88 Energy

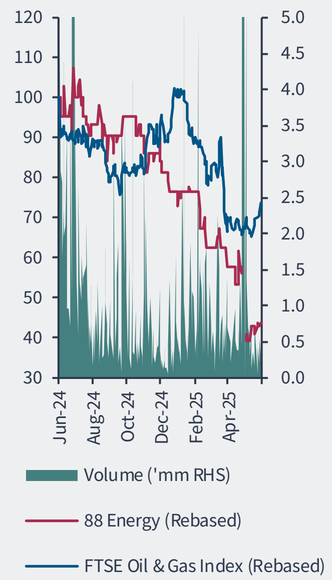
Initiation: High Impact Alaska and Namibia Exposure

GICS Sector	Energy
Ticker	AIM: 88E
Market cap 10-Jun -25 (US$mm)	17.4
Share price 10-Jun-25 (GBp)	1.18

NAV summary (p/sh)

Asset	Unrisked	Risked
Cash & other	0.5	0.5
Longhorn	0.5	0.5
Phoenix	36.0	6.8
Leonis	423	6.9
Total NAV	**460**	**14.7**

Source: H&Pe



Source: S&P CapIQ

We initiate coverage on 88E with a risked NAV of 14.7p/sh

88 Energy ("88E") is a UK (AIM:88E) and Australian listed (ASX:88E) oil and gas E&P company, with a primary focus on Alaska. It also has production in the US Permian basin and high impact exploration acreage in Namibia. Its strategic focus is early exploration and appraisal (E&A), providing outsized exposure to large scale discovery success. Its E&A assets are chosen to be high value and easy to commercialise, with an aim to monetise prior to development/final investment decision ("FID"). Management excels in exploration: combining technical, operational, commercial and financial skills. It has a solid track record in asset appraisal, project execution in challenging environments, securing funding and completing farm-outs.

Phoenix: Large, discovered resource after long drilling history in Alaska

88E is targetting >1bnboe of gross resource in Alaska with potentially billions of dollars of unrisked value. It has discovered >250mmbbl liquids (2C resource) in Project Phoenix, with the potential to start early production in 2027/8 and reach a plateau rate of >7.5kbbl/d from an early production system. Encouraging flow tests from the most recent Hickory-1 well, as well as several nearby wells, have derisked its acreage. It is located adjacent to the main oil pipeline and highway aiding commercialisation. 88E currently owns 75% of the asset but has struck a farm-out deal to reduce its stake down to 35% and to be fully funded through CY'26 (including the planned horizontal appraisal well in mid '26) and potentially further to 25% for another US$10mm in carry. With a successful test, Phoenix should be close to FID ready and 88E should be in a strong position to monetise. At 25%, 88E would have 63mmbbl of net 2C recoverable liquids, which we would value at >US$280mm.

Exposure to two of the most exciting countries for exploration

High-impact exploration, with a disciplined capital focus, remains a compelling investment strategy due to its improved returns and ability to deliver substantial value through low-cost, low-carbon discoveries that replace declining reserves and support long-term energy security. In Alaska the discovery of previously missed oil pay has unlocked multi-billion barrel reserves and has shaped 88E's strategy. Project Leonis offers a compelling near-term exploration opportunity, with 100% working interest and ~800mmbbl of gross mean unrisked prospective resource over two reservoirs, with ~33% geological chance of success ("COS"), de-risked by re-interpretation of historical well data and modern 3D seismic. In Namibia, 88E has a substantial frontier exploration opportunity, with multi-billion barrel discovery potential, seismic completed and planned drilling potentially in H2'27, leveraging the country's favourable operating environment.

Catalysts: read-across drilling, farm-outs and 2026 drilling

The catalysts for 88E this year are the progress on farm-outs of its main projects: Phoenix (dependent on progress with agreed farm-out partner Burgundy), Leonis and Namibia. Also, there will be read-across this summer from other wells being tested nearby in Namibia (e.g. ReconAfrica) and Alaska (e.g. Pantheon). In 2026 there is the potential for an appraisal/producer well at Phoenix and an exploration well at Leonis (Tiri-1 worth 6.9p/sh risked). We also expect a resource certification in Namibia, which would then allow us to assign value in our NAV.

Valuation: Risked NAV provides a 12x upside to the current share price

Our risked NAV is 14.7p/sh for 88E and unrisked is 460p/sh. On a market-cap/bbl (excluding producing assets) of current 2C resources, 88E trades on US$0.06/bbl, a fraction of that ascribed to peers such as Pantheon and recent Alaskan transactions. Furthermore, the market is assigning negligible value to 88E's exploration prospects, especially compared to peers such as ReconAfrica for Namibia.

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Investment Case

88E offers investors exposure into exploration and appraisal opportunities in Alaska and Namibia. 88E has strategically diversified its portfolio with several high-impact projects to mitigate risk and avoid overconcentration in any single venture. It has a track record of successfully farming down its acreage in Alaska. 88E has adapted the strategy to be much more commercially focused: by targeting the conventional play with better economics, sticking to areas close to infrastructure (lower capex, quicker time to market), better utilising data (e.g. to spot missed oil pay), leveraging off nearby drilling success (e.g. Pantheon), farming down before drilling and reducing well costs considerably ($13mm for Hickory vs. US$35mm for its Merlin wells). 88E targets an exit and full project monetisation prior to development FID.

Valuation: At 1.18p/sh or US$17mm market cap, 88E looks highly undervalued on several different metrics. On an overall risked NAV basis, we see ~12x upside to 14.7p/sh even after heavily risking our estimates. The current share price is close to the end Q1'25 cash plus value of producing 2P reserves (Permian) valuation. From an Alaskan discovered resource perspective (Phoenix only) and assuming a farm down to 25%, it looks cheap on our bottom up valuation (5.8p/sh risked; 23p/sh unrisked), also based on past M&A for Alaskan pre-FID resource of US$1-3/bbl implies 5-16p/sh of value and based on the farm-down transaction value to Burgundy implies 3.4p/sh. 88E's market cap implies just US$0.06/bbl of 2C resource based on its current stake in Phoenix, when backing out the US Permian value of US$7mm. Pantheon is trading on US$0.24/bbl of contingent liquids resource, which is 4x that of 88E. Furthermore, there is large exploration potential from Alaska from its ~700mmbbl Tiri-1 exploration prospect. ReconAfrica, focused on Namibia onshore exploration, is drilling a prospect similar to 88E's. Recon has a market cap of ~US$100 million, equating to 7p/share for 88E.

Why Alaska? Alaska's North Slope is a premier oil exploration area, with vast resources and a favourable fiscal and political environment. Despite past production declines, new discoveries and projects are revitalising the region. Post-2013 reforms and a pro-oil stance create an attractive business climate. Recent major finds affirm that large oil reserves remain. Companies are investing in billion-dollar developments like Willow, Pikka and Alaska LNG, showing confidence in the region's future. For 88E, Alaska offers substantial exploration potential with U.S. legal security and established infrastructure. While Arctic operations pose challenges, modern techniques have proven them manageable. Overall, Alaska's rich geology, improved competitiveness, supportive governance and existing infrastructure make it an appealing location for oil exploration.

High-impact exploration remains a compelling investment strategy, even amid cyclical downturns in oil prices. According to Wood Mackenzie, despite reduced exploration budgets, the industry has maintained discovery volumes while improving returns—from an average full-cycle return of 11% to 17% between 2019 and 2023. This success is attributed to disciplined capital allocation, focusing on prospects with robust IRRs, swift payback periods, and lower emissions intensity. Discoveries have yielded great value, with companies like ExxonMobil, Eni, and TotalEnergies each creating >US$5bn in value from 2019 to 2023. As existing fields decline, even as the energy transition progresses, continued exploration investment is essential to meet future demand and replace reserves with low-cost, low-carbon barrels. Companies equipped with strategic foresight, technical expertise, and financial discipline are well-positioned to capitalise on these opportunities, balancing short-term capital discipline with long-term value creation.

Unlocking Overlooked Oil: Proven Strategy on Alaska's North Slope – The discovery of low-resistivity oil pay has unlocked multi-billion barrel reserves across Alaska's North Slope. This success, seen in major fields like Willow, Pikka, Polaris, and West Sak, has shaped 88E's strategy of re-evaluating legacy wells for overlooked pay. This approach led to the identification of new conventional targets in the Icewine-1 well, originally drilled in 2015 and ultimately to the successful drilling and testing of Hickory-1 in 2023–24, which produced oil from both the SFS and SMD reservoirs. 88E has been exploring in Alaska for over a decade. It has drilled several wells and poured over the data from historic wells and seismic data, which now gives it a unique understanding of the geology and potential.

Project Phoenix is a de-risked, multi-reservoir light oil play – Phoenix is 88E's most advanced asset in Alaska, with discovered resources and encouraging flow tests from the most recent Hickory-1 well, as well as several other wells derisking its acreage. The asset is located adjacent to the main Trans-Alaska Pipeline System ("TAPS") oil pipeline and Dalton Highway aiding commercialisation. 88E currently owns 75% of the asset with Burgundy owning 25% but has struck a farm-out deal to reduce its stake down to 35%. With the farm-out agreed with Burgundy, 88E should be fully funded on Phoenix at least through H1'26 (including the planned horizontal appraisal well). If Burgundy exercises the right to take a further 10%, it would provide a further US$10mm in gross funding, which would leave 88E on 25% of an asset that should be close to FID ready and 88E should be in a strong position to monetise. At 25%, 88E would have 63mmbbl of net 2C recoverable liquids, which we see worth >US$280mm. There is a further 47mmbbl of risked net prospective resource.

Project Leonis: High impact, low cost exploration opportunity near Prudhoe Bay – Project Leonis offers a compelling near-term Alaskan exploration opportunity. 88E has a 100% working interest and ~800mmbbl of gross mean unrisked prospective resource with ~33% geological COS. Strategically located near key infrastructure (TAPS and Highway), the project targets conventional stacked oil reservoirs in the USB and Canning formations, now de-risked by re-interpretation of historical well data and modern 3D seismic. A re-evaluation of the legacy HSU-3 well has confirmed >200ft feet of previously missed net pay in the USB and strong hydrocarbon indicators in the deeper Canning zone. Furthermore, the reservoir quality hence expected oil recovery per well and capital intensity is expected to be better at Leonis than Phoenix. There is also deeper potential which has not been fully evaluated in the Kuparuk and Ivishak reservoirs. With planning and permitting underway for the 664mmbl Tiri-1 well, which will test both zones from an existing gravel pad, and a farm-out process to secure a carried interest, 88E is well-positioned to deliver a high-impact exploration result at low upfront cost. Based on our US$7/bbl NPV, we believe it could be worth US$5bn unrisked: assuming a much more conservative 25% post farm-down and only US$1/bbl NPV still implies US$180mm of unrisked value net to 88E.

Namibia: high impact exploration in an emerging global hotspot: 88 Energy's 20% interest in PEL 93 offers exposure to one of the world's last true frontier oil plays, located in Namibia's underexplored Owambo Basin. Covering 18,500 km²—over 10 times larger than its Alaskan acreage—PEL 93 holds multi-billion barrel potential supported by seismic interpretation, surface anomalies, and identified anticlinal structures. With drilling targeted for H2'26, the staged farm-in structure limits capital exposure while preserving upside. Namibia's recent 10+ billion barrel offshore discoveries have de-risked the regional petroleum system and spotlighted its onshore potential, which shares analogues with prolific Middle Eastern basins. The investment case is underpinned by compelling fiscal terms—5% royalty, 35%

tax with full cost recovery—and a transparent, pro-business regime. With billion-barrel prospects like P-20-01 carrying independent US$2bn unrisked NPV10 estimates (17% CoS), PEL 93 offers rare early-mover access to a high-impact, low-cost basin with strong readthrough from proven geology, favourable infrastructure, and political stability.

Project Longhorn: low-risk, cash-generative conventional oil and gas asset - It is in the mature, infrastructure-rich Permian Basin of West Texas. Producing ~65% oil from proven Wichita-Albany and Clearfork reservoirs, the asset has delivered stable output since acquisition of ~390–450 boe/d and is expected to generate ~US$2mm of EBITDA net to 88E in 2025. Acquired for just US$5/boe of 2P reserves, Longhorn has grown to 2,830 net acres with ~50 producing wells and 1.4 mmboe of net 2P reserves. With development IRRs ranging from 75% to 400% and breakeven oil prices of US$21–28/bbl, the project offers compelling reinvestment returns through low-capex workovers and infill opportunities. Crucially, it underpins 88E's broader exploration strategy by funding high-impact frontier plays in Alaska and Namibia. Overall, we estimate a value of ~US$7mm for the assets net to 88E (equivalent to 37% of 88E's market cap) based on our 2P developed producing reserves valuation.

Management aligned with high impact exploration strategy: 88E's leadership team is fully aligned with its strategy of progressing high-impact exploration and appraisal assets—particularly on Alaska's North Slope—toward value realisation through farm-outs or monetisation rather than capital-intensive self-development. Several key members of the management team and board were appointed in 2021, included the CEO and CFO, shifting the strategy to a more commercial focus. The team possesses a strong blend of technical, operational, commercial, and financial expertise, with a proven track record in identifying and appraising assets, executing projects in challenging environments, securing funding, and delivering successful farm-out transactions. 88E has been successful in farming out its prospects in the past (e.g. Premier Oil, Burgundy), which gives confidence for further farm-outs. Not only does a farm-out reduce the capital required and risk, it gives industry validation to an exploration play for investors. This depth of experience across the E&P lifecycle enables disciplined capital allocation and supports the company's goal of unlocking value from frontier exploration while maintaining financial flexibility through its production-backed platform.

Investment risks: see page 70 for full details: 88E faces a broad spectrum of risks typical of frontier oil and gas explorers, including high geological uncertainty, regulatory hurdles and funding constraints. Its operations in Alaska and Namibia are potentially exposed to permitting delays, logistical challenges and execution risks in remote and emerging jurisdictions. The company's reliance on farm-outs to mitigate costs introduces partner and negotiation risks, while its ability to progress exploration is contingent on capital availability in possibly volatile market conditions. Additionally, commodity price fluctuations, shifting regulatory landscapes, and increasing ESG scrutiny could all influence project viability and access to funding.

Valuation and NAV

Our favoured valuation methodology is a bottom-up risked NAV, modelling out the various fields and prospects and applying a geological and commercialisation risk to each. In our base-case scenario, we use a long-term flat Brent oil price of US$70/bbl from 2026, a USD/GBP FX rate of 1.35 and a 10% discount rate.

Our risked NAV, on a fully diluted basis, is 14.7p/sh, which implies 12x upside to the current share price. Our risked NAV on a basic share basis would be 15.3p/sh. Overall, we estimate that 88E's unrisked value is US$5.5bn or 460p/sh which is >350x the current share price.

88E (stripping out US$7mm of Permian value) is trading on a market cap/bbl of contingent resource (liquids only) of US$0.06/bbl based on its pre farm-out working interest in Phoenix; it would be even lower on an EV/bbl basis given its cash balance. This is a ~90% discount to our US$4.4/bbl NPV of the contingent resource. As a comparison, Pantheon is trading on US$0.24/bbl of contingent liquids resource, which is 4x that of 88E.

Furthermore, asset transactions in Alaska have gone for US$1-3/bbl for similar pre-development barrels. The purchase price for the acquisition of the Pikka field in 2018 is equivalent to US$3.1/bbl based on Oil Search's estimate for acquisition purposes of 500mmbbl (gross) in the Nanushuk and satellite oil fields. However, the price reduces to US$1.3/bbl if JV partner estimates of ultimate recoverable resources of 1.2bnbbl is used.

Burgundy funding US$22mm of 88E's share of Phase 1 testing on Project Phoenix to gain 40% implies a gross value of US$55mm for Project Phoenix. This is US$41mm for its current 75% or 3.4p/sh.

Looking at two of the pure play companies in Alaska (Pantheon) and Namibia (Recon Africa) shows the potential value the market is putting on the similar plays to what 88E has on its acreage. Pantheon has a ~US$390mm EV and Recon African ~US$100mm: the combined EV is ~25x the current EV of 88E. We see both companies having analogue acreage but slightly further ahead in the derisking process.

Risked NAV

Asset	Gross mmboe	88E W.I.	Net mmboe	NPV US$/boe	Unrisked US$mm	Unrisked p/sh	Geo. CoS	Comm. CoS	Risked $mm	Risked p/sh
Cash					$7	0.6p			$7	0.6p
Options and Warrants					$3	0.2p			$3	0.2p
Capitalised G&A @2x					-$4	-0.3p			-$4	-0.3p
Longhorn 2P PDP	0.8	70%	0.5	$12.3	$7	0.5p	100%	100%	$7	0.5p
Phoenix - 2C	252	25%	63	$4.4	$281	23p	100%	25%	$70	5.8p
Phoenix - 2U	241	25%	60	$2.5	$152	13p	78%	10%	$12	1.0p
Leonis - USB	406	100%	406	$7.1	$2,887	239p	32%	5%	$46	3.8p
Leonis - Canning	311	100%	311	$7.1	$2,211	183p	33%	5%	$36	3.0p
Total NAV	**1,211**		**841**		**$5,543**	**460p**			**$177**	**14.7p**

Source: H&Pe

Cash – At end Q1'25, 88E reported cash and cash equivalents of A$11mm (US$7mm), equivalent to 0.6p/sh or ~50% of the current market capitalisation.

Options and warrants – We include ~48mm options and warrants (adjusted post share consolidation) of which ~24mm are performance options and the balance have an average exercise price of A$0.18/sh or 11.5p/sh. If exercised they would generate US$2.9mm in cash.

Capitalised G&A – We estimate that cash G&A will be ~US$2mm per annum and we forecast it to be flat at this level, capitalised at 2x, which has a negative 0.3p/sh impact on our risked NAV.

Longhorn 2P PDP – We have an unrisked NPV of US$7mm or US$12.3/mcf. Since these are producing reserves, there is no geological or commercial risk for these assets. Thus, on a risked basis, Longhorn's NAV is 0.5p/sh or ~40% of the current share price.

Phoenix 2C – We calculate an unrisked NPV of US$281mm, equivalent to US$4.4/mcf assuming a farm down to 25%. Since these are contingent resources, there is no geological risk for this asset. We assign a commercial chance of success ("CoS") of 25% as we await the derisking from the flow test and to factor in future dilution from the capital required to fully develop the asset. This results in a risked NAV of US$70mm or 5.8p/sh.

Phoenix 2U – We have an unrisked NPV of US$152mm or US$2.5/mcf for Phoenix's prospective resources. We apply a geological CoS of 78% based on the weighted estimates from the CPR and a 10% commercial CoS given that the immediate focus is on developing the 2C resources for Phoenix. This leads to a risked NAV of US$12mm or 1p/sh.

Leonis: Canning – We derive an unrisked NPV of US$2.9bn or US$7.1/mcf for this exploration target. We apply a 32% geological CoS (as per the CPR) and a 5% commercial CoS given the early stage nature and likelihood of farming down, resulting in a risked NAV of US$46mm or 3.8p/sh.

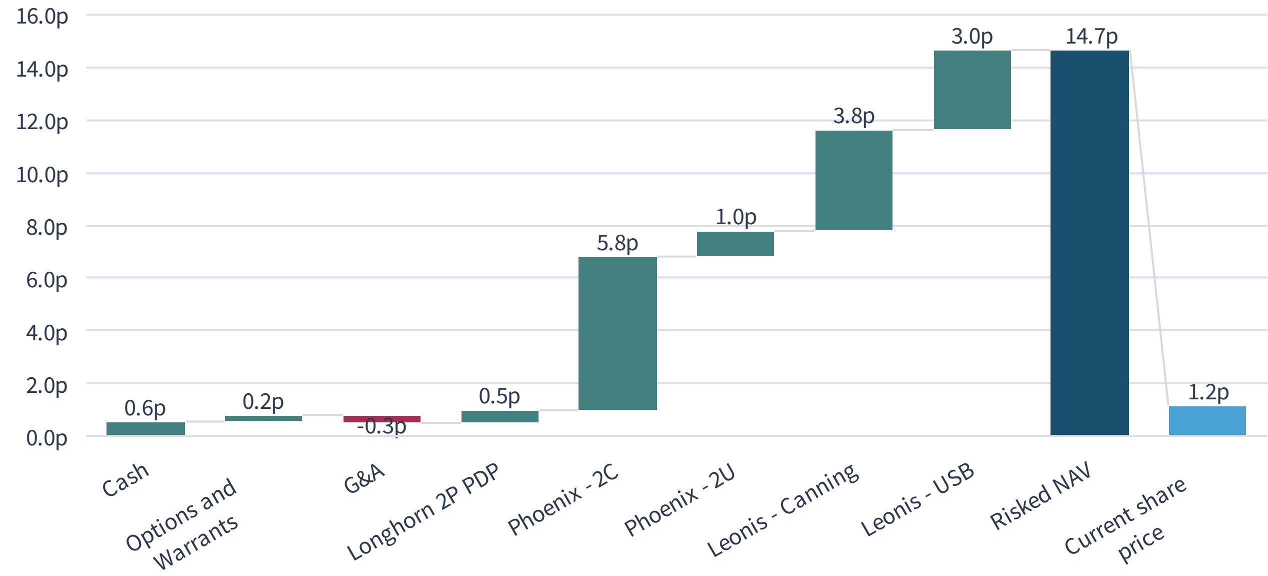
Leonis: USB – We derive an unrisked NPV of US$2.2bn for this exploration target. We apply a 33% geological CoS (as per the CPR) and a 5% commercial CoS as above, resulting in a risked NAV of US$36mm or 3p/sh.

Sensitivity of risked NAV (GBp/sh) to the oil price and discount rate

		Oil price (US$/bbl)				
		50	60	70	80	90
Discount rate (%)	8%	16.0	22.3	28.4	34.3	40.2
	9%	10.9	15.6	20.1	24.5	28.9
	10%	7.6	11.2	**14.7**	18.0	21.3
	11%	5.4	8.2	11.0	13.6	16.2
	12%	3.9	6.2	8.4	10.5	12.6

Source: H&Pe

Risked NAV build-up



Source: H&Pe

Our valuation shows that a large portion of 88E's value lies within Project Phoenix's 2C resources. The project's economics are heavily influenced by the prevailing oil price given the fiscal regime. We have sensitised Phoenix's 2C risked value to the oil price and discount rate to show the range of values based on movements in the macro environment.

Sensitivity of Project Phoenix's 2C risked value (GBp/sh) to the oil price and discount rate

		Oil price (US$/bbl)				
		50	60	70	80	90
Discount rate (%)	8%	5.8	8.9	11.8	14.6	17.3
	9%	3.7	6.0	8.2	10.3	12.4
	10%	2.3	4.1	**5.8**	7.4	9.0
	11%	1.4	2.8	4.2	5.4	6.7
	12%	0.8	1.9	3.0	4.0	5.0

Source: H&Pe

Catalysts

88E has a robust pipeline of near-term and longer-term catalysts that could transform its valuation. The catalysts that we see impacting the equity story are:

Burgundy Xploration Farm-in Agreement Completion – The completion of the farm-in with Burgundy, which involves Burgundy funding up to US$39mm gross spend on Project Phoenix, is contingent on Burgundy, which is pursuing an IPO or securing funding from high net worth and institutional investors, securing the necessary capital by 31st December 2025. We also see a successful funding event as being a catalyst for 88E given it would both secure the funding but also provide a read-across valuation. 88E's peer, Pantheon is also pursuing a US listing.

Fully carried appraisal well at Project Phoenix – A horizontal well is planned for mid-2026 utilising an existing well pad. The plan is for a 90-day extended well test of the SMD-B horizon with a 3,500ft lateral, which flowed 50bbl/d from a vertical well at Hickory-1. The SMD-B has an estimated 35mmbbl of 2C resource (111mmbbl in the 3C case). The aim is to prove commercial viability for field development.

Gas monetisation upside – Although we carry no value for the natural gas resource that 88E has in Alaska, with the Alaska LNG project moving forward, there may be an opportunity to monetise this gas and based on nearby results there may also be helium within the natural gas that could further boost the economics.

Project Leonis farm-out – 88E is actively seeking a farm-out partner to fund the exploration on the acreage, primarily the drilling of the Tiri-1 exploration well.

Leonis exploration well (Tiri-1) – At Project Leonis, 88E has identified multiple stacked potential reservoirs, including the USB and deeper Canning Formation. The planned Tiri-1 well in H1'26 targets both horizons in an optimal location. A successful result would derisk 664mmbbl (Pmean) of prospective resource.

Regional well results on the North Slope – Offset operator activities in the Brookian trend, such as Pantheon's upcoming Dubhe-1 well, can significantly de-risk the broader area. Any success in analogous formations near Phoenix would likely uplift 88E's acreage value.

Namibian farmout – 88E is currently considering the option of collaborating with partners to jointly advance resource assessment and further reduce the risks associated with the acreage.

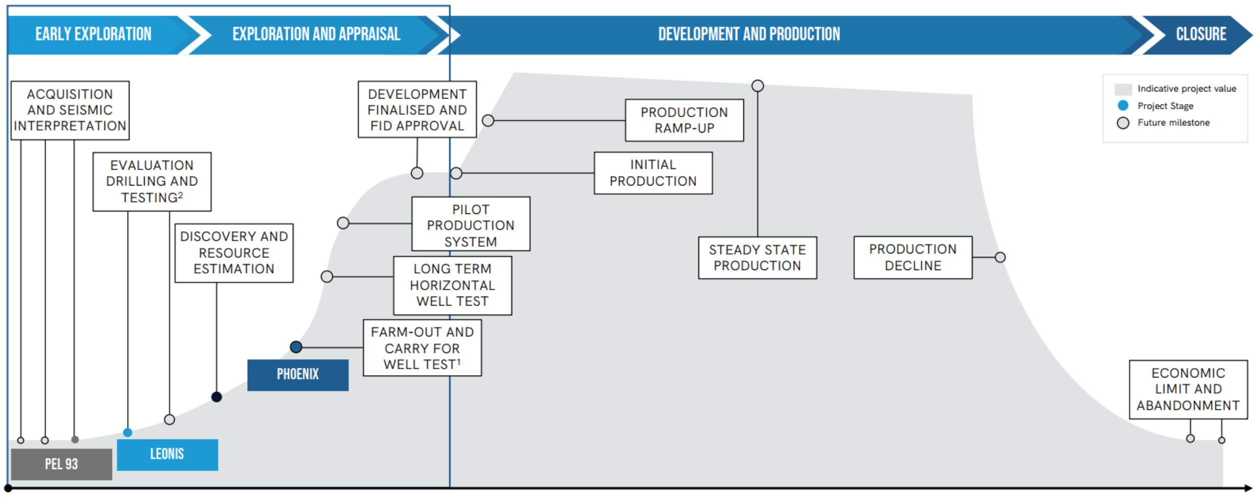
Regional Namibian drilling – Recon Africa's Prospect 1 well is planned to be drilled in June 2025. Prospect I is targeting 346mmbbl of unrisked prospective oil resource. This is an excellent analogue for MEL's Lead 9. Success on Prospect I would considerably de-risk the Owambo Basin and Lead 9.

Resource certification in Namibia – Onshore PEL 93, 2D seismic data identified multiple large structural closures. The company expects to release an independently certified prospective resource estimate in the near term. The seismic program over PEL 93 is a critical step towards de-risking this vast and underexplored acreage, with ten significant structural closures already identified.

Ongoing development at Project Longhorn – A series of new completions in at Project Longhorn (88E's Permian Basin asset) offer opportunities for incremental production gains.

Company Overview

Early exploration and appraisal focus to provide investors with outsized exposure to large scale discovery success



Source: 88 Energy

88E's corporate strategy centres on high-impact oil and gas discovery and appraisal, supported by a proven exploration framework. The company focuses on building an attractive portfolio of opportunities across the globe, underpinned by assets that offer scale, quality, and geographic diversity. Its exploration efforts are data-driven and currently targeted at two highly-prospective frontier regions. 88E maximises asset value and minimises risk through rapid appraisal and advanced pre-development activities. This approach is strengthened by deep technical expertise and strategic partnerships.

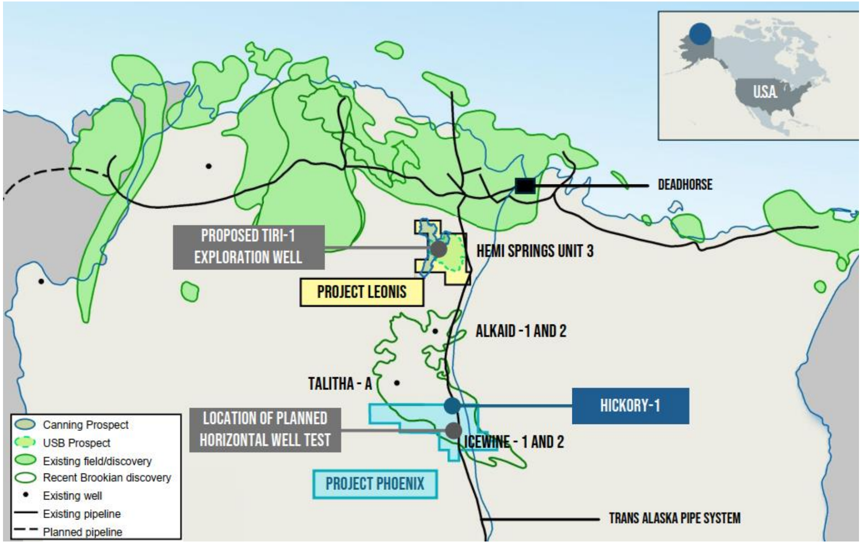
88E stands out as one of a few UK-listed Alaskan oil and gas plays. It benefits from an experienced leadership team that thoroughly understands the North Slope's geological potential, operational terrain, and regulatory framework. While Alaska remains the central growth platform, 88E also maintains a cash generating asset in the prolific Permian Basin, Texas, providing a diversified operational base and a measure of financial resilience unusual for a pure-play explorer. Furthermore, 88E has an interest in the new global oil and gas hot-spot – Namibia.

Project Name	Location	Net Acres (k)	Company Interest
Project Phoenix	Onshore, North Slope Alaska	45	75%
Project Peregrine	Onshore, North Slope Alaska (NPR-A)	126	100%
Project Longhorn	Onshore, Permian Basin Texas	2.8	65%
Project Leonis	Onshore, North Slope Alaska	25	100%
Umiat Unit	Onshore, North Slope Alaska (NPR-A)	18	100%
Namibia	Onshore, Owambo Basin, Namibia	914	20%

Source: 88 Energy

In Alaska, 88E has four projects at various stages. Phoenix is the most advanced having made a large discovery and 88E moving towards appraisal next year through a long-term flow test, ahead of an early production system. Leonis has the most exciting and sizeable exploration potential and is strategically well located for development. The other two projects, Umiat and Peregrine contain discoveries but are currently on hold given the more remote location for commercialisation and are in voluntary suspension due to the existing NPRA regulations.

88E's key Alaska acreage: Leonis and Phoenix



Source: 88 Energy

Over recent years, the company has selectively advanced its Alaskan acreage by drilling wells, undertaking comprehensive seismic surveys, and systematically maturing prospective targets. Management's strategy centres on unlocking large-scale resources near existing pipelines and processing infrastructure, thus lowering barriers to commercialisation. Recent flow test successes at key wells underscore the potential for material oil discoveries, which can be developed relatively rapidly if follow-up appraisal confirms reservoir quality and continuity.

A key element of 88E's approach is to de-risk its Alaskan portfolio through phased exploration and farm-outs. It has agreed a farm-out deal for Project Phoenix and is in the farm-out process for Project Leonis. By securing partners to fund sizeable portions of drilling or early-stage capital, the company aims to retain exposure to discoveries without the burden of excessive levels of financial commitment.

88E has secured suspensions from the Bureau of Land Management Alaska (BLM) for its Project Peregrine and Umiat Unit leases, following regulatory changes proposed prior to the Trump administration. The suspension for Project Peregrine has been extended to 30 November 2025, while the Umiat Unit is suspended until 30 June 2025. These suspensions relieve the company of ~A$0.6mm in lease rental obligations for 2025 and enable it to focus on advancing its strategically located assets near existing infrastructure.

Beyond Alaska, the company's subsidiary in Texas, Project Longhorn, delivers cash flow from conventional wells in the Permian Basin. While Longhorn provides a modest in output of ~300boe/d, this asset offers stable monthly revenues that partially offset corporate overheads and exploration outlays.

Additionally, 88E has acquired 20% working interest (with the potential to increase to 45%) in an onshore Namibia licence block that represents another frontier growth avenue for the company. Namibia has been at the forefront of the oil and gas industry after multi-billion barrel offshore oil finds over the last few years. Recent seismic campaigns have revealed multiple large-scale structural closures onshore, which, if validated by drilling, could transform Namibia into a valuable component of 88E's longer-term expansion strategy. 88E is now exploring the option of bringing in partners to further de-risk the acreage.

Shareholder structure

The company's shares are listed on the Australian Securities Exchange (ASX) and the AIM market in the UK, both under the ticker 88E. Additionally, the shares are traded on the US OTC market under the ticker EEENF. In May 2025, 88E undertook a 25:1 share consolidation to streamline its capital structure. Following the consolidation, the number of shares outstanding stood at 1.16bn, with 48mm in options and warrants.

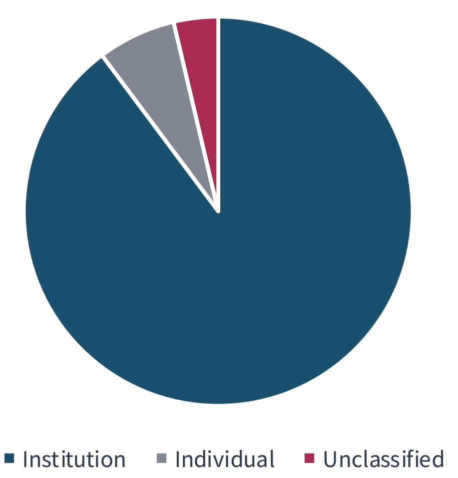
Capital raise history

Date	Amount (A$mm)	Shares issued (mm)	Issue Price (A$)	Adjusted shares issued (mm)*	Adjusted issue price (A$)*
13-Sep-19	6.8	540	0.0125	22	0.3125
24-Jan-20	5.0	238	0.0210	10	0.5250
12-Feb-21	12.0	1,500	0.0080	60	0.2000
02-Sep-21	24.0	856	0.0280	34	0.7000
14-Feb-22	32.0	914	0.0350	37	0.8750
15-Feb-23	17.5	1,842	0.0095	74	0.2375
09 Aug 2023 (Rights)	3.3	553	0.0060	22	0.1500
22 Aug 2023 (Shortfall)	4.7	783	0.0060	31	0.1500
17-Nov-23	9.9	2,200	0.0045	88	0.1125
18-Apr-24	9.7	3,232	0.0030	129	0.0750

Source: H&Pe, 88 Energy; * Adjusted for the 25:1 share consolidation in May 2025

88E's equity base is diversified across institutional, high-net-worth, and retail shareholders, with a sizeable portion of trading liquidity. The company's top twenty shareholders comprise of institutional investors and HNWIs who collectively own >50%, reflecting sustained interest among resource-focused funds and specialist oil and gas investors. Management, directors, and key technical personnel also hold stakes in the business, aligning their interests with broader shareholder objectives. Additionally, 88E's dual-listing structure on the AIM and ASX, supported by OTC trading in the United States, widens its capital-market exposure and contributes to a consistently active trading environment.

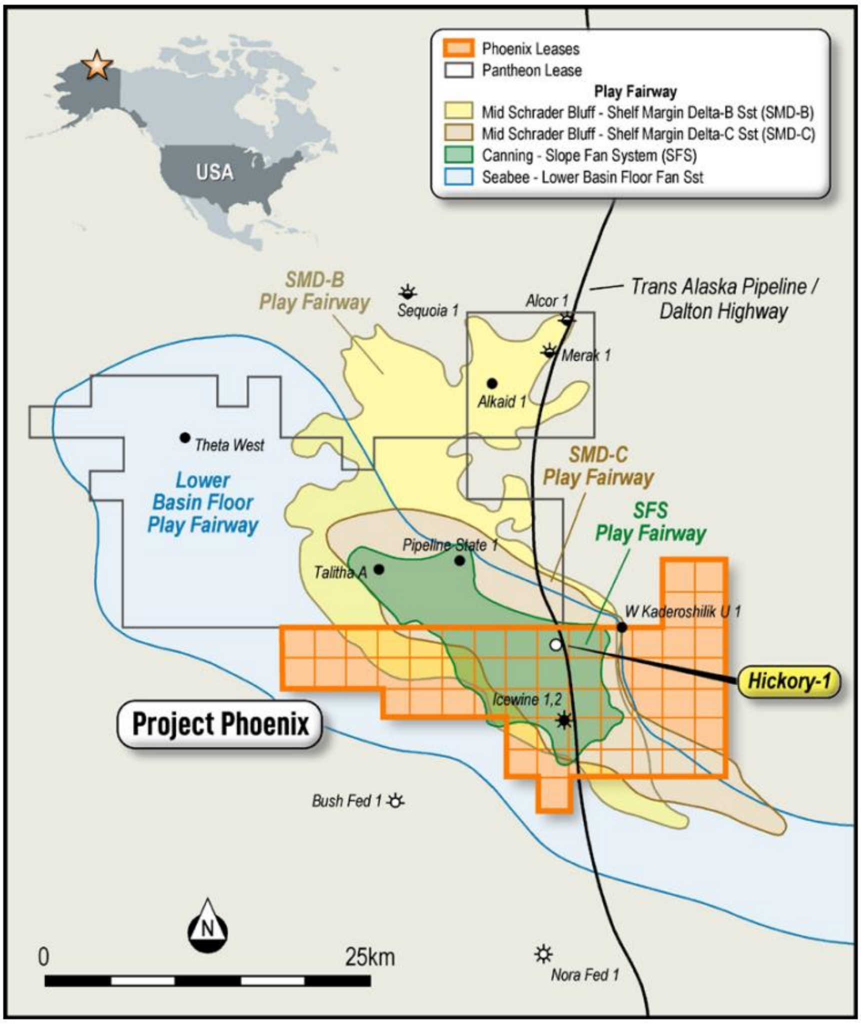
88 Energy's shareholder strcture



Source: Bloomberg as on 28th May 2025

Project Phoenix

Project Phoenix and surrounding acreage



Source: 88 Energy

Project Phoenix is a de-risked, multi-reservoir light oil play located south of Project Leonis on the Alaskan Northen Slope. The project is located adjacent to the Trans-Alaskan Pipeline System ("TAPS") and the Dalton Highway smoothening the commercialisation process. 88E currently holds 75% in the project and will be fully carried for the first phase of the project on completion of a farm-out deal down to 35%. This deal de-risks the project financially and operationally, enabling 88E to maintain a sizable equity stake while passing on operational responsibility to Burgundy.

The exploration focus has shifted over time from the deeper shale play under the previous Board and management to the shallower conventional oil play. 88E made a 70mmbbl condensate discovery in 2020 with the now relinquished Charlie-1 well (US$25mm cost), which demonstrates its successful geological approach but the size and distance from infrastructure meant it was uneconomic to develop.

Following the 2024 Hickory-1 well, oil has been discovered and booked as contingent resource (~250mmbbl gross 2C) from four reservoirs with a further two reservoirs containing prospective oil resources (further ~250mmbbl 2U). The oil quality suggests a highly marketable and valuable light oil. The acreage has been largely derisked by the success of Pantheon to the north, which is targeting the same reservoirs, which can be mapped on seismic spanning both companies' acreage. This allowed 88E to book contingent resource for the basin floor fan play.

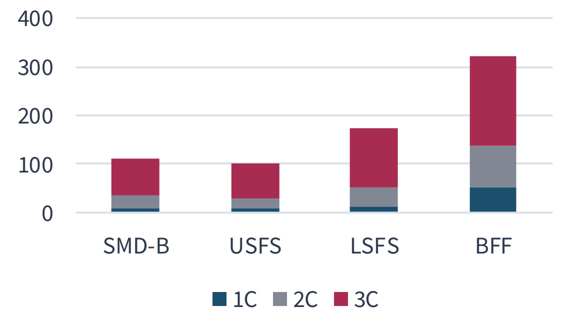
A horizontal well is planned for mid-2026 utilising an existing well pad. The plan is for a 90-day extended well test of the SMD-B horizon with a 3,500ft lateral, which flowed 50bbl/d from a vertical well at Hickory-1. The SMD-B has an estimated 35mmbbl of 2C resource (111mmbbl in the 3C case). The aim is to prove commercial viability for field development.

88E views the Pilot Production System (Phase 2), following the horizontal well test (Phase 1), as a crucial step towards full field development. It aims to confirm commercial viability, generate cash flow, and gather essential data, benefiting from the strategic location and the use of high-productivity horizontal wells

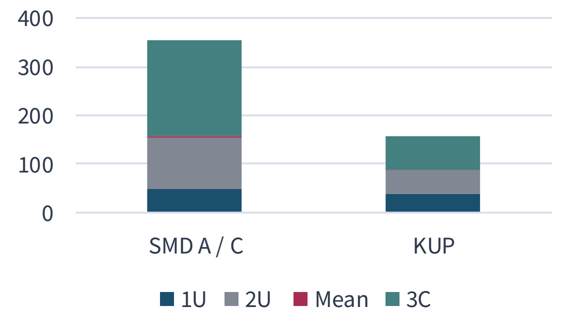
For the development of just the contingent resource, our scoping economics suggest a gross NPV10 of US$4.4/bbl or US$1.1bn (US$280mm net to 88E at 25%) and an IRR of 38% at US$70/bbl Brent price. We see an oil price break-even at a 10% discount rate at <US$40/bbl Brent. The key assumptions are total development costs of US$13/bbl and operating costs of US$6/bbl. Production should be able to reach 40kbbl/d by 2035 generating >US$700mm of EBITDA and >US$300mm of FCF.

Resource size

Gross contingent resource (mmbbl)



Gross unrisked prospective resource (mmbbl)



Source: 88 Energy

Project Phoenix is currently estimated to contain ~250mmbbl of 2C marketable liquids (378mmboe in total) split over four zones. There is a further 153mmbbl of prospective resource (best or 2U), with an 81% geological COS in the SMD-A and C zones and 88mmbbl with a 72% GCOS in the Kuparak (KUP) formation. Therefore, there is a total gross unrisked 2C and 2U of 492mmbbl. Using the risked 2U plus the 2C gives 437mmbbl.

The total pre-drill 2U prospective resource estimate was 647mmbbl or 325mmbbl risked (with the chance of success between 50-81% depending on the reservoir interval) and post drill this has fallen to a combined 2C plus unrisked 2U of 492mmbbl, however now >50% of that is contingent resource. 88E sees further upside to the 2C resources based on a successful horizontal flow test.

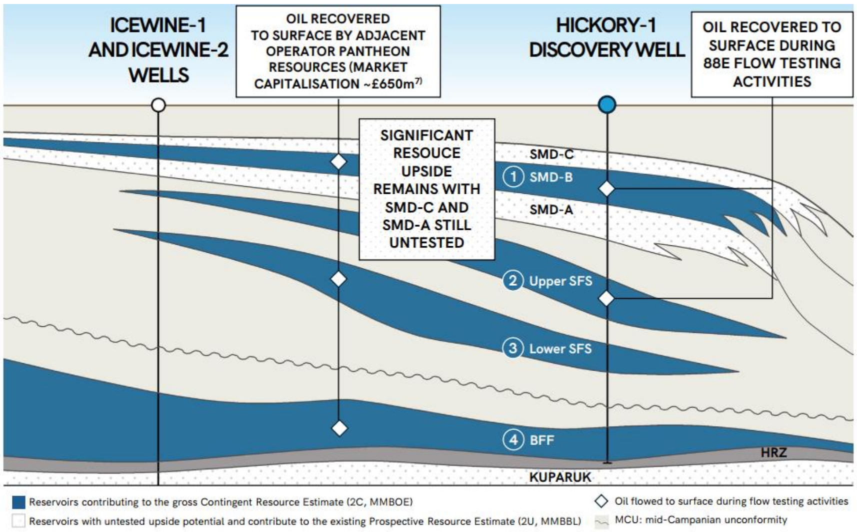
Exploration history

Project Phoenix was previously called Project Icewine. It has been derisked by four wells: Icewine-1, Icewine-2, Charlie-1 and Hickory-1. The Icewine-West acreage containing Charlie-1 has been relinquished.

Icewine-1 and 2

The Icewine-1 and 2 wells were primarily designed to test a deep unconventional exploration play targeting the HRZ (Hue Shale/HRZ) liquids-rich resource play. The observation of oil shows in the shallower SMD at Icewine-1 and 2 was crucial in the re-evaluation of the conventional potential of the acreage and contributed to the refreshed exploration strategy focusing on these shallower, proven oil-bearing reservoirs. Post-well analysis indicated that the Icewine-1 well was drilled outside of interpreted Amplitude Variation with Offset (AVO) anomalies, unlike the more optimally located Hickory-1 well. The Icewine-1 and Icewine-2 wells are situated to the southwest of the Hickory-1 discovery well within the project area.

Hickory-1 flowed light oil in SMD-B and U-SFS eservoirs



Source: 88 Energy

Hickory-1

The Hickory-1 well was spudded in March 2023 and flow tested in February 2024. It was a vertical well to appraise six stacked reservoir targets. These included the primary target: Shelf Margin Delta (SMD A, B & C), Slope Fan System (SFS), Basin Floor Fan (BFF), and Kuparuk (KUP) formations.

The location was selected to test significant fluid factor anomalies (where the seismic signal suggested the presence of pore fluids other than water) in the SMD-C to SMD-A interval. The well was positioned to be the closest to the Shelf Edge (SMD) within the acreage and in a relative down-dip position (to access potentially better developed parts of the reservoir). The well location was optimised based on 3D seismic data (FB3D), including Amplitude Versus Offset (AVO) analysis and seismic inversion. AVO analysis validated 88E's depositional model, indicating the highest energy region was in the northeast of the Phoenix acreage, adjacent to the shelf break. RMS amplitude extractions suggested higher quality sands at Hickory-1 compared to Icewine-1 in the SMD reservoir unit.

Hannam&Partners

The Hickory-1 well successfully intersected all primary and secondary targets, and a newly identified Upper SFS reservoir, before reaching Total Depth (TD) within the HRZ. Petrophysical interpretation confirmed the presence of multiple hydrocarbon-bearing pay zones across all zones. Average porosity across all pay zones was 9-12%, with key zones in the Upper and Lower SFS showing 11-16% total porosity. Pre-drill expectations were met or exceeded regarding reservoir quality (higher than expected porosity in SFS and BFF) and thickness (higher total gross reservoir, total net reservoir, and total net pay. Post-well analysis, including geochemical testing, indicated reservoirs appeared free of biogenic mixing and a general trend of increasing thermal maturity with depth.

Testing focused on the two shallower primary targets: USFS and SMD-B with small frac jobs performed. These are not unconventional targets but tighter sands that benefit from fracturing to produce. The total cost of the flow test was US$14.5mm.

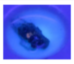
- Flow testing of the Upper SFS reservoir achieved a peak flow rate of >70bbl/d of light oil (~40° API), flowing naturally. This is substantial as flow back from other reservoirs in adjacent offset wells only produce under nitrogen lift.

- Flow testing of the SMD-B reservoir achieved a peak flow rate of ~50bbl/d of light oil (~ 39° API oil gravity, under nitrogen lift), with little to no measurable associated gas (low Gas-oil-Ratio).

Following the initial discovery, extensive technical studies and resource evaluations were carried out. Independent audits by ERCE and NSAI subsequently verified large resource volumes in multiple zones, adding contingent resources from the SMD-B, U-SFS, L-SFS, and previously established BFF reservoirs.

Independent certification by NSAI confirmed discovery status for the BFF reservoir at Hickory-1 and Icewine-1 prior to testing operations. This was based on multiple successful flow tests on nearby acreage and log data and petrophysical interpretations showing continuity of the BFF across Hickory-1 and Icewine-1, Talitha-A and Theta West-1, which demonstrated sufficient similarity to confirm producibility in Project Phoenix. Therefore, no flow test was undertaken on the BFF as it was not required for 88E to book contingent resources.

Pre-drill versus post-drill analysis

PRE-DRILL ASSESSMENT UNRISKED NET ENTITLEMENT TO 88E[2] PROSPECTIVE OIL RESOURCES (MMSTB)[3,4]					POST-DRILL INITIAL OBSERVATIONS HICKORY-1			
Prospects (Probabilistic)	Best (2U)[5]	COS[1]	AVO anomaly	Oil recovery from offset wells	Shows[6]	Estimated Gross / Net Pay	Porosity Range (Average / High)	Sample image of florescence in cuttings
Shelf Margin Delta (SMD A, B & C)	140	81%	Strong	Talitha A	✓	~540ft / ~95ft	~10.5% / ~12%	
Upper Slope Fan System (Upper SFS)	**New reservoir – to be assessed**	-	**Moderate**	**Not previously intersected**	✓	**~360ft / ~80ft**	**~10.5% / ~16%**	
Lower Slope Fan System (SFS)	84	50%	Subtle	Alkaid-1 and Talitha A	✓	~380ft / ~120ft	~10.5% / ~14%	
Basin Floor Fan (BFF)	341	50%	Not detected	Theta West	✓	~325ft / ~160ft	~9.5% / ~12%	
Kuparuk (KUP)	56	72%	Subtle	Talitha A	To be drilled and tested at a future date[7]			

Source: 88 Energy

Other read across wells

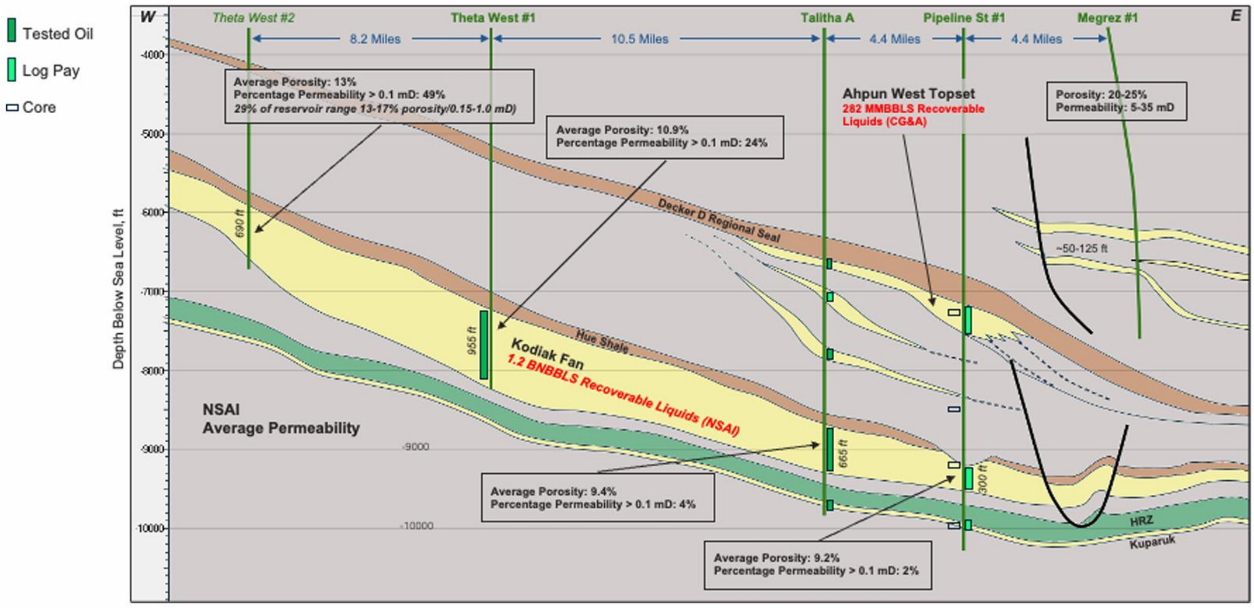
Well in and around Phoenix and which horizons encountered

Well	SMD	SFS	BFF
Icewine-1	✅	✅	✅
Icewine-2	✅	✅	✅
Hickory-1	✅	✅	✅
Alkaid-1	❌	❌	✅
Alkaid-2	❌	❌	✅
Talitha-A	✅	✅	✅
Theta West-1	❌	❌	✅
Pipeline State-1	✅	✅	✅
Ahpun-1	✅	❌	❌

Source: H&P estimates

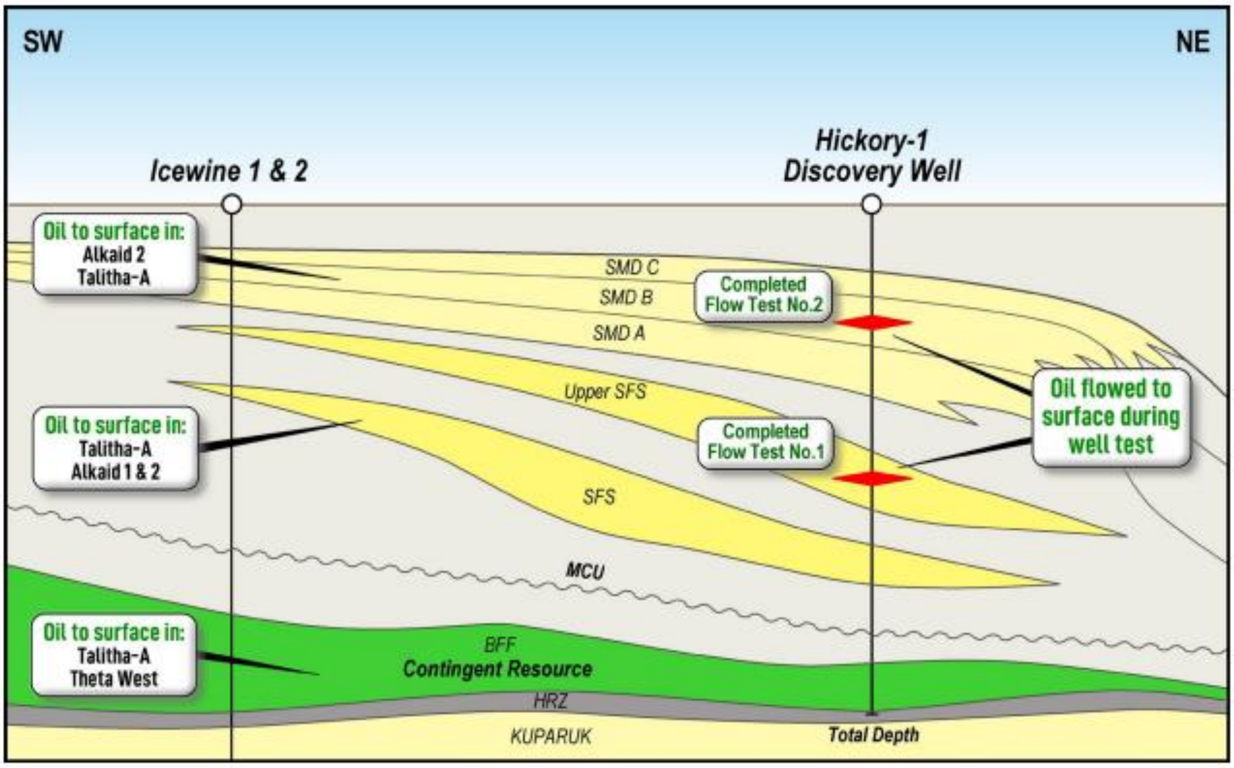
The results at near-by wells are highly encouraging regionally for several formations that extend into Project Phoenix. Pantheon's Kodiak Project (BFF horizon) was discovered in the Talitha-A well and successfully appraised in the Theta West-1 well. Pantheon's Ahpun Project (SMD and SFS reservoirs) was originally discovered in Arco's 1988 Pipeline State-1 well and appraised by Pantheon's Alkaid-1, Alkaid-2 and Talitha-A wells.

Pantheon wells



Source: Pantheon Resources

Phoenix historical wells and corresponding zones where Pantheon encountered oil



Source: 88 Energy

Talitha #A Well

The Talitha-A well provides a strong readthrough for 88E's Project Phoenix, confirming the presence of moveable hydrocarbons across the BFF, SFS, and SMD intervals within the Brookian sequence. Successful tests at Talitha-A validate reservoir quality, charge, and deliverability, materially de-risking the petroleum system targeted by Phoenix and providing confidence in its exploration model.

In early 2022, Pantheon tested the BFF at the Talitha #A well. Three separate 10-foot intervals were perforated and individually stimulated, resulting in the production of high-quality light oil (35° to 39° API). The well achieved an average flow rate of 73bbl/d over a three-day test period, with a sustained rate of approximately 40bbl/d on the final day.

Pantheon also tested the SFS. Two separate five-foot intervals within distinct ~50-foot sand bodies were perforated and stimulated. The combined flow test yielded high-quality light oil (35° to 38° API), averaging 45bbl/d over a three-day period, and a sustained rate of ~32bbl/d on the final day. This marked the first indication of producible oil in the SFS on Pantheon's acreage, suggesting promising reservoir properties.

Testing of the SMD horizon at Talitha #A was initiated but encountered operational challenges. After successful perforation and fracture stimulation, a blizzard caused a suspension of operations. Upon resumption, the well ceased flowing shortly after, with only 45% of the fracture fluid recovered and minimal amounts of 34° API light oil produced. The lack of reservoir fluids was attributed to a blockage preventing flow into the wellbore. Despite this, Pantheon remains optimistic about the SMD's potential, planning further operations to fully assess its productivity.

Theta West #1 Well

At the Theta West #1 location, Pantheon targeted both the Upper and Lower BFF horizons. The well encountered ~1,160 gross feet of hydrocarbon-bearing reservoir across these horizons. During testing, three 10-foot intervals were perforated and stimulated, producing light oil (35.5° to 38.5° API). The average flow rate was >57bbl/d, with peak rates >100bbl/d during a 2.5-day test period. On the final day before shut-in due to severe weather, the well maintained an average flow rate of approximately 59bbl/d. These results confirmed the presence, quality, and mobility of light sweet crude oil, supporting Pantheon's pre-drill resource estimates.

The Theta West #1 well provides a valuable readthrough for Project Phoenix, confirming the presence of a large, oil-charged BFF system within the Brookian play. Although testing at Theta West was limited by surface equipment constraints and ice plug issues, it still demonstrated the presence of light oil and reservoir continuity over a broad area. This supports 88E's interpretation that the BFF extends into the Phoenix acreage with similar reservoir characteristics, bolstering confidence in both the prospectivity and scale of the target.

Alkaid-1 Well (2019):

Drilled in 2015 and flow-tested in 2019, the Alkaid-1 well encountered 50-80ft of net pay and confirmed the presence of light oil in the BFF (named Alkaid Horizon by Pantheon). The well flowed at 100bbl/d (with no artificial lift) of light oil of 40–42° API. Flow was through perforated casing, not through a fracture stimulation. The successful test provided early validation of the reservoir's potential and informed subsequent development plans. It was the first well to flow oil from the BFF in this part of the North Slope. This led Pantheon to book 76.5mmbbl of 2C contingent recoverable resource.

The Alkaid-1 well provides a constructive readthrough for Project Phoenix, having successfully tested light oil from BFF and encountered hydrocarbons in the SFS and SMD, though these were not flow tested. Prior to Alkaid-2, Alkaid-1 confirmed a working petroleum system, mobile hydrocarbons, and favourable reservoir properties across these zones, materially de-risking the play and reinforcing the potential for commercial resource development within 88E's acreage.

Alkaid-2H Well (2022–2024)

Alkaid-2H was drilled and tested to evaluate the Alkaid Zone (BFF) and the SMD reservoirs. The well had a 5,300ft lateral into the BFF and was stimulated with 30 frac stages and over 8mmlb of proppant. Initial testing in early 2023 yielded approximately 505bbl/d of liquid hydrocarbons (180bbl/d of oil and 325bbl/d of condensate and NGLs, along with 2.3mmcf/d of natural gas, but performance fell short of commercial expectations due to specific and avoidable wellbore complications - specifically poor fracture placement and elevated water cut. Also, the wellbore exited the optimal reservoir window, intersecting a localised gas cap, limiting productivity and increasing GORs to over 12,000 scf/bbl, suggesting significant gas breakout. Despite this, the test confirmed a working petroleum system and the presence of mobile hydrocarbons.

In 2024, Pantheon re-entered the well to analyse the SMD-B Western Topsets. This zone demonstrated substantially better reservoir properties, including fracture efficiency estimated around 50% and GORs between 3,000–4,000 scf/bbl, indicating improved drawdown management and lower gas liberation. These outcomes, combined with log-confirmed net pay and analogues to commercial North Slope fields, led Pantheon to prioritise the SMD Topsets for early development.

As detailed field development planning progressed, Pantheon determined that it would be technically unfeasible to reinject the produced natural gas back into the low-permeability BFF (Alkaid Horizon) at the volumes required for sustained production. Reinjection is essential to comply with regulatory flaring limits and maintain reservoir pressure.

As a result, the company shifted its focus to the Western Topsets in the Ahpun Field, which are interpreted to be part of the SMD system. These shallower reservoirs offer ~100x higher permeability than the BFF, making them far better suited to support both liquids production and gas reinjection, and enabling Pantheon to move forward with a more robust and scalable near-term development plan.

The Alkaid-2 well provides constructive validation for Project Phoenix, which targets the same Brookian reservoirs—BFF and SMD. While Alkaid-2's BFF flow test fell short of commercial expectations due to avoidable wellbore issues, it nonetheless confirmed light oil mobility and a functioning petroleum system. The identification of higher permeability and continuity in analogous SMD underscores the potential of this interval when optimally targeted. Given that 88E's Hickory-1 intersected oil shows and net pay in both the BFF and SMD, the Alkaid-2 results support the premise that—with improved completions and zone selection—Phoenix could deliver commercial production from these proven oil-bearing reservoirs.

Aphun-1 / Megrez

The Megrez-1 exploration well, drilled in late 2024 in the eastern SMD system of the Ahpun Field, encountered a substantial hydrocarbon column across seven stacked reservoirs, spanning over 2,400 feet vertically — all part of the Brookian topset and shelf-edge depositional system. While core and log data confirmed light oil saturations exceeding 50% in multiple zones, flow testing of the first three targets — Topset 1 (SMD-A), Lower Prince Creek (SMD-B), and Lower Sag 3 — failed to produce mobile oil to surface, despite high fluid rates in excess of 1,000–2,000bbl/d. The results are consistent with an oil-wet reservoir system, in which longer-term production-scale flow may be required to mobilise hydrocarbons.

Despite disappointing short-term flow results, Megrez-1 provided valuable technical confirmation of a large, oil-charged system in the eastern Ahpun SMD. The well validated Pantheon's pre-drill geological model, with indications of greater-than-expected reservoir thickness. However, due to the lack of mobile oil recovery, no contingent resources have yet been booked from Megrez-1.

Megrez-1 confirms the presence of a large, hydrocarbon-charged Brookian deltaic system, supporting the validity of the petroleum system underlying Project Phoenix. However, the lack of mobile oil flow from the SMD topsets at Megrez highlights potential deliverability and execution risk in shallow SMD intervals. In contrast, 88E's Hickory-1 well flowed light oil from the SMD-B, indicating that portions of the reservoir — particularly deeper or better developed sands — can support flow. For commercial success, 88E will need to demonstrate that its targeted SMD intervals offer sufficient permeability, continuity, and respond positively to modern completion techniques.

Dubhe-1

Pantheon's planned Dubhe-1 well, expected to spud in summer 2025, will target the Ahpun West Topsets, a high-permeability section of the Brookian Shelf Margin Delta (SMD-A/B) system. As a horizontal well designed for commercial demonstration, Dubhe-1 aims to prove the deliverability of oil at commercial rates without extensive stimulation. A successful outcome would validate not only Pantheon's development concept in the Ahpun field but also enhance confidence in the broader Brookian topset play across the North Slope.

For Project Phoenix, Dubhe-1 offers a critical read-across: both companies are targeting the same SMD system. Key watchpoints for Dubhe include: confirmation of high flow rates from the SMD-A/B topsets, validation of reservoir continuity, and implications for infrastructure-led development via the nearby TAPS corridor. Results are anticipated in Q3'25, and success would set a regional benchmark for commercial development of Brookian topsets, directly informing the viability and design strategy for 88E's future horizontal wells.

Pikka and Willow developments

Historical flow rates in Alaskan wells on Pikka and Willow

Well	Field	Test Duration (days)	Peak Rate (bopd)	End Rate (bopd)	Hole Angle (degs)	Completion	GOR (mcf/bbl)	Comment
Expl & Appraisal								
Qugruk-7	Pikka	3.29	520	150	23°	plug & perf		78.09 bbl oil recovered
Pikka B ST1	Pikka	2 + 4	(2 day clean up) 2,500 (4 day flow) 1,375	750	73°	1 stage frac	2,400	4 day flow: initial rate spike up to 1,375 bopd, average 750-800 bopd
Tinmiaq 6	Willow	10.00	(Average) 1537	n/a	Vertical	1 stage frac, 51,000 lbs proppant	1,089	
Pikka C ST1	Pikka	1.05	1,900	850	90°	6 stage frac	4,650	After 1 hr surge of 1,900 bopd , average rate ±850 bopd
Qugruk-8	Pikka	2.75	2,150	300	Vertical	1 stage frac, 80,000 lbs proppant	440	Multirate test
Putu 2A	Pikka	1.50	3,000	2,100	Vertical	2 stage frac	365	Clean up flow
Putu 2A	Pikka	8.00	3,000	750	Vertical	2 stage frac, tank farm		Flow, Build Up, Flow 8,500 bbl oil recovered
Tinmiaq 2	Willow	0.50	3,200 (vs 241 bopd average over 12 days?)	n/a	Vertical	1 stage frac, 104,000 lbs proppant	3,672	OGJ reports 12 hour test, Filing with DOG shows total 2,941 bbl oil recovered in 293 hour test
Qugruk-301	Pikka	17.63	4,000	1,600	90°	6 stage frac	317	Multirate test
Development								
NBD-043i	Pikka	n/a	4,110	n/a	90°	Water injection well		Santos Corporate Presentation
NBD-024	Pikka	n/a	4,180	n/a	90°	12 frac stages		Santos Corporate Presentation

Source: Pantheon Resources, Alaska Division of Oil & Gas, well files and company presentations

This is some key flow data showing the range of outcomes from 240 bpd (apparently average rate over a longer term test) to an initial transient rate of 4,000 bpd. Each test will have been influenced by the various factors noted above.

Charlie-1

The Charlie-1 well was an appraisal to test multiple stacked conventional Brookian prospects, evaluating three horizons within the Torok Formation (Upper Stellar, Middle Stellar, and Lower Stellar) with gross mean prospective resource of 639mmbbl. Additionally, the well aimed to test two horizons in the Schrader Bluff Formation with a gross mean prospective resource of 584mmbbl and two horizons in the Seabee Formation (Upper Lima and Lower Lima prospects) with a gross mean prospective resource of 376mmbbl. It was a step out to the historic Malguk-1 discovery well drilled by BP in 1991. The Charlie-1 well achieved an impressive outcome, with the announcement of a condensate discovery in the Torok Formation and oil pay interpreted in the Seabee Formation in April 2020.

Farmout agreement

Phase	Burgundy WI	88E WI	Note
Current	25%	75%	88E held majority interest prior to agreement
Phase 1	65%	35%	Burgundy earns 40% by funding US$22mm of 88E's share in the programme
Phase 2	75%	25%	Burgundy earns additional 10% by funding up to US$10mm gross
Phase 2 - Option	70%	30%	If 88E co-funds US$3.75mm (50% of the cost) in Phase 2, WI dilution is capped

Source: 88 Energy

88E currently holds 75% of Project Phoenix with Burgundy Xploration, a private Texas-based oil and gas company, who owns the balance and has invested US$26mm to date. On 17 February 2025, 88E announced it had entered binding terms for a Farmout Participation Agreement (PA) with Burgundy in relation to Project Phoenix. This agreement outlines a two-phase structure where Burgundy will fully fund upcoming work programs in exchange for up to an additional 50% Working Interest (WI). Upon completion of the PA, Burgundy will assume the role of operator.

The agreed terms result in a transaction value that represent an ~50% uplift of invested capital on 88E's share of Project Phoenix since mid-2022. Burgundy's commitment reflects recognition of the progress 88E has made since then in enhancing the value of the acreage, while also validating both the potential of the broader region and the opportunity on Alaska's North Slope. The PA including a long-stop date of 31 December 2025 for Burgundy to secure Phase 1 funding, unless extended by mutual consent. Burgundy is planning an IPO to raise the necessary funds and is progressing along that route having secured seed capital and appointed advisors.

Phase 1: Burgundy is to fund up to US$29mm of the 2025/26 work program (i.e. US$22mm of 88E's costs based on 75%). This includes lease payments, drilling a horizontal well and conducting an extended flow test in mid'26. Upon completion of Phase 1, 88E's WI will decrease to 35% (from a starting point of ~75%).

Phase 2: (Contingent on Phase 1 success) Burgundy is to fund up to US$10mm for an additional well or other capex. In return, Burgundy may earn an additional 10% WI, potentially increasing its total ownership to 75%, while 88E's WI could decrease to 25%. 88E retains an option to limit the earn-in and retain a 30% WI.

As part of the February 2025 PA agreement, Burgundy committed to settling the remaining balance of the outstanding cash calls. Burgundy paid US$1mm prior to signing the and settled the residual balance of US$2.2mm (including interest and fees) on 31 March 2025. This final payment was for the Hickory-1 flow test expenditure.

88E is negotiating with Burgundy for a joint venture while also running an independent farm-out process to monetise Project Phoenix. This dual strategy may attract additional parties. If Burgundy cannot raise the needed capital, 88E will seek non-dilutive financing through horizontal production testing and development planning. 88E aims to exit and fully monetise the project before development FID.

Development Strategy and Future Plans

Phoenix timeline

	H1-24	H2-24	H1-25	H2-25	H1-26	H2-26
Successful Hickory-1 flow test flows light crude oil to surface	✓					
Post-well analysis and updated Contingent Resource Estimate		✓				
Targeted farmout to de-risk and provide pathway to production test		■	■			
Farm-out program to secure funding for forward program		■	■	■		
Planning/permitting/design for horizontal production test[1]		■	■	■	■	
Extended horizontal production test[1]					■	■

Source: 88 Energy

The near-term development strategy for Project Phoenix centres around the drilling and flow-testing of a horizontal appraisal well from the existing Franklin Bluffs gravel pad, targeting the proven SMD-B interval. The SMD contains 35mmbbl of discovered (2C gross) resource or 111mmbbl of 3C resource. There is a further 158mmbbl of prospective resource in the SMD-A and SMD-C, which has a very high 81% geological chance of success. This horizontal well, expected to have ~3,500ft lateral, will undergo a comprehensive flowback test lasting ~90 days, scheduled to begin mid-2026. Experienced Alaskan service provider Fairweather LLC has been engaged to oversee planning, permitting, and operational execution, ensuring effective project delivery.

It is anticipated that these reservoirs will be developed from long horizontal production wells, which typically produce at multiples of between 6 to 12 times higher than vertical wells. For development wells using 7.5-10k ft laterals there is the potential to produce at 1,000 to 1,500bbl/d.

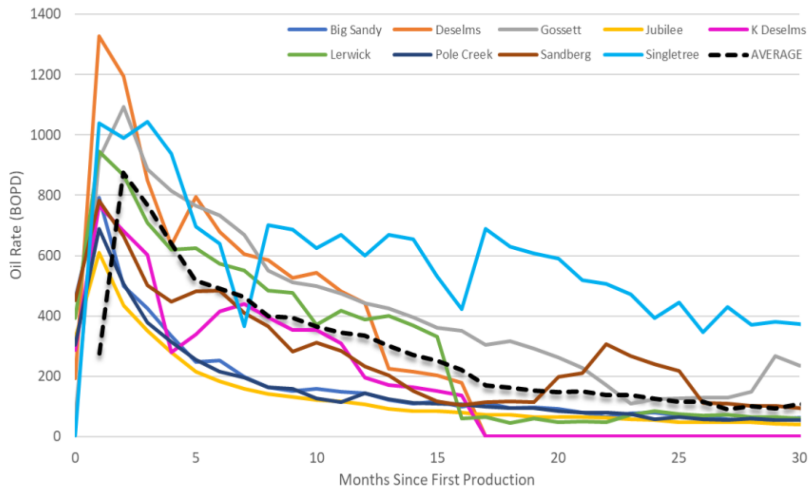
Codell Sandstone comparison to Project Phoenix

	Unit	CODELL SANDSTONE DJ BASIN	PROJECT PHOENIX NORTH SLOPE
Reservoir Properties			
Self-Sourced		No	**No/Minor**
Permeability	mD	0.004 - 0.1	**0.02 - 0.5**
Reservoir		Sandstone	**Sandstone**
Naturally Fractured		No	**No**
Gross Thickness	ft	30 - 100	**1,000-2,000**
Net Thickness	ft	20 - 45	**> 500**
Porosity	%	8 - 16	**7 - 14**
Water Saturation	%	30 - 50	**25 - 50**
Average Well Performance			
Initial Production Rate (Horizontal well IP30)	BOPD	500 - 1000	**Target 750- 1,500**
Expected Ultimate Recovery	MMBO	0.3 - 0.6	**Target 1 - 2**
Initial Decline Rate	%/year	60 - 75%	**Target 40 - 60%**
Horizontal to Vertical Well IP30 ratio		7 - 14	**Target 6 - 12**

Source: 88 Energy

The Codell Sandstone in the Northern DJ Basin, Wyoming and Colorado, is a key producing analogue for Project Phoenix. While many analogues exist, the Codell was identified as having the best data set available at a well level. The Codell serves as a benchmark illustrating that even with less favourable reservoir properties than those expected at Project Phoenix, profitable development is achievable, suggesting strong potential for higher performance and better economics at Phoenix due to its greater thickness and permeability giving the potential for higher IP30's, lower decline rates and considerably higher ultimate recoveries. With modern completions and optimal well orientations, Codell often achieves an IP30 of over 1,000bbl/d and EUR of more than 0.5mmbbl.

Average well production rates for Codell Sandstone Fields

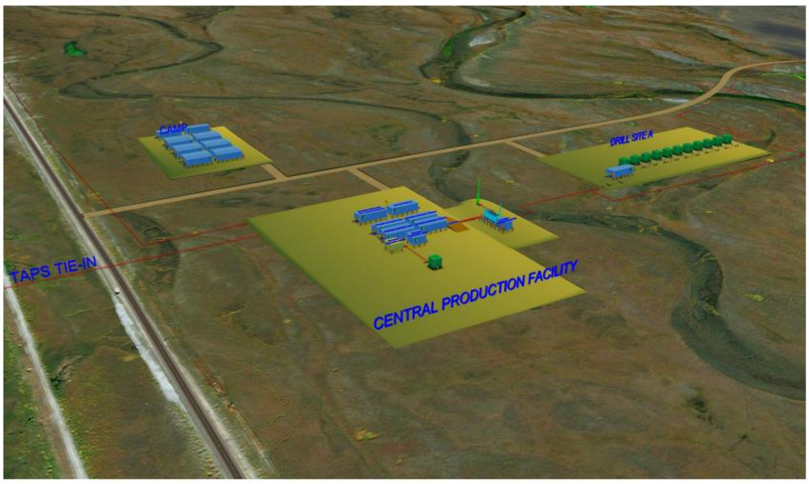


Source: 88 Energy

Early production system

Following the completion of a long-term horizontal well test, the objective is to confirm commerciality and support planning for a small, modular Early Production System (EPS) or pilot development. This would be aimed at demonstrating production capabilities across the acreage, while also generating early cash flows ahead of full field development. This will likely involve using the horizontal well that is being drilled in 2026 for the EWT being supplemented by another horizontal producer and potentially a disposal well. A modular facility could be put in place in 2027. It is envisioned as a capital-light modular system that leverages the Phoenix location adjacent to the Dalton Highway and Trans-Alaskan Pipeline System (TAPS) infrastructure. This will likely involve using the horizontal well that is being drilled in 2026 for the EWT being supplemented by another horizontal producer and potentially a disposal well. A modular facility could be put in place in 2027.

Pilot production system

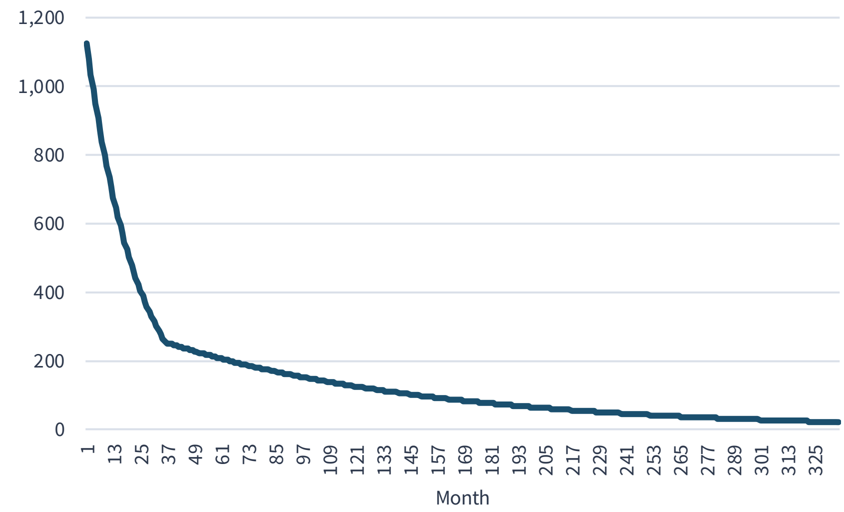


Source: 88 Energy

Full field development

We have modelled out a potential full field development plan for Phoenix to derive a valuation and look at some of the key metrics. We model all contingent and prospective resources at Project Phoenix within the full-field development plan. Phoenix has gross 2C contingent resources of 252mmbbl and 2U unrisked prospective resources of 239mmbbl. Our methodology involves modelling the 2C case separately and then combining the 2C and 2U cases, as prospective resources, if commercial, would be developed alongside the 2C resources. Both scenarios would commence after initial development demonstrates commercial production.

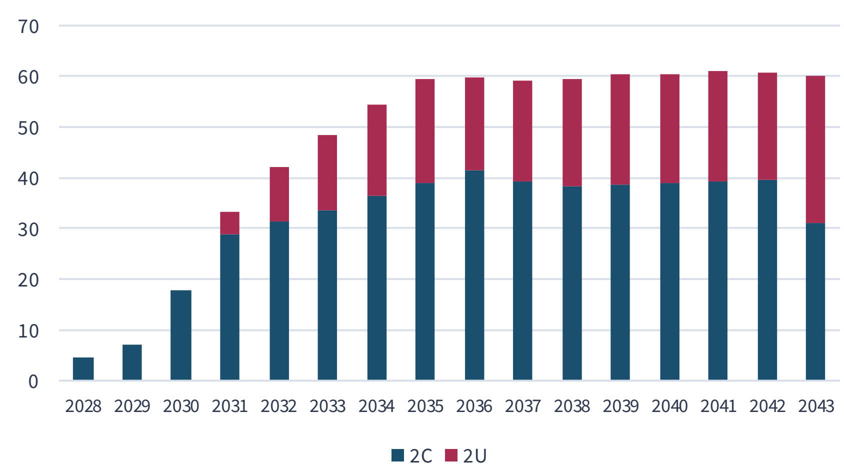
Production type curve (bbl/d)



Source: H&Pe

88E estimates the wells could achieve an IP30 rate between 750-1,500bbl/d; we assume an average rate of 1,125bbl/d in the first month and an EUR of 1.5mmbbl per well. An initial decline rate of ~40% per year is expected for the first three years, followed by a long-term annual decline of 10%. This translates to a first-year production rate of ~900bbl/d per well.

Gross 2C and 2U production (kbbl/d)



Source: H&P estimates

Contingent resources

To develop the 252mmbbl 2C resource, we assume drilling starts with 5 wells in 2028-2029, increases to 10 to 15 wells per year thereafter to a total of 180 wells over the life of the asset.

Our long-term Brent oil price assumption is US$70/bbl and we assume this is the price that 88E will sell for, with pipeline tariffs of US$5/bbl bringing the realised price down to US$65/bbl. Royalties are charged at 12.5% and an overriding royalty of 4% applies on Phoenix. We assume variable opex of US$3/bbl, while fixed opex is forecast at ~US$200k/year per well. This results in life of field opex of US$6/boe.

Drilling and completion (D&C) capex totals ~US$4bn over the asset life, comprising US$13mm per producing well and US$10mm per injector well (we assume 1 injector for every 10 producers is required). Facility costs, pipelines, and other development capex amount to US$730mm over ten years, totalling a gross capex of US$3.2bn (~US$800mm net to 88E). Over the life of the field this is a development cost of US$13/bbl of resource.

There are several taxes that apply in Alaska. The fiscal regime includes:

- Surcharges: US$0.05/bbl of gross production.

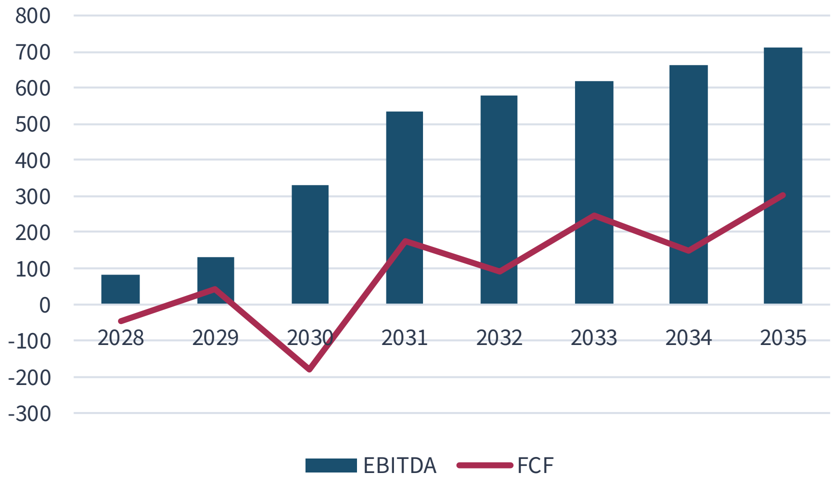
- Property tax: ~2% on cumulative depreciable tangible capex; drilling capex depreciates at 15%, non-drilling capex at 100%.

- Production tax: Production tax is calculated on the net revenue post royalty and deductions. There is also a benefit given in the form of credits for the changes in oil prices. Realised oil prices below US$80/bbl receive a US$8/bbl credit. A production tax of 35% applies while it a minimum tax of 4% is applied in years when there are excess credits/heavy capex which allows for higher deductions.

- State tax: The state tax is charged at 9.4% on a separately calculated tax base and begins in 2028. The tax is base is calculated by taking the EBITDA less all the taxes mentioned above and then less the tangible and intangible depreciable capex.

- Federal tax: Similar to the state tax, it is charged at 21% on a separately calculated tax base and begins in 2028. In addition to the tax base of the state tax, the amount of state tax is also deducted from the EBITDA to reach the federal tax base.

Gross EBITDA and FCF from 2028 to 2035 (US$mm)



Source: H&Pe

For the development of just the contingent resource, our scoping economics suggest a gross NPV10 of US$4.4/bbl or US$1.1bn (US$280mm net to 88E at 25%) and an IRR of 38% at US$70/bbl Brent price. We see an oil price break-even at a 10% discount rate at <US$40/bbl Brent. The key assumptions are total development costs of US$13/bbl and operating costs of US$6/bbl. Production should be able to reach 40kbbl/d by 2035 generating >US$700mm of EBITDA and >US$300mm of FCF.

Sensitivity of net unrisked NPV (US$mm) to the oil price and discount rate

		Oil price (US$/bbl)				
		50	60	70	80	90
Discount rate (%)	8%	163	270	370	466	560
	9%	136	232	322	408	493
	10%	112	200	**281**	359	436
	11%	92	172	245	316	386
	12%	75	148	215	279	342

Source: H&Pe

Sensitivity of net unrisked NPV (US$mm) to the oil price and capex per well

		Oil price (US$/bbl)				
		50	60	70	80	90
Capex per well (US$mm)	11	140	225	306	384	457
	12	126	213	293	371	446
	13	112	200	**281**	359	436
	14	98	186	268	347	425
	15	83	172	255	335	412

Source: H&Pe

Sensitivity of the project's IRR to the oil price and capex per well

		Oil price (US$/bbl)				
		50	60	70	80	90
Capex per well (US$mm)	11	24%	33%	42%	50%	57%
	12	22%	32%	40%	48%	55%
	13	21%	30%	38%	46%	54%
	14	19%	28%	36%	44%	52%
	15	18%	26%	34%	43%	50%

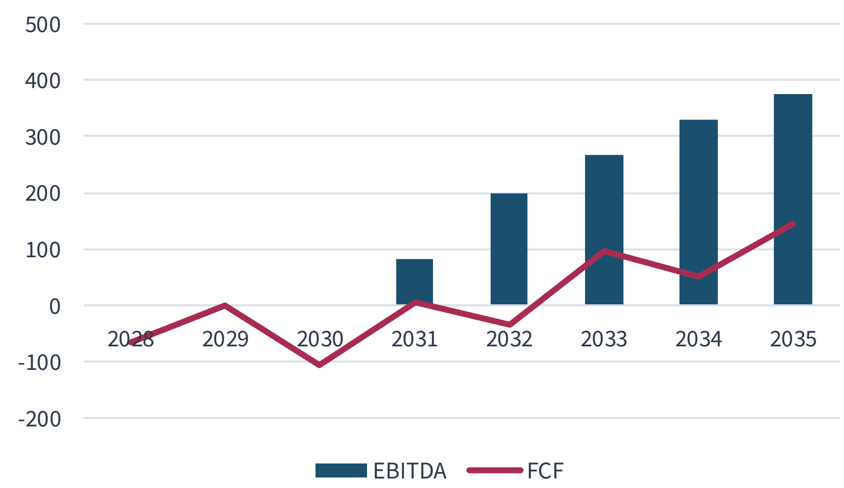
Source: H&Pe

Prospective resources

We model combined development of the 241mmbbl 2U prospective and 252mmbbl 2C contingent resources, totalling 493mmbbl. This scenario requires ~380 wells, beginning with 5 wells in 2028-209, and between 20-25 annually until 2046.

All other assumptions remain consistent with the 2C development case: oil price, pipeline tariffs, royalties, fiscal terms, variable opex, capex, abandonment. We estimate EBITDA at US$83mm in 2028, surpassing US$1bn by 2035.

Gross EBITDA and FCF from 2028 to 2035 (US$mm)

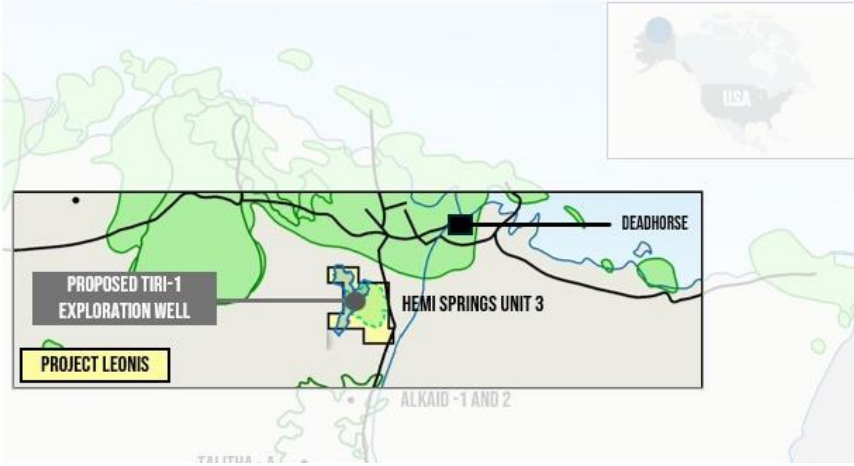


Source: H&Pe

For the development of the contingent and prospective resources, our scoping economics suggest a gross NPV10 of US$3.6/bbl or US$1.8bn (~US$450mm net to 88E at 25%) and an IRR of 35% at US$70/bbl Brent price. Production should be able to reach 60kbbl/d by 2040 generating >US$1bn of EBITDA and >US$400mm of FCF.

Project Leonis

Project Leonis acreage



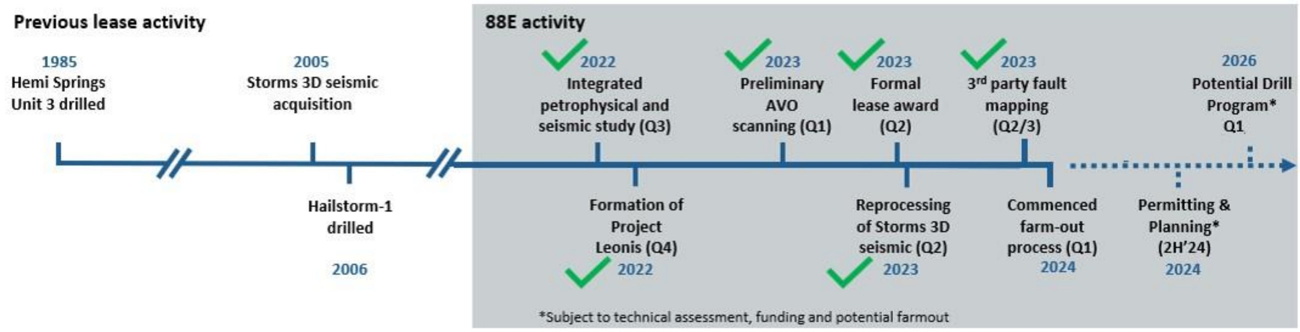
Source: 88 Energy

Project Leonis is strategically located on the North Slope, comprising 36k acres (100% working interest) over 14 leases with ~800mmbbl of gross mean unrisked prospective resource with an ~33% geological chance of success. An initial 26k acres were acquired when 88E was declared the highest bidder for ten leases in November 2022. In December 2024, 88E expanded Leonis through the award of four additional leases. Leonis stands out for its strategic location close to the Trans-Alaskan Pipeline System ("TAPS") and the all-weather Dalton Highway, two critical pieces of infrastructure that could fast-track commercial development. Leonis targets conventional stacked reservoirs in both the Upper Schrader Bluff ("USB") and the deeper Canning Formation, offering multiple shots at a substantial oil discovery.

This is a classic case of applying modern techniques and technology to legacy data to spot previously missed oil and gas reserves. This has been highly successful on the North Slope with discoveries from Oil Search (now Santos), Repsol, Armstrong and ConocoPhillips. Historical data from the Hemi Springs Unit 3 (HSU-3) well (within 88E's acreage), drilled in 1985, provides valuable insights. This well targeted deeper reservoirs without the benefit of modern seismic data, potentially overlooking shallower pay. Re-evaluation of petrophysical data has since identified net oil pay within the USB (>200ft of net pay) and oil saturations within Canning Formations in this well. The oil shows observed in the HSU-3 mud log correlate with extensive areal mapped potential.

88E is actively pursuing a farm-out partner to fund the drilling of the Tiri-1 exploration well, currently anticipated in H1'26. 88E intends to secure a large proportionate carry on any future well due to its 100% working interest. Llamas and Bannister Energy Advisors Ltd ("LAB") were appointed to manage an active, relaunched and expanded farm-out process. An exploration well is expected to cost US$16mm.

Exploration history and development plan

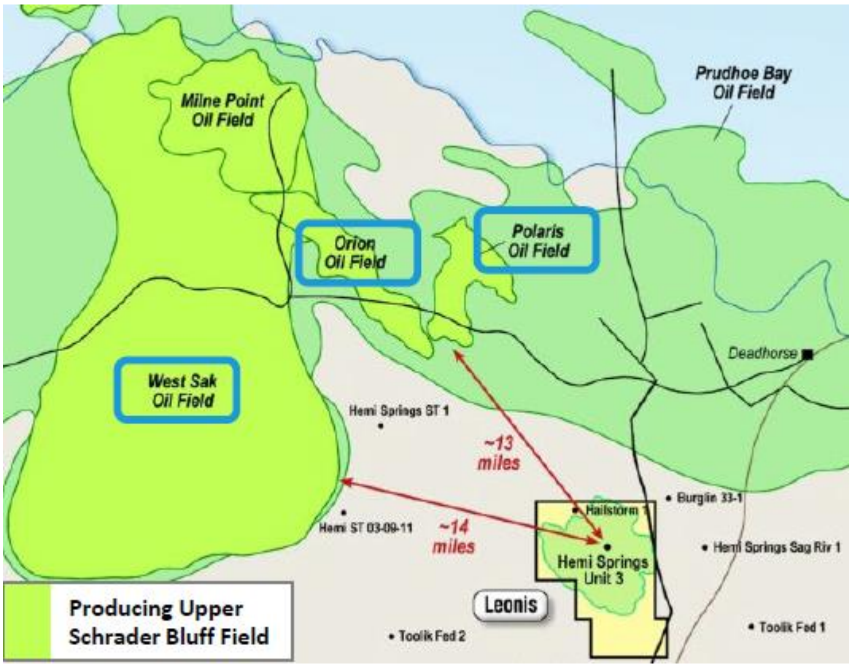


Source: 88 Energy

88E is leveraging the reprocessed Storms 3D seismic data, to refine exploration targets and identify optimal drilling locations within both the USB and Canning prospects. 88E has engaged Fairweather to initiate planning and permitting of the Tiri-1 exploration well to target both the USB and Canning reservoir zones at an optimal location. By targeting two stacked plays in a single campaign, the company aims to maximise geological information while minimising incremental costs. It will be drilled from the existing gravel pad at the Hemi Springs Unit-3 well to reduce drilling costs. If Tiri-1 demonstrates commercial flow rates an extended production test would likely follow to confirm well deliverability, reservoir continuity, and fluid characteristics at scale.

De-risking of prospectivity by new technology

Project Leonis area map

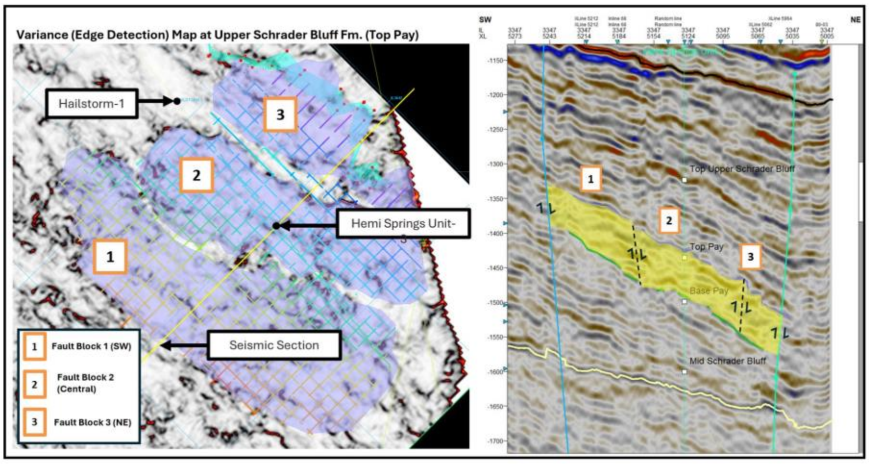


Source: 88 Energy

Project Leonis lies just south of Alaska's giant Prudhoe Bay oil fields, in an area historically overlooked despite clear geological potential. A re-interpretation of seismic data and well logs has uncovered two material exploration prospects in the USB and Canning formations, which can be targeted with one exploration well.

HSU-3 well was drilled in 1985 before the acquisition of modern 3D seismic data, specifically the Storms 3D seismic in 2005, which has allowed for a re-evaluation of the area's potential. Hydrocarbon signatures in AVO and Inversion from this modern seismic correspond to live oil shows in HSU-3 at both the Canning and USB Prospects. Re-examination of mud logs from Hemi Springs Unit 3 noted "oil over shakers" and "streaming cut" in both the USB and Canning intervals.

Zone of interest (USB Fm.) at the Hemi Springs Unit-3 well (green) and the Hailstorms-1 (blue) wells. Reprocessed 2005 Storms 3D.

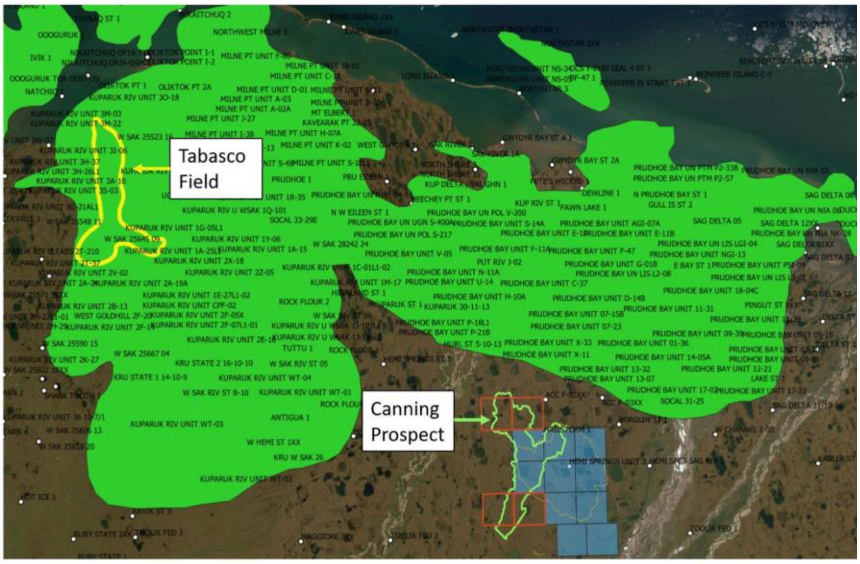


Source: 88 Energy

Hannam&Partners

The USB Formation, encountered in HSU-3, is a known producing reservoir in adjacent fields such as Polaris, Orion, and West Sak. Seismic analysis suggests the USB in Leonis is geologically isolated from previous wells, opening up a fresh, undrilled extension of this productive unit. Further support comes from the Hailstorm-1 well, drilled in 2006, which provided an additional calibration point. Reinterpretation of legacy data across both wells revealed over 200 feet of net pay in the USB and confirmed a second target within the deeper Canning zone, strongly analogous to the Tabasco field.

ConocoPhillips' Tabasco field, 23 miles north-west of Project Leonis.



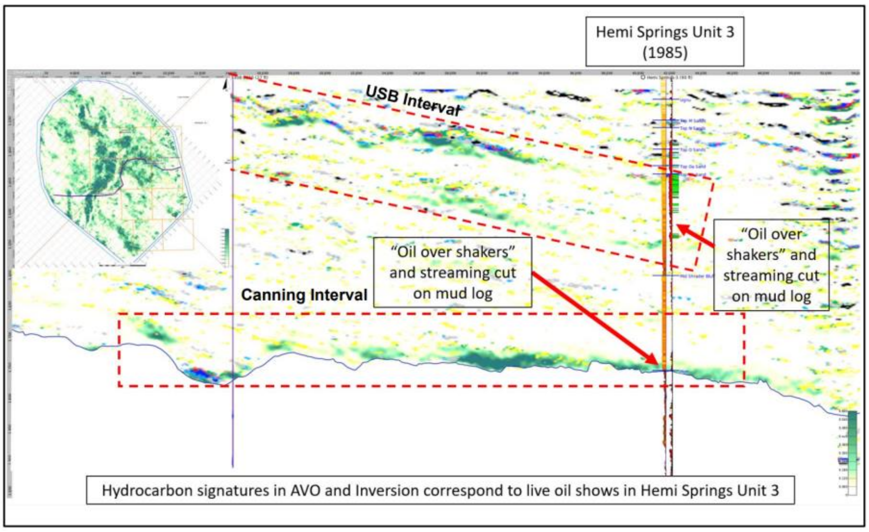
Source: 88 Energy

The acreage contains a major canyon-like feature in the Hue Shale formed by Mid-Campanian erosion, later filled by thick, oil-bearing turbidites up to 336 feet thick and covering approximately 43 km^2. These structures resemble proven producing systems nearby, including ConocoPhillips' Tabasco field just 23 miles to the northwest.

The Canning Prospect remains untested but has been de-risked by the historic HSU-3 well. Although that well targeted deeper zones in the Kuparuk and Ivishak formations, it encountered oil shows and high porosity (up to 28%) in shallower sections—the very intervals now being targeted. At the time, modern 3D seismic data such as the 2005 Storms survey was unavailable, which meant these upper formations were not properly evaluated.

Modern understanding of low-resistivity pay has already led to significant new discoveries across Alaska's North Slope, including Willow, Pikka, and 88E's own Hickory-1 well. Project Leonis follows this same model, integrating historical well data with modern seismic and petrophysics.

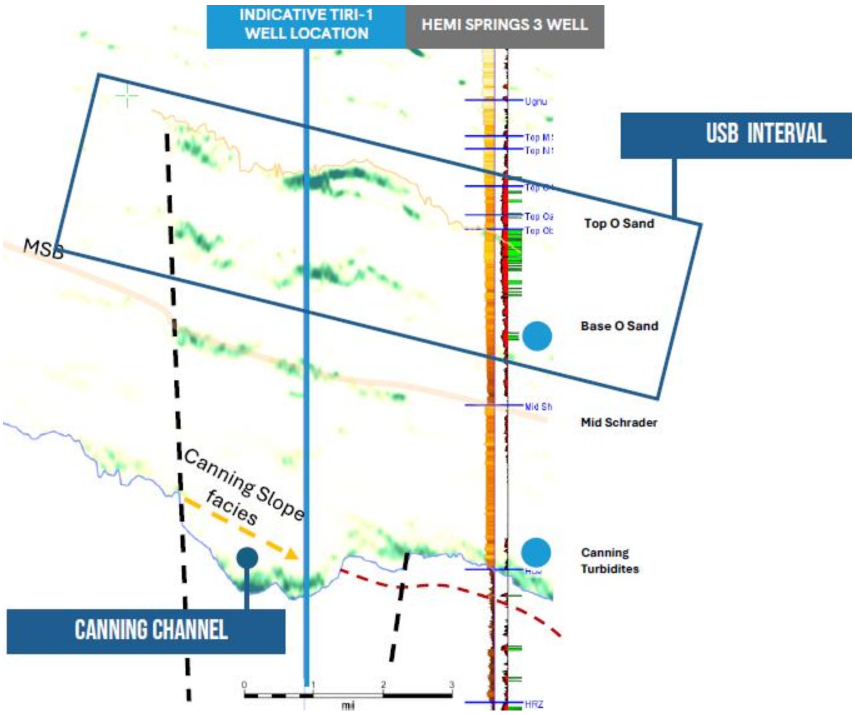
Hydrocarbon signatures in AVO and Inversion correspond to live oil shows in Hemi Springs Unit 3 at both the Canning Prospect and the USB Prospect



Source: 88 Energy

A comprehensive QI study, completed in early 2025, confirmed considerable amplitude anomalies across both targets—highlighting "sweet spots" in both the USB and Canning prospects. These data underpin the strategy to drill the Tiri-1 well, which will test both formations simultaneously. The reprocessed seismic data, calibrated against legacy well logs, has enabled 88E to validate the regional continuity of producing horizons and to more precisely delineate prospective drilling targets. This comprehensive dataset now underpins the company's strategy to drill the Tiri-1 exploration well, designed to simultaneously test the USB and Canning intervals.

Hydrocarbon signatures in AVO and Inversion correspond to live oil shows in Hemi Springs Unit 3 at both the Canning Prospect and the USB Prospect



Source: 88 Energy

Resource potential

88E's targeted formations

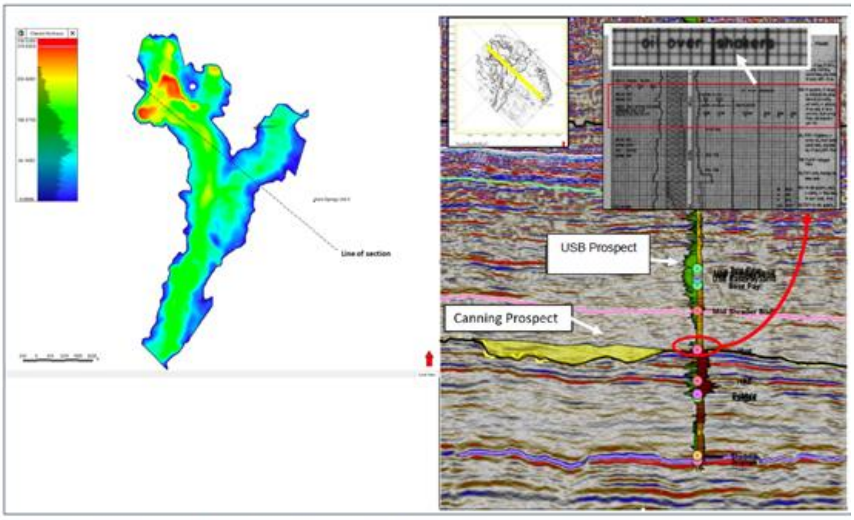


Figure 3: Seismic cross-section highlighting new Canning Formation reservoir and noted live oil over shakers at corresponding interval within this formation at the Hemi-Springs #3 well log.

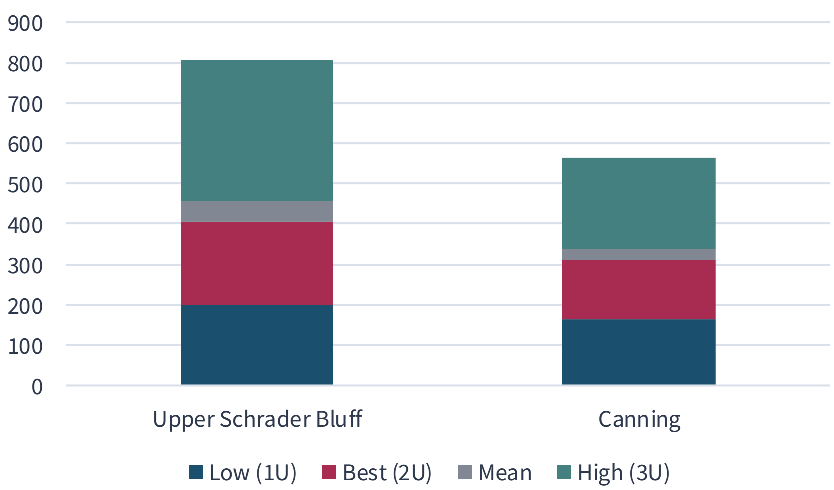
Source: 88 Energy

Leonis has prospective resource spread over two reservoirs. The maiden internal estimates announced in June 2024 allocated a gross mean prospective resource of 458mmbbl for the USB formation. In January 2025, the company revealed an additional gross mean prospective resource of 340mmbbl in the Canning Formation, bringing Leonis' total gross mean prospective resource to 798mmbbl. The geological chance of success is 32% and 33% for the USB and Canning respectively.

Management has indicated that older well tests at HSU-3 validate moveable hydrocarbons in the Schrader Bluff reservoir, although further drilling is needed to formally shift volumes from 'prospective' into the 'contingent' resource category.

The Project Leonis leases have a ten-year term and the original 10 leases expire on 30 April 2033. The four new leases expire 10 years from the award date, in 2035.

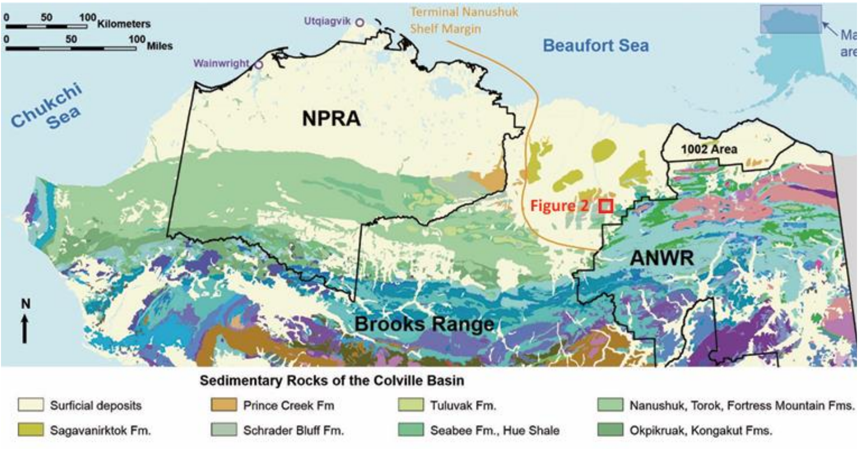
Project Leonis prospective resource (mmbbl)



Source: 88 Energy

Upper Schrader Bluff

Regional geological map of northern Alaska



Source: Alaska Division of Geological & Geophysical Surveys

The Schrader Bluff Formation is a sequence of rock layers located in northern Alaska, particularly on the North Slope region. It was deposited during the Late Cretaceous period, though different parts of Schrader Bluff can date to different stages within that window. The Upper Schrader Bluff portion ("USB") specifically refers to the higher (younger) layers within the overall Schrader Bluff Formation.

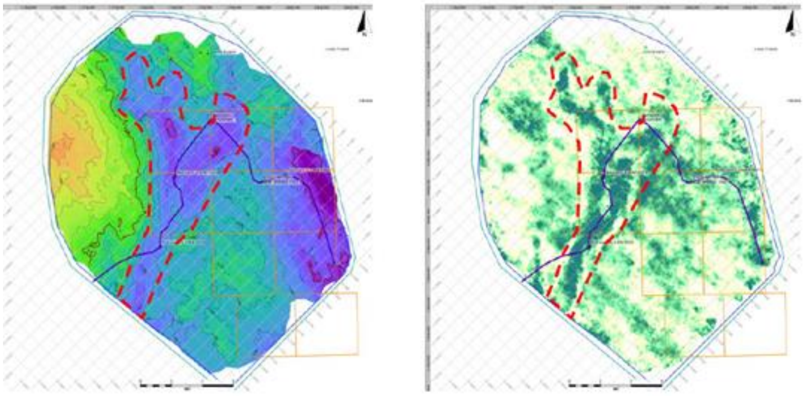
A sequence is a series of sedimentary rocks that were laid down over a certain broad period and share a common depositional history. The USB is part of the Brookian sequence on the Alaskan North Slope, which spans a large part of the Cretaceous to Tertiary periods. The USB sits nearer the top of this sequence, meaning it was deposited relatively late in Brookian time.

The USB contains several types of rock that each tell a story about how the environment shifted from deeper waters to shallower coastal areas over time. For example, shale often forms in quieter, deeper settings where mud settles out of the water. As conditions become shallower, one can see siltstones and then coarser sandstones. This stacking pattern, known as a coarsening-upward sequence, is a crucial clue to geologists that the sea was becoming shallower, or the shoreline was moving outward as new sediments arrived. Such sandstone layers can become excellent reservoirs, since their larger grain size creates small spaces (pores) where hydrocarbons can collect and be stored. Meanwhile, the finer mudstones can act as seals, preventing oil and gas from escaping, which is key for building up commercially viable accumulations.

Because the USB Formation formed in a marine shelf environment influenced by deltas, you can think of loads of sediment arriving from rivers and piling up along the coast. This setting is ideal for building thick stacks of sand, silt, and mud. Each type of sediment plays its part in hydrocarbon exploration: a thick sandy bed might mean easier drilling and potentially higher flow rates if the sand is well-connected, while abundant mud can either help trap hydrocarbons below or, if too thick, can make it more challenging to reach deeper layers.

Canning Formation

Canning Prospect



Source: 88 Energy

The Canning Formation is located on Alaska's North Slope, primarily within the Colville Foreland Basin and along the northern Chukchi Shelf. It is regarded as a "toe-of-slope turbidite" sequence, meaning that the sediments within it were laid down in deeper water environments by gravity flows unlike the parasequencing in the USB. These turbidites can be highly porous and laterally extensive making them excellent targets for oil accumulation.

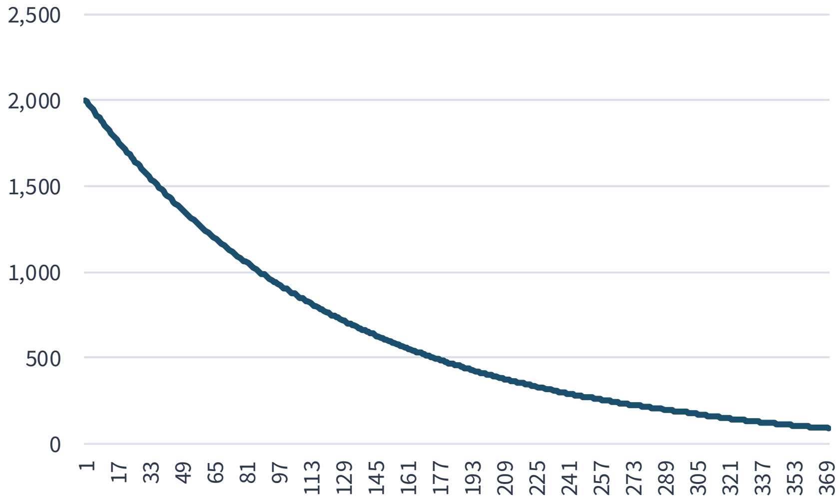
In the image above shows the Two-Way Travel Time ("TWT") on the LHS and probability of hydrocarbons on the from inversion on the RHS at the Canning Prospects. The canyon incision identified corresponds strongly with inversion derived hydrocarbon probability. This means that the deep channel-like feature in the subsurface lines up closely with areas where seismic analysis suggests there is a high chance of oil being present.

The thick reservoir succession is considered a product of basin-wide erosion during the Mid-Campanian period, creating channels or valleys in the underlying Hue Shale. This "accommodation space" (an area that can receive and hold sediments) allowed these high-energy flows to deposit big volumes of sand. Such thick, continuous sand layers can make drilling easier by providing a more uniform reservoir to target; plus, a higher net-to-gross ratio (the proportion of reservoir-quality rock compared to the total thickness) typically means better odds of producing oil profitably.

Development plan

Project Leonis holds prospective resources in the Canning and USB prospects, with 2U estimates of 406mmbbl and 311mmbbl, respectively. As Leonis is an early-stage exploration asset, our valuation approach uses a working model applying a US$/bbl NPV to these prospective resource estimates.

Production type curve (bbl/d)



Source: H&Pe

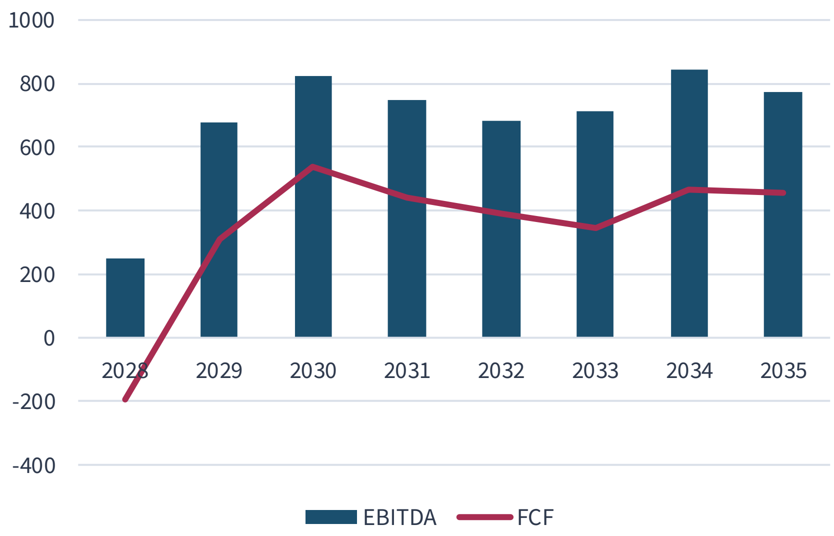
We forecast an initial production (IP) rate of 2,000bbl/d commencing in 2026, followed by an annual decline of ~10%. Full-field development would require 64 producing wells and 6 injectors, with each well estimated to deliver an EUR of 5.8mmbbl.

Our regional and macro assumptions remain consistent with those outlined for Project Phoenix on pg. 26: oil price, pipeline tariffs, and taxes under the fiscal regime.

Operating costs include fixed opex of US$200k per well annually, and a variable opex of US$3/bbl. This results in EBITDA of US$250mm in 2028, rising to between US$600–800mm annually from 2029 onwards.

Total life-of-project capex is estimated at approximately US$1.4bn, predominantly driven by drilling expenditures. Producing wells are budgeted at US$15mm per well, while injectors are estimated at US$10mm each, together totalling ~US$1bn in drilling and completion (D&C) costs. Additional expenditures include pipelines (~US$100mm over 2 years), facilities and maintenance (~US$70mm over 6 years), and other downstream development capex (~US$233mm). This equates to an overall capex of US$1.4bn or US$3.8/bbl. Abandonment costs are estimated at US$55mm towards the end of the licence period in 2055.

EBITDA and FCF from 2028 to 2035 (US$mm)



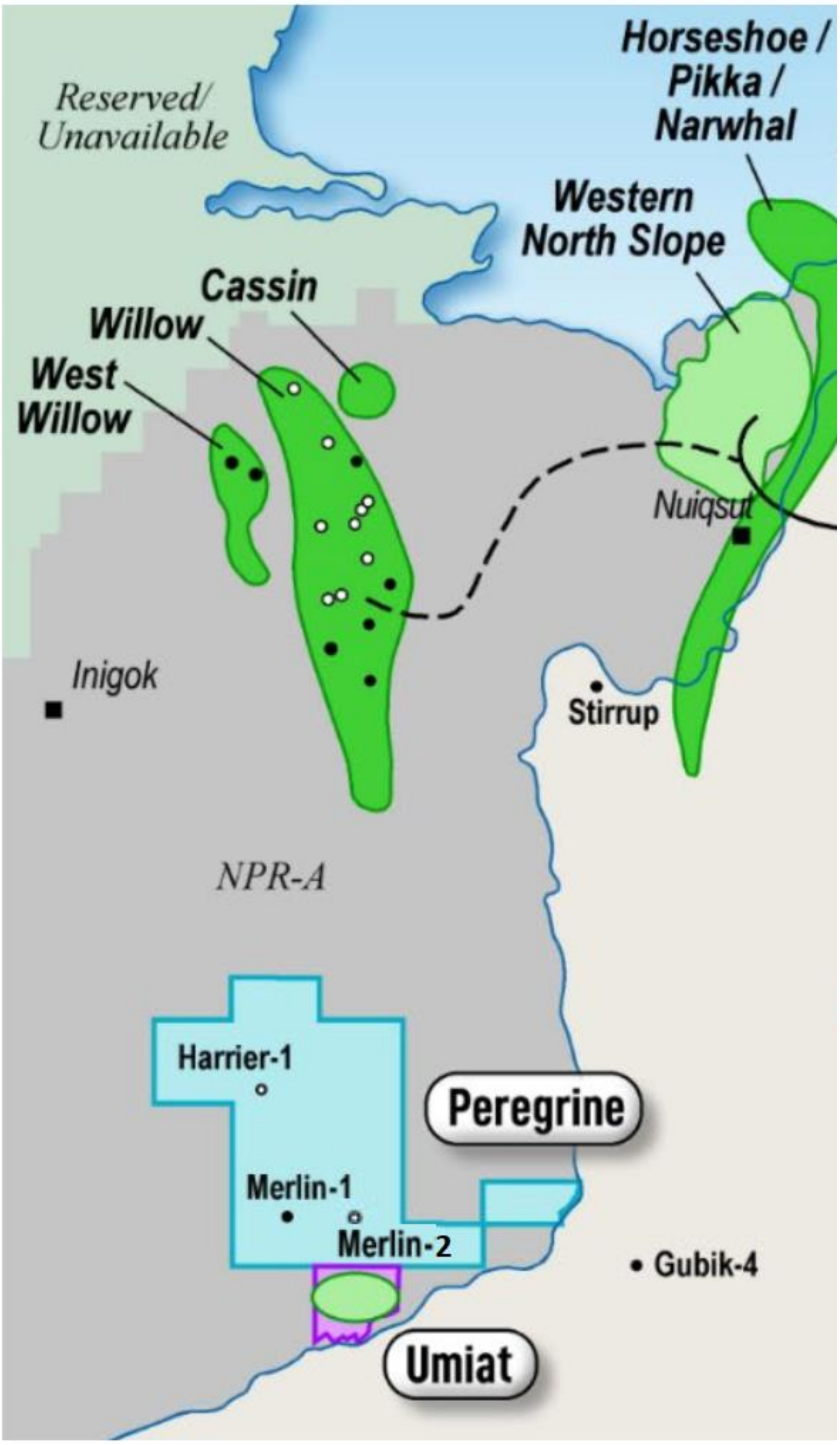
Source: H&Pe

Positive FCF generation begins by 2029 at US$311mm, increasing to US$400–500mm annually from 2030. At a 10% discount rate, this implies an unrisked NPV of US$2.6bn, equivalent to US$7.1/bbl, generating a project IRR of 88%.

Applying this US$7.1/bbl NPV, the Canning prospect's 2U estimate of 406mmbbl results in an unrisked NAV of US$2.9bn, while the USB's 311mmbbl yields US$2.2bn. Collectively, should both prospects prove commercial, they represent a combined unrisked NAV exceeding US$5bn.

Project Peregrine and Umiat

Project Peregrine and Umiat map



Source: 88 Energy

88E has secured suspensions from the Bureau of Land Management Alaska (BLM) for its Project Peregrine and Umiat Unit leases, following regulatory changes proposed prior to the Trump administration. The suspension for Project Peregrine has been extended to 30 November 2025, while the Umiat Unit is suspended until 30 June 2025. These suspensions relieve the company of approximately A$0.6 million in lease rental obligations for calendar year 2025 and enable it to focus on advancing its strategically located assets near existing infrastructure, which is expected to support faster commercialisation. Project Peregrine, alongside Umiat, holds the potential to anchor a future large-scale development hub in this emerging western North Slope play.

Peregrine

Project Peregrine is a high-impact exploration project located within the National Petroleum Reserve–Alaska (NPRA) on the North Slope. Operated by 88E with a 100% working interest, the project spans approximately 125,735 acres, strategically positioned between ConocoPhillips' Willow development to the north and the Umiat oil field to the south.

The acreage sits within a proven petroleum province, with multiple independent, drill-ready prospects targeting the Nanushuk and Torok formations. Seismic data and geochemical analyses have confirmed the presence of a working petroleum system, including high-quality Hue/HRZ shale source rocks, oil-prone characteristics, and evidence of hydrocarbons from sidewall core and mud gas analysis. The primary targets include the Merlin and Harrier prospects.

Exploration activity to date includes the Merlin-1 well, drilled in Q1'21, which demonstrated the presence of oil across multiple stacked targets and confirmed key geological parameters. The Merlin-2 appraisal well followed in 2022, validating the petroleum system but encountering low permeability reservoirs, with no hydrocarbons recovered for flow testing.

Post-well analysis has since focused on understanding reservoir quality and refining future drilling plans. The company has identified new targets (N12 and N13) and continues to progress towards future drilling at Harrier-1 and Merlin-1A. A farm-out process is underway to secure funding and a strategic partner for future appraisal, with low-cost dual-well drilling options being evaluated.

Umiat

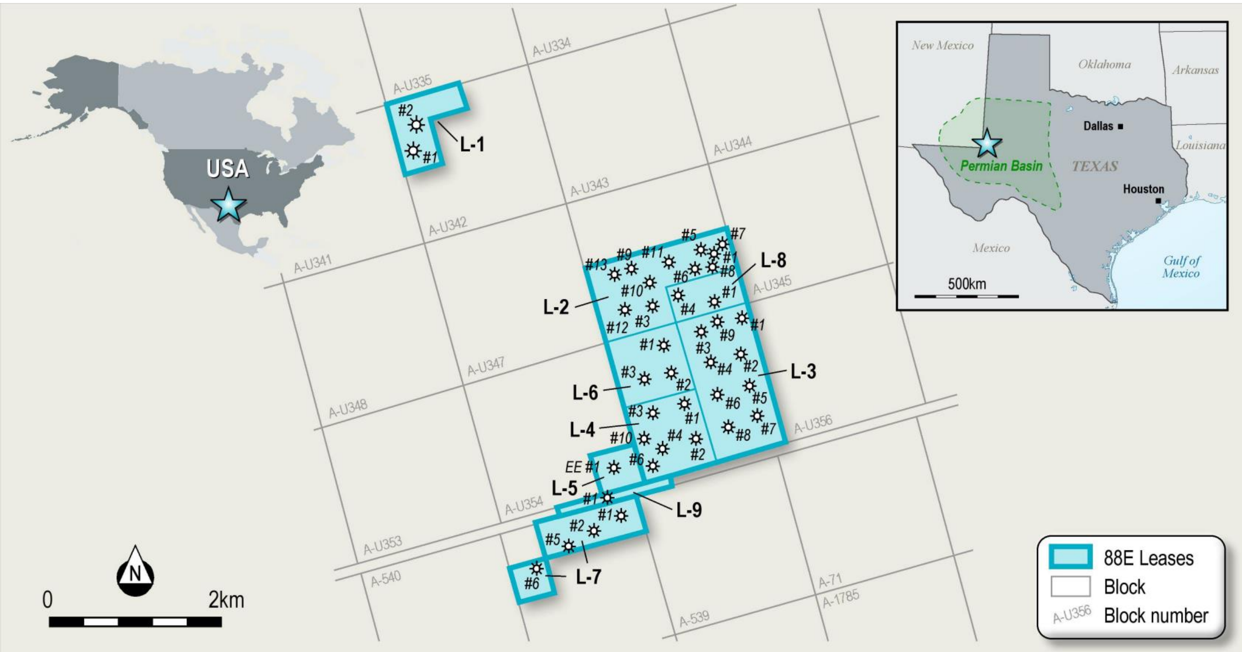
Project Umiat is a historic, shallow oil discovery located on Alaska's North Slope, directly south of 88E's Project Peregrine. Acquired in early 2021, 88E holds a 100% working interest and operatorship over ~18,000 net acres. The field was originally discovered in 1945 and later appraised by Linc Energy in 2014 with the Umiat-23H well, which flowed at rates of up to 800bbl/d of oil, sustaining 200bbl/d with no water cut. However, follow-up analysis suggested this well underperformed due to suboptimal drilling and completion practices.

Umiat holds independently certified 2P reserves of > 94mmbbl of oil and 3P reserves of a further 43mmbbl, although no 1P reserves have been assigned due to the absence of an approved development plan. Technical work by 88E, including reinterpretation of modern 3D seismic and AVO analysis, has identified new untested reservoir potential in both the hanging wall and footwall of the Umiat structure, with initial internal volumetrics indicating additional multi-million-barrel upside.

A 12-month suspension of lease obligations was granted through to June 2025, providing regulatory clarity and allowing the company to advance technical and commercial evaluations without lease cost pressures.

Project Longhorn

Project Longhorn (original lease position from 2022)



Source: 88 Energy

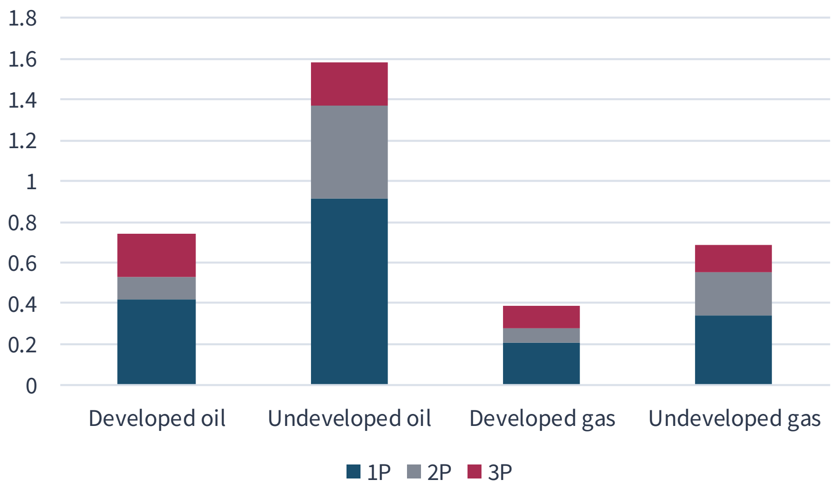
88E's Project Longhorn (in which it has a ~70% working interest pre-royalty), located in the prolific Permian Basin across Andrews and Ector Counties, Texas, is a core producing asset underpinning the company's cash flow base. The Bighorn Joint Venture (JV) comprises 88E and the operator, Lonestar I, which also owns ~0.5% of 88E's shares. Project Longhorn is a strategically important asset within 88E's diversified portfolio. It provides essential cash flow that supports high-impact exploration efforts, including lease payments and studies related to its Alaska and Namibian positions. The asset continues to offer attractive reinvestment options through low-capex, quick-payback workovers and infill development as well as potential complementary bolt-on acquisitions in the region. For 2025, we estimate gross production of 330boe/d, generating around US$3mm of EBITDA net to 88E. We believe the combination of stable production, active development, and positive cash yield positions Longhorn as a robust foundation for 88E's broader growth ambitions.

Acquired in February 2022, for US$10mm (US$5/boe of 2P), this conventional onshore asset delivers stable oil and gas production and has become a vital contributor to the company's financial flexibility. The project was initially secured with ~1,300 net acres (producing 300boe/d) and has since grown substantially through targeted acquisitions to 2,830 net acres with an average net working interest of ~64%. 88E targeted development IRRs: 75% to 400% depending on the type of drilling or work-over and an oil price break-even of US$21-28/bbl. The asset includes ~50 producing wells and net 2P reserves are 1.4mmboe (70% oil). Prior to commencing the 2024 development program, the Bighorn JV also executed a strategic ~10% (gross) sell-down of its 2023 acreage, netting ~A$0.3mm for 88E and securing a 25% carry on the workover costs from the new non-operated partners.

Overall, we estimate a value of ~US$7mm for the assets net to 88E (equivalent to 37% of 88E's market cap) using reasonable read-across multiples for US onshore assets. Based on 1.4mmboe of 2P reserves and US$5/boe valuation implies US$7mm of value. Based on net production of ~200boe/d and a US$40k per boe/d implies a valuation of US$8mm. Assuming US$2mm of EBITDA and a 4x multiple also implies US$8mm. Our bottom up NAV valuation of the proved developed producing (PDP) assets on a 2P basis is US$7mm at a 10% discount rate. The carrying value of the assets are A$22mm which is the equivalent of US$14mm.

Production performance has been consistent, averaging between 390–450boe/d gross in 2024 (~65% oil). The sales point for gas is upstream of the purchaser's processing facilities, thus NGL's and condensates are included in the gas stream. In 2024, the JV agreed on a five-well workover program. Four of the five workovers were completed successfully and within budget. The fifth encountered an unexpected tubing fish and was subsequently plugged and abandoned, with capital exposure capped at A$0.5mm versus a budget of A$1.2mm. This disciplined execution helped ensure Project Longhorn continued to generate strong post-workover cash flows, resulting in ~A$2.3mm in cash distributions to 88E in 2024.

Project Longhorn gross reserves, mmboe



Source: 88 Energy

The conventional oil and gas play in the Permian Basin, particularly across Andrews and Ector Counties in West Texas, is characterised by mature, low-risk reservoirs with long-established production histories. Unlike the more recent wave of horizontal shale drilling in unconventional plays like the Wolfcamp and Spraberry, the conventional development in this region targets shallower, vertically drilled reservoirs such as the San Andres, Clearfork, Glorieta, and Grayburg formations. These carbonate and sandstone reservoirs are typically found at depths of 3,000–7,000 feet and have been producing since the mid-20th century. They offer predictable decline profiles, stable oil cuts (often 60–70% oil), and are well-suited to optimisation through recompletions, workovers, and low-capex infill drilling.

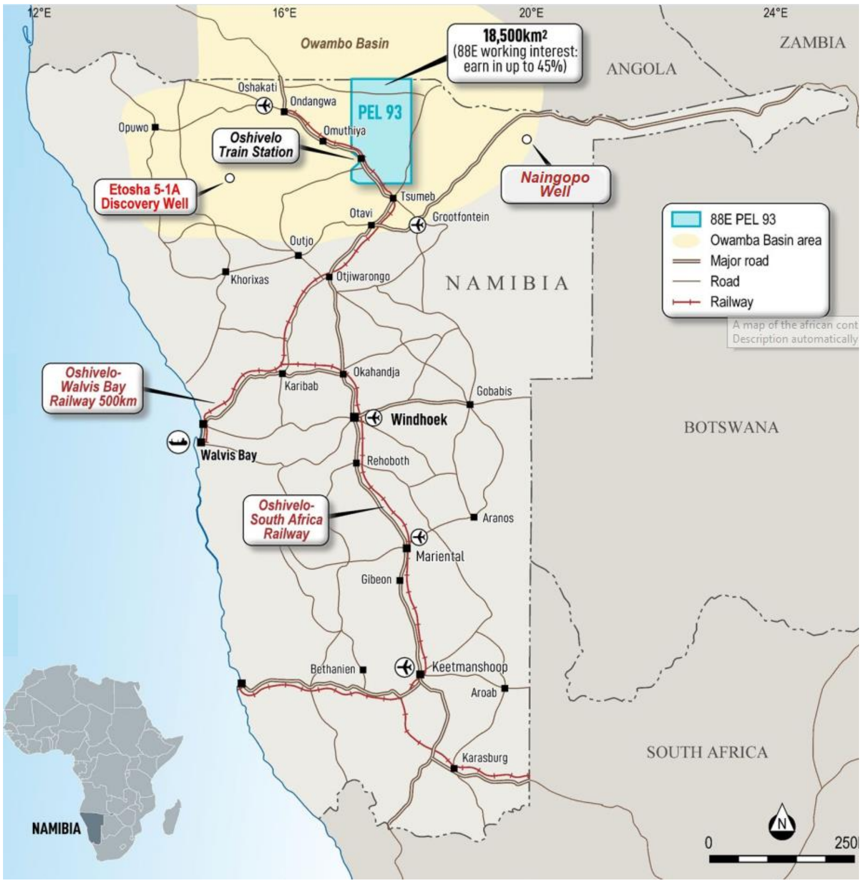
Infrastructure in Andrews and Ector Counties is well developed, with extensive gathering systems and field services, making this part of the Permian ideal for cost-effective, cash-generative operations—particularly for operators seeking to leverage existing wells and enhance recovery in proven fields.

Namibia Project (PEL 93)

88E currently holds a 20% interest in Petroleum Exploration Licence 93 (PEL 93) in the Owambo Basin, onshore Namibia. It covers a vast area of 18,500 km², more than 10 times larger than 88E's Alaskan portfolio. It is an impressive frontier exploration opportunity with large-scale discovery potential (multi-billion-barrel potential), supported by a clear forward work program including completed seismic acquisition/interpretation and planned drilling potentially in H2'26, leveraging the country's favourable operating environment and the strategic staged farm-in structure.

88E was attracted to this acreage position due to its size and scale, as well as the staged nature of the farm-in terms. Namibia has a stable government, regulatory regime, and a favourable business environment, evidenced by the level of oil and gas activity. The region is considered one of the world's most prospective new exploration regions and one of the last true frontiers for multi-billion-barrel onshore oil and gas discoveries but remains underexplored. Scientific data analysis led by Monitor Exploration identified a range of anticlinal structures (folds) in PEL 93, attributed to the Damara fold and thrust belt, and coincident with passive seismic anomalies and elevated ethane concentrations in soil gas sampling, indicating potential hydrocarbon accumulation at depth.

Onshore Namibia: PEL93



Source: 88 Energy

Hannam&Partners

Farm-in transaction

88E, through its wholly-owned Namibian subsidiary, Eighty Eight Energy (Namibia) (Pty) Ltd, entered into a three-stage farm-in agreement for up to a 45% non-operated working interest in PEL 93. The initial entry involved the successful transfer of a 20% working interest in February 2024, which was approved by the Namibian Ministry of Mines and Energy. The operator for the exploration and development program of PEL 93 is Monitor Exploration Limited (Monitor), which holds a 55% working interest. The remaining interests are held by local entities: Legend Oil Namibia (15%) and the National Petroleum Corporation of Namibia (NAMCOR) (10%).

The farm-in agreement is structured in stages with attractive commercial terms. The initial entry required funding a 2D seismic program. Terms include payments for back costs and work programme carries. A US$0.9mm payment was made in 88E shares for the final back costs and 2024 work-program carry as part of the fourth and final Stage 1 instalment. 88E also has an option to fund the first US$7.5mm of the first well gross cost, estimated at US$12mm, to receive a further 17.5% working interest, and an option to fund the first US$7.5mm of the second well gross cost for up to a total of 45% working interest.

A targeted high-resolution 2D seismic campaign was shot in 2024 and processing of the 200 line km of 2D seismic data has been completed. Initial interpretation has confirmed 11 independent leads and identified significant structures. 88E expects to engage an independent resource auditor to prepare a maiden prospective resource estimate, expected later in 2025. The farm-in enables fast-track near-term drilling, with the first exploration well planned for as early as H2’26. The initial programme will focus on the southern opportunity within the acreage, with further potential yet to be unlocked in the northern areas.

Strategic Infrastructure Access Supporting Efficient Operations

PEL 93 benefits from a strong logistics advantage, underpinned by its proximity to Namibia’s existing transport infrastructure. The licence area lies near the Oshivelo train station in the southeast, which connects directly to Walvis Bay—one of southern Africa’s key logistical ports with the capacity to handle >1mm containers annually and served by an international airport. The railway link from Oshivelo to Walvis Bay spans ~ 660 km and provides a critical export and import route for equipment and materials.

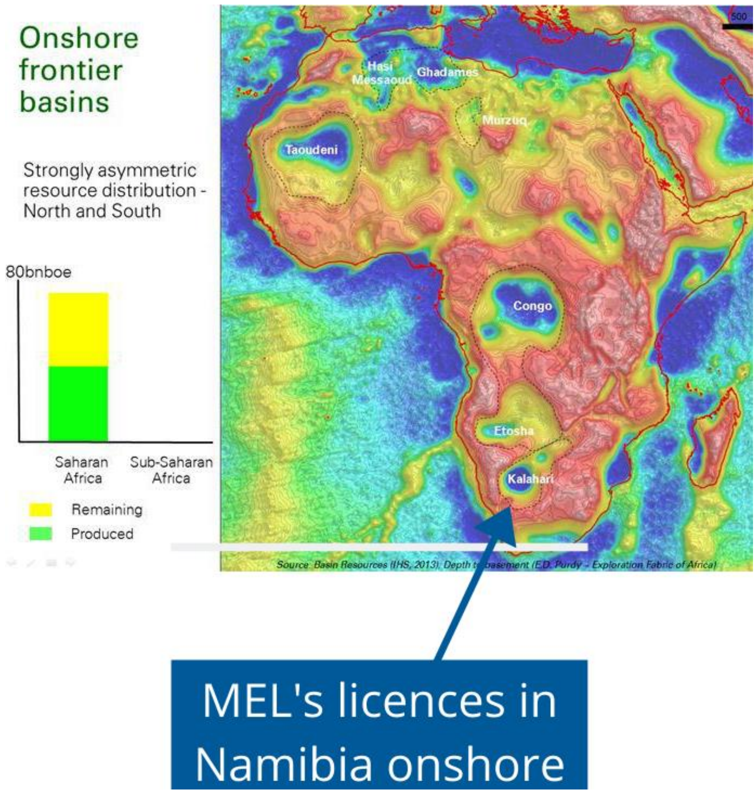
Namibia’s state railway operator, TransNamib, operates specialised tank wagons capable of transporting fuel to key locations across the country, enhancing midstream potential for future developments. Windhoek, the country’s administrative and industrial hub, lies roughly 500 km from Oshivelo and is accessible by rail and air. The railway also connects to South Africa, enabling cost-effective cross-border freight movements. These logistical connections provide PEL 93 with a low-cost, accessible route to key supply chains, reducing exploration and development risk and supporting efficient mobilisation.

Namibian oil and gas industry

Namibia is rapidly gaining recognition as one of the world’s most promising frontiers for oil exploration, with the offshore success in the Orange Basin acting as a catalyst for growing interest in its vast and underexplored onshore basins. Since 2022, discoveries exceeding 10bnboe of oil and gas offshore by majors such as TotalEnergies, Shell, Chevron, and Qatar Energy, have transformed perceptions of Namibia’s hydrocarbon potential. These high-profile offshore finds have de-risked the broader petroleum system and drawn attention to the onshore regions, which share geological analogues with prolific hydrocarbon basins in Oman and elsewhere. Multiple surface oil seeps, favourable stratigraphy, and a largely untapped onshore domain make Namibia a compelling play for explorers looking to enter early in a high-upside province.

According to bp's Michael C. Daly, Executive Vice President Exploration when he gave a speech in 2019, he classified Namibia as one of the three most prospective onshore basins, together with Congo and Angola, for future oil and gas exploration. He said that onshore, the remaining frontiers and deep land will follow with low cost, low impact, high quality seismic being key. This 'Depth to Basement' image of Africa below, shows the major basins of Africa with annotated Saharan and sub-Saharan Cratonic basins of similar age and scale. The histogram shows the disparity in their resources, 75bnboe v 0bnboe. This is more likely to be an understandable exploration maturity issue rather than a profound geological shortcoming.

Osnhore Sub-Saharan Africa is underexplored

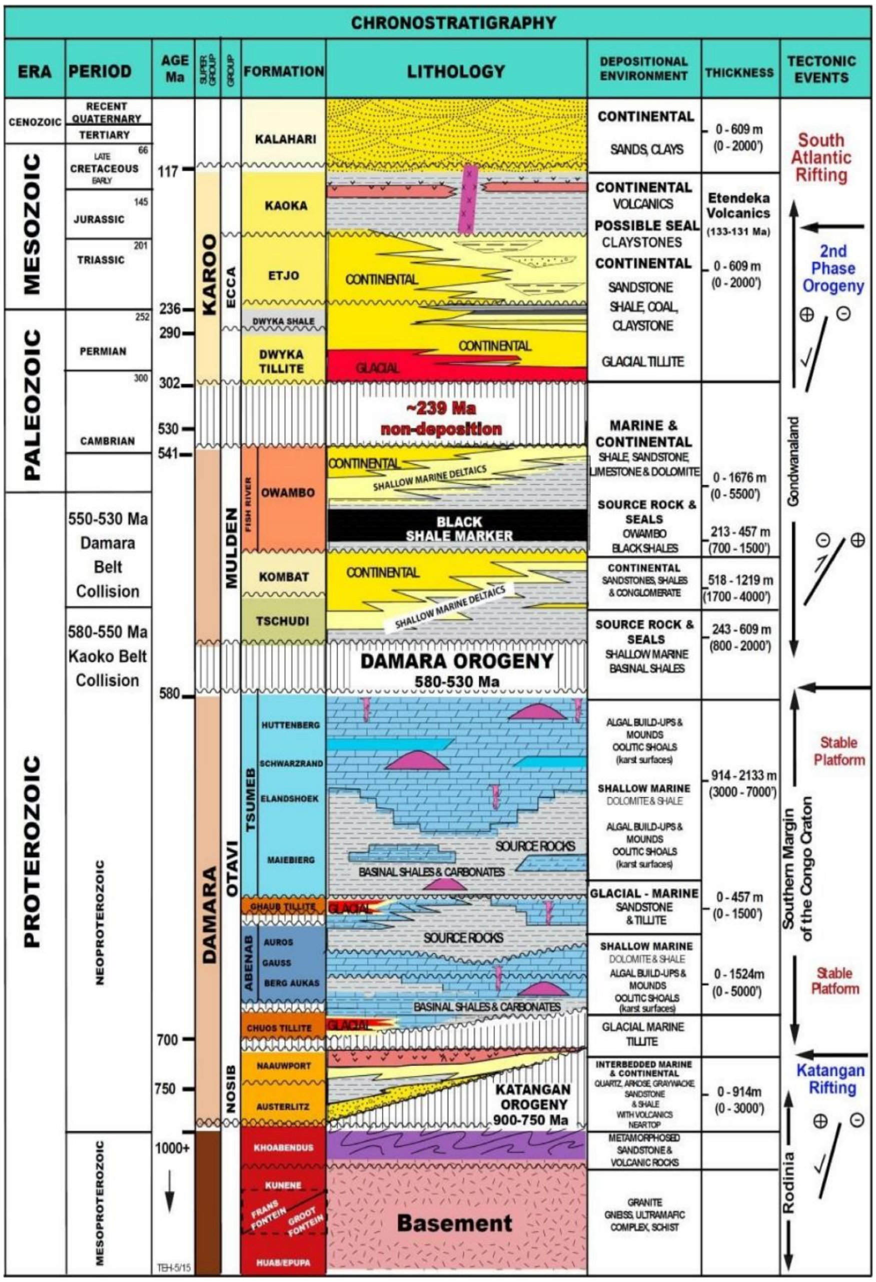


Source: Monitor Exploration

Onshore exploration is supported by an attractive fiscal and operating environment. Namibia offers a low-cost exploration regime, no signature or production bonuses, and a simple tax framework—highlighted by a 5% royalty and a 35% production income tax with 100% immediate deductibility of exploration and operating costs. The legal and regulatory system is stable and transparent, underpinned by strong national partners like NAMCOR. Infrastructure, such as transport links and an educated workforce, supports operational efficiency, while the arid, dry climate ensures year-round access. With a politically stable, pro-business government, and the state holding only a 10% carried interest through to commercialisation, Namibia offers explorers a rare combination of basin potential, fiscal competitiveness, and security—making it a standout destination for frontier onshore oil exploration.

Owambo basin

Onshore Namibia: PEL93

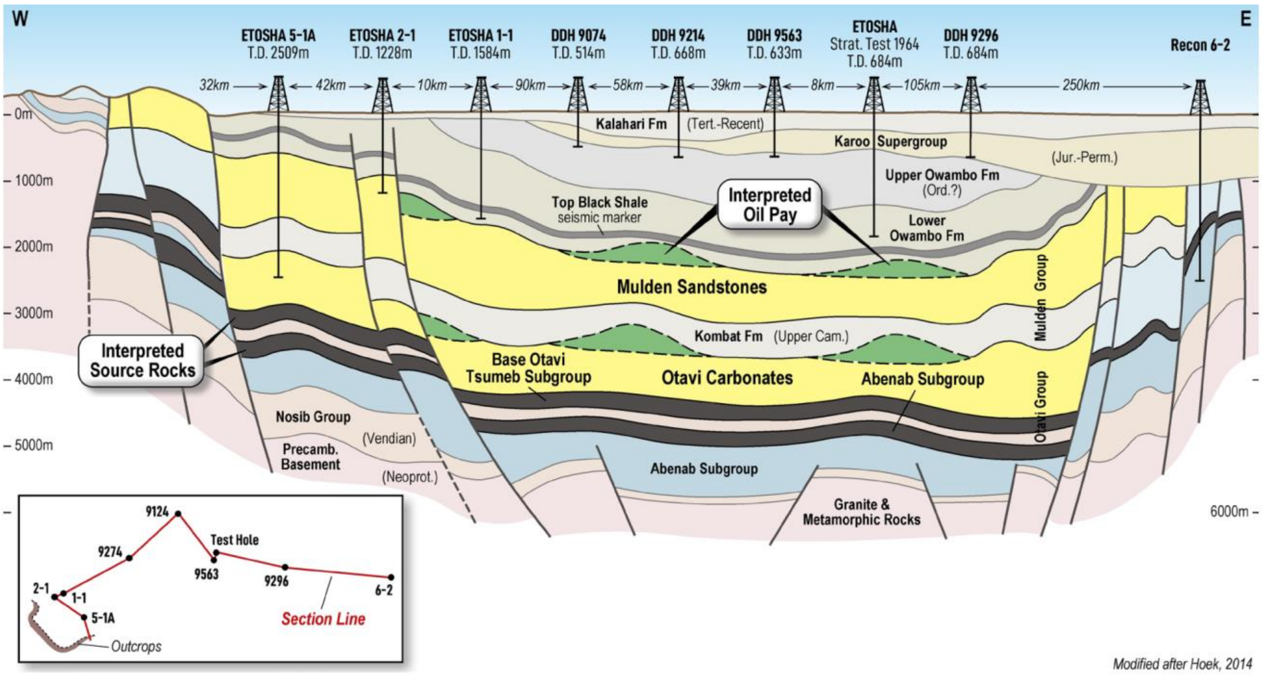


Source: Monitor Exploration

The Owambo basin is probably the most important area in terms of hydrocarbons exploration onshore Namibia. Its stratigraphy comprises rocks from Pre-Cambrian times until the Tertiary cover of the Kalahari Sands Formation with a total thickness up to 8,000m. The Otavi Group, a Neoproterozoic carbonate platform, represents the main target.

PEL 93 comprises the Damara branch of the fold belt towards the south. It sits in a geologically rich area with strong indicators of both source rocks and high-quality reservoirs. The block benefits from thick organic-rich layers formed during a global post-glacial sea-level rise—these rocks, particularly the Otavi carbonates, are thought to be excellent generators of oil and gas.

Well-defined sedimentary basin with proven oil charge, reservoirs and seals



Source: 88 Energy

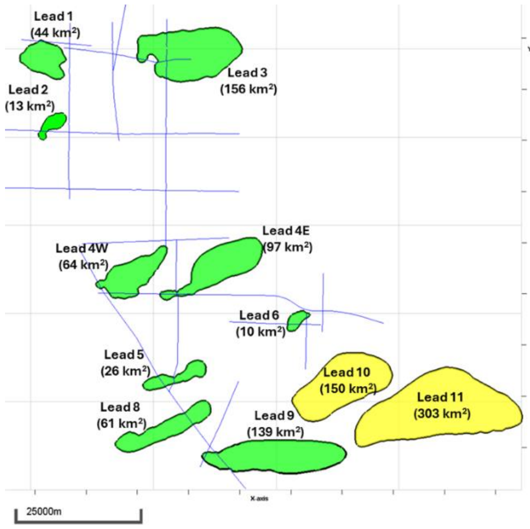
Owambo is a well-developed sedimentary basin with a proven oil charge, effective reservoir and seal pairs, and a series of large structural traps capable of hosting several billion barrels of oil. While initial exploration focused on the shallower Karoo Play, attention is now shifting to the deeper and largely untested Damara Play. Formed by a major fold-and-thrust event, the Damara Play comprises large anticlines and thrust features that offer substantial, independent exploration potential—comparable in scale to Namibia's recent offshore discoveries.

In the nearby Etosha 5-1A well, these carbonates have shown good porosity, meaning they can store and transmit hydrocarbons effectively. These reservoirs are further enhanced by natural fracturing and karstic features, which improve their permeability and flow potential. Several hundred metres of oil shows in Recon 6-2 well above and below base Karoo, proves oil generation in the Basin.

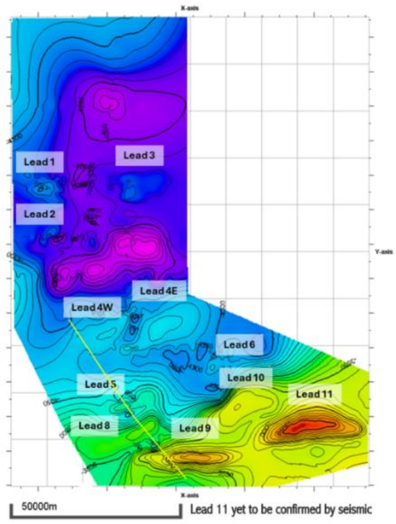
Seismic data have revealed: several large anticlinal structures with pronounced relief, reservoirs in the Otavi and Kombat formations, and access to source rocks of the Tsumeb and Abenab formations. The seismic data have confirmed at least four different types of geological traps where oil and gas could accumulate. These include large, folded structures caused by ancient tectonic forces, uplifted formations, mounded carbonate features like stromatolites and older rift structures that have been pushed upwards. Together, this combination of proven source rock, porous reservoirs, and multiple trapping mechanisms points to strong prospectivity and multiple drilling targets across the licence.

Prospectivity

Post seismic prospects



Gross unrisked prospective resource (mmbbl)



Source: 88 Energy

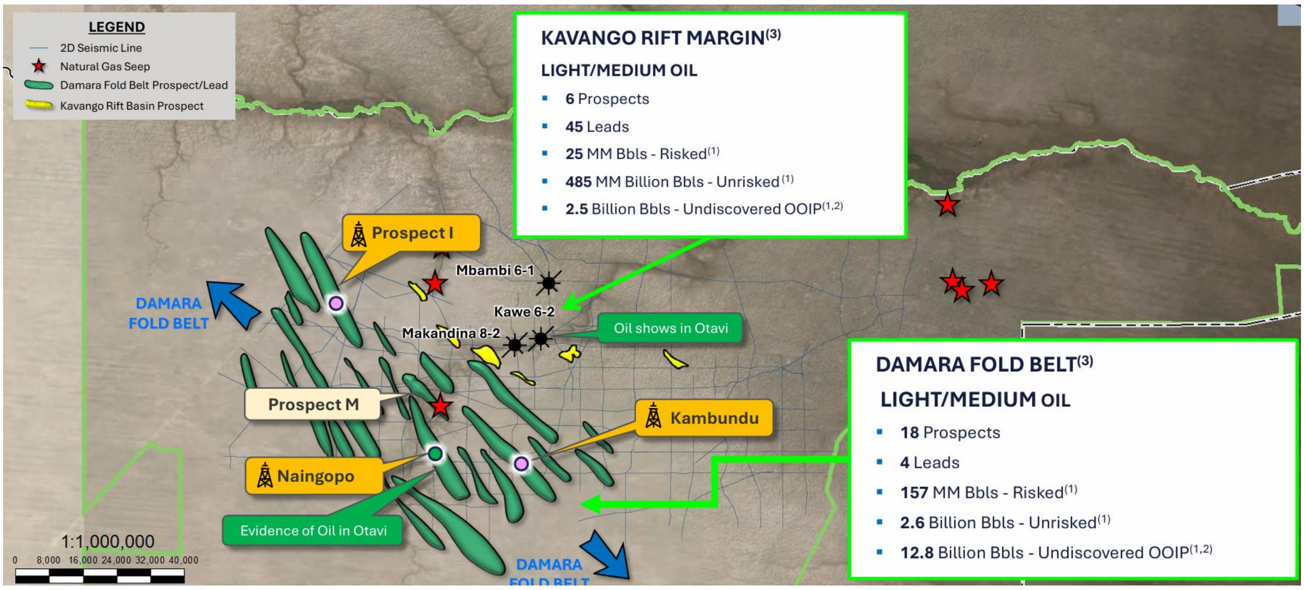
Monitor describes billion barrel potential with ~350mmbbl immediately drillable prospect. At US$70/bbl Monitor sees the P-20-01 prospect as worth US$2bn unrisked using an NPV10 (US$7.4/bbl) with a 17% geological COS. The presence of multiple trap types and reservoir intervals across both carbonate and clastic settings greatly enhances the overall exploration potential of the block.

Monitor believes that PEL 93 is at the heart of the basin. 2D seismic has identified 11 distinct structural leads, confirming strong subsurface prospectivity and multiple potential drilling targets. The primary target is the Otavi carbonates, a well-developed carbonate platform comprising the Huttenberg and Elandshoek Formations. These formations are underlain by a robust regional top seal—440m of Lower Tschudi shales, as demonstrated in well 5-1—providing excellent trapping conditions. The Otavi leads are structurally defined and lie at depths of around 3,300 to 3,510 metres TVD, with favourable closure geometry that supports large volumetric potential.

There is a secondary target within the Mulden siliciclastics, which consists of Lower Combat unit sandstones, sealed by a 90m thick Black Shale Member in the West Etosha area. The Mulden targets are shallower, between 2,070m and 2,260m TVD, offering a stacked play opportunity.

Reconnaissance Energy Africa read-through

Naingopo Exploration Well Confirms Liquid Potential of Damara Fold Belt



Source: Reconnaissance Energy Africa

Reconnaissance Energy Africa or Recon Africa (REA) is a Canadian listed company focused on onshore Namibian exploration with a market cap of US$92mm as of 10th June 2025. It is actively drilling the Damara Play on its PEL 73 licence, located to the East of PEL 93, a central block in the basin with access to a substantial hydrocarbon kitchen. Recon's exploration area, located on the eastern edge, faces different geological challenges.

Recon drilled the Naingopo exploration well in November 2024. The results demonstrated a working petroleum system within the Damara Fold Belt with oil indications and substantial net reservoir of 50m encountered in the Otavi Group. The fact that Naingopo confirmed oil presence in Otavi means the risk is lower for future wells, including those in 88E's PEL 93 area. Although this well might not be commercially viable, it marks a significant advancement in understanding the Owambo basin's hydrocarbon potential.

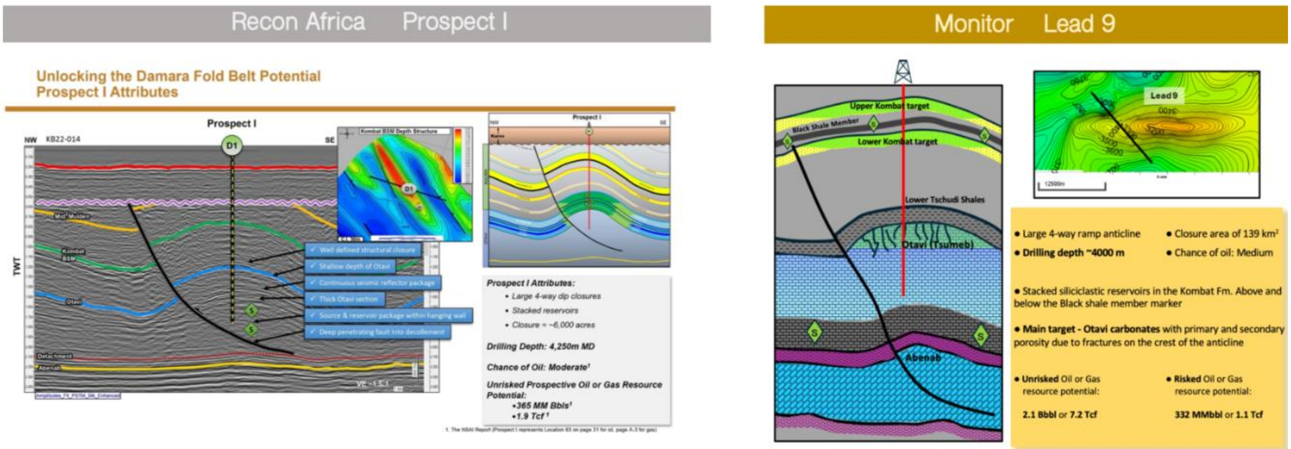
The well encountered a large structure in the shallower Mulden formation, but lacked a clear trap in the deeper Otavi formation, preventing oil from accumulating. This highlights seismic interpretation challenges, particularly with depth conversion, affecting oil migration and accumulation.

One of the key technical findings from the Naingopo well is that while a large structure exists at the shallower Mulden formation, due to seismic uncertainties such as depth conversion the deeper Otavi did not have a clear trap to hold and accumulate oil. This means oil generated in the deeper source rocks did not accumulate in the Otavi reservoir and, without a structure to focus migration, had no reason to move upwards into the shallower Mulden layers.

Recon drilled 3 "strat test" wells in recent years to test the potential of the major rifted play of the Kavango Basin within PEL73. North of the Omatako River, the wells Kawe 6-2 (April 2021), Mbambi 6-1 (July 2021), and Makandina 8-2 (August 2022) variously reported oil and gas shows through the Karoo, early Paleozoic and late Proterozoic.

REA entered into a highly attractive farm down agreement with BW Energy Limited, for a strategic farm down of a 20% working interest in PEL 73, including a US$16mm equity investment to support a multi-well exploration program, and additional contingent payments of up to US$125mm, based on meeting certain development, production and cash flow milestones.

Comparison Recon Africa Prospect I vs Monitor Lead 9



Otavi – area within closure	✓✓✓	P5 73 km²	✓✓✓	Maximum 139 km2
Interpretation confidence	✓✓	Several seismic lines	✓	Two seismic lines, further delineation required
Reservoir - Otavi	✓✓	Expect similar to 50m net in Naingopo plus 104m in Elandshoek as reported from Kawe well	✓✓✓	Potential for more reservoir and better primary porosity preservation in basin central location with early structure
Reservoir – Kombat		Sandstones mainly cemented, potentially due to igneous complex	✓✓	Better reservoirs expected away from igneous complex and with more shale in the system to slow hydrothermal activity
Source	✓✓	Source within structure and reasonable fetch area	✓✓✓	Source within structure and access to large kitchen area
Seal		Several shales seen in Naingopo well, although Mulden has high sand content	✓✓	Shales better developed in Etosha-5-1A to west expected to extend towards PEL 93's basin central position

Source: Reconnaissance Energy Africa

Recon recently announced that it is changing its next drilling target to Prospect I which has the full stratigraphic section, including source rocks, within structural closure. Therefore, Prospect I looks much more promising. All the key horizons—including the oil source and potential reservoirs in both the Otavi and Mulden formations—appear to be within structure, creating a much better possibility for trapping oil.

Prospect I is targeting 346mmbbl of unrisked prospective light/medium crude oil. This well is due to spud in June 2025 and it is an excellent analogue for 88E's Lead 9. Success on Prospect I would considerably de-risk the Owambo Basin and, in particular, Lead 9, which has even greater potential at multiple rock levels

Notably, some challenges seen at Naingopo—such as rock formations that may have become cemented due to the igneous complex beneath Recon's acreage in the east of the Basin—are expected to be less of an issue as drilling moves westward, closer to 88E's area.

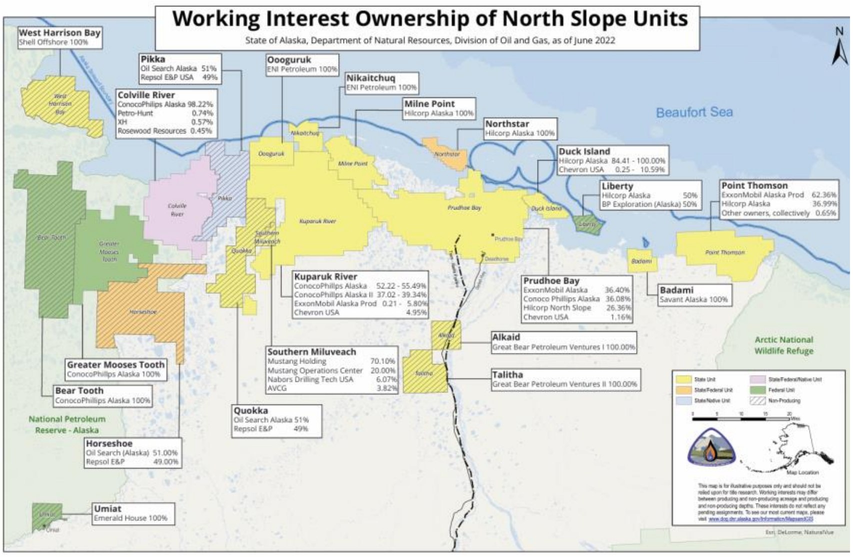
Alaska North Slope

Alaska North Slope basin

Source: IHS Markit

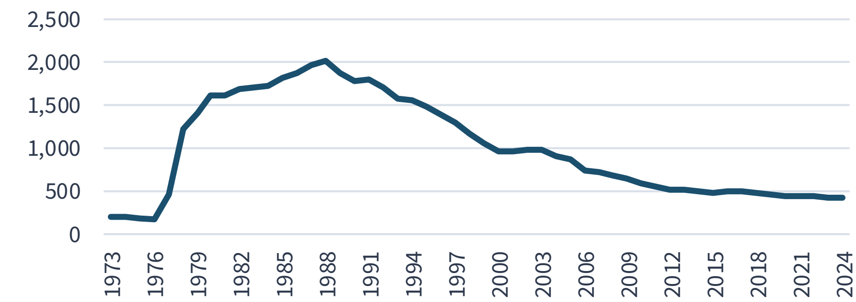
Alaska has been a cornerstone of US oil output for decades. North Slope crude production famously peaked in the late 1980s at over 2mmbbl/d, then representing about 25% of total US oil. Since that peak, output has gradually declined. The Trans-Alaska Pipeline System ("TAPS") now carries around 500kbbl/d, about 75% below late-80s levels. Despite this long-term decline, Alaska's cumulative production exceeds 18bn bbl since Prudhoe Bay's discovery, and huge untapped resources remain (~40–50bn bbl) in the North Slope and offshore. Notably, after tax reforms in 2013, Alaska even saw a brief production uptick in 2016, the first increase in 14 years. The state's oil output today stands at 400–430kbbl/d, but new discoveries and projects offer hope of boosting production in coming years.

North Slope Units and Ownership, June 2022



Source: North Slope Science Initiative

Alaskan crude oil production (kbbl/d)



Source: US EIA

Alaska's production history underscores both the legacy of giant fields and the opportunity for new development. Prudhoe Bay (discovered 1967) remains one of North America's largest oil fields, having produced >12bnbbl to date. Other large fields like Kuparuk, Alpine, and Kuparuk satellites (Milne Point, Endicott, etc.) helped sustain North Slope output through the 1990s and 2000s. By 2018, however, Alaska had fallen from the #2 oil-producing state to around #6 as Lower 48 shale boomed. New discoveries in the past five years – such as ConocoPhillips' Willow and the Nanushuk play – are now poised to breathe life into the Slope. These projects could add hundreds of thousands of barrels per day of new output, crucial for keeping TAPS viable at lower throughputs (below ~350,000 bpd, oil in the pipeline faces cooling and wax buildup issues). In short, Alaska's production has declined from its heyday, but remains consequential – and a handful of new developments promise to partly reverse the trend and extend Alaska's oil legacy well into the 2030s.

Overall, the past five years have demonstrated that Alaska is far from tapped out. Entirely new play types (Nanushuk formation, Torok formation basin floor fans) have been unlocked with billion-barrel potential. These successes have not only increased prospective resources but have also catalysed development projects, attracting capital. The North Slope's exploration renaissance has drawn comparisons to a new boom: "geologists label the western North Slope a new global energy 'super basin'" thanks to these Brookian discoveries. For 88E, these regional results are highly relevant – they validate the geologic model the company is pursuing on its own leases (adjacent to or in the trend of these discoveries).

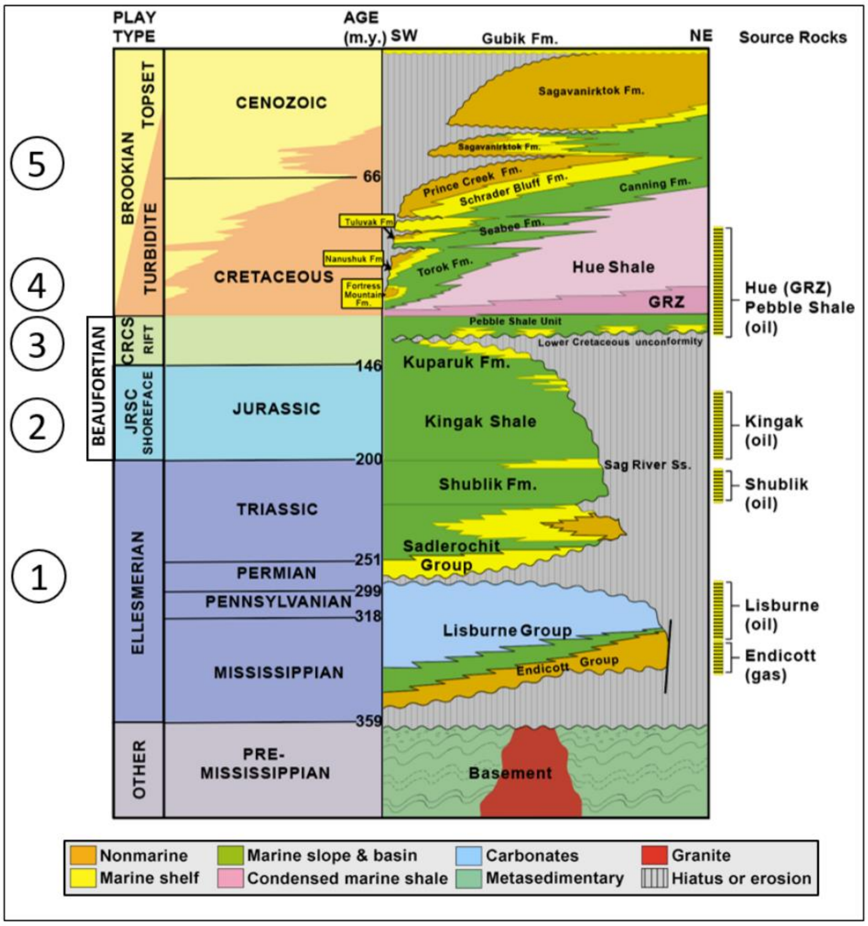
Major recent Brookian Discoveries

	Smith Bay	Willow	Pikka/Horseshoe
Operator(s)	Caelus	ConocoPhillips	Oil Search/ConocoPhillips
Reservoir Formation	Torok Fm	Nanushuk Fm	Nanushuk Fm
Penetrations to date	2	7	12
Location	State Waters Offshore of NPRA	Federal Onshore Northeast NPRA	Onshore Colville Delta
Road/Pipeline Tie-in	~ 125 miles	~ 28 miles	~ 20 miles
Trap type	Turbidite Stratigraphic	Topset Stratigraphic	Topset Stratigraphic
Net Pay	183-223 ft	42-72 ft	< 225 ft
Oil Gravity	40-45 degree API (calc)	44 degree API	30 degree API
Test Rate	No Flow Tests	< 3,200 bopd vertical	~ 2,100 bopd vertical; 4,600 bopd horizontal
Contingent Recoverable Resource	1.8-2.4 BBO (est)	300 MMBO	1.2 BBO
Expected Production (Operator Releases)	< 200,000 bopd	40,000-100,000 bopd	< 120,000 bopd

Source: nextinvestors.com/articles/asx-oil-stock-set-drill-multi-billion-barrel-alaska-north-slope/

Stratigraphy and Play Types

Generalised stratigraphic column for north Alaska



Source: https://dggs.alaska.gov/webpubs/dggs/mp/text/mp167.pdf

Wells have targeted five main play types:

- Ellesmerian clastics and carbonates (Kekiktuk, Lisburne, Ivishak, Shublik, and Sag River),
- Jurassic shoreface sands (Barrow, Simpson, Kugrua, Nechelik, Nuiqsut, and Alpine),
- Cretaceous rift sands (Walakpa, Kuparuk, Put River, Kemik, and Thomson),
- Brookian turbidites (Torok, Seabee, and Canning), and
- Brookian topsets (Nanushuk, Tuluvak, Schrader Bluff, West Sak, Ugnu, Prince Creek, and Sagavanirktok).

Exploration at Milney Point took off in the early 1990s; extensive development of West Sak sands and the reservoir in the Schrader Bluff Formation started in 1998 and continues today. The Nikaitchuq discovery in 2004 set off a new wave of delineation and exploration drilling targeting topsets in the Schrader Bluff Formation.

Attractive and Competitive Fiscal Terms

Alaska offers a unique fiscal regime for oil and gas that, in recent years, has become more competitive relative to other regions. In 2013 the state enacted the *More Alaska Production Act* (commonly called SB 21), overhauling a burdensome tax system (ACES) that had made Alaska less competitive for investment. SB 21 introduced a balanced tax structure with a base 35% net profits tax and per-barrel credits to incentivise new production, plus a 4% gross minimum tax floor at low prices. This reform drew billions in new investment and was followed by improved production trends: 2014 saw no decline, 2016 registered a production increase – the first uptick in 14 years. The current terms encourage development especially for new fields, offering credits and relatively predictable taxes even in volatile price environments.

From a comparative perspective, Alaska's government "take" (taxes and royalties) remains substantial – the state still often earns more from a barrel than the producer does, via royalties, production tax, property tax, etc.. However, these terms are considered fair given the scale of Alaska's resources and have been calibrated to attract investment. Unlike many Lower 48 states where royalties on private lands and severance taxes apply, Alaska owns most oil-bearing lands, so the state's share replaces what would be private royalties elsewhere. Incentives such as exploration tax credits (especially prevalent in the 2000s under ACES) helped independents fund new drilling, and though the cashable credit program wound down in recent years, companies can still deduct losses and carry forward expenditures against future production tax. In fact, under SB 21, companies operating legacy fields on the North Slope have enjoyed sizable tax credits per barrel, contributing to healthy profit margins even in a low-price environment. (Notably, ConocoPhillips' Alaska operations were more profitable than its Lower 48 segment in late 2010s, illustrating the attractive economics.)

When comparing across jurisdictions, Alaska's fiscal terms today are investor-friendly given the resource size. The effective tax rate on new barrels can be competitive with the Lower 48 on a risked basis: for example, a new North Slope development can qualify for credits that offset the 35% base tax, whereas in the Lower 48 a producer might pay ~20% royalty to a landowner plus state severance and corporate taxes with fewer incentives. Canada's regimes (e.g. Alberta's oil sands or frontier projects) also often carry higher royalties post-payout (25%+), whereas Alaska allows faster recovery of costs via its net-profit system.

Crucially, Alaska has maintained a stable fiscal policy since 2013 – a 2020 referendum to raise production taxes was rejected, signalling to industry that the state wants a stable, pro-development tax environment. This stability and the alignment of state interest (Alaska relies on oil for up to 90% of its discretionary revenue) make the North Slope's fiscal terms attractive in the context of global oil opportunities. In summary, generous credits, a stable tax regime, and the prospect of large discoveries mean Alaska's terms lends itself to excellent project economics, comparing favourably to many high-tax offshore or international projects and remaining competitive enough to draw companies away from Lower 48 shale plays.

Political and Regulatory Support

Both the Alaska state government and, to a notable extent, the U.S. federal government provide support for responsible oil exploration in the region. State-level support is exceptionally strong. Alaska's economy "still runs on oil" – oil revenues have historically funded the majority of the state budget, so political leaders consistently encourage new development. The state administration and legislature regularly advocate for oil projects: for instance, in 2023 the Alaska House voted unanimously to support the Willow project and urged federal approval. The state even participated directly in leasing (through the Alaska Industrial Development and Export Authority) to promote exploration in frontier areas like the Arctic National Wildlife Refuge (ANWR). Permitting at the state level is typically efficient and geared toward facilitating drilling during the limited winter season. In short, Alaska's political climate is pro-oil, reflecting the industry's contribution to jobs (one-quarter of Alaska's jobs) and state finances.

At the federal level, support has been more mixed in recent years, but key approvals have moved forward. The most prominent example is the Willow project in the National Petroleum Reserve–Alaska (NPRA). In March 2023, the Biden Administration approved ConocoPhillips' Willow development – a massive $8 billion plan to tap an estimated 576mm barrels over 30 years, with a peak of 180,000bbl/d. This decision, described by regulators as "striking a balance", allowed Willow to proceed on three drill sites (instead of five originally proposed) to mitigate environmental impact. The approval was significant: it signalled continued federal willingness to honour leases and enable Arctic oil development even under a climate-focused administration. (A U.S. District Court upheld the Willow approval against legal challenges in 2023.)

That said, federal policy also includes restrictions to protect sensitive areas. On the same weekend Willow was greenlit, the Interior Department announced plans to bar new oil leasing on ~16mm acres of the NPRA and Arctic offshore, limiting future expansion in ecologically important zones. Likewise, leases in ANWR's 1002 Area auctioned in January 2021 were suspended by the current administration over environmental concerns. The long-running debate over Arctic drilling means any federal support often comes with additional safeguards (wildlife protections, seasonal limits, etc.). Nonetheless, NPRA was explicitly set aside for oil production (dating back to 1923), and successive administrations have held lease sales there. ConocoPhillips and others have successfully navigated federal permitting for NPRA projects (e.g., GMT-1 and GMT-2 drill sites in recent years), working within robust environmental regulations and consultation with local communities.

In summary, political/regulatory support in Alaska is generally positive for exploration. The state government is firmly pro-development and has created a stable policy environment (even offering infrastructure support and advocacy for projects). Federally, while there is careful scrutiny of Arctic projects, major developments have been allowed to proceed – indicating a recognition of Alaska's strategic importance. So long as projects are designed with environmental safeguards, the regulatory path, though rigorous, is navigable. The approval of projects like Willow – "one of the largest…on US soil" – underscores that Alaska remains open for business at the highest levels of government, backed by a decades-long track record of safe operations on the North Slope.

Successful Operators and New Entrants in Alaska

A wide spectrum of oil companies, both major publicly traded firms and independent/private players, have operated successfully in Alaska – a testament to the region's attractiveness. The North Slope was originally developed by majors (BP, Exxon, ARCO which became part of ConocoPhillips), and today ConocoPhillips stands as the largest operator on the Slope. ConocoPhillips Alaska leads development in NPRA (Alpine field and satellites) and has pursued new hubs like Willow; it has demonstrated the ability to execute complex Arctic projects and maintain good relations with the state. ExxonMobil remains a key owner at Prudhoe Bay and operates the Point Thomson gas/condensate field, underscoring that supermajors still find value in Alaska's giant resources.

Equally notable is the success of independent companies in Alaska:

- **Hilcorp** (private) – Entered Alaska in 2012 by acquiring mature Cook Inlet fields, then expanded to the North Slope. Hilcorp specialises in revitalizing aging fields: at Milne Point, a legacy field, Hilcorp nearly doubled production from ~18,000 bpd in 2014 to 34,000+ bpd by 2020 through drilling and efficiency improvements. Hilcorp's focus on cost reduction and innovation in heavy oil has paid off, and in 2020 it acquired BP's entire Alaska portfolio (including BP's stake in Prudhoe Bay). This bold move made Hilcorp one of Alaska's top producers – a privately-held company now operating assets that produce on the order of 150,000+ bpd. Hilcorp's success shows that smaller, agile operators can thrive where majors see diminishing returns.

- **Armstrong Oil & Gas** (private) – A small Denver-based explorer, Armstrong has an outsized legacy in Alaska. It spent 15+ years exploring the North Slope and, in partnership with Repsol, made the huge **Pikka (Nanushuk) discovery**. After proving up at least 500mm barrels (unrisked potential >1.5 billion barrels) in the Nanushuk formation, Armstrong sold a majority stake to Oil Search/Santos in 2017 for $850mm – monetising its find at an attractive ~$3/bbl of resource. Armstrong's president has described the North Slope geology as a "ridiculous amount of opportunity" – even if the environment is "wicked cold" and remote – underscoring the rewards available to those willing to brave Alaska's challenges. Without Armstrong's wildcatting, the Nanushuk play might not have been unlocked. This juniors-to-majors model (independents finding oil, then larger companies buying in to develop) has been repeated several times in Alaska.

- **Caelus Energy** (private) – In 2016, Caelus announced a major discovery at Smith Bay on the remote western North Slope. The company (a small independent backed by private equity) estimated 6–10 billion barrels of oil in place at Smith Bay and envisioned potential production of 200,000 bpd of light oil. While still unconfirmed by flow tests (none were done due to seasonal limits), the Smith Bay find, if developed, could rank among Alaska's largest. Caelus successfully operated the smaller Oooguruk field and demonstrated that even frontier acreage off infrastructure can attract serious investors when the prize is big.

- **Pantheon Resources** (public, UK-listed) – A recent entrant, Pantheon has amassed acreage south of Prudhoe Bay and drilled a series of exploration/appraisal wells (2019–2022) targeting Brookian reservoirs. It has reported encouraging results, such as flowing 35–38° API oil from the

Talitha A well in 2022 (achieving ~45 barrels per day from a short vertical test, proving movable light oil in a large interval). More notably, Pantheon's Theta West-1 well confirmed an extensive oil accumulation in a basin floor fan play: it encountered a 950-foot hydrocarbon column and flowed ~57 bpd (peaks up to 100 bpd) of high-quality crude in a limited test, validating a recoverable resource of ~1.2 billion barrels. Pantheon, though small, is working to commercialise this large discovery, and its ongoing testing (including horizontal development wells like Alkaid-2) will determine if these finds become the next development. The company's presence highlights that even in 2025, exploration upside on the North Slope attracts public-market investment and can yield substantial new oil.

Other successful operators include ENI (Italy's ENI has operated the Nikaitchuq offshore field and participated in others, recently selling to Hilcorp), Santos (Australia's Santos Ltd., which acquired Oil Search, now leads the Pikka project development in partnership with Spain's Repsol), and Repsol (which besides Pikka has multiple discoveries with Armstrong). In Cook Inlet (South-central Alaska), independents like Hilcorp and subsidiaries of Cook Inlet Region Inc. have kept oil (and gas) production viable, again benefiting from state incentives.

In summary, Alaska's roster of operators ranges from oil majors to small wildcatters. The common thread is that those companies have been rewarded by large discoveries or by extending field life, making Alaska an attractive arena for a variety of E&P strategies.

Recent Exploration Successes

Exploration results since 2018 have been some of the most encouraging in Alaska's modern history, rejuvenating interest in the region. A series of discoveries and well tests have confirmed new oil plays or largely extended known ones. Here are key highlights:

- **Nanushuk Play – Pikka/Horseshoe (Repsol/Armstrong):** In 2017, Repsol and Armstrong announced the Horseshoe-1/1A wells had extended the Nanushuk oil trend 20 miles south, confirming a total ~1.2 billion barrels of recoverable light oil in the combined Pikka-Horseshoe area. This was heralded as the "largest U.S. onshore conventional discovery in 30 years". The Nanushuk formation, a relatively shallow Cretaceous sandstone, was a new play for the North Slope and has proven prolific. The discovery indicated potential production of 120,000 bpd from Pikka unit alone. This success immediately drew global attention and investment (Oil Search and Repsol moving toward development, see Pikka project below).

- **Willow (ConocoPhillips):** Discovered in 2016 in the NPRA, ConocoPhillips drilled several Willow appraisal wells (e.g. Tinmiaq series) through 2018 to delineate the field. By 2020 the company estimated Willow held ~600mm barrels recoverable. In 2021–22 ConocoPhillips continued geotechnical work and in early 2023, Willow received federal approval for development. The confirmation and sanctioning of Willow is a major milestone – it validated the earlier exploration. Willow's plan for up to 180,000 bpd by 2029, and the fact that it survived legal/environmental challenges, is very encouraging for explorers with nearby prospects (it proves that large remote finds *can* be brought to market under today's regulations).

- **Pantheon's Brookian Discoveries:** As mentioned, Pantheon Resources drilled **Talitha-A (2021)**, which encountered multiple oil-bearing zones in the Brookian section. Although weather truncated testing, oil was recovered from the Basin Floor Fan and Slope Fan system. In 2022 Pantheon drilled Theta West-1, a bold step-out, which flowed 35.5–38.5° API crude and affirmed a vast oil accumulation (estimated >1bnbbl recoverable) in the Lower BFF. These results proved that the Brookian "pipeline-quality" reservoirs extend far from existing fields and are oil-charged. Also in 2022, Pantheon's Alkaid-2 well (a horizontal on the Dalton Highway) commenced a long-term production test in a shallower Brookian horizon. While early flow rates (~150–200 bpd with some gas) were modest, Pantheon is applying reservoir stimulation and learning to improve flow. If extraction can be optimised, these discoveries could lead to a whole new production centre just south of Prudhoe Bay infrastructure.

- **Project Peregrine – Merlin Wells (88E):** In 2021, 88E (with partner) drilled the Merlin-1 exploration well in the NPRA (Project Peregrine area). Merlin-1 targeted Nanushuk-aged sands west of the Horseshoe discovery. The well encountered several zones with oil shows and good petrophysical indicators (one zone with ~41 feet net pay was reported), and laboratory analysis of fluid samples confirmed the presence of light oil. Although a planned flow test could not be done before the tundra travel season ended, Merlin-1's results were promising enough that 88E drilled **Merlin-2 (2022)** as a follow-up. Merlin-2 encountered additional shows and improved reservoir quality, but operational issues prevented a full test. Even so, sidewall cores and fluorescence from Merlin-2 strengthened evidence of moveable oil. These Merlin wells suggest a potential new Nanushuk accumulation on 88E's acreage – a success that is still in appraisal stage but encouraging for the company's prospects.

- **Umiat Reassessment:** 88E also acquired the historic Umiat oil field (discovered in the 1940s on the southern margin of the North Slope). Umiat had been long known but deemed marginal. In 2021–22, 88E conducted new studies and re-entered an old well, showing that with modern techniques (e.g. horizontal drilling, artificial lift) Umiat's shallow oil might flow at commercial rates. While not a headline "new discovery," the renewed focus on Umiat – which holds ~50mm barrels of proven oil – is part of the overall trend of re-examining known oil pools with fresh eyes amid higher prices and pipeline tariff benefits.

In addition to these, there have been ongoing **exploration/appraisal campaigns by ConocoPhillips** (e.g. Narwhal prospect near Alpine), **Santos/Repsol** (delineating the Pikka unit), and others:

- ConocoPhillips in 2020 drilled exploration wells at Harpoon (near Willow) and reported oil shows, indicating potential satellite prospects to Willow that could add resources.

- Oil Search (now Santos) in 2019 drilled an appraisal at Pikka B, confirming excellent reservoir deliverability (over 3,000 bopd on test) in the Nanushuk, de-risking that development.

- An independent, Emerald House, tested a prospect called Cascade west of Alpine in 2019, finding condensate/gas – a minor result, but part of increased exploratory activity.

Major Projects Underway and Regional Developments

Several **large-scale development projects** on the North Slope are now moving forward, which is a very positive signal for the region's outlook. These projects will bring material new production online and also improve infrastructure that future explorers (like 88E) can leverage:

- **Willow (ConocoPhillips):** As noted, Willow was federally approved in 2023 and has since been sanctioned by ConocoPhillips. The project involves building a new standalone production hub in the NPRA. It will include up to three drill pads with ~199 wells, a central processing facility, pipelines connecting to the Alpine infrastructure, and a new operations road. Willow is expected to cost ~$8 billion and produce 180,000 bpd at peak, with first oil currently projected around 2027–2028. Importantly, Willow establishes infrastructure deep into the NPRA – this includes roads and pipelines that reduce the barrier to entry for nearby exploration. For example, 88E's Project Peregrine prospects lie south of Willow; success at Willow means any discovery there could potentially tie in more easily. Willow's construction will also create jobs and reaffirm the economic viability of Arctic projects in a carbon-conscious era (Conoco has incorporated measures like potential chilling of permafrost under pads to adapt to climate warming). Once online, Willow will boost TAPS throughput and extend its lifespan. Willow is a cornerstone development for the next generation of North Slope oil.

- **Pikka Project (Santos/Repsol):** The Pikka development (Nanushuk field) is the largest oil project on state lands in Alaska in decades. Santos Ltd. (operator) and Repsol sanctioned Pikka Phase 1 in August 2022. Phase 1 involves a single drill site, a central processing facility, and an export pipeline tying into existing infrastructure. First oil is expected in 2026, with output of 80,000 bpd in this initial phase. Moreover, Pikka has additional phases under consideration that could double that rate (full development could exceed 120,000–150,000 bpd). The Pikka project's significance is multi-fold: it confirms that a new discovery can move from exploration (2013–2017) to production in roughly a decade, it brings a new operator (Santos, an Australian firm) into Alaska which diversifies the player base, and it will add substantial volumes to TAPS (Santos estimates Pikka will send an "additional 80,000 barrels down TAPS" daily at peak Phase 1). Technologically, Pikka is leveraging modern drilling (extended-reach horizontals) and is designed as one of the first North Slope projects developed on a "net-zero" basis for Scope 1 and 2 emissions (the partners plan to purchase offsets for operations). Pikka's success will signal that Alaska's fiscal and regulatory regime can support new entrants and that Alaska still yields world-class projects outside the legacy Prudhoe Bay area.

- **GMT-2 and Narwhal (ConocoPhillips):** ConocoPhillips in late 2021 brought online its GMT-2 project (Greater Mooses Tooth-2), which is a satellite to the Alpine field in NPRA. GMT-2 added ~30,000 bpd of production in 2022 and was the second NPRA drill site after GMT-1 (2018, ~20,000 bpd). Additionally, ConocoPhillips has been developing the Fiord West (Narwhal) project near Alpine. These smaller developments (tens of thousands of barrels) are important as they incrementally raise throughput and expand infrastructure westward. Each successful satellite (CD5 in 2015, GMT-1, GMT-2, etc.) builds roads and pipelines a bit farther into NPRA, paving the way for bigger projects like Willow. They also demonstrate the company's continued commitment to Alaska and ability to execute multi-billion-dollar investments sequentially.

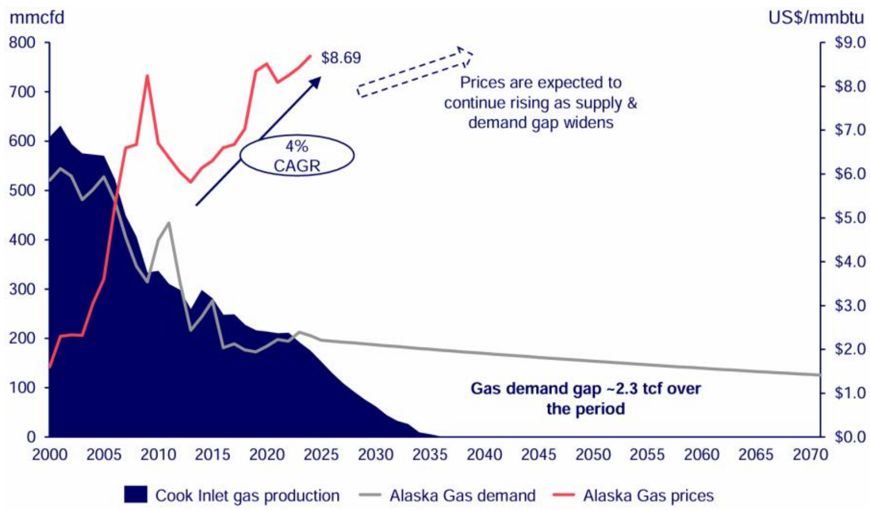
- **Point Thomson Gas Cycling (ExxonMobil/Hilcorp):** On the eastern North Slope, ExxonMobil's Point Thomson field (a large gas condensate reservoir) began initial production in 2016. While primarily a gas project, it produces ~10,000 bpd of condensate that is piped to Prudhoe Bay. Point Thomson's successful startup proved that even technically challenging fields (high-pressure gas) can be tackled. More importantly, the existence of the Point Thomson infrastructure could someday facilitate gas commercialisation or additional oil development in that vicinity (including potential future development of ANWR 1002 Area if ever permitted, since Point Thomson is adjacent to the ANWR boundary). The state sees Point Thomson as a stepping stone to an Alaska LNG gas export project in the future, which would greatly enhance the full value extraction of North Slope resources (though LNG is a longer-term prospect, outside the 5-year focus of this note).

In **aggregate, these developments are positive** for the region because they ensure that critical infrastructure (TAPS pipeline, processing facilities, roads) is utilised and upgraded rather than winding down. TAPS, built in the 1970s with ~2mm bpd capacity, has been flowing at quarter capacity in recent years. A concern had been that if throughput drops too low (under ~300,000 bpd), the pipeline could face operational shutdown. Projects like Willow and Pikka could add 250,000+ bpd combined at peak, potentially raising TAPS throughput by 50% by late this decade. This not only extends TAPS's life but also lowers the per-barrel transport tariff (more barrels to spread fixed costs), improving economics for all North Slope oil.

Additionally, new roads to sites like Willow will improve logistical access to surrounding exploration acreage, reducing costs for explorers. Each project also comes with community and state benefits: Willow is expected to generate at least $8 billion in revenues for federal, state, and local governments, and Pikka will create hundreds of construction jobs and contracting opportunities for Alaska Native corporations. The confidence shown by investors in sanctioning these multi-billion projects indicates that Alaska is viewed as a stable, attractive region for long-term oil investments. This positive momentum can have a virtuous cycle – encouraging further exploration (companies want acreage near the next Willow or Pikka) and thus sustaining the pipeline of new projects.

Alaskan gas landscape

Cook Inlet Gas production, demand and gas prices



Source: Wood Mackenzie

Alaska's North Slope is home to approximately 35 trillion cubic feet (Tcf) of proven natural gas reserves, with potential resources estimated at an additional 200 Tcf. Historically, the absence of infrastructure to transport this gas to markets has led to its reinjection into oil reservoirs to maintain pressure.

Gas production in Cook Inlet is rapidly declining, forecasted to deplete entirely by the mid-2030s despite exploration efforts. Only three commercial discoveries were made from 34 wells drilled over the past 15 years. Consequently, gas demand has consistently declined at a rate of 5% annually over two decades due to limited secure gas supplies, impacting industrial activities such as the mothballing of Kenai LNG and closure of Nutrien's fertilizer plant. A cumulative demand gap of approximately 2.3 trillion cubic feet (tcf) is anticipated by 2071, driven by rising demand and shrinking supply. This gap necessitates alternative solutions as Cook Inlet's reserves are insufficient.

Alaska LNG

Phase 1 Pipeline Route

Source: Alaska Gasline Development Corporation (AGDC)

Phase 1 of the Alaska LNG project is dedicated to constructing critical pipeline infrastructure to transport natural gas from Alaska's North Slope to the energy-demanding regions of Southcentral and Interior Alaska. This initial phase involves laying down an extensive 807-mile, 42-inch-diameter pipeline capable of moving up to 3.3 billion cubic feet of gas per day. A vital component of this phase is the establishment of a sophisticated Gas Treatment Plant located at Prudhoe Bay, designed to process and purify the natural gas, including the critical removal and subsequent reinjection of carbon dioxide back into the reservoirs.

Commencing construction around 2026, the pipeline is expected to become operational by approximately 2029, representing an impressive infrastructure achievement. With an estimated investment cost of around $10.8 billion, this foundational phase addresses the imminent energy shortfall resulting from declining production in Cook Inlet. Ensuring a reliable gas supply will considerably enhance energy security and support regional economic stability.

Strategically, this initial development not only addresses Alaska's immediate energy needs but also establishes the necessary groundwork for future phases. It provides the critical physical and logistical backbone required to facilitate the subsequent construction of liquefaction and export facilities, positioning Alaska as a significant player in the global natural gas market.

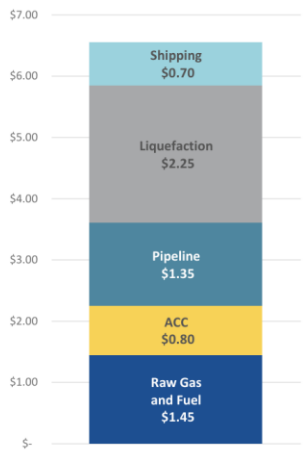
In June 2024, Pantheon Resources signed a Gas Sales Precedent Agreement (GSPA) with the Alaska Gasline Development Corporation (AGDC), outlining commercial terms for supplying up to 500 mmcfd of natural gas from its Ahpun and Kodiak fields into Phase 1 of the Alaska LNG project. The deal sets a base gas price of $1/mmBtu (2024 dollars) under a 20-year term, supporting AGDC's plan to deliver low-cost energy via an 807-mile pipeline from the North Slope to Southcentral Alaska. For Pantheon, the agreement enables monetisation of its large gas resource (over 6 Tcf), provides infrastructure access, and potentially underpins project financing without heavy equity dilution.

Given 88E's North Slope acreage lies in proximity to Pantheon's assets and the proposed pipeline route, it may hold similar potential to supply gas into Alaska LNG Phase 1. Leveraging future production from prospects Project Phoenix or Leonis could allow 88E to secure offtake agreements, improve project economics, and unlock value through infrastructure-led development.

Alaska LNG cost of supply to Asia

- $6.55 cost of supply delivered to Asia is lower than prevailing contract prices
  - Brent Linked: $9.10 *($70 Brent* x 13 percent)*
  - U.S. Gulf Coast: $9.00 *($3.00 Henry Hub** + $6.00)*
  - JKM: $9.00 *(approx. current spot price)*
- Verified by Wood Mackenzie
- 2023 update to account for recent construction inflation, 45Q tax credits, and financial return expectation – remains largely unchanged

* Based on forward curve for Brent ~$70/bbl
** Forward curve for Henry Hub averages closer to $3.50/MMBtu



Source: Alaska Gasline Development Corporation (AGDC)

The second phase focuses on the construction and development of LNG export infrastructure designed to convert and ship Alaskan natural gas to global markets, particularly targeting demand in Asian countries. Central to this phase is a large-scale liquefaction plant proposed for Nikiski on the Kenai Peninsula, which upon completion will have the capacity to produce up to 20 million metric tons of LNG annually. This facility is complemented by storage tanks and dedicated marine export terminals to efficiently handle international shipments.

Scheduled to follow promptly after the pipeline's completion in Phase 1, Phase 2 infrastructure aims to be operational by 2030 or 2031. It represents a substantial increase in scope and investment, with estimated costs reaching approximately $33 billion. Such investment underscores the project's scale and ambition, reflecting the global significance and market opportunities available for Alaskan LNG.

The completion of this phase positions Alaska strategically within the global energy landscape, providing material economic benefits through export revenues. It strengthens trade relationships with key international markets, diversifying Alaska's economic prospects, and enhancing geopolitical ties. By establishing Alaska as a reliable LNG exporter, Phase 2 significantly broadens the state's economic base beyond domestic consumption.

Operational Considerations Unique to Alaska

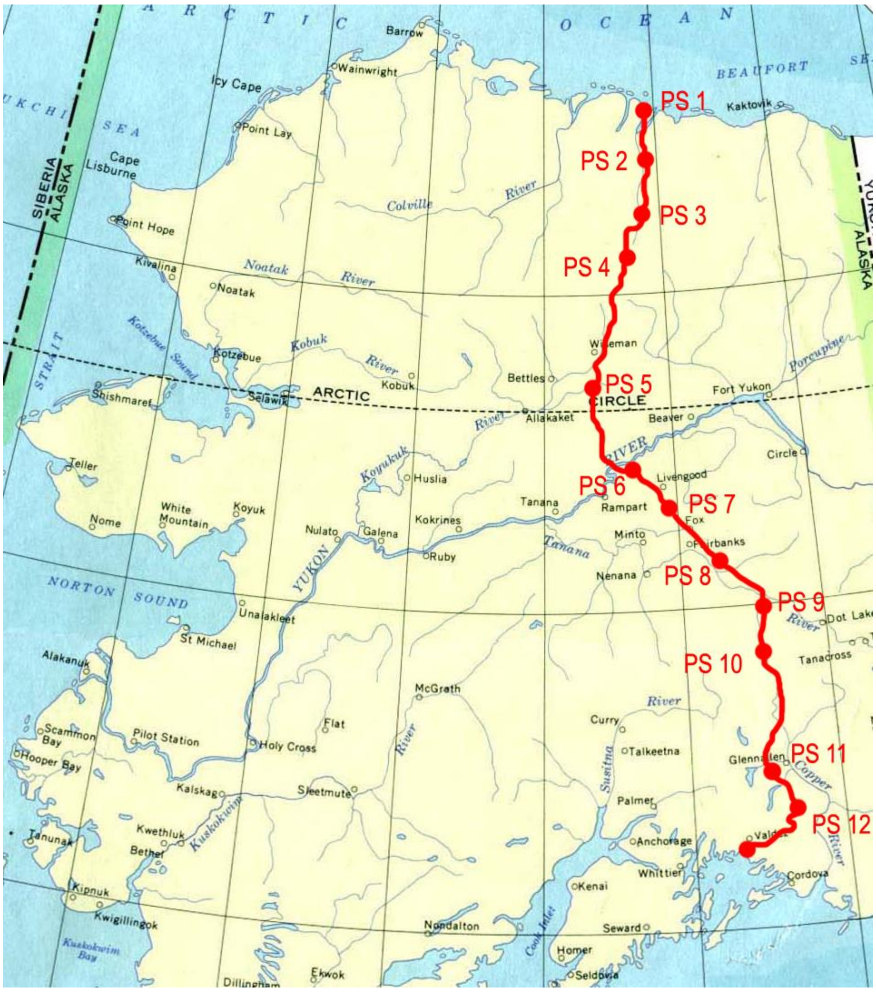
Operating in Alaska's North Slope comes with distinct challenges and requirements, but industry has developed effective strategies to manage them. Key factors include:

Seasonal Drilling Windows: Much of the North Slope's exploration activity occurs in winter. Outside of existing road infrastructure, the tundra is only accessible when it is frozen and snow-covered (typically December through April). Companies build ice roads and ice pads during winter to move rigs and equipment to remote drill sites; when spring comes, these ice roads simply melt, leaving no trace on the tundra. The short season means exploration wells must be drilled efficiently within winter, or operations must pause until the next season. This influences project scheduling – for example, 88E's Merlin wells and Pantheon's winter campaigns had hard stop dates as the tundra travel season ended. Development drilling at established pads (with gravel roads/airstrips) can occur year-round, but any new exploration in unroaded areas follows this winter-only rhythm. The industry has adapted by using modular rigs designed for Arctic moves, and by extensive pre-planning so that everything (personnel, materials) is on site once ice roads are open. While the seasonal constraint is a challenge, it also ensures minimal environmental impact during the sensitive summer period for wildlife.

Extreme Climate and Logistics: The North Slope is an Arctic desert with winter temperatures dipping to –40°F/C, fierce winds, and 24-hour darkness in mid-winter. These conditions require specialised equipment (winterised rigs, heated enclosures) and experienced crews. Logistics are complex: heavy equipment and modules often must be barged to Prudhoe Bay or brought up the Dalton Highway (the lone road connection from Fairbanks to Deadhorse) during summer, staged at base camps, then moved via ice road in winter to site. Despite the cold, operators note that the frozen ground in winter actually facilitates heavy operations (no mud, load is spread on ice). Still, companies must be prepared for weather downtime (blizzards can halt flights or trucking). As one veteran explorer quipped, "it's wicked cold, it's remote…costs are higher because of that" – which is true, but modern technology and decades of experience have largely tamed the Arctic. For instance, companies utilise icebreaker tugs to keep sea lanes open for late-season barge deliveries and employ enhanced weather forecasting to optimise work windows. Over the years, service providers in Alaska have become adept at these logistics, making it routine to deliver drilling campaigns on schedule despite the weather.

Infrastructure & Transportation: A major advantage in Alaska is the **Trans-Alaska Pipeline System (TAPS)** – an existing 800-mile pipeline that ships crude from Prudhoe Bay to the ice-free port of Valdez. Any new oil discovery on the North Slope can theoretically be tied into TAPS, giving direct access to world markets without the need to build a brand-new long pipeline (a huge cost saving). TAPS has substantial spare capacity (currently ~25% utilised) and is a regulated common-carrier pipeline, so explorers know they have an export route. Oil arriving at Valdez is loaded onto tankers; historically, Alaska crude was mostly sent to West Coast U.S. refineries, but since the U.S. export ban was lifted in 2015, Alaska North Slope crude can also be exported to Asia or elsewhere if economics favour. Within the North Slope, a network of feeder pipelines connects various fields to TAPS. New developments typically build small pipelines to link into this network. For example, Pikka will connect via an 18-mile pipeline to the Kuparuk field pipeline system, and Willow will connect via a 200-mile pipeline system to Alpine and onward to TAPS. The **map below** shows the TAPS route from Prudhoe Bay to Valdez, with pump stations along the way:

Trans-Alaska Pipeline System (TAPS) route (red line) spanning ~800 miles from Prudhoe Bay in the North (PS 1) to the Valdez Marine Terminal in the South (PS 11/12).



Source: Wikipedia

TAPS has been operating since 1977 and remains in good condition, but lower throughput has required mitigation like adding heaters and pigging more frequently to prevent wax deposition. The pipeline's operators have studied solutions to keep it running at even 150,000 bpd if needed, but the preferred solution is of course more oil. Every new barrel from projects like Willow/Pikka or future 88E successes will help keep the pipeline above the critical threshold (~300–350k bpd) for smooth operation. On the North Slope, aside from pipelines, road infrastructure is limited to the Prudhoe/Kuparuk area and the Dalton Highway to Fairbanks. Thus, companies often rely on seasonal ice roads or on air transport (helicopter or small planes to ice airstrips) for more distant prospects.

For coastal prospects, sealift barges deliver heavy modules in summer via the Arctic Ocean. These logistical considerations are built into project costs, which is why large-scale discoveries are needed to justify development. The flip side is, once infrastructure is extended to a new area, it opens up access for smaller accumulations around it.

Environmental and Regulatory Practices: Alaska operations are governed by stringent environmental standards (both state and federal). Companies must have robust oil spill contingency plans, utilise specific technologies like down-hole safety valves in wells, and adhere to wildlife disturbance mitigations (e.g. suspending operations if caribou are moving through). Over decades, industry and regulators have collaborated to minimise footprint: drilling pads have shrunk in size even as the number of wells per pad increased via extended-reach drilling. For example, one gravel pad can host dozens of wells that reach out 4-8 miles in all directions underground, tapping a large area while surface impact is minimal. Operators time certain activities (like seismic surveys or heavy air traffic) to avoid sensitive periods for polar bears or subsistence hunting. The use of ice roads itself is an innovation to have a temporary footprint. All of this means working in Alaska requires careful planning and often higher upfront costs for mitigation – but it has allowed development to coexist with the Arctic environment successfully. The proof is that fields like Prudhoe Bay have been producing for over 45 years with a strong safety record, and projects like Alpine (in the sensitive Colville River delta) were developed roadlessly to protect caribou migration. Political support, as mentioned, is tied to doing things "the right way" – the state expects operators to uphold high standards.

In summary, Alaska's operational environment demands **adaptation and resilience**. The short winter drilling season, remote logistics, and environmental safeguards add complexity (and cost) compared to, say, drilling a well in Texas. However, the industry has refined its methods (ice roads, modular moves, enhanced drilling technology) to the point where these challenges are manageable and well-understood. The reward for overcoming them is access to significant oil accumulations with relatively little competition. As veteran Bill Armstrong noted, the opportunities are huge – you just have to deal with the cold and isolation. Indeed, many companies have found that the scale of Alaska's prize makes the extra effort worthwhile. Plus, each successful project tends to improve the infrastructure and knowledge base, making subsequent operations easier. With new pipeline connections, roads, and continued innovation, the operational hurdles are gradually lowering. For a company like 88E, partnering with experienced contractors and leveraging existing infrastructure can mitigate many of these challenges, allowing it to focus on the geology which – in Alaska – has proven to be very favourable for those who crack the code.

Management Overview

88E's leadership team demonstrates a strong alignment with the company's stated strategy, which emphasises high-impact exploration and appraisal, particularly on Alaska's North Slope. The leadership team collectively possesses the requisite technical skills for identifying and appraising assets, operational experience for project execution in key regions, and the commercial and financial acumen for managing funding, executing farm-outs, and implementing value realisation strategies. This integration of experience across various aspects of the exploration and production lifecycle, particularly in technical, operational, and financial/commercial domains, aligns well with the company's strategy of advancing high-impact exploration projects toward monetisation.

Name	Experience
Mr Ashley Gilbert (Managing Director)	• Chartered Accountant with over 25 years' experience, including senior finance, commercial and governance roles in the oil and gas industry. • Held leadership roles at 88 Energy, Neptune Marine Services, Nido Petroleum, Woodside Petroleum, and GlaxoSmithKline.
Mr Oliver Mortensen (Chief Financial Officer)	• Chartered Accountant with over 20 years of experience in executive leadership, financial planning, and analysis. • Held senior roles in the resources sector at Newmont, Barrick, Bardoc, BGC, and Thiess.
Mr Philip Byrne (Non-Executive Director)	• A petroleum geologist with over 40 years of international oil and gas experience across technical, exploration, commercial, and executive leadership roles. • Held senior positions at Santos Energy, Nido Petroleum, the North-West Shelf Australia LNG organisation, and BHP Petroleum.
Ms Joanne Williams (Non-Executive Director)	• A petroleum engineer with over 25 years of global oil and gas experience, including senior leadership and board roles. • Most recently served as Managing Director and CEO of Blue Star Helium.
Dr Stephen Staley (Non-Executive Director)	• Over 35 years of international experience in the oil, gas, and power sectors. • Co-founder of Fastnet Oil & Gas and Independent Resources, and founder of Derwent Resources. • Held prior roles at Cove Energy, Cinergy, Conoco, and BP.
Dr Stephen Staley (Non-Executive Director)	• Over 35 years of international experience in the oil, gas, and power sectors. • Co-founder of Fastnet Oil & Gas and Independent Resources, and founder of Derwent Resources. • Held prior roles at Cove Energy, Cinergy, Conoco, and BP.
Mr Ric Jason (Exploration Manager)	• Geoscientist with over 30 years of international oil and gas experience, delivering multiple commercial discoveries. • Held leadership roles at Pancontinental, Key, Neon, FAR, and OMV, with operational roles at Hardman, BHP, Origin, and Cultus.
Mr Matt Fittal (Principal Subsurface Advisor)	• Geologist with over 30 years of experience in technical and operational roles. • Held exploration and production roles at BHP Billiton and contributed to several commercial oil and gas discoveries.

Source: 88 Energy

Company History

2020

April: Charlie-1 well confirmed as a condensate discovery in the Torok Formation; commerciality under review. Preliminary petrophysical interpretation confirmed hydrocarbon pay in the Torok and Seabee Formations.

May: 88 Energy and XCD Energy agreed to merge, creating an Alaska-focused explorer with three key projects.

August: Completed acquisition of XCD Energy, securing 100% ownership.

August: Final petrophysical analysis of Charlie-1 upgraded net hydrocarbon pay.

October: 88E increased its working interest in Project Icewine.

November: Declared a large 1.77bnboe boe Prospective Resource at Project Icewine.

December: Farm-out agreement signed with APDC for 50% of Project Peregrine, funding Merlin-1 well.

2021

January: Executed agreement to acquire the Umiat Oil Field, adding 123.7mmbbl of 2P reserves.

February: Received Permit to Drill Merlin-1; spudded in late Feb.

February: Released Independent Prospective Resources Report for Project Peregrine, totalling over 1.6bnbbl.

May: Ashley Gilbert appointed as Managing Director (previously CFO)

June: Acquired 50% in Project Peregrine from APDC, taking 88E to 100%.

July: Hydrocarbons confirmed in Merlin-1 sidewall cores; further analysis pending.

July: Final share issuance for Peregrine acquisition; 88E fully owns the project.

August: Merlin-1 confirmed light oil across multiple targets; appraisal well planned for Q1'22.

November: Oliver Mortensen joined 88E as CFO

December: Merlin-2 preparations underway with road construction and permitting in progress.

2022

January: Commenced trading on the US OTCQB under the ticker EEENF.

February: Acquired producing oil and gas assets in the Texas Permian Basin for US$9.7M.

March: Spudded the Merlin-2 appraisal well; drilling targeted three Brookian intervals.

April: Production at Project Longhorn > 400boe/d following successful workovers.

August: Declared maiden 1.03bnbbl Prospective Resource at Project Icewine East.

2023
March: Spudded Hickory-1 to appraise six reservoirs including SMD and BFF.

April: Petrophysical interpretation from Hickory-1 confirmed multiple hydrocarbon zones with ~450 ft net pay.

April: Awarded full lease for Project Leonis by the Alaskan DNR.

July: Acquired new Permian Basin assets near Project Longhorn for US$1.1mm; targeting 160–200boe/d from new drills.

July: Updated Prospective Resources at Project Peregrine after new seismic and reservoir interpretation.

September: Flow test planning for Hickory-1 progressed; Upper SFS found to be more extensive.

October: Provided portfolio-wide update; flow test planning advanced, and new prospects identified across Alaska.

October: Engaged NSAI to certify maiden BFF Contingent Resource at Project Phoenix.

November: Confirmed Hickory-1 discovery; 250mmboe 2C resource certified for BFF.

November: Farm-in agreement signed to earn up to 45% of Namibia's PEL 93, large onshore position in the Owambo Basin, with 200 km 2D seismic planned.

December: JV partner Burgundy funded US$2mm towards Hickory-1 testing; standstill on default agreed.

December: Acquired further Permian Basin acreage; new wells and workovers targeting 600–675boe/d by YE'24.

2024
February: 88E completed the transfer of 20% in Namibia's PEL 93.

February: Preparations commenced for flow testing of the Hickory-1 discovery.

March: Hickory-1 flow testing started with the Upper SFS zone.

April: The Upper SFS zone at Hickory-1 flowed light oil, confirming a high-quality reservoir with marketable liquids; operations transitioned to the SMD-B reservoir.

April: A second light oil discovery was confirmed in the SMD-B reservoir at Hickory-1; both reservoirs demonstrated strong deliverability to support independent Contingent Resource declarations.

May: 88E awarded a seismic contract to Polaris for the PEL 93 exploration programme; 2D acquisition of ~200 line-km was planned for mid-2024.

June: A maiden internal Prospective Resource of 381mmbbl was declared for Project Leonis' USB reservoir; farm-out discussions and Tiri-1 well planning began.

July: 2D seismic acquisition over PEL 93 was completed on time and on budget, with processing underway to support future resource estimation.

September: 88E announced a >50% increase in Project Phoenix Contingent Resources following independent certification of the SFS and SMD-B reservoirs.

October: Seismic processing for PEL 93 was finalised, confirming significant structural closures and setting up for a maiden Prospective Resource estimate.

December: Initial interpretation of 2D seismic confirmed 10 promising leads in southern PEL 93; internal validation and integration with geophysical data commenced.

December: 88E secured four new lease blocks adjacent to Project Leonis, expanding its position to over 35,000 acres and unlocking multi-zone potential.

2025

January: A maiden Prospective Resource estimate of 283mmbbl (net mean, unrisked) was declared for the Canning Formation at Project Leonis; the combined multi-reservoir total now stands at 798mmbbl gross (Pmean).

February: 88E signed a farm-out agreement with Burgundy Xploration for the 2025/26 Phoenix horizontal well programme, fully carried up to US$39mm; Burgundy will become operator.

May: 88E completed a 25:1 share consolidation, reducing total shares outstanding to ~1.16bn.

Investment Risks

88E is exposed to a range of investment risks common to frontier oil and gas explorers, as well as several specific to its North Slope Alaska and onshore Namibia operations. Key risks include:

Exploration risk: 88E's exploration projects – Project Leonis and Phoenix, carry geological risks. Despite de-risking activities like reinterpreting historical data and recent flow tests, unexpected reservoir complexities, poor permeability, or water intrusion could result in sub-commercial discoveries. Past experiences, such as the low permeability encountered in Project Peregrine's Merlin-2 well, underline these inherent exploration uncertainties.

Operational challenges in remote locations: The company operates in remote areas with extreme climates like Alaska's North Slope and frontier regions in Namibia, posing logistical and operational risks. Although existing infrastructure reduces some risk, challenges related to harsh weather, limited operating windows, equipment failure, or difficulty accessing sites can hinder drilling schedules and budgets.

Permitting and environmental approvals: 88E's projects in Alaska require multiple environmental and operational permits, which can face delays, notably for planned wells like Tiri-1 and Phoenix's horizontal appraisal well. Additionally, any tightening of environmental regulations or unexpected compliance requirements in Alaska or Namibia could further delay project timelines, increase costs, or even halt planned drilling operations.

Funding risk: Although partially mitigated by production revenues from Project Longhorn, 88E remains reliant on external financing given the large capex requirements. Failure to secure sufficient funding could force delays or cancellations of key exploration and appraisal activities.

Partner and farm-out risk: 88E relies on farm-out arrangements with Burgundy Xploration for Project Phoenix and potential partners for Leonis. If partners fail to raise adequate capital, as Burgundy might face IPO funding challenges, or withdraw from agreements, 88E may incur additional financing obligations or project delays.

Namibia: As 88E continues to build its portfolio, such as its recent entry into onshore Namibia, there is execution risk associated with entering new geological settings, securing data, navigating local regulations, and building operational capabilities in-country.

Dependence on early-stage exploration success: The value proposition for 88E substantially relies on high-impact exploration. 88E's strategy is to begin with a small initial development and only if its of commercial grade will it proceed towards the full field development. Any negative exploration outcomes, even from adjacent operators like Pantheon or Recon Africa, could considerably increase perceived risk for its assets. Poor initial results may jeopardise the full field development which holds substantial value in the NAV.

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