Late Triassic-Early Jurassic opening in the Northwest-Southeast direction
  2. North Atlantic Phase (Blue), during Late Jurassic-Early Cretaceous opening in the East-West direction
  3. Labrador Phase (Yellow), during late Early Cretaceous opening the Basin further in the Southwest to Northwest orientation

Jeanne d'Arc Basin Geology (continued)

- The rift phases propagated a series of extensional faults in the crust to form the Jeanne d'Arc Basin region which subsequently created a deep depression in which to capture the northeast thickening wedge of clastic sediments (Figures 3 & 4).
- The four petroleum system elements: source, reservoir, trap and seal exist to create the optimal conditions for hydrocarbon accumulations in the Jeanne d'Arc Basin (Figure 4).
  1. Jurassic source rocks of the Egret Formation consists of organic-rich deep marine silts and muds
  2. Late Jurassic, Cretaceous and Tertiary reservoir rocks contain porous permeable siliciclastic sandstones
  3. Numerous structural-stratigraphic traps
  4. Prevalent lateral and top seals
- The 50 m to 500 m Late Jurassic Tithonian and Kimmeridgian organic rich shales of the Rankin Formation is the predominant source rock underlying the fields in the Jeanne d'Arc Basin. The Kimmeridgian Egret Member is a Type II, oil prone source rock with up to 9% TOC and the average hydrogen index (HI) ranging from 560 mg HC/g TOC to 410 mg HC/g TOC.
- Expulsion of the kerogen and migration of oil started in the Early Cretaceous and continue to present day with the oil phase transitioning to gas phase in the deeper northern Basin areas in the Late Cretaceous Aptian/Albian time (Figure 4).
- The Basin exhibits numerous stacked siliciclastic sandstone intervals from the Late Jurassic to the Tertiary age and are proven to be high reservoir quality with porosities ranging from 10-30% in the sandstones.
- Regional flooding events resulted in deep marine muds deposited over the reservoirs sandstones providing the impermeable seal necessary to trap the hydrocarbons in place.

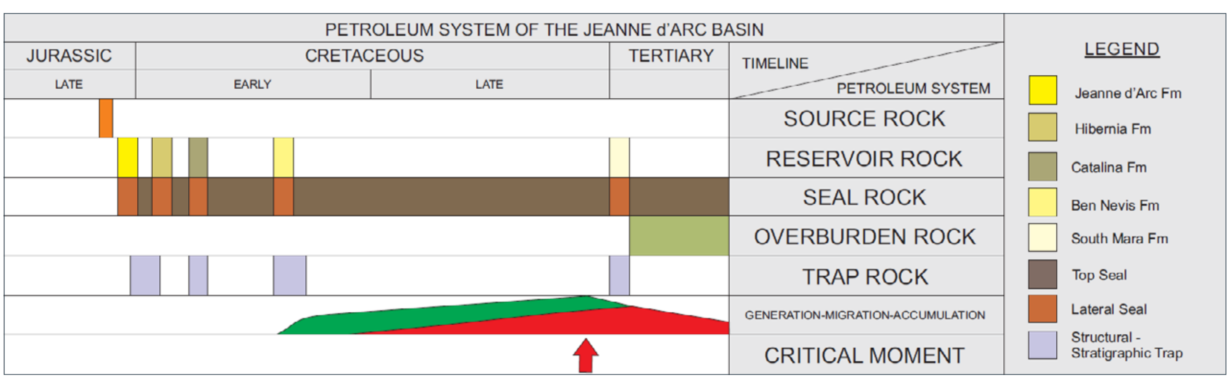


Figure 4: Petroleum system event chart summarizing the timing of each petroleum element for the Jeanne d'Arc Basin. Source: Department of Industry, Energy and Technology 2025

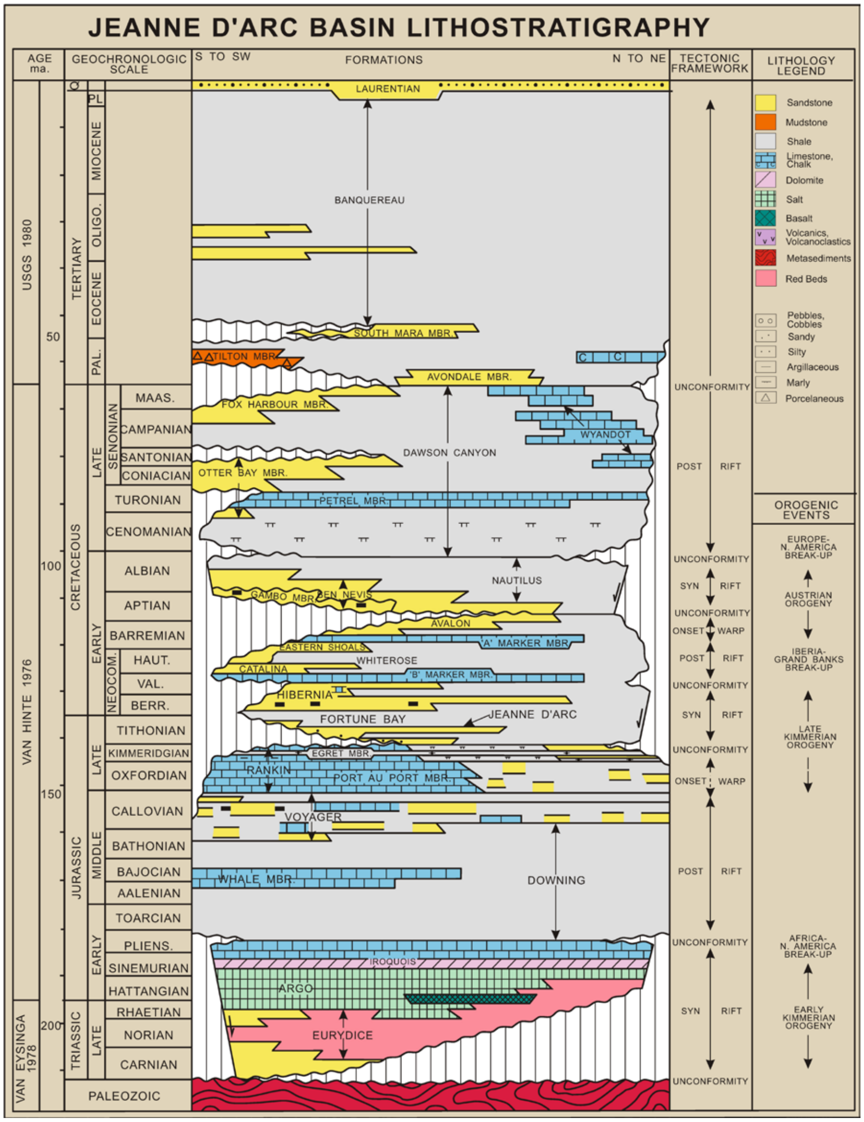


Figure 3: Jeanne d'Arc Basin stratigraphic chart illustrating deposition of sediment during the synrift and post rift phases.
Source: Modified after Sinclair 1992

NOMENCLATURE

- **Gross Thickness:** Total thickness from top reservoir to base reservoir or contact
- **Net Thickness:** Gross Interval that passes a volume of clay (Vcl) cut off
- **Reservoir Thickness:** Net Interval that passes a Vcl and porosity cut off (i.e. net sand)
- **Pay Thickness:** Reservoir Interval that passes a Vcl, porosity and water saturation cut off (i.e. net pay)
- **Reservoir:Gross** ($N:G_{res}$): reservoir interval / gross interval
- **Pay:Gross:** ($N:G_{pay}$) pay / gross
- **Average Porosity:** (Avg Phi_{res}): average phi over the Reservoir
- **Gas Saturation (Sg):** average gas saturation over the Pay
- **Formation volume Factor** (1/Bg)
- **Bulk Rock Volume** (BRV)
- **Net to Gross** (N:G)
- **Repeat Formation Sampler** (RFS)
- **Drill Stem Test** (DST)
- **Original Gas In Place** (OGIP; bcf)
- **Recoverable Gas** (REC; bcf)
- **Natural Gas Liquid Yield** (NGL; bbls/mmscf)

HYDROCARBON CONTACTS

- **Gas-Oil Contact** (GOC)
- **Gas-Water Contact** (GWC)
- **Gas Down To Contact** (GDT)
- **Oil Up To Contact** (OUT)
- **Water Up To Contact** (WUT)

Jeanne d'Arc Basin SDL Gas Resouce (P50) Summary

Significant Discovery	Forma-tion	SDL (PL)	OGIP P50 (bcf)	REC P50 (bcf)	NGL Yields (bbls/mmscf)	NGL (MMb-bls)
White Rose (H-70 Area)	BNA	1019, 1023, 1025, 1026, 1027, 1028, 1054	2243	1436	37	123.4
White Rose (N-22 Area)	BNA	1025, 1028	1469	947		
White Rose (C-30 Area)	BNA	1028, 1025; (PL 1010 & 1009)	1045	673		
White Rose (J-49 Area)	BNA	1025, (PL 1010 & 1009)	416	268		
White Rose (H-20)	BNA	1025	10	7		
White Rose (B-19z)	BNA	1025; (PL 1006)	8	5		
North Amethyst (K-15 Area)	BNA	(PL 1007 & 1008)	53	34	37	1.3
Ballicatters (M-96/z)	BNA	1051, 1052	1718	1109	22	24.4
Nautilus (C-92)	Catalina	1001, 1041	796	511	48	24.5
Trave (E-87)	Hibernia	1031	591	382	24	9.2
North Ben Nevis (P-93/M-61)	BNA	1008	299	192	32	6.1
West Bonne Bay (F-12/z)	Hibernia	1040	276	178	24	4.3
South Fortune (G-57)	Hibernia	1011, 1012	139	90	23	2.6
North Fortune (G-57)	Hibernia	1011, 1012	36	24		
North Dana (I-43)	Tempest	200A, 200B, 200C	119	77	23	1.8
Springdale (M-29)	South Mara	1013, 1014, 1015, 1016, 1017	111	71	36	2.6
South Mara (C-13)	BNA	1003	55	36	47	1.7
South Tempest (G-88)	Tempest	197	20	13	23	0.3

Table 2: A @risk statistical assessment of the P50 gas resource summaries for the main gas bearing formations on the SDLs and select PLs, with the applicable NGL yields.

- NGLs are a mixture of light hydrocarbons that exist in the gaseous phase in the reservoir and are recovered as liquids in gas processing plants. NGLs differ from condensate in two principal respects:
  1. NGLs are extracted and recovered in gas plants rather than lease separators or other lease facilities, and
  2. NGLs include very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensates (Source from SPE).
- NGLs on the SDLs are derived from formation flow tests (Table 2).
- Statistical mathematical volumes for P50's (or P90's or P10's) can not be added together to calculate an overall total.

Production Fields in the Jeanne d'Arc Basin: Contingent Resources

- For the production fields, the associated solution gas that is not consumed in operations (CiO) during oil production is reinjected into the reservoir to enhance oil recovery and/or for conservation.
- A conservative approach has been applied which assumes gas development or gas cap 'blowdown' occurs at the end of the field life (EOFL), with CiO projections accounted for up to that point.
- To estimate the solution gas available at EOFL, the range of oil Estimated Ultimate Recovery (EUR) published by the C-NLOPB is used, multiplied by the initial gas-oil ratio (GOR), with adjustments made to exclude CiO (fuel and flare gas). The same recovery factor distribution for gas fields is applied, when a gas cap is present.
- The NGL yield estimates are derived from formation flow tests, typically Drill Stem Test (DST) results. These estimates provide a data-driven assessment of recoverable liquids, ensuring a comprehensive evaluation of the resource potential.

Field	P90 Gas (bcf)	P50 Gas (bcf)	P10 Gas (bcf)	P90 NGL (mmbbl)	P50 NGL (mmbbl)	P10 NGL (mmbbl)
Hibernia	1154	1615	2122	77	100	123
Hebron	77	161	330	2	2	3
Terra Nova	59	98	139	0	0	0
White Rose	873	1163	1460	31	41	50
North Amethyst	45	62	78	2	2	2
TOTAL	**2208**	**3169**	**4129**	**112**	**145**	**178**

Table 3: Associated recoverable gas resources for the fields on production for all formations. Shrinkage was accounted for in the recovery factor.

Study Area: SDLs - H-70 Region

- SDL 1019, 1023, 1025, 1026 1027 1028, 1054
- **Effective date:** February 16, 1990
- **License Representative:** Cenovus Energy Inc
- **Prospect Area:** 9110 ha

Key Well: White Rose H-70
Interval: Ben Nevis Siltstone top to A-Marker top

- **Gross :** 585m
- **Gas Pay:** 33.5m
- **GOC:** -3642m TVDss
- **Sg:** 66%
- **N:G $_{res}$:** 11%
- **N:G $_{pay}$:** 6%
- **Avg Phi $_{res}$:** 12%

- The White Rose H-70 prospect uses range of contacts supported by gas pressures, samples and DST in H-70/z, A-78 and L-61
- P90 BRV was determined from mapping the Ben Nevis Siltstone top to AMarker (both flexed to well tops to account for depth error) with GDT of -3584m TVDss (burgundy area on Figure 5; and yellow interval on Figure 6)
- P50 BRV was determined from same methodology as P90 and most likely GOC of -3642m TVDss based on pressures (burgundy & pink areas on Figure 5; and yellow interval on Figure 6)
- P10 BRV was determined from same methodology as P90 to OUT 3661m TVDss (burgundy, pink, yellow areas on Figure 5; and yellow interval on Figure 6)
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Ben Nevis Siltstone top to A-Marker top interval; offset wells were used (Figure 7 & Table 4)
- Contingent gas resources in South Mara Fm (volumes not calculated) as noted in WR L-61
- Reservoir pressure is approximately 37000 kpa. Bg ranges are from offset wells
in the White Rose Field
- Recovery Factor analysis from analogues using industry trends and standards

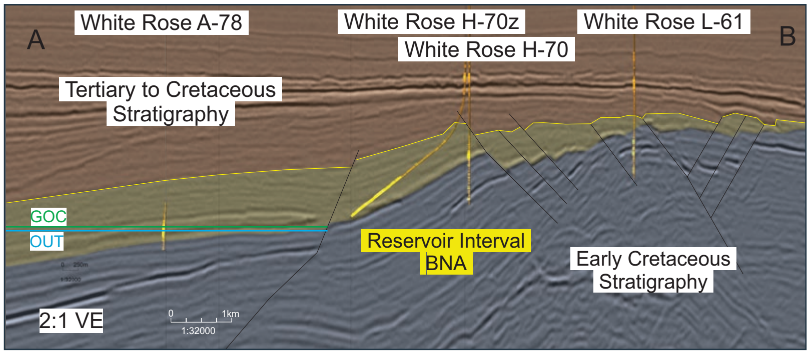


Figure 6: Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the northeast to southwest extent across the White Rose A-78/H-70/z prospect. Target reservoir interval from Ben Nevis Formation top to A-Marker top (highlighted in yellow).

	BRV (e^6m^3)	N:G$_{res}$	Phi$_{res}$	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	23243	7	10	60	239	1227	763
P50	25358	12	12	66	265	2243	1436
P10	27473	19	14	72	284	3698	2465

Table 4: Input values from top Ben Nevis Siltstone Formation top to A-Marker within the White Rose H-70 prospect boundary, using @risk to determine probabilistic OGIP and REC.

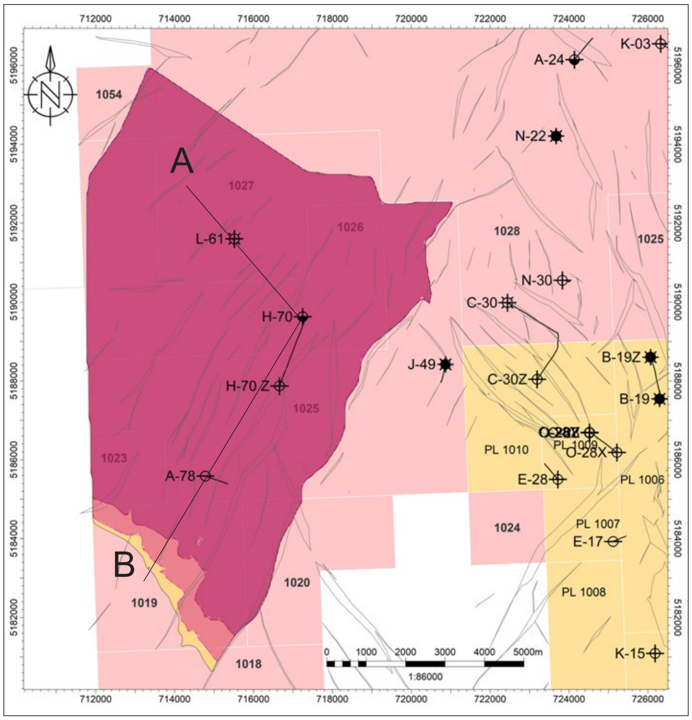


Figure 5: Basemap illustrating the outline for White Rose A-78/H-70/H-70z prospect; (burgundy/pink/yellow) used as input to determine the BRV for the in-place gas calculation, A-B line depicting location of schematic cross section.

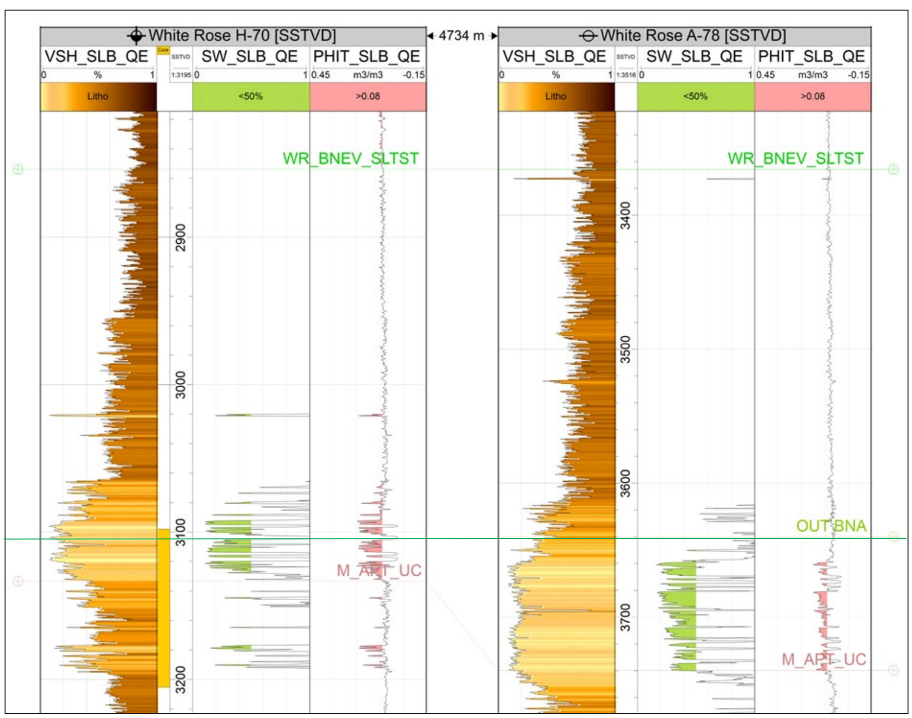


Figure 7: White Rose H-70/A-78 well section over the reservoir interval from Ben Nevis Siltstone Formation top to A-Marker top including the OUT.

Study Area: SDL 1028 & 1025 - N-22 Region

- SDL 1028 & 1025
- **Effective date:** February 16, 1990
- **License Representative:** Cenovus Energy Inc
- **SDL Size:** 11649 ha, 4589 ha respectively (16238 ha)

Key Well: White Rose N-22
Interval: Ben Nevis Siltstone to Mid-Aptian Unconformity

- **Gross :** 77m
- **Gas Pay:** 10.3m
- **GOC:** -3014m TVDss
- **Sg:** 65%
- **N:G $_{res}$:** 55%
- **N:G $_{pay}$:** 19%
- **Avg Phi $_{res}$:** 14%

- The White Rose N-22 prospect uses the GOC of -3014m TVDss from the White Rose N-30 well; supported by pressure data
- P50 BRV was determined from mapping the Ben Nevis Siltstone top to Mid-Aptian Unconformity (both flexed to well tops to account for depth error) down to the GOC within the fault bounded block (burgundy area on Figure 5; and yellow interval on Figure 6)
- P1 BRV was determined from same methodology as P50 but includes the light pink area to the west (dark pink & burgundy area on Figure 5; and yellow interval on Figure 6)
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Ben Nevis Siltstone to Mid-Aptian Unconformity interval; offset wells were used (Figure 7 & Table 4)
- Contingent gas resources in Wyandot and Lower Hibernia Fm (volumes not calculated)
- Reservoir pressure is approximately 37000 kpa. Bg ranges are from offset wells in the White Rose Field
- Recovery Factor analysis from analogues using industry trends and standards

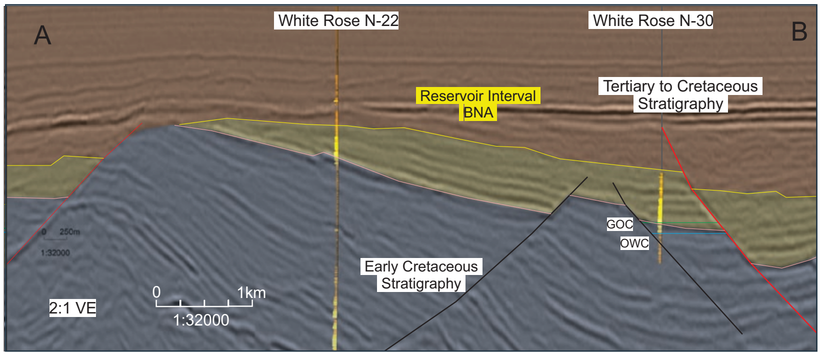


Figure 6: Schematic cross-section from CA-3000696 2008 Husky JDAWhiterose 3D survey (converted to depth) illustrating the north to south extent across the White N-22 prospect. Target reservoir interval from Ben Nevis Formation top to Mid-Aptian Unconformity (highlighted in yellow) to the red fault.

	BRV (e^6m^3)	N:G$_{res}$	Phi$_{res}$	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	4557	33	12	62	239	1198	709
P50	4811	38	13	66	265	1469	947
P10	5065	46	14	71	284	1811	1258

Table 4: Input values from top Ben Nevis Siltstone Formation top to Mid-Aptian Unconformity within the White Rose N-22 prospect boundary, using @risk to determine probabilistic OGIP and REC.

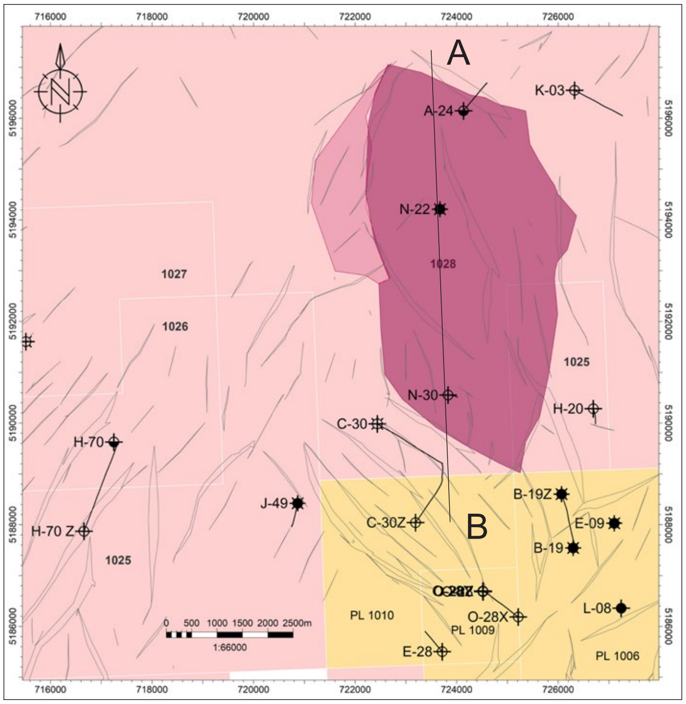


Figure 5: Basemap illustrating the outline for White Rose N-22 prospect; (burgundy and dark pink) used as input to determine the BRV for the in-place gas calculation, A-B line depicting location of schematic cross section.

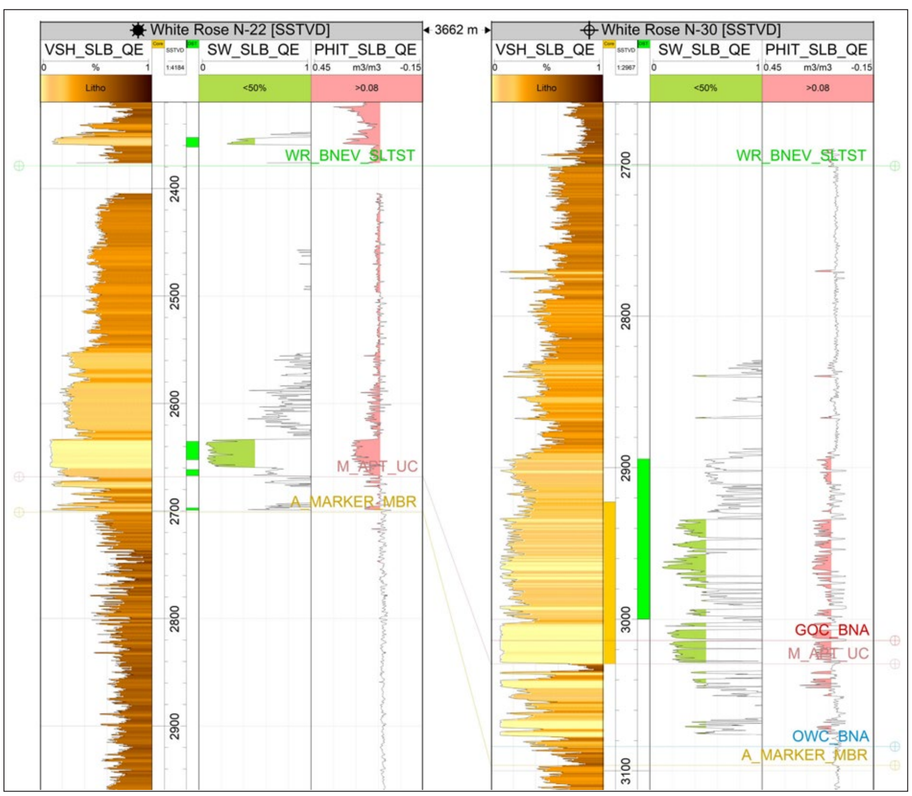


Figure 7: White Rose N-22 to N-30 well section over the reservoir interval from Ben Nevis Siltstone Formation top to Mid-Aptian Unconformity including the gas-oil contact GOC.

Study Area: SDL 1028 1025; PL 1010 1009 - C-30 Region

- SDL 1028 & 1025; PL 1010 & 1009
- **Effective date:** March 28, 1990
- **License Representative:** Cenovus Energy Inc
- **SDL Size:** 5321 ha, 355 ha respectively (5676ha)

Key Well: White Rose C-30z
Interval: Ben Nevis Siltstone to Mid-Aptian Unconformity

- **Gross :** 377m
- **Gas Pay:** 15m
- **GOC:** -3085m TVDss
- **Sg:** 59%
- **N:G $_{res}$:** 40%
- **N:G $_{pay}$:** 4%
- **Avg Phi $_{res}$:** 13%

- The White Rose C-30/z prospect uses the GOC of -3085m TVDss observed in White Rose C-30z; supported by gas samples and DST
- P50 BRV was determined from mapping the Ben Nevis Siltstone top to Mid-Aptian Unconformity (both flexed to well tops to account for depth error) down to the GOC within the fault bounded block (burgundy area on Figure 5; and yellow interval on Figure 6)
- P1 BRV was determined from same methodology as P50 but includes the light pink area to the North (dark pink & burgundy area on Figure 5; and yellow interval on Figure 6)
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Ben Nevis Siltstone to Mid-Aptian Unconformity interval; offset wells were used (Figure 7 & Table 4)
- Reservoir pressure is approximately 35000 kpa. Bg ranges are from offset wells in the White Rose Field
- Recovery Factor analysis from analogues using industry trends and standards

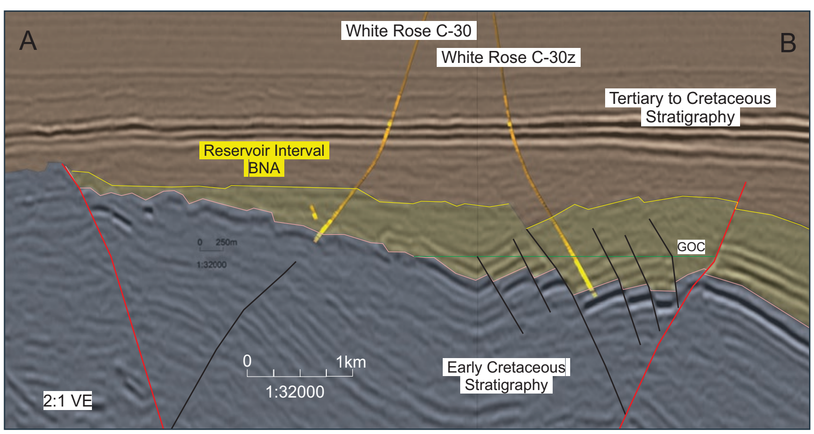


Figure 6: Schematic cross-section from CA-3000696 2008 Husky JDAWhiterose 3D survey (converted to depth) illustrating the northwest to southeast extent across the White Rose C-30/C-30z prospect. Target reservoir interval from Ben Nevis Formation top to Mid-Aptian Unconformity (highlighted in yellow) between the two red faults.

	BRV (e^6m^3)	N:G$_{res}$	Phi$_{res}$	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	2905	29	12	61	239	682	414
P50	2997	43	13	67	265	1045	673
P10	3089	63	14	71	284	1548	1046

Table 4: Input values from top Ben Nevis Siltstone Formation top to Mid-Aptian Unconformity within the White Rose C-30/z prospect boundary, using @risk to determine probabilistic OGIP and REC.

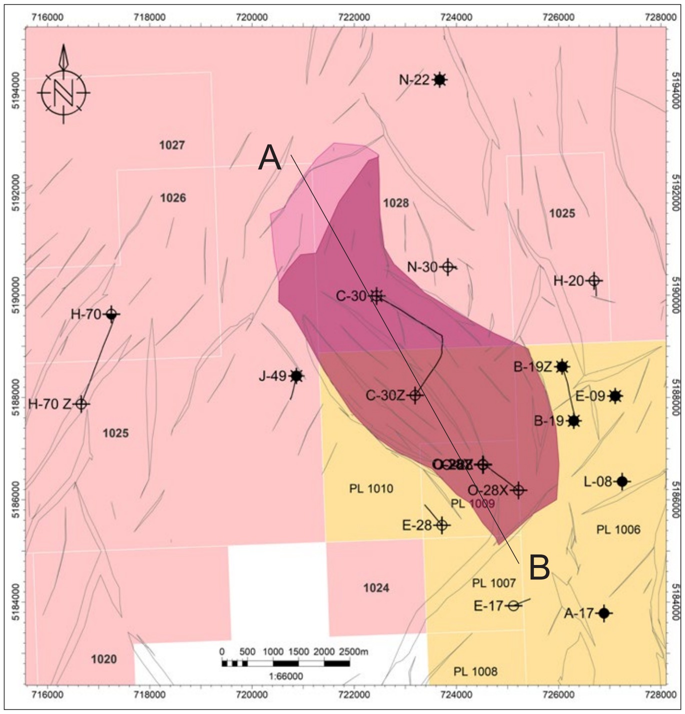


Figure 5: Basemap illustrating the outline for White C-30/z prospect; (burgundy and dark pink) used as input to determine the BRV for the in-place gas calculation, A-B line depicting location of schematic cross section.

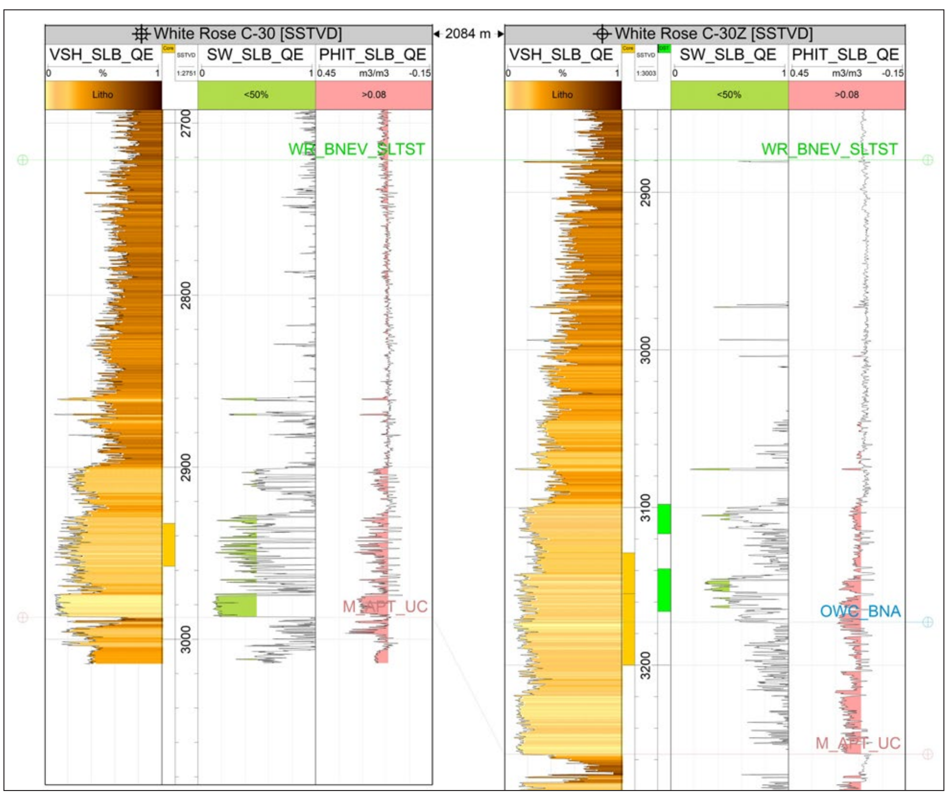


Figure 7: White Rose C-30/C30z well section over the reservoir interval from Ben Nevis Siltstone Formation top to Mid-Aptian Unconformity including the gas-oil contact GOC.

Study Area: SDL 1025 PL 1010 & 1009 - J-49 Region

- SDL 1025; PL 1010 & 1009
- **Effective date:** February 16, 1990
- **License Representative:** Cenovus Energy Inc
- **SDL Size:** 4589 ha

Key Well: White Rose J-49
Interval: Ben Nevis Siltstone to Mid-Aptian Unconformity

- **Gross :** 343m
- **Gas Pay:** 28m
- **GOC:** -3070m TVDss
- **Sg:** 71%
- **N:G res:** 17%
- **N:G pay:** 8%
- **Avg Phi res:** 11%

- The White Rose J-49 prospect uses the GOC of -3070m TVDss; supported by gas samples and DST
- P50 BRV was determined from mapping the Ben Nevis Siltstone top to Mid-Aptian Unconformity (both flexed to well tops to account for depth error) down to the GOC within the fault bounded block (burgundy area on Figure 5; and yellow interval on Figure 6)
- P1 BRV was determined from mapping the Ben Nevis Siltstone top to A-Marker down to GOC (burgundy area on Figure 5; and yellow interval on Figure 6)
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Ben Nevis Siltstone to Mid-Aptian Unconformity interval; offset wells were used (Figure 7 & Table 4)
- Reservoir pressure is approximately 31000 kpa. Bg is 0.0037 and ranges are from offset wells in the White Rose Field
- Recovery Factor analysis from analogues using industry trends and standards

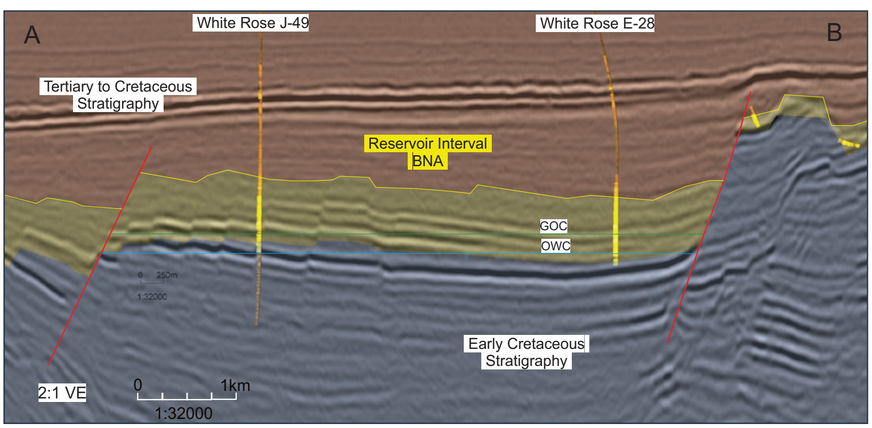


Figure 6: Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the northwest to southeast extent across the White Rose J-49 prospect. Target reservoir interval from Ben Nevis Formation top to Mid-Aptian Unconformity (highlighted in yellow) between the two red faults.

	BRV (e^6m^3)	N:G$_{res}$	Phi$_{res}$	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	2107	12	12	61	239	213	132
P50	2203	24	13	67	265	416	268
P10	2299	46	14	73	284	819	546

Table 4: Input values from top Ben Nevis Siltstone Formation top to Mid-Aptian Unconformity within the White Rose J-49 prospect boundary, using @risk to determine probabilistic OGIP and REC.

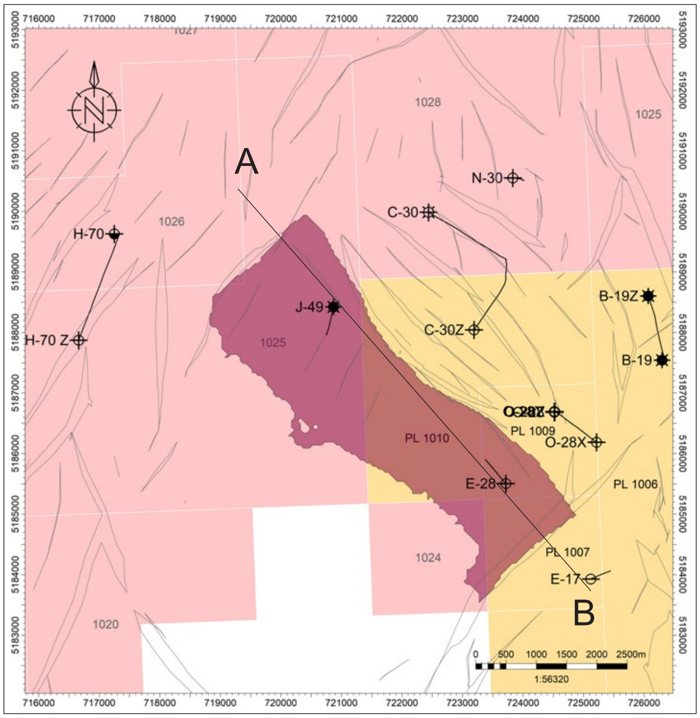


Figure 5: Basemap illustrating the outline for White Rose J-49 prospect; (burgundy) used as input to determine the BRV for the in-place gas calculation, A-B line depicting location of schematic cross section.

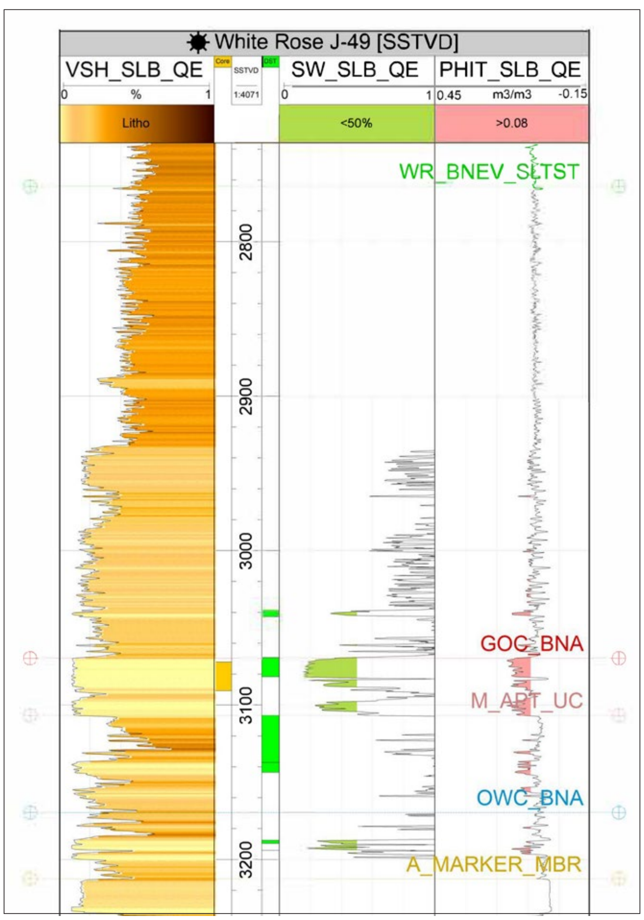


Figure 7: White Rose J-49 well section over the reservoir interval from Ben Nevis Siltstone Formation top to Mid-Aptian Unconformity including the gas-oil contact GOC.

Study Area: PLs 1007 & 1008 North Amethyst

- PL 1007 & 1008
- **Effective date:** November 19, 2007
- **License Representative:** Cenovus Energy Inc
- **SDL Size:** 2832 ha, 2124 ha respectively (4956 ha)

Key Well: North Amethyst K-15
Interval: Ben Nevis Siltstone Fm top to Gas-Oil-Contact

- **Gross :** 74m
- **Gas Pay:** 67m
- **GOC:** -2334m TVDss
- **Sg:** 73%
- **N:G $_{res}$:** 91%
- **N:G $_{pay}$:** 91%
- **Avg Phi $_{res}$:** 17%

- The North Amethyst K-15 well contains a gas response in well logs, supported by pressures and recovered gas samples in the Ben Nevis Fm
- P50 BRV was determined from Ben Nevis Fm top (flexed to well top) to the GOC (burgundy area on Figure 5; yellow on Figure 6)
- P10 BRV was determined from Ben Nevis Siltstone Fm top (flexed to well tops) to the GOC (burgundy & pink area on Figure 5; yellow on Figure 6)
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Ben Nevis Siltstone Fm top to Gas-Oil-Contact interval; four offset wells were used (Figure 7 & Table 4)
- Reservoir pressure is approximately 23700 kpa. Bg is based on the North Amethyst wells
- Recovery Factor analysis from analogues using industry trends and standards

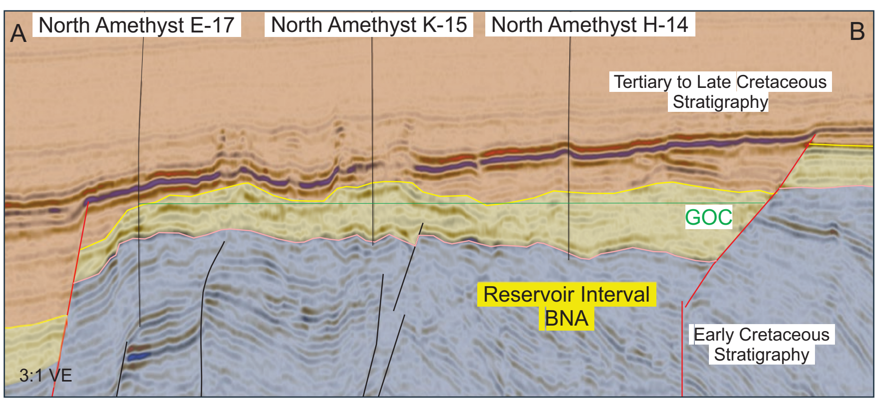


Figure 6: Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the northwest to southeast extent of the North Amethyst prospect. Target reservoir interval from Ben Nevis Formation top to GOC (highlighted in yellow) between the red faults.

	BRV (e^6m^3)	N:G$_{res}$	Phi$_{res}$	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	43	27	12	72	204	16	10
P50	116	50	17	76	217	53	34
P10	320	73	22	80	230	166	108

Table 4: Input values from top Ben Nevis Siltstone Formation top to GOC within the North Amethyst prospect boundary, using @risk to determine probabilistic OGIP and REC.

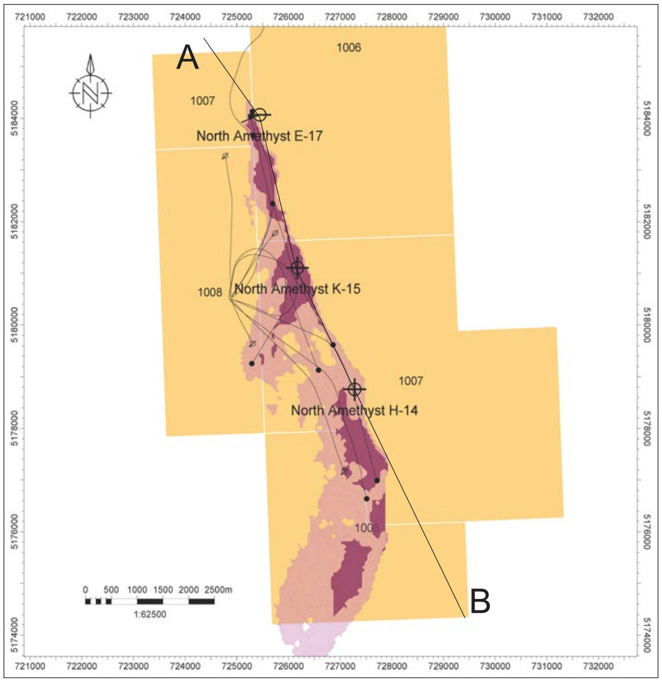


Figure 5: Basemap illustrating North Amethyst prospect outline; P10 (burgundy & pink) and P50 (burgundy) gas accumulations used as input to determine the BRV for the in-place gas calculation, A-B line depicting location of schematic cross section.

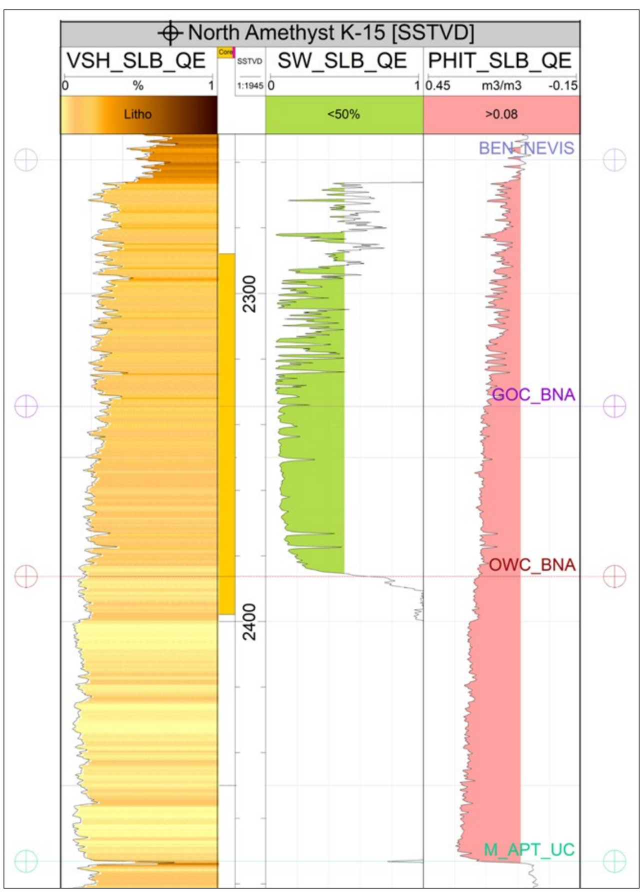


Figure 7: North Amethyst K-15 well section over the reservoir interval from Ben Nevis Formation top to the gas-oil contact GOC.

Study Area: SDL 1025 - H-20 Region

- SDL 1025
- **Effective date:** February 16, 1990
- **License Representative:** Cenovus Energy Inc
- **SDL Size:** 4589 ha

Key Well: White Rose H-20
Interval: Ben Nevis Siltstone to Mid-Aptian Unconformity

- **Gross :** 437m
- **Gas Pay:** 1.0m
- **GOC:** -2872m TVDss
- **Sg:** 52%
- **N:G $_{res}$:** 66%
- **N:G $_{pay}$:** 0.2%
- **Avg Phi $_{res}$:** 12%

- The White Rose H-20 well contains a gas oil contact (GOC) at -2872m TVDss as noted in the End of Well Report
- P50 BRV was determined from mapping the Ben Nevis Siltstone top (flexed to well tops to account for depth error) down to the GOC (burgundy area on Figure 5; yellow on Figure 6)
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Ben Nevis Siltstone to Mid-Aptian Unconformity interval; offset wells were used (Figure 7 & Table 4)
- Contingent gas resources in the Lower Hibernia Fm and Jeanne d'Arc Fm (volumes not calculated) encountered in White Rose E-09
- Reservoir pressure is approximately 32000 kpa. Bg ranges are from offset wells in the White Rose Field
- Recovery Factor analysis from analogues using industry trends and standards

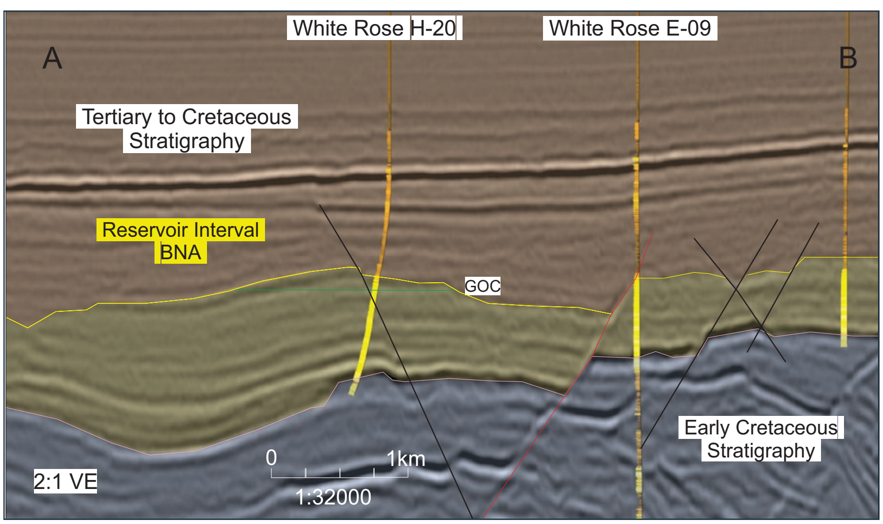


Figure 6: Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the north to south extent across the White Rose H-20 prospect. Target reservoir interval from Ben Nevis Siltstone Formation top to Mid-Aptian Unconformity (highlighted in yellow).

	BRV (e^6m^3)	N:G$_{res}$	Phi$_{res}$	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	43	32	9	54	239	8	5
P50	49	37	10	60	265	10	7
P10	55	44	11	66	284	13	9

Table 4: Input values from top Ben Nevis Siltstone Formation top to Mid-Aptian Unconformity within the White Rose H-20 prospect boundary, using @risk to determine probabilistic OGIP and REC.

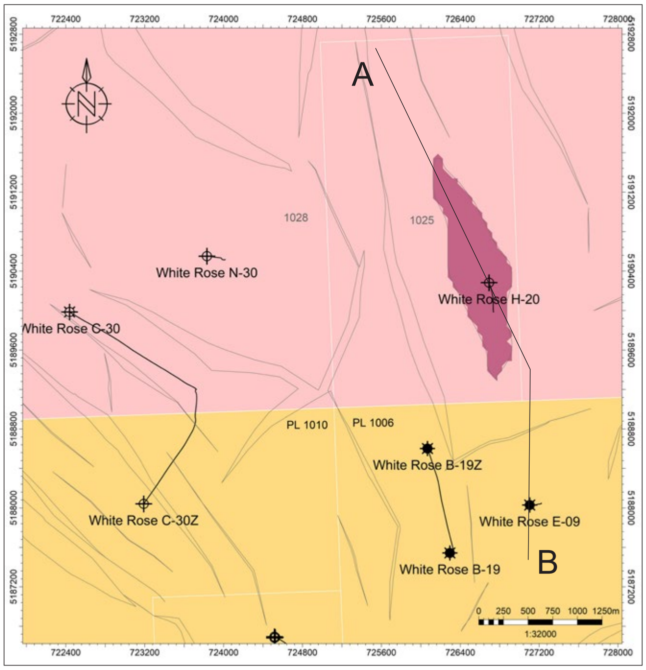


Figure 5: Basemap illustrating the outline for White Rose H-20 prospect; (burgundy) used to dertermine the BRV for the in-place gas calculation, A-B line depicting location of schematic cross section.

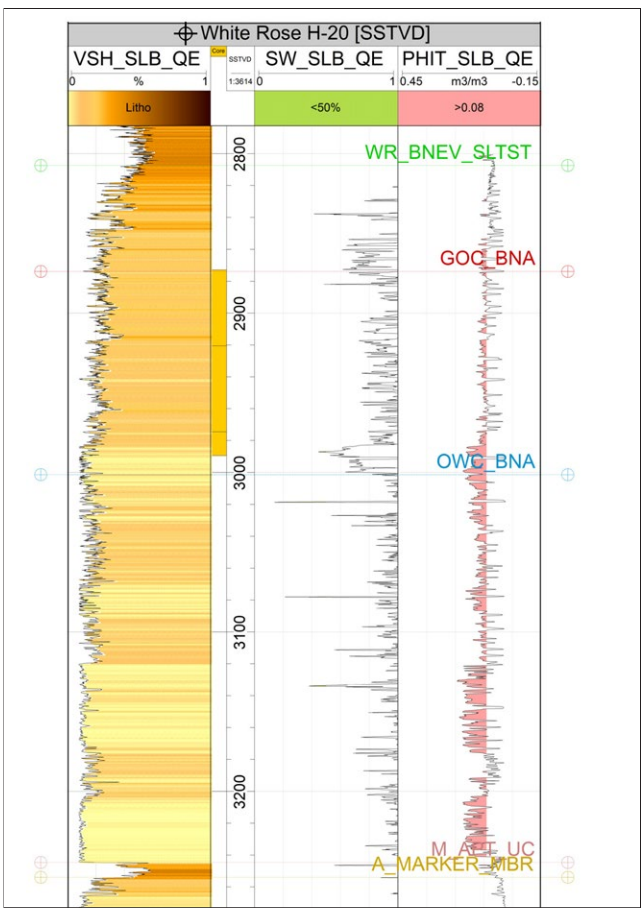


Figure 7: White Rose H-20 well section over the reservoir interval from Ben Nevis Siltstone Formation top to Mid-Aptian Unconformity including the gas-oil contact GOC.

Study Area: SDL 1025 - PL 1006 - B-19z Region

- SDL 1025; PL 1006
- **Effective date:** February 16, 1990
- **License Representative:** Cenovus Energy Inc
- **SDL Size:** 4589 ha

Key Well: White Rose B-19z
Interval: Ben Nevis Siltstone to Mid-Aptian Unconformity

- **Gross :** 315m
- **Gas Pay:** 34m
- **GOC:** -2893m TVDss
- **Sg:** 62%
- **N:G $_{res}$:** 89%
- **N:G $_{pay}$:** 11%
- **Avg Phi $_{res}$:** 15%

- The White Rose B-19z well contains a gas oil contact (GOC) at -2893m TVDss as noted in the Development Plan Amendment Report
- P50 BRV was determined from mapping the Ben Nevis Siltstone top (flexed to well tops to account for depth error) down to the GOC (burgundy area on Figure 5; and yellow interval on Figure 6)
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Ben Nevis Siltstone to Mid-Aptian Unconformity interval; offset wells were used (Figure 7 & Table 4)
- Reservoir pressure is approximately 36000 kpa. Bg ranges are from offset wells in the White Rose Field
- Recovery Factor analysis from analogues using industry trends and standards

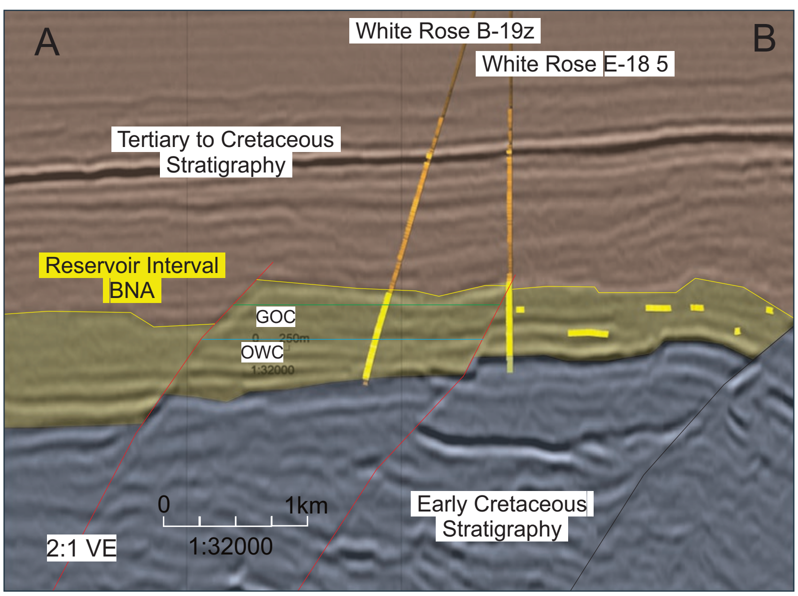


Figure 6: Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the north to south extent across the White Rose B-19z prospect. Target reservoir interval from Ben Nevis Formation top to Mid-Aptian Unconformity (highlighted in yellow) between the two red faults.

	BRV (e^6m^3)	N:G$_{res}$	Phi$_{res}$	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	16	45	11	64	239	6	4
P50	20	55	12	70	265	8	5
P10	24	65	13	76	284	11	8

Table 4: Input values from top Ben Nevis Siltstone Formation top to Mid-Aptian Unconformity within the White Rose B-19z prospect boundary, using @risk to determine probabilistic OGIP and REC.

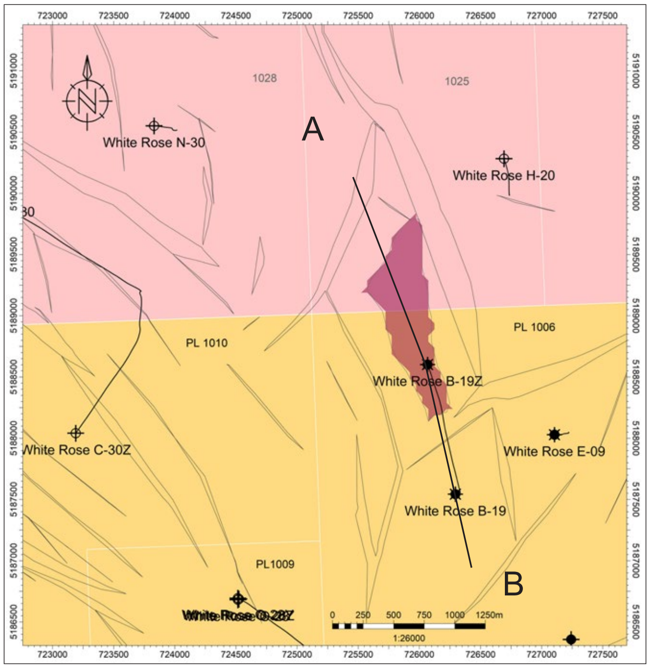


Figure 5: Basemap illustrating the outline for White Rose B-19z prospect; (burgundy) used as input to determine the BRV for the in-place gas calculation, A-B line depicting location of schematic cross section.

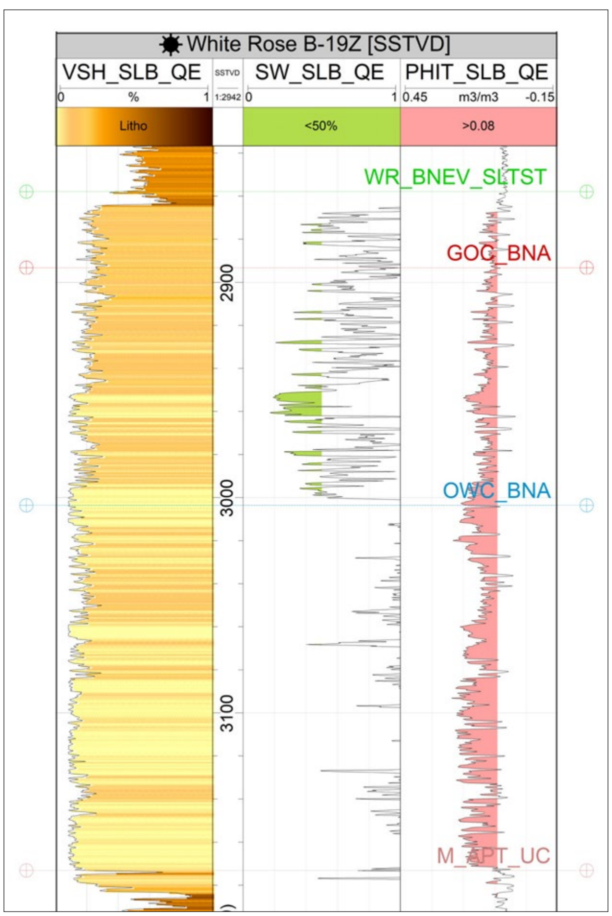


Figure 7: White Rose B-19z well section over the reservoir interval from Ben Nevis Siltstone Formation top to Mid-Aptian Unconformity including the gas-oil contact GOC.

Study Area: SDLs 1051 - 1052 Ballicatters

- SDL 1051 & 1052
- **Effective date:** September 24, 2013
- **License Representative:** Suncor Energy Inc.
- **SDL Size:** 4240 ha & 3538 ha respectively (7778 ha)

Key Well: Ballicatters M-96/M-96z
Interval: Ben Nevis Fm top to Upper Avalon base seismic marker

- **Gross :** 232m
- **Gas Pay:** 54m
- **GWC:** -3680m TVDss
- **Sg:** 63%
- **N:G $_{res}$:** 34%
- **N:G $_{pay}$:** 23%
- **Avg Phi $_{res}$:** 11%

- Ballicatters observed a most likely gas-water contact of -3680m TVDss in the Ben Nevis Formation based on logs, pressures and is supported by DST's
- P50 BRV was determined by mapping the top of the Ben Nevis (flexed to the well tops) to the gas-water contact (orange on Figure 5, yellow on Figure 6)
- P90 and P10 BRV were calculated by adjusting the top structure plus or minus 15m to account for seismic interpretation uncertainty
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the well averages for the Ben Nevis – Upper Avalon base seismic marker interval; five offset wells were used (Figure 7; Table 4)
- Reservoir pressure tested at 46Mpa approximating a 0.004 for Bg value
- Contingent resources (volumes not calculated): high liquid yield condensate penetrated and sampled in mid-Avalon interval
- Recovery Factor analysis from analogues using industry trends and standards

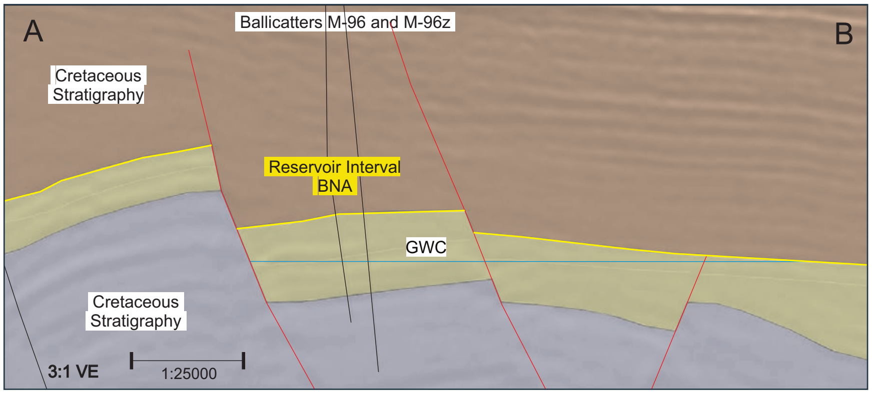


Figure 6: Schematic cross-section from TTI.158760.SOUTH_JEANNE_DARC_KPSTMSTK$_2$ depth survey illustrating the 2 Ben Nevis - Upper Avalon Formation in the fault blocks, highlighted by the three red faults.

	BRV (e^6m^3)	N:G$_{res}$	Phi$_{res}$	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	3092	40	9	74	237	1067	649
P50	3397	56	13	80	256	1718	1109
P10	3731	72	18	86	275	2776	1850

Table 4: Input values from top Ben Nevis to Upper Avalon base seismic marker over mapped interval within the Ballicatters SDL 1051-1052 boundary, using @risk to determine probabilistic OGIP and REC.

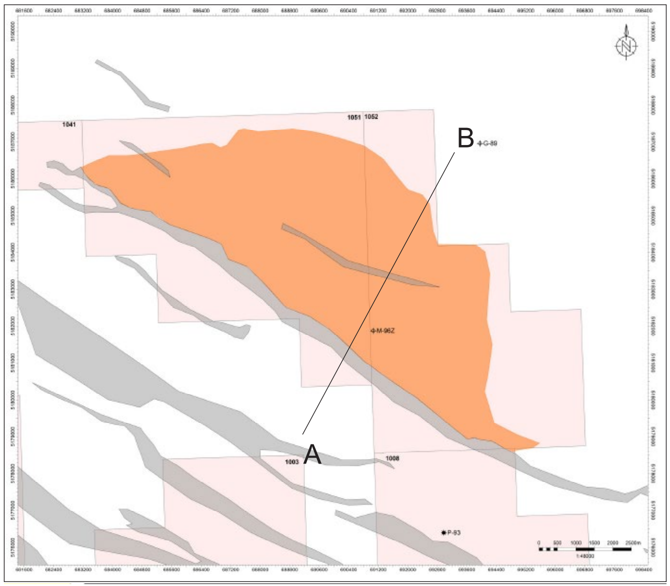


Figure 5: Basemap illustrating SDL outline; P50 (orange) gas accumulation used as input to determine the BRV for the in-place gas calculation. A-B line depicting location of schematic cross section.

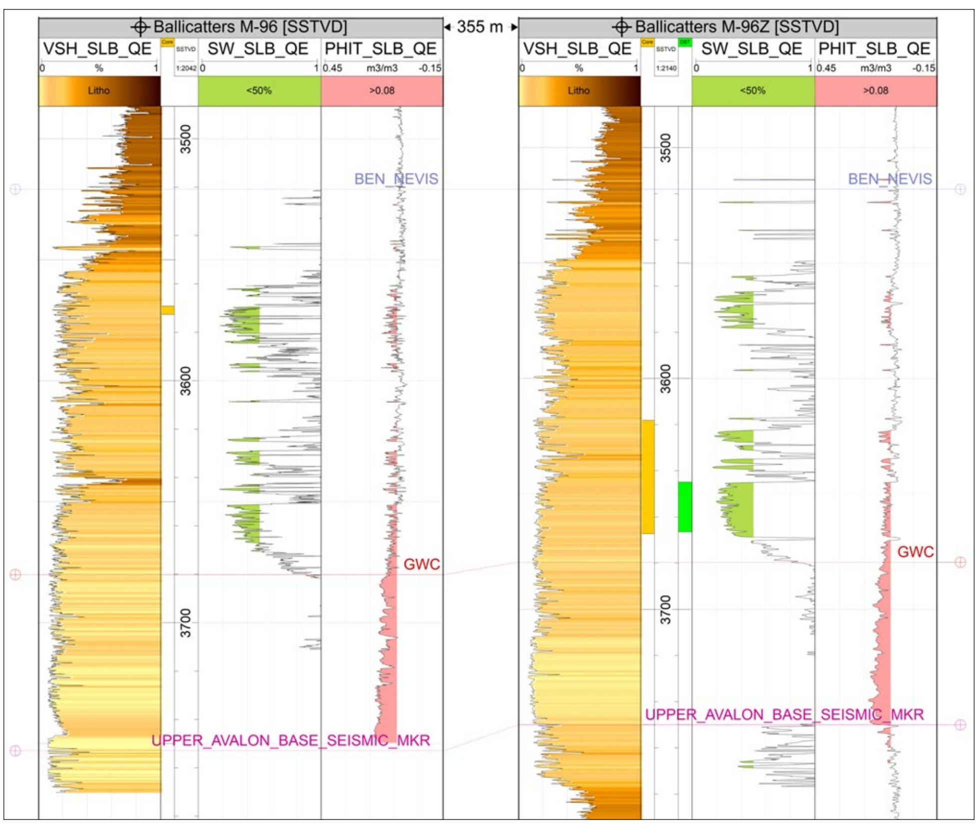


Figure 7: Ballicatters well section over the reservoir interval from Ben Nevis Fm top to Upper Avalon base seismic marker illustrating the GWC.

Study Area: SDLs 1001 & 1041 Nautilus

- SDL 1001 & 1041
- **Effective date:** February 16, 1990
- **License Representative:** ExxonMobil Canada & Chevron Canada
- **SDL Size:** 3883 ha, 3883 (7766 ha)

Key Well: Nautilus C-92
Interval: Catalina Top to B-Marker Top

- **Gross :** 305m
- **Gas Pay:** 70m
- **GDT:** -4136m TVDss
- **Sg:** 80%
- **N:G res:** 23%
- **N:G pay:** 23%
- **Avg Phi res:** 12%

- Nautilus C-92 observed a most likely gas-down-to contact of -4136m TVDss in the Catalina Formation based on well logs and supported by pressures and DST's
- P90 BRV was determined by mapping the top of the Catalina Fm to the gas-down-to contact (orange & yellow on Figure 5, yellow on Figure 6)
- P10 BRV was determined by mapping the top of the Catalina Fm to down to the B-Marker (orange & yellow on Figure 5, yellow on Figure 6)
- The Nautilus C-92 well is assumed to represent the distal end of the depositional environment
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Catalina interval; offset wells were used (Figure 7; Table 4)
- Reservoir pressure tested at ~75000 kpa; analogue field data was used to approximate 1/Bg at 238
- Recovery Factor analysis from analogues using industry trends and standards

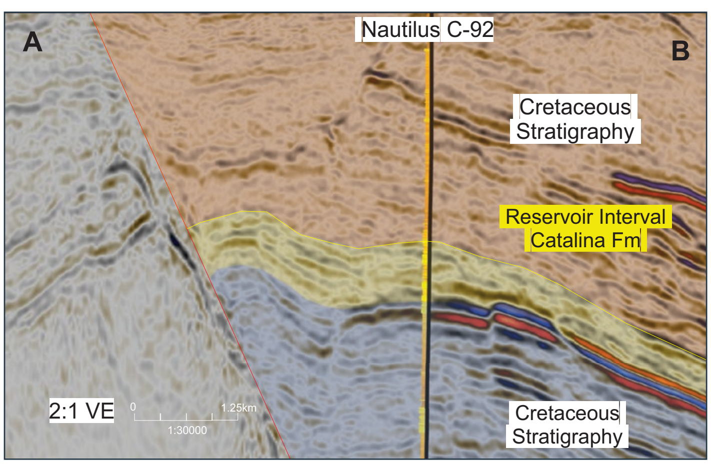


Figure 6: Schematic cross-section from CA-3001011_2015 Hibernia IsoMetrix 4D M1 Survey illustrating the reservoir interval from the Catalina Formation to the B-Marker, highlighted by yellow.

	BRV ($e^6 m^3$)	$N{:}G_{res}$	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	3707	10	10	74	225	311	196
P50	3772	27	12	80	238	796	511
P10	3838	48	15	86	251	1516	995

Table 4: Input values from top of the Catalina Formation to top of B-Marker Member within the SDLs 1001 &1041 boundary, using @risk to determine probabilistic OGIP and REC.

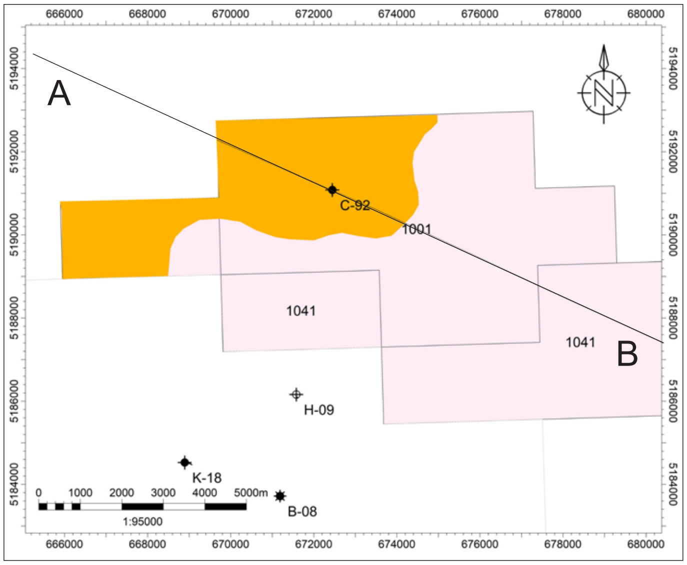


Figure 5: Nautilus basemap illustrating SDL outline and P50 (orange) area used as input to determine the BRV for in-place gas calculation. A-B line depicting location of schematic cross section.

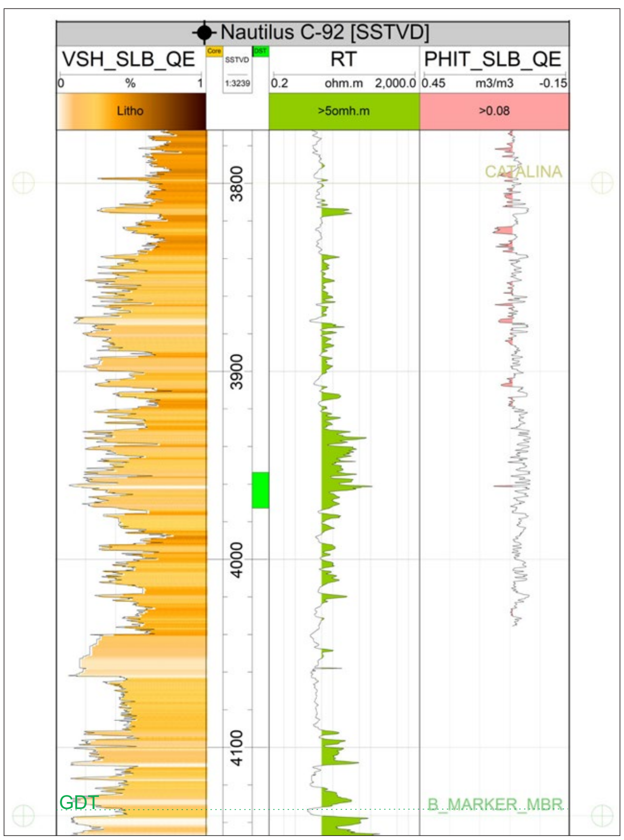


Figure 7: Nautilus C-92 well section over the reservoir interval from the Catalina Formation to top of B-Marker Member.

Study Area: SDL 1031 Trave

- SDL 1031
- **Effective date:** February 16, 1990
- **License Representative:** Cenovus Energy Inc
- **SDL Size:** 7045 ha

Key Well: Trave E-87
Interval: Hibernia Fm top to Fortune Bay Fm Top

- **Gross :** 379m
- **Gas Pay:** 1.9m
- **GWC:** -2250m TVDss
- **Sg:** 54%
- **N:G $_{res}$:** 57%
- **N:G $_{pay}$:** 0.5%
- **Avg Phi $_{res}$:** 12%

- The Trave E-87 well tested and recovered gas from DST's in the Hibernia Fm; the GWC is confirmed by pressures
- P50 BRV was determined by mapping from the preserved upper Hibernia Fm (bulk shifted -64m to account for velocity error) to the GWC. (yellow area on Figure 5 & 6)
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Hibernia Fm interval; offset wells were used (Figure 7 & Table 4)
- Reservoir pressure tested at 24000kpa approximating a 0.005 value for Bg
- Recovery Factor analysis from analogues using industry trends and standards

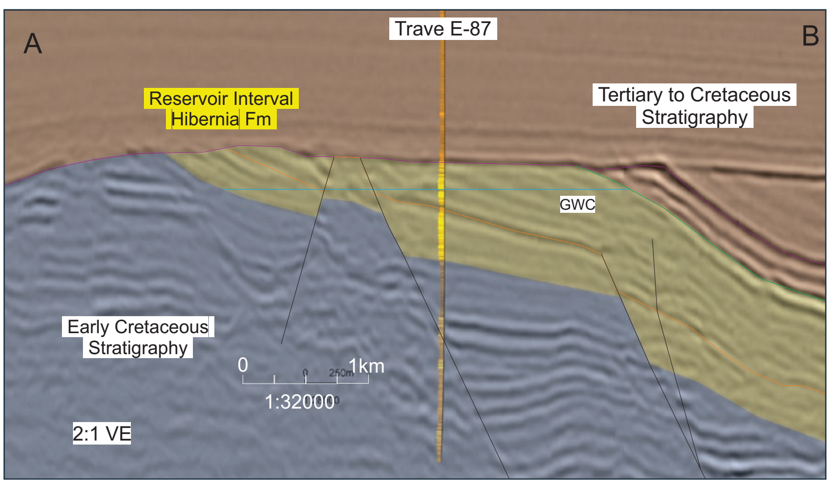


Figure 6: Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the northwest to southeast extent across the Trave prospect. Target reservoir interval is the Hibernia Formation to Fortune Bay top (highlighted in yellow).

	BRV (e^6m^3)	N:G$_{res}$	Phi$_{res}$	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	1939	42	10	52	196	408	247
P50	2122	55	12	58	204	591	382
P10	2322	68	15	71	212	845	570

Table 4: Input values from Hibernia Formation interval; using @risk to determine probabilistic OGIP and REC within the Trave prospect boundary.

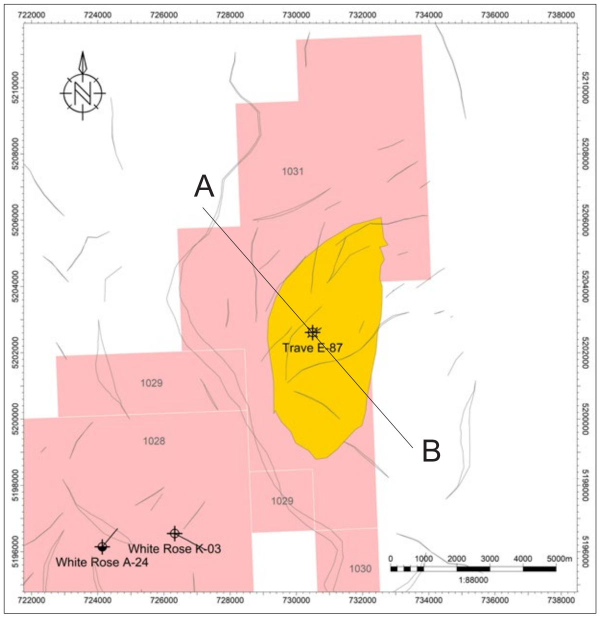


Figure 5: Basemap illustrating the outline for Trave prospect; (orange) used as input to determine the BRV for the in-place gas calculation, A-B line depicting location of schematic cross section.

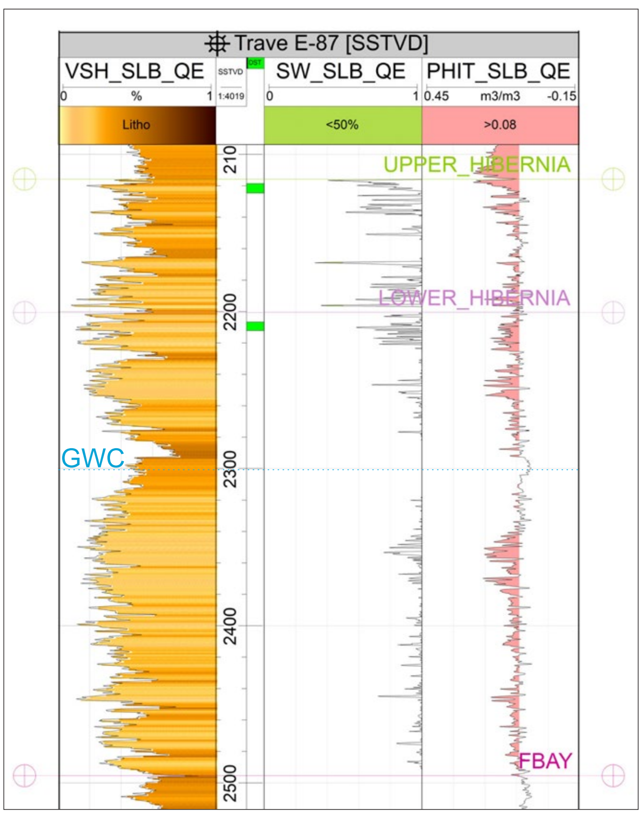


Figure 7: Trave E-87 well section over the reservoir interval from the preserved upper Hibernia Fm showing the GWC.

Study Area: SDL 1008 North Ben Nevis

- SDL 1008
- **Effective date:** February 16, 1990
- **License Representative:** Cenovus Energy Inc
- **SDL Size:** 6372 ha

Key Well: North Ben Nevis P-93 and M-61
Interval: Ben Nevis Fm top to Upper Avalon base seismic marker

- **Gross :** 175m
- **Gas Pay:** 35m
- **GOC:** -3043m TVDss
- **Sg:** 63%
- **N:G$_{res}$:** 57%
- **N:G$_{pay}$:** 20%
- **Avg Phi$_{res}$:** 16%

- North Ben Nevis observed a most likely gas-oil contact of -3043m TVDss in the Ben Nevis Formation based on logs, pressures and supported by DST's
- P50 BRV was determined by mapping the top of the Ben Nevis (bulk shifted 12m to account for velocity error) to the gas-oil contact within the SDL 1008 boundary (orange in figure 5, yellow in figure 6)
- P90 and P10 BRV were calculated by adjusting the top of the structure plus or minus 15 m to account for seismic interpretation uncertainty
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Ben Nevis - Upper Avalon interval; five offset wells were used (Figure 7; Table 4)
- Reservoir pressure tested at 30-40Mpa approximating a 0.005 value for Bg
- Contingent gas resources (volumes not calculated): Hibernia Fm tested by DST
- Recovery Factor analysis from analogues using industry trends and standards

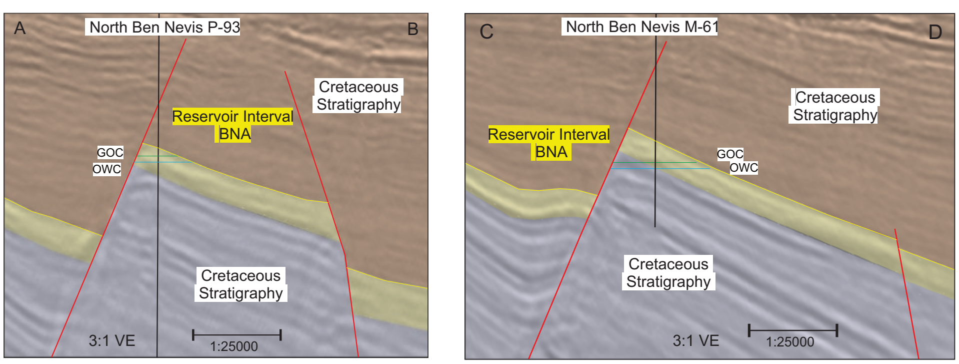


Figure 6: Two schematic cross-sections from TTI.158760. SOUTH_JEANNE_DARC_KPSTMSTK$_2$ depth survey through North Ben Nevis P-93 and North Ben Nevis M-61 illustrating the BNA resource interval as outlined by the highlighted bounding red faults.

	BRV (e^6m^3)	N:G$_{res}$	Phi$_{res}$	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	599	43	11	57	199	186	115
P50	599	56	16	65	212	299	192
P10	815	69	21	73	225	451	304

Table 4: Input values from top Ben Nevis to Upper Avalon base seismic marker interval within the North Ben Nevis SDL 1008 boundary, using @risk to determine probabilistic OGIP and REC.

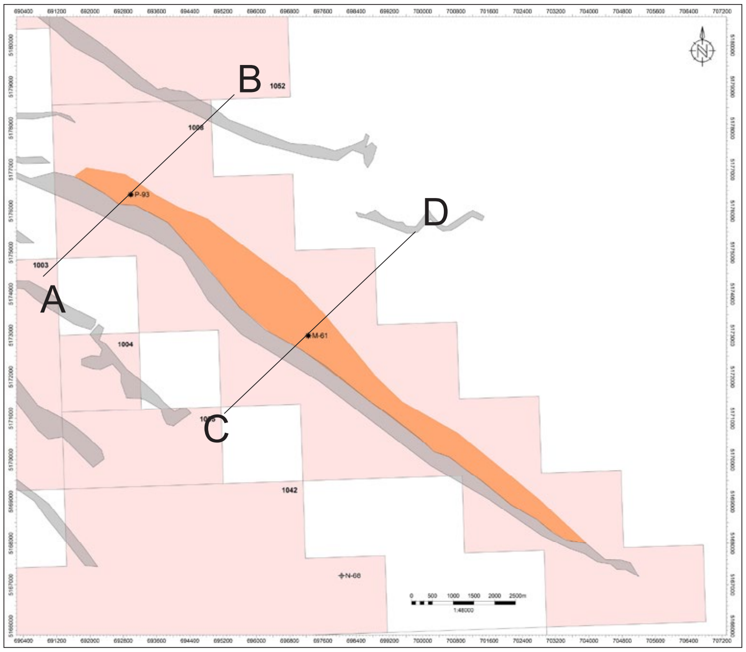


Figure 5: Basemap illustrating SDL outline; P50 (orange) gas accumulation used as input to determine the BRV for the in-place gas calculation. A-B and C-D lines depicting location of schematic cross sections.

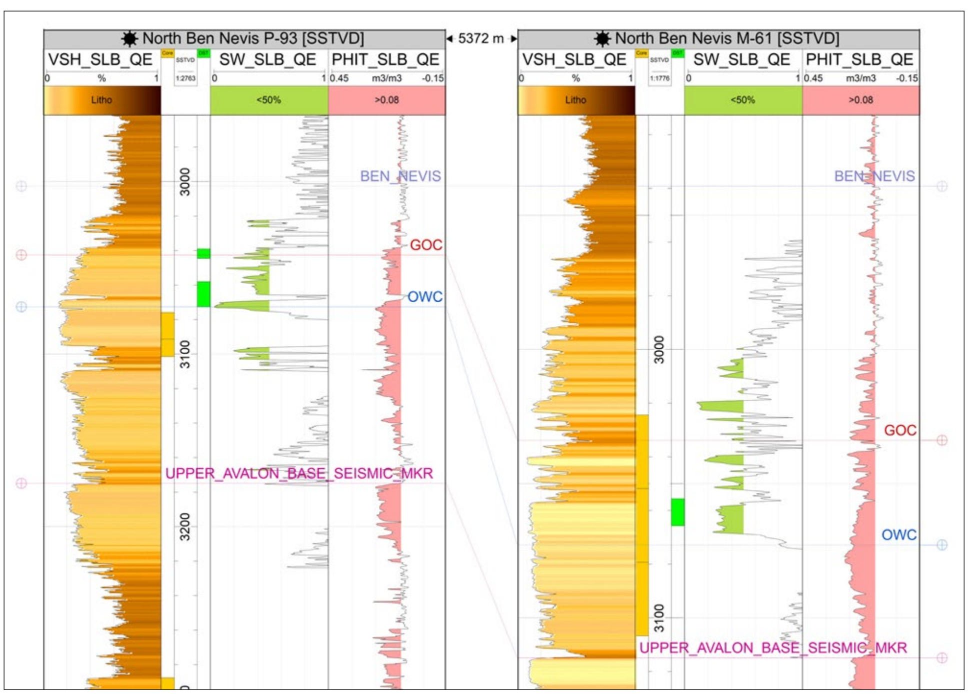


Figure 7: North Ben Nevis well section over the reservoir interval from Ben Nevis Fm top to Upper Avalon base seismic marker illustrating the GOC and OWC.

Study Area: SDL 1040 West Bonne Bay F-12/F-12z

- SDL 1040
- **Effective date:** January 8, 2001
- **License Representative:** Cenovus Energy Inc
- **SDL Size:** 3195 ha

Key Well: West Bonne Bay F-12/F-12z
Interval: Upper Hibernia top to Lower Hibernia top

- **Gross :** 272m
- **Gas Pay:** 49m
- **GDT:** -3620m TVDss
- **Sg:** 60%
- **N:G $_{res}$:** 36%
- **N:G $_{pay}$:** 18%
- **Avg Phi $_{res}$:** 11%

- The West Bonne Bay F-12/z prospect uses range of contacts supported by gas samples and pressures
- P99 was determined from mapping the Upper Hibernia (flexed to well tops to account for depth error) to GDT of -3620m TVDss (orange area on Figure 5; and yellow interval on Figure 6)
- P1 BRV was determined from same methodology as P99 to OUT -3682m TVDss (orange area on Figure 5; and yellow interval on Figure 6)
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Hibernia interval; offset wells were used (Figure 7 & Table 4)
- Reservoir pressure tested at 36000kpa ; Bg based on analogous fields
- Recovery Factor analysis from analogues using industry trends and standards

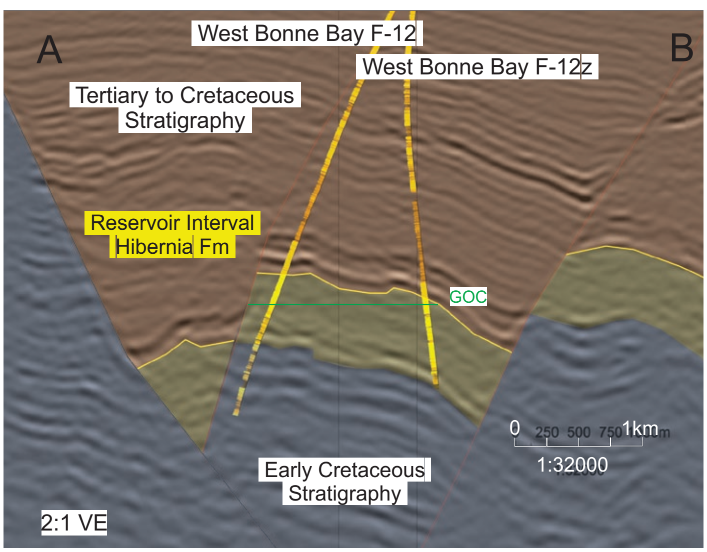


Figure 6: Schematic cross-section from CA-3000695 2006 Husky Fortune 3D survey (converted to depth) illustrating the north to south extent across the West Bonne Bay F-12/z prospect. Target reservoir interval from Upper Hibernia top to Lower Hibernia top (highlighted in yellow).

	BRV (e^6m^3)	N:G$_{res}$	Phi$_{res}$	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	924	30	9	63	204	175	107
P50	1089	42	12	69	217	276	178
P10	1254	55	15	75	230	422	281

Table 4: Input values from Upper Hibernia top to Lower Hibernia top within the West Bonne Bay F-12/F-12z prospect boundary, using @risk to determine probabilistic OGIP and REC.

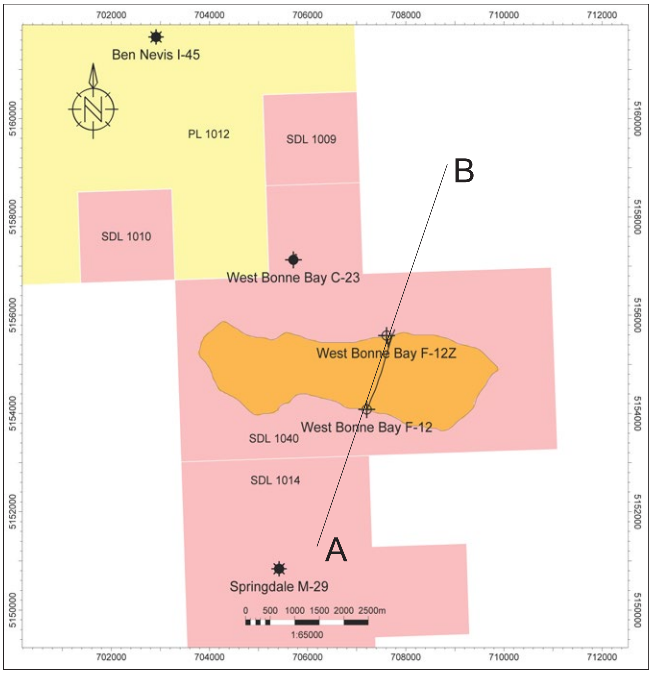


Figure 5: West Bonne Bay F-12 basemap illustrating the outline for the prospect (orange) that was used as input to determine the BRV for the in-place gas calculation, A-B line depicting location of schematic cross section.

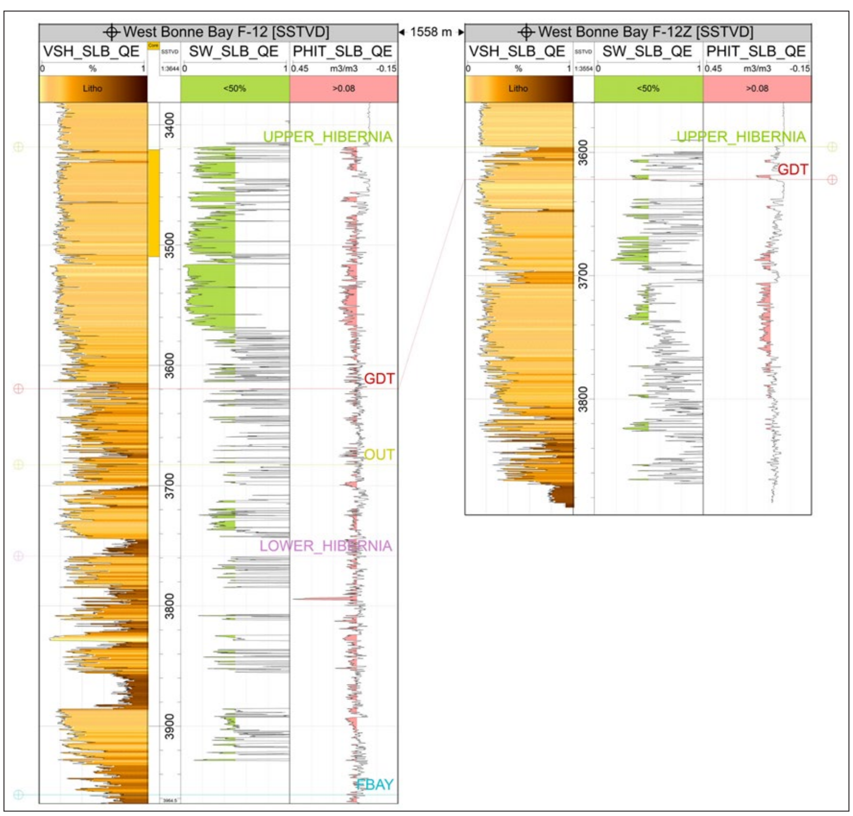


Figure 7: West Bonne F-12/F-12z well section over the reservoir interval from Upper Hibernia top to Lower Hibernia including the GDT and OUT.

Study Area: SDLs 1011 & 1012 Fortune South

- SDL 1011 & 1012
- **Effective date:** March 28, 1990
- **License Representative:** Cenovus Energy Inc
- **SDL Size:** 5321 ha, 355 ha respectively (5676 ha)

Key Well: Fortune G-57
Interval: Basal Hibernia Member top to Fortune Bay top

- **Gross :** 77m
- **Gas Pay:** 5.4m
- **GOC:** -3870m TVDss
- **Sg:** 65%
- **N:G $_{res}$:** 55%
- **N:G $_{pay}$:** 7%
- **Avg Phi $_{res}$:** 15%

- The Fortune G-57 well crossed a fault in the reservoir interval of the Basal Hibernia. The true thickness is not representative. The surrounding wells were a key factor to determining Gross and Pay Intervals
- P50 BRV was determined from Basal Hibernia Member top to the GOC at -3870m TVDss (inferred from industry standard of applying 1/3 gas cap shown as red contour line in South Fortune) (orange with black outline on Figure 5, yellow on Figure 6)
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Basal Hibernia Member interval; offset wells were used (Figure 7 & Table 4)
- Reservoir pressure tested at 39190 kpa approximating a 0.0052 value for Bg
- Recovery Factor analysis from analogues using industry trends and standards

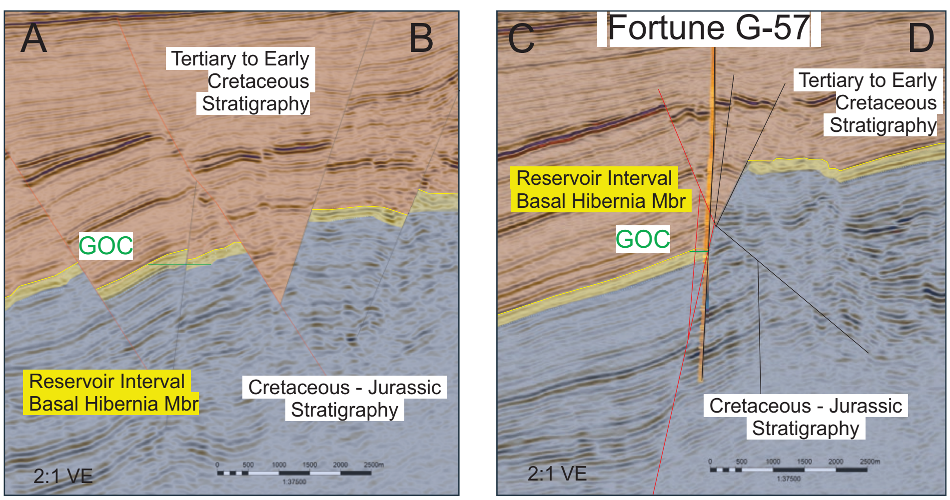


Figure 6: Two schematic cross-section from CA-3000695 2006 Husky Fortune 3D survey (converted to depth) illustrating the northwest to southeast extent across the South Fortune prospect. Target reservoir interval from Basal Hibernia Member top to Fortune Bay top (highlighted in yellow) between the two red faults.

	BRV (e^6m^3)	N:G$_{res}$	Phi$_{res}$	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	355	51	12	54	201	109	65
P50	414	55	14	60	207	139	90
P10	583	60	16	66	212	177	122

Table 4: Input values from top Basal Hibernia Member top to Fortune Bay top within the Fortune prospect boundary, using @risk to determine probabilistic OGIP and REC.

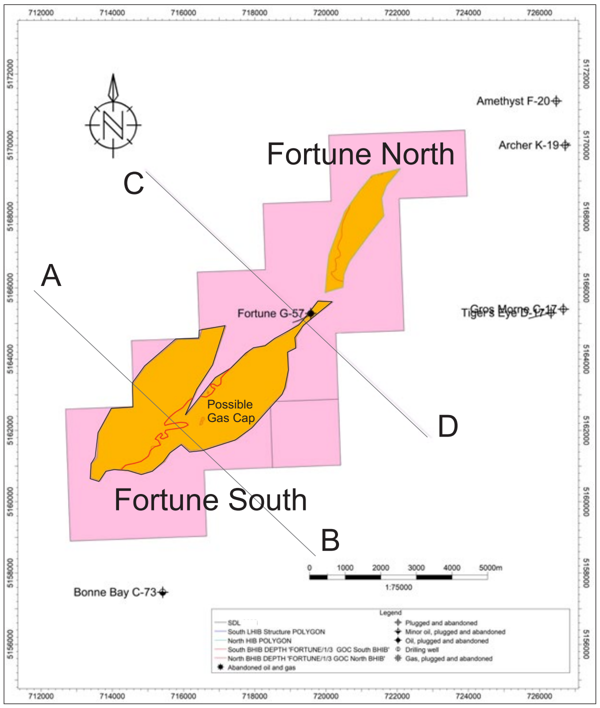


Figure 5: Basemap illustrating the South Fortune prospect; (orange outlined in black) with red line depicting the possible 1/3 gas cap intersection as input to determine the BRV for the in-place gas calculation, two lines depict the location of two schematic cross sections.

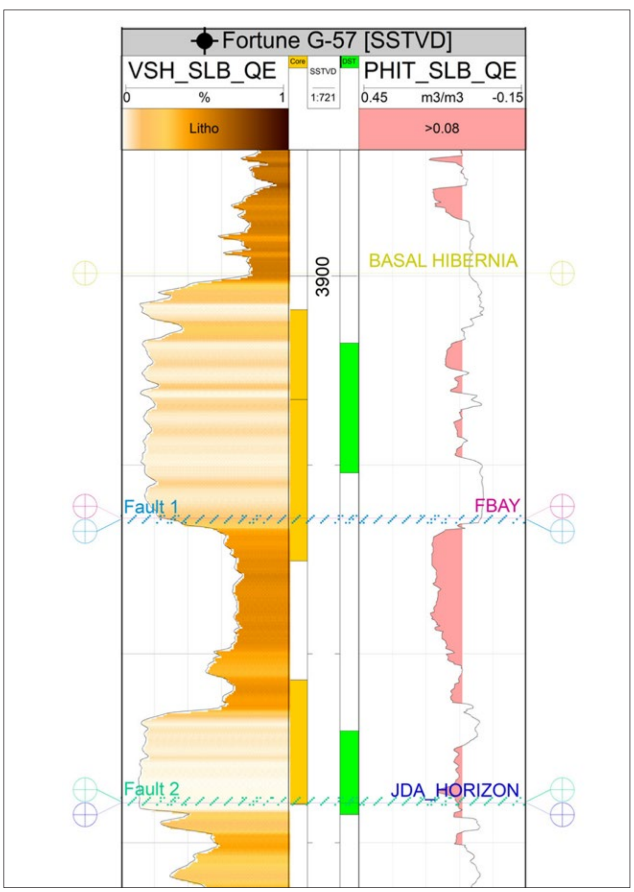


Figure 7: Fortune G-57 well section over the reservoir interval from Basal Hibernia Mbr to the Fault. This is not a complete section of this Member as the well path crossed a fault.

Study Area: SDLs 1011 & 1012 Fortune North

- SDL 1011 & 1012
- **Effective date:** March 28, 1990
- **License Representative:** Cenovus Energy Inc
- **SDL Size:** 5321 ha, 355 ha respectively (5676 ha)

Key Well: Fortune G-57
Interval: Basal Hibernia Member top to Fortune Bay Fm top

- **Gross :** 77m
- **Gas Pay:** 5.4m
- **GOC:** -3689m TVDss
- **Sg:** 65%
- **N:G $_{res}$:** 55%
- **N:G $_{pay}$:** 7%
- **Avg Phi $_{res}$:** 15%

- The Fortune G-57 well crossed a fault in the reservoir interval of the Basal Hibernia. The true thickness is not representative. The surrounding wells were a key factor to determining Gross and Pay Intervals
- P50 BRV was determined from Basal Hibernia Member top to the GOC at -3689m TVDss (inferred from industry standard of applying 1/3 gas cap shown as red contour line in Fortune North) (orange with black outline on Figure 5, yellow on Figure 6)
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Basal Hibernia Member interval; six offset wells were used (Figure 7 & Table 4)
- Reservoir pressure tested at 39190 kpa approximating a 0.0052 value for Bg
- Recovery Factor analysis from analogues using industry trends and standards

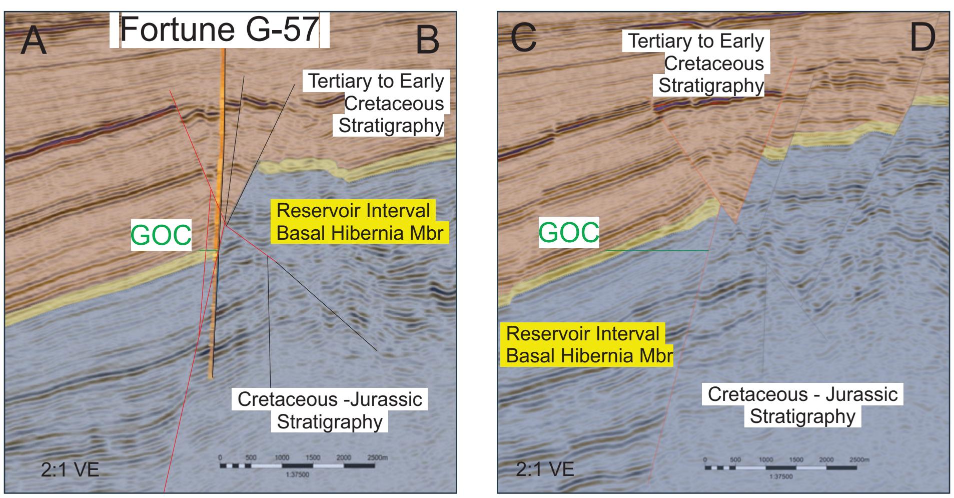


Figure 6: Two schematic cross-sections from CA-3000695 2006 Husky Fortune 3D survey (converted to depth) illustrating the northwest to southeast extent across the North Fortune prospect. Target reservoir interval from Basal Hibernia Member top to Fortune Bay top (highlighted in yellow).

	BRV (e^6m^3)	N:G$_{res}$	Phi$_{res}$	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	103	51	12	54	201	30	17
P50	109	55	14	60	206	36	24
P10	115	60	16	66	212	45	31

Table 4: Input values from top Basal Hibernia Member top to Fortune Bay top within the Fortune prospect boundary, using @risk to determine probabilistic OGIP and REC.

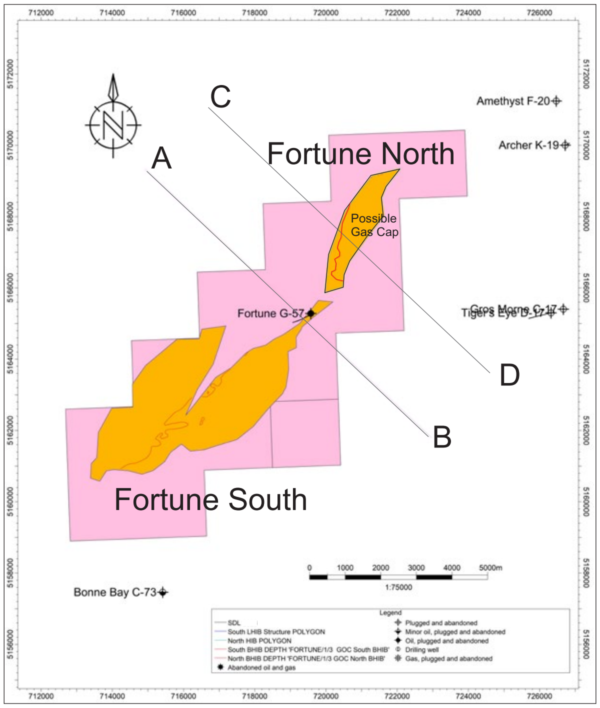


Figure 5: Basemap illustrating the outline for North Fortune prospects; (orange with black outline) with red line depicting the possible 1/3 gas cap intersection as input to determine the BRV for the in-place gas calculation, two lines depict the location of two schematic cross sections.cross sections.

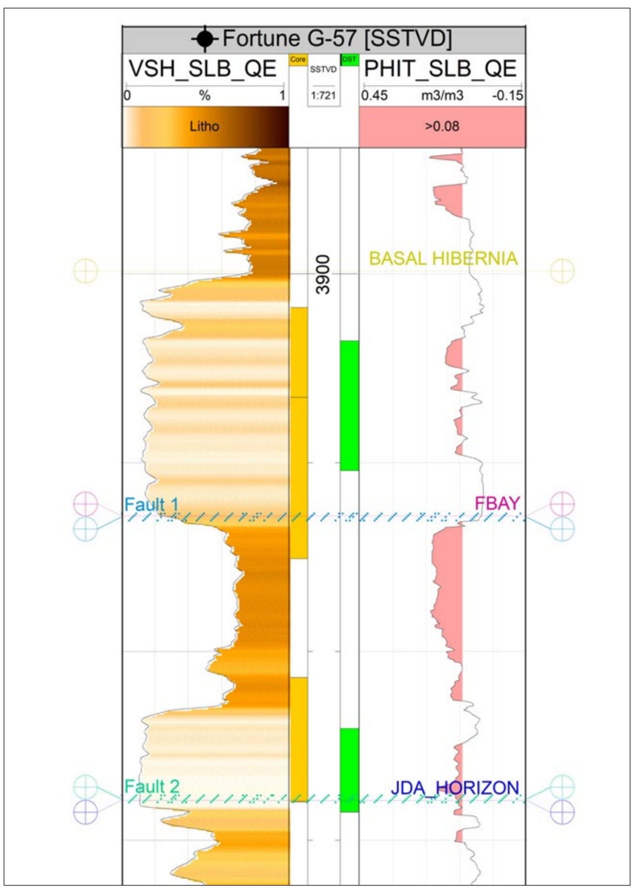


Figure 7: Fortune G-57 well section over the reservoir interval from Basal Hibernia Mbr to the Fault. This is not a complete section of this Member as the well path crossed a fault.

Study Area: SDL 200A, 200B, 200C North Dana

- SDL 200A, 200B, 200C
- **Effective date:** April 4th, 1987
- **License Representative:** ExxonMobil Canada Properties
- **SDL Size:** 8765 ha

Key Well: North Dana I-43
Interval: Tempest Member to Egret Member (Rankin Formation)

- **Gross :** 171m
- **Gas Pay:** 8.5m
- **GDT:** -4512m TVDss
- **Sg:** 65%
- **N:G $_{res}$:** 13%
- **N:G $_{pay}$:** 5%
- **Avg Phi $_{res}$:** 9%

- North Dana I-43 well recovered gas from the DST's in the Tempest Member of the Rankin Formation
- The Tempest Member stratigraphy is interpreted as a series of stacked sand channels which shows as a package of strong trough and peak response in the seismic data.
- P50 BRV was determined from Tempest Member top to the GDT within the brightest anomaly from the North Dana I-43 well up to the bound updip red fault (yellow area on Figure 5 & 6)
- P1 BRV was determined by mapped down to the saddle of the structure (yellow and orange area on Figure 5 & yellow on Figure 6)
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Tempest Member interval; four offset wells were used (Figure 7 & Table 4)
- Reservoir pressure tested at 73983kpa approximating a 0.003 value for Bg
- Recovery Factor analysis from analogues using industry trends and standards

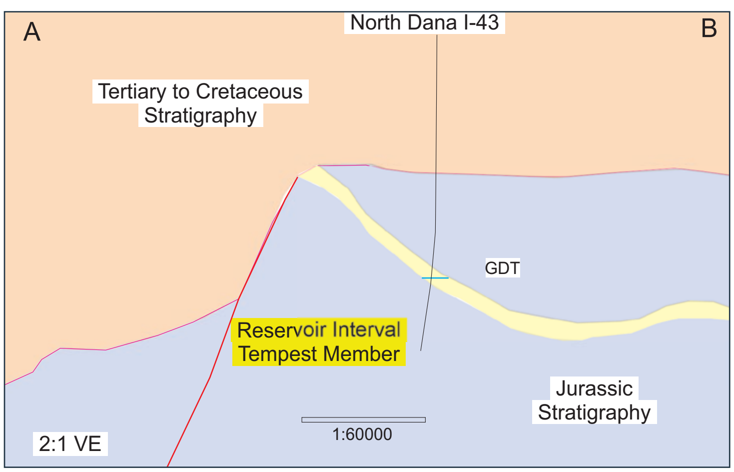


Figure 6: Schematic cross-section illustrating the southwest-northeast extent of the North Dana prospect. Target reservoir interval from Tempest Member to the Egret Member (highlighted in yellow).

	BRV (e^6m^3)	N:G$_{res}$	Phi$_{res}$	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	652	6	8	56	357	49	30
P50	1020	13	11	65	370	119	77
P10	1595	20	15	74	383	249	165

Table 4: Input values from top Tempest Member to Egret Member of the Rankin Fm within the SDL 200B boundary, using @risk to determine probabilistic OGIP and REC.

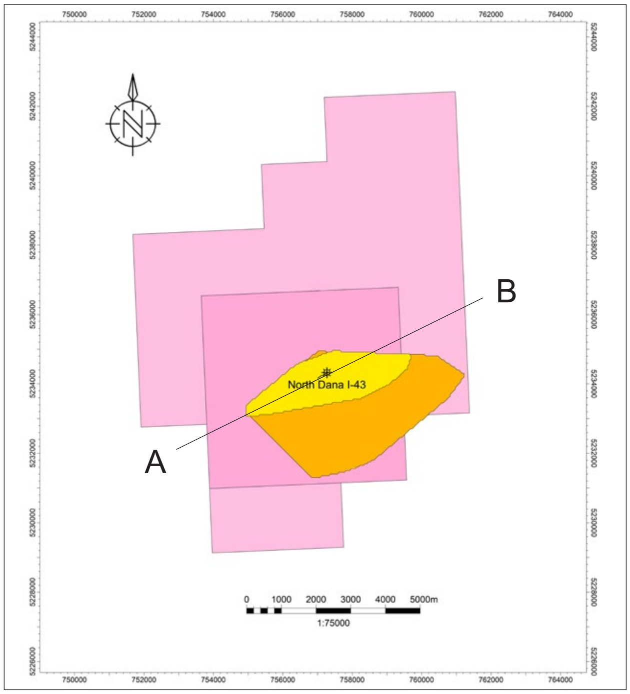


Figure 5: North Dana basemap illustrating SDL outline; P1 (yellow & orange) and P50 (yellow) gas accumulations used as input to determine the BRV for the in-place gas calculation, A-B line depicting location of schematic cross section.

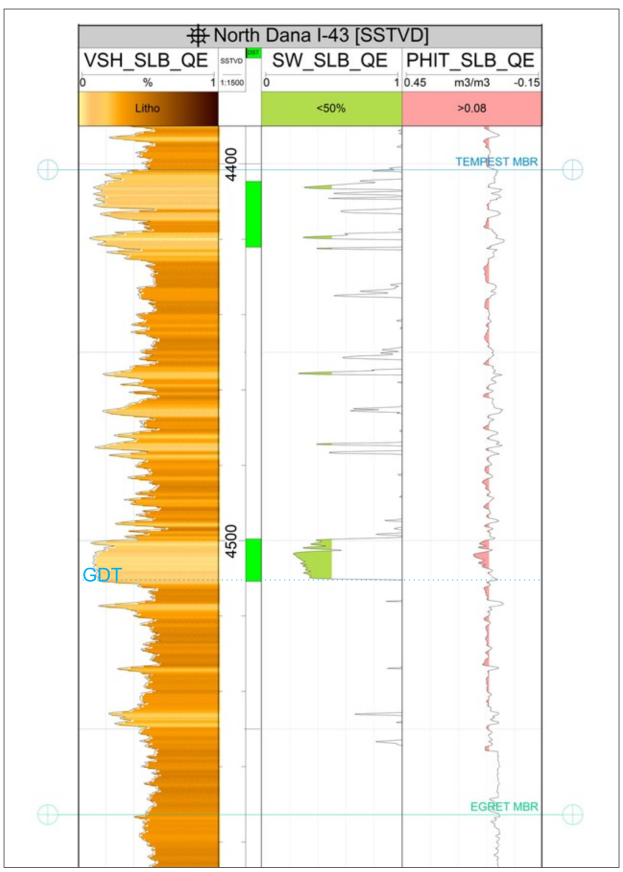


Figure 7: North Dana I-43 well section over the reservoir interval from South Tempest Member to the Egret Member.

Study Area: SDLs 1013 - 1017 Springdale

- SDL 1013, 1014, 1015, 1016 and 1017
- **Effective date:** March 28, 1990
- **License Representative:** Esso Resources; 1017 - Cenovus Energy
- **SDL Size:** 2136 ha, 2487 ha, 356 ha, 712 ha and 356 ha respectively (6047 ha)

- **Gross :** 146m
- **Gas Pay:** 4.6m
- **GOC:** -1294.5m TVDss
- **Sg:** 65%
- **N:G $_{res}$:** 39%
- **N:G $_{pay}$:** 3%
- **Avg Phi $_{res}$:** 31%

Key Well: Springdale M-29
Interval: South Mara Fm top to Base Tertiary Unc (BTU)

- Springdale M-29 and North Trinity H-71 wells contain a gas response in well logs and recovered gas from the DST's in the South Mara Fm
- The South Mara Formation illustrates a strong trough over peak amplitude response in the seismic data. This response is indicative of reservoir and is a possible hydrocarbon indicator
- P99 BRV was determined from South Mara top (flexed to well tops) to the GOC within the brightest anomaly around the Springdale M-29 well (yellow area on Figure 5 & 6)
- P1 BRV was determined by lateral continuity of the trough-peak signature within the South Mara to BTU reservoir interval in the SDL boundary (yellow and orange area on Figure 5 and yellow on Figure 6)
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 27%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the South Mara to BTU interval; four offset wells were used (Figure 7; Table 4)
- Reservoir pressure tested at 13268kpa approximating a 0.009 value for Bg
- Recovery Factor analysis from analogues using industry trends and standards

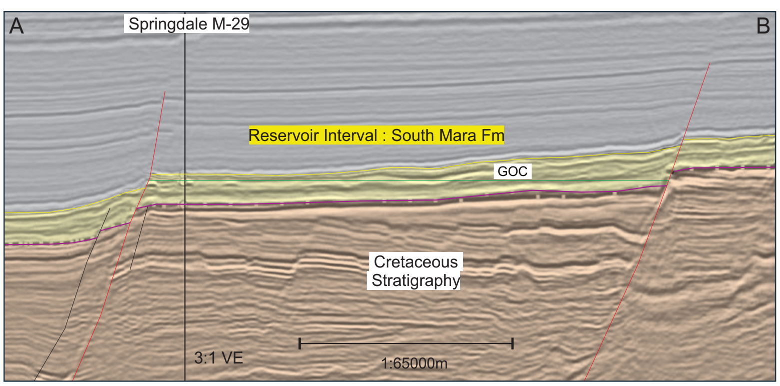


Figure 6: Schematic cross-section from CA-3000718 GOA time (converted to depth) survey illustrating the north-south extent of the Springdale prospect. Target reservoir interval from South Mara Formation top to BTU (highlighted in yellow) between the red faults.

	BRV (e^6m^3)	$N:G_{res}$	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	141	22	22	56	108	32	21
P50	430	36	30	65	111	111	71
P10	1282	47	38	76	114	367	239

Table 4: Input values from top South Mara to BTU within the Springdale SDL boundary, using @risk to determine probabilistic OGIP and REC.

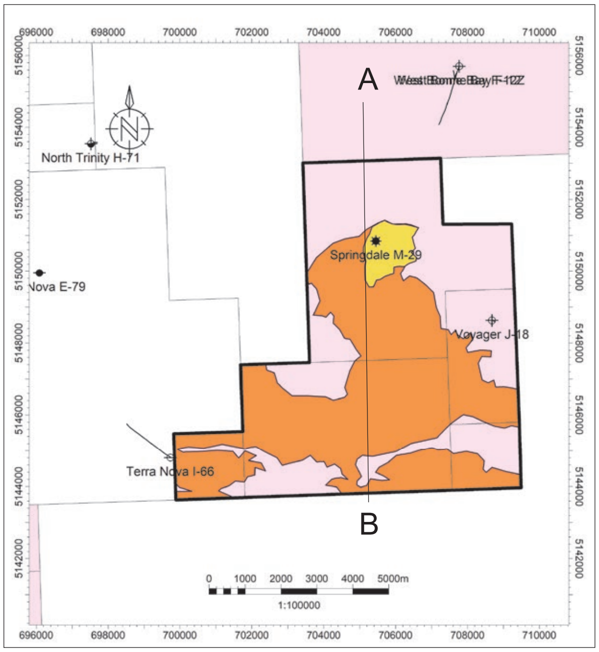


Figure 5: Basemap illustrating SDL outline; P1 (yellow & orange) and P99 (yellow) gas accumulations used as input to determine the BRV for the in-place gas calculation, A-B line depicting location of schematic cross section.

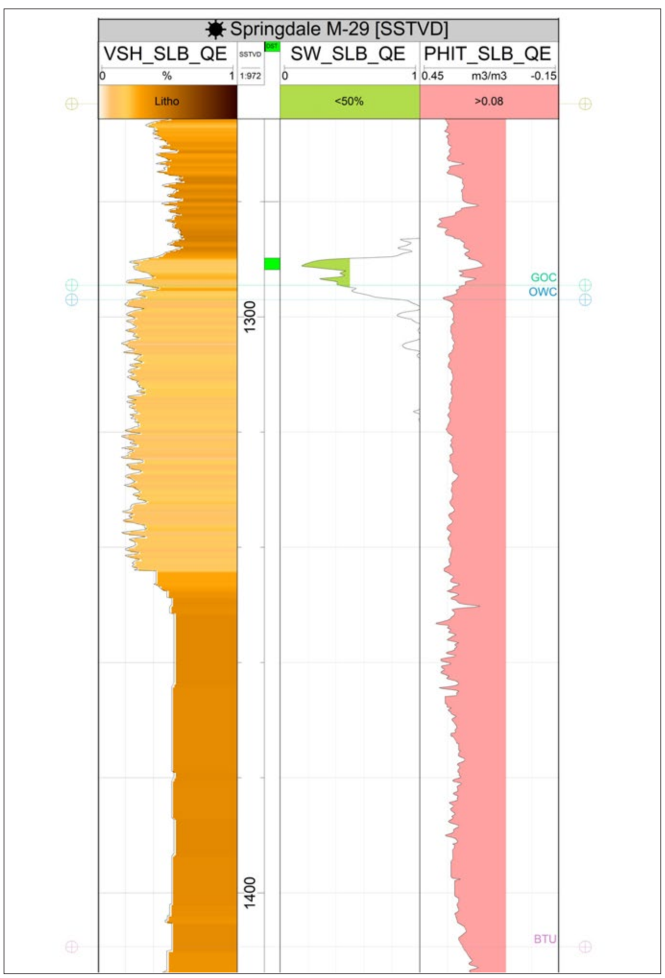


Figure 7: Springdale M-29 well section over the reservoir interval from South Mara Formation top to BTU illustrating the GOC.

Study Area: SDLs 1003 - 1005 South Mara

- SDL 1003, 1004, 1005
- **Effective date:** February 16, 1990
- **License Representative:** Mobile Oil
- **SDL Size:** 3894 ha, 706 ha, 354 ha (4956 ha)

Key Well: South Mara C-13
Interval: Ben Nevis Fm top to Upper Avalon seismic base marker

- **Gross :** 32m
- **Gas Pay:** 26m
- **GOC:** -2917m TVDss
- **Sg:** 87%
- **N:G $_{res}$:** 84%
- **N:G $_{pay}$:** 81%
- **Avg Phi $_{res}$:** 17%

- South Mara C-13 observed a most likely gas-oil contact of -2917m TVDss in the Ben Nevis Formation based on neutron-density well log crossover and supported by pressures and DST's
- P50 BRV was determined by mapping the top of the Ben Nevis (flexed to the well tops) to the gas-oil contact within the SDL 1003 -1005 boundary (orange on Figure 5 & yellow on Figure 6)
- P90 and P10 BRV were calculated by plus or minus 10% to account for seismic interpretation and velocity model uncertainties
- The South Mara C-13 well is assumed to represent the high side reservoir properties based on depositional environment
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Ben Nevis - Upper Avalon seismic base marker; five offset wells were used (Figure 7; Table 4)
- Reservoir pressure tested at 33000kpa approximating a 0.0047 value for Bg
- Contingent gas resources (volumes not calculated): Jeanne d'Arc Fm sampled gas from a RFS tool
- Recovery Factor analysis from analogues using industry trends and standards

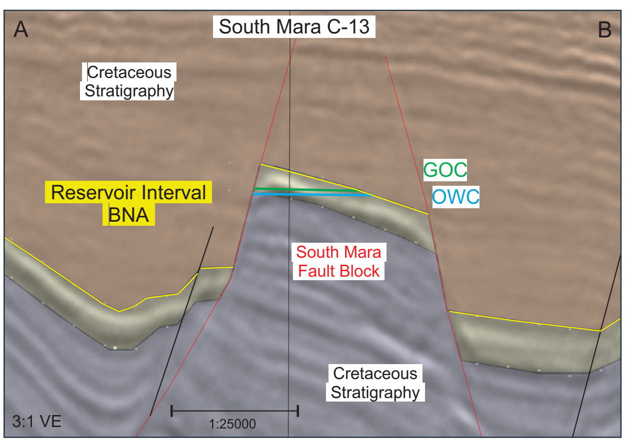


Figure 6: Schematic cross-section from TTI.158760.SOUTH_JEANNE_DARC_KPSTMSTK$_2$ depth survey illustrating the reservoir interval from the Ben Nevis - Upper Avalon seismic base marker in the fault block, highlighted by the two (red) bounding faults.

	BRV (e^6m^3)	N:G$_{res}$	Phi$_{res}$	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	80	49	12	75	201	36	22
P50	86	65	17	80	212	55	36
P10	92	81	22	85	224	81	55

Table 4: Input values from top Ben Nevis to Upper Avalon seismic base marker over mapped interval within the South Mara SDLs 1003-1005 boundary, using @risk to determine probabilistic OGIP and REC.

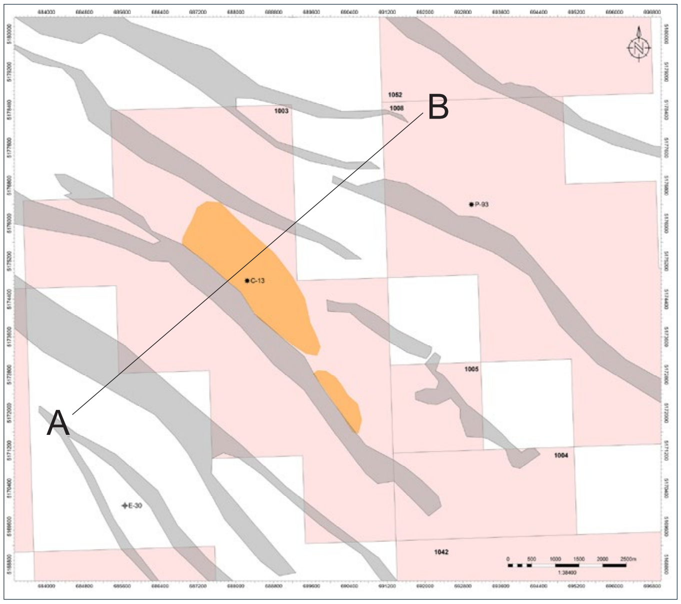


Figure 5: Basemap illustrating SDL outline; P50 (orange) gas accumulation used as input to determine the BRV for the in-place gas calculation. A-B line depicting location of schematic cross section.

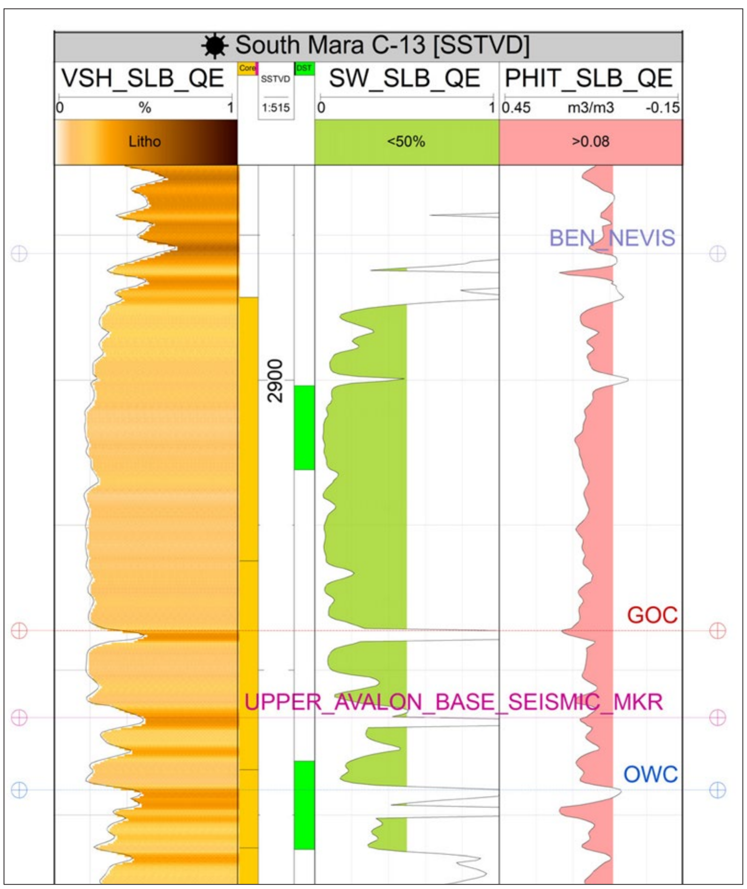


Figure 7: South Mara C-13 well section over the reservoir interval from Ben Nevis Fm top to Upper Avalon base seismic marker illustrating the GOC.

Study Area: SDL 197 South Tempest

- SDL 197
- **Effective date:** April 4, 1987
- **License Representative:** ExxonMobil Canada
- **SDL Size:** 7722 ha

Key Well: SouthTempest G-88
Interval: Tempest Member to Egret Member (Rankin Formation)

- **Gross :** 721m
- **Gas Pay:** 29m
- **GDT:** -4275m TVDss
- **Sg:** 65%
- **N:G res:** 20%
- **N:G pay:** 4%
- **Avg Phi res:** 10%

- South Tempest G-88 well recovered gas from the DST's in the Tempest Member of the Rankin Formation
- The Tempest Member is a series of stacked sand channels which shows as a package of strong trough and peak responses in the seismic data
- P50 BRV was determined by an updip fault and a gas-down-to contact (-4275m TVDss) to create a closure within the Tempest Member Interval (yellow area on Figure 5; yellow on Figure 6)
- P10 BRV was determined by an updip fault and down dip to the SDL boundary to create a closure within the Tempest Member Interval (yellow and orange area on Figure 5; yellow on Figure 6)
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Tempest Member interval; four offset wells were used. (Figure 7 & Table 4)
- Reservoir pressure tested at 74000 kpa approximating a 0.003 value for Bg
- Recovery Factor analysis from analogues using industry trends and standards

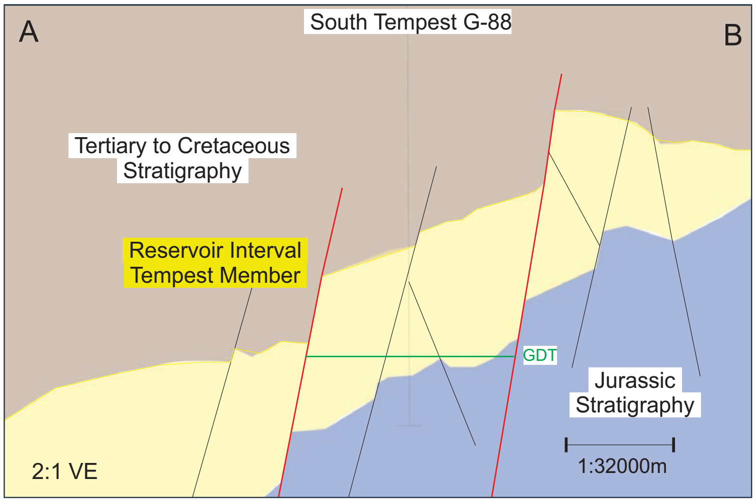


Figure 6: Schematic cross-section illustrating the north-south extent of the SouthTempest prospect. Target reservoir interval from Tempest Member to the Egret Member (highlighted in yellow) between the red faults.

	BRV (e^6m^3)	$N:G_{res}$	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	42	8	8	59	357	5	3
P50	115	21	10	65	370	20	13
P10	319	40	14	71	383	72	47

Table 4: Input values from top Tempest Member to the Egret Member within the SDL 197 boundary, using @risk to determine probabilistic OGIP and REC.

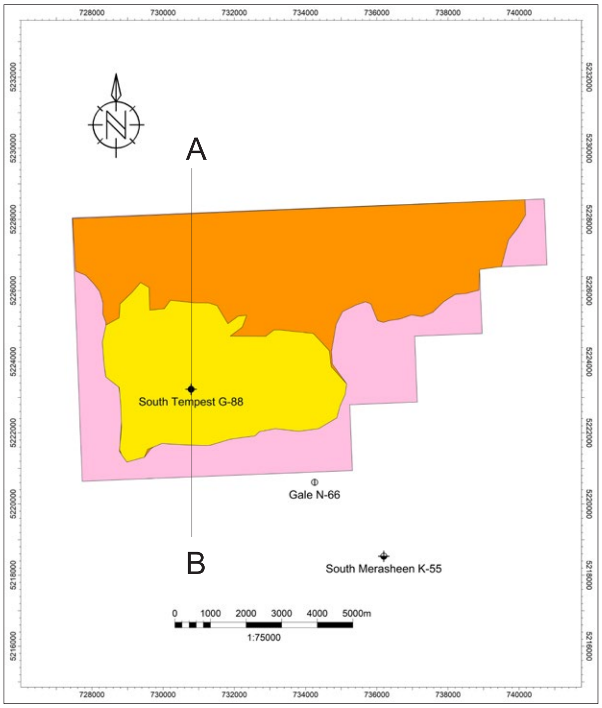


Figure 5: South Tempest basemap illustrating SDL outline; P10 (yellow + orange) and P50 (yellow) gas accumulations used as input to determine the BRV for the in-place gas calculation, A-B line depicting location of schematic cross section.

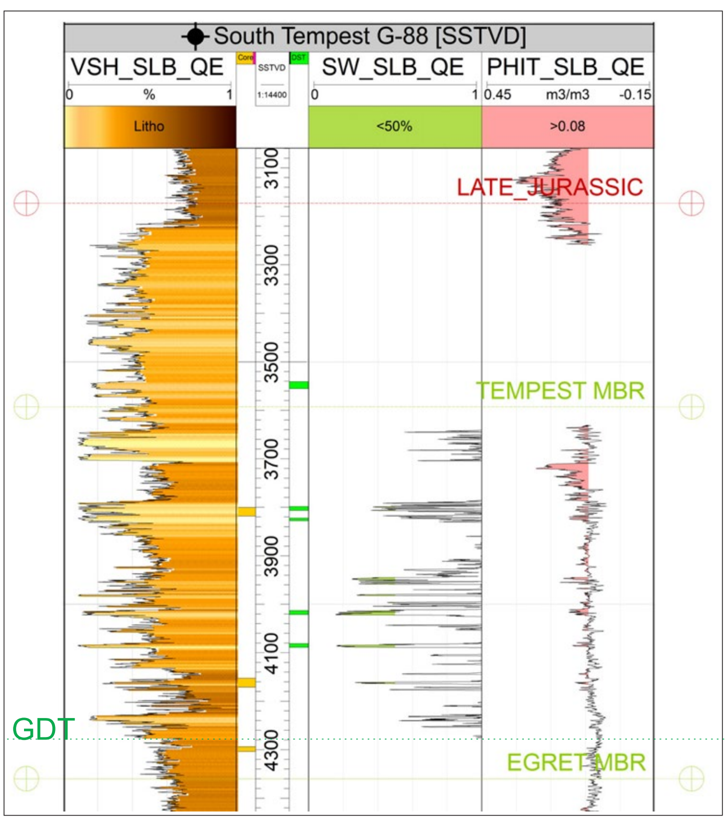


Figure 7: South Tempest G-88 well section over the reservoir interval from Tempest Member to the Egret Members.

References

- C-NLOPB[1] (January 22, 2025) Petroleum Estimated Ultimate Recovery and Contingent Resources Newfoundland Offshore Area. https://www.cnlopb.ca/wp-content/uploads/disc _rr-1.pdf
- TTI.158760.SOUTH_JEANNE_DARC_KPSTMSTK[2] 3D seismic data provided by PGS-TGS Geophysical Company*, Operational Headquarters, 10451 Clay Road, Houston, Texas 77041, USA
  *Permission granted to use seismic images seen in this document
- All remaining seismic data used provided by C-NLOPB (public data)
- In-house Natural Gas Assessment completed by the Petroleum Development Division of the Department of Industry, Energy and Technology.
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