BOE Report Weekly Round-up
February 14th, 2025

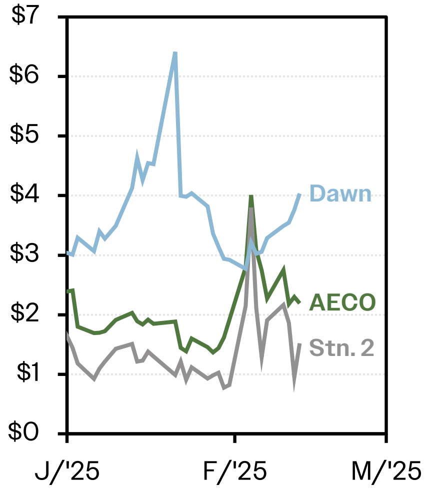
Happy Valentines Day!

Tourmaline is done flowing back their B-024-I/094-B-09S pad, an extremely consequential one as it's their first high-intensity completion with lagged development and wine-rack spacing *within* each bench. By the numbers – we think the 21 north wells will average 3.5Bcf of raw gas each, not bad – but we think the south wells will all outperform the best north wells in each bench. Currently, there are 7 south producers targeting the Upper & Upper Middle Benches, with another 10 to come online targeting the Lower Middle & Lower benches. Early well results are phenomenal, and we're potentially seeing a capital efficiency improvement story unfold, aided by a new transload terminal.

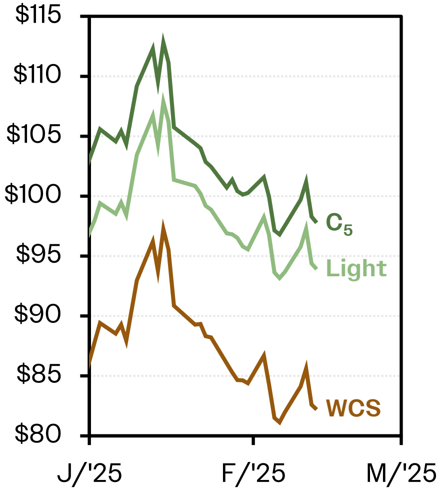
Inside, we discuss WCSB well results compared to the Permian, frac efficiency in the Duvernay, and the oil-weighted assets that may be next to transact.

Recently, consistently improving well results have driven Montney development updip into the volatile oil windows at Wembley, Gold Creek, Pouce Coupe, and Waskahigan. Results from 2024 development wells have been best-yet, with rumors of HWN wells testing at >1,500Bbls/d, and Veren's Karr wells posting ~1,600Bbl/d IP_{30PD} rates. As operators revisit old areas with new D&C technology (NCS sleeves, better pumping equipment, even multilaterals) and a better reservoir understanding, well results have improved commensurately. Historically, there has been some horizontal development in the conventional Montney where traps made for oil accumulations in small pools, though the renewed focus has been targeting the updip fairway as more of a resource play.

Producer Netback Gas Prices by Hub (CAD$/GJ)



Spot Edmonton/Hardisty Crude Pricing (CAD$/Bbl)



Note: Gas netbacks assume Gordondale plantgate, long-haul tolls assumed at minimum FT-R rates
Source: Bloomberg, NGI, HTM Data Suite

Weekly Headlines

[The AER appoints Rob Morgan as its new CEO]

[PD announces 2024 year end financial results]

[BIR announces 2024 year end financial results]

[LTC announces its listing on the TSXV]

[PSK announces 2024 results, dividend increase]

[IPCO announces 2024 results, 2025 budget, reserves]

[TVE announces reserves, provides operational update]

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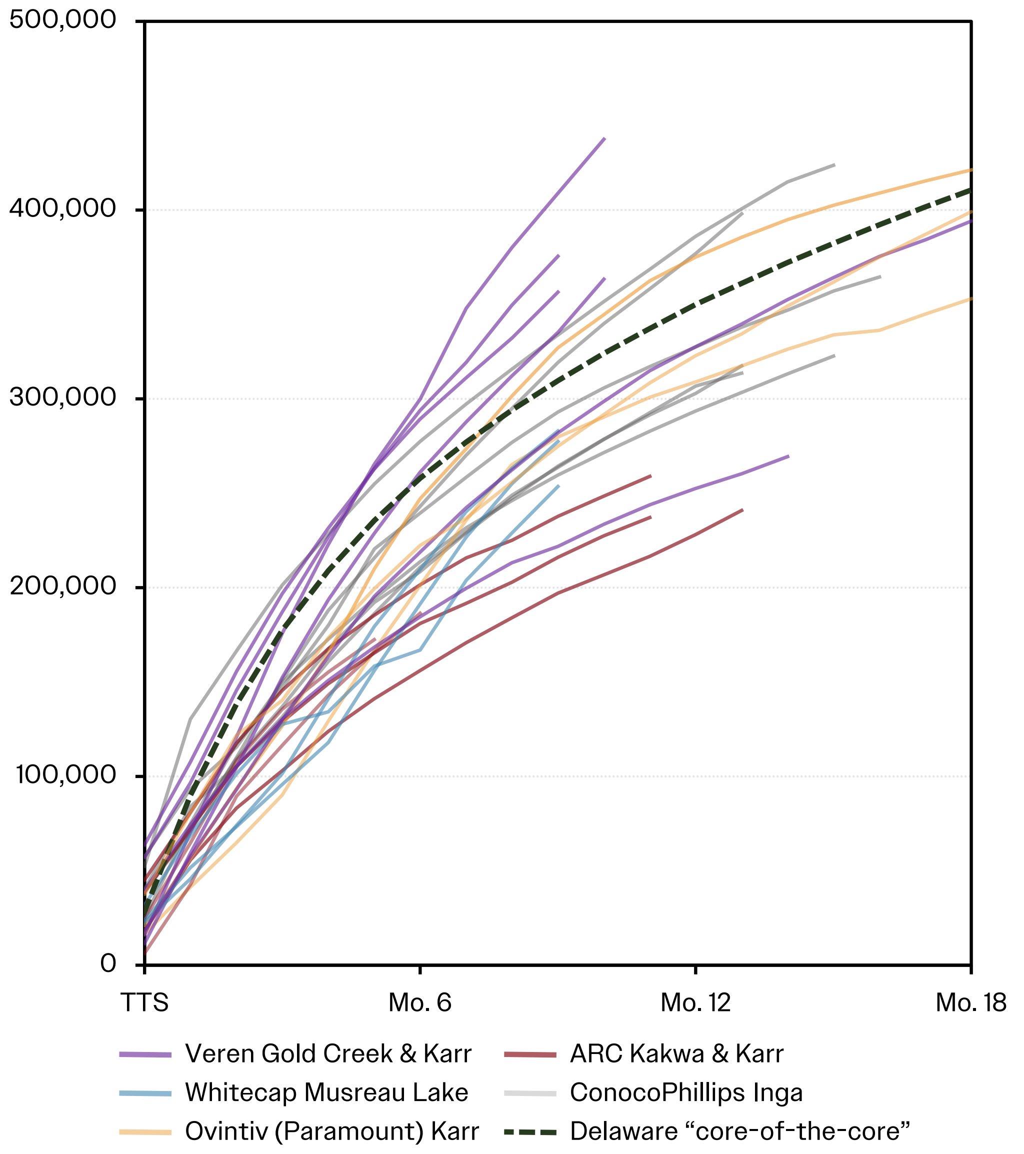
2-14.1: Select WCSB Oil/Condy Cumes vs. Core Delaware (Bbls)



The Best Wells in North America... Now Made in Canada

While most are familiar with the first-developed Midland side of the Permian Basin, development economics to the West in the Delaware side are even more attractive; with "core-of-the-core" Delaware wells (bounding and bench agnostic) producing ~700,000Bbls throughout their lifetime, and ~400,000Bbls in the first 1½ years online.

Each year, <15% of wells drilled in the Delaware cinch that 'core-of-the-core' status by breaking 700,000Bbl EURs, though in the Montney, it may be more than you'd think – with ~60 wells (~6% of TILs) competing with the prestigious core-of-the-core Delaware. Earning that 'core-of-the-core' status is nothing to take lightly, the wells are some of the most economic in the world, and highly desirable in the M&A market. In 2024, we estimate Matador paid C$5.2MM per risked Delaware location in their Ameredev acquisition.

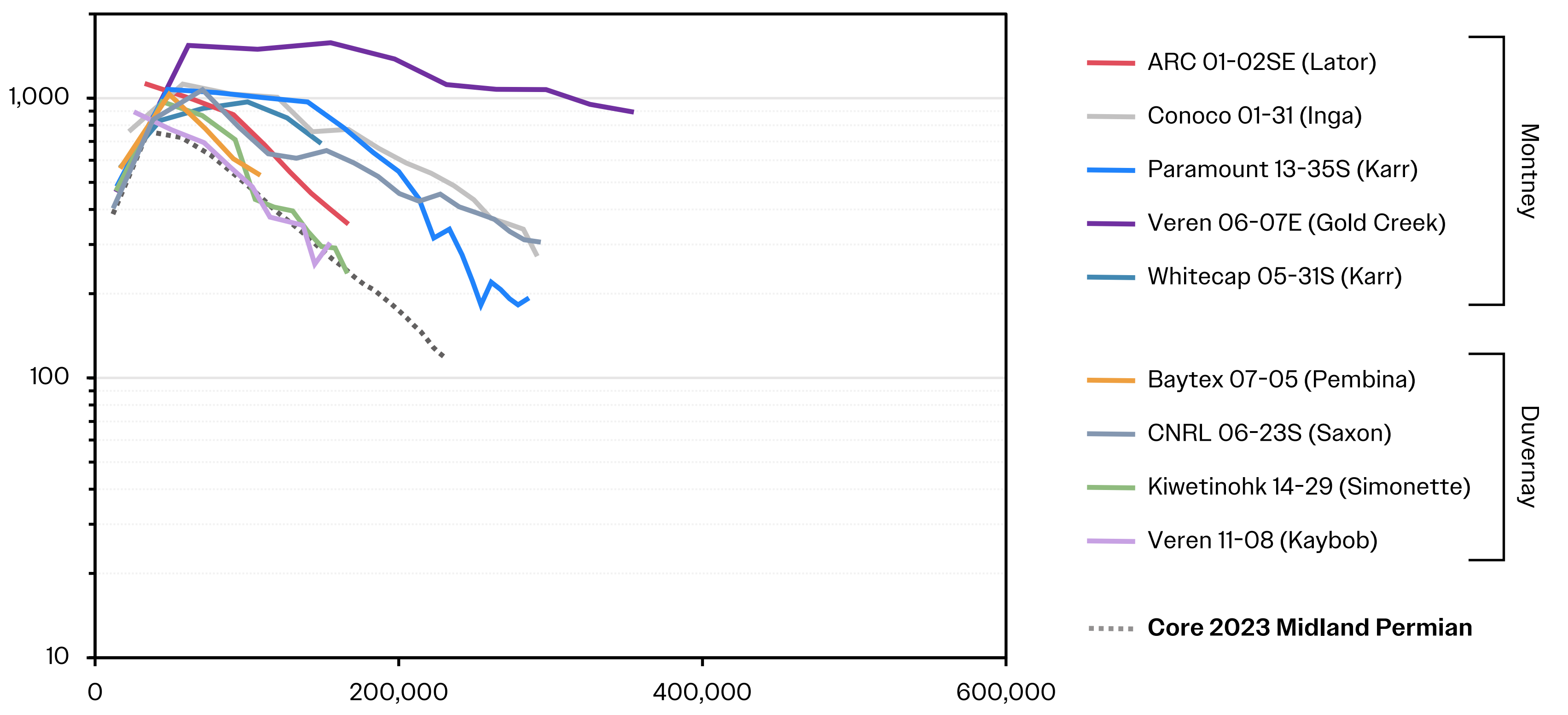
Take Paramount's (now Ovintiv's) Karr asset for example – it's unquestionably the second best Montney asset, beat only by ConocoPhillips' Inga asset. When Ovintiv bought it, they claimed it expanded their "premium inventory" count by 60% (their metrics!) at just C$1.4MM per premium location, a 75% discount to prevailing US deal metrics!

HTM is so focused on appraising Canada's unconventional plays because the US is addicted to shale. While they'll continue to scratch that itch through exploration and bench expansion in the L48; there's no denying that as Canadian E&Ps continue to progress local plays, the WCSB becomes an increasingly attractive place to search for well delineated and highly productive inventory at a discount. Shale wells are one of the most beautiful assets in the world, with the best now made right here in Canada.

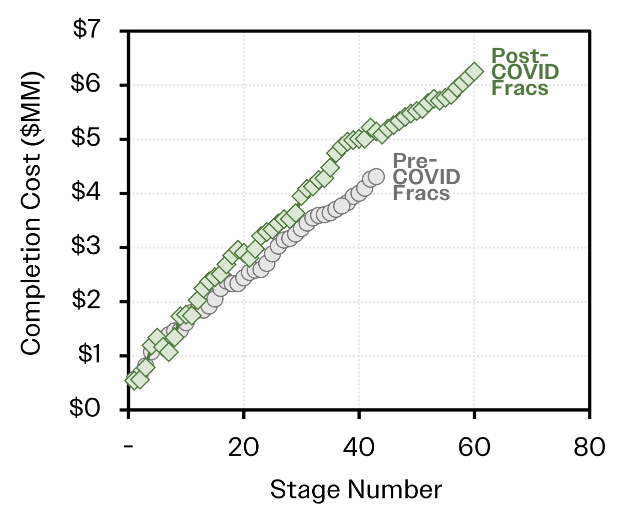
While only a handful of individual development wells can compete with the core of the Delaware Permian, much more consistently do WCSB unconventional wells compete with the core of the Midland Permian where EURs are lower, in the 4-500,000Bbl range. US focused M&A still sees a relatively sizeable (and persistent) 'Permian premium', and while other US basins still do compete with the Midland (namely, the Uinta, Bakken, and parts of the SCOOP/STACK); running room is challenged in those plays compared to Canada, and A&D competition still fierce. While Midland locations trade for C$2-4MM, in Canada, equivalent quality locations are <C$1MM.

Generally, we prefer unconventional plays as we don't think large US producers will cross the border for Clearwater-type inventory (where economics are still phenomenal) – driven by our view that capital absorbability is an underrated though extremely important M&A factor. Meaning, an E&P can invest US$15-17Bn into 2,000 unconventional locations; while 2,000 conventional locations, even with waterflood support from day one, can only support $4-5Bn of capital investment.

2-14.2: Select WCSB Unconventional Pad Average Oil/Condensate Performance (Bbls/d & Bbls)



2-14.3: Running Duvernay Frac Costs

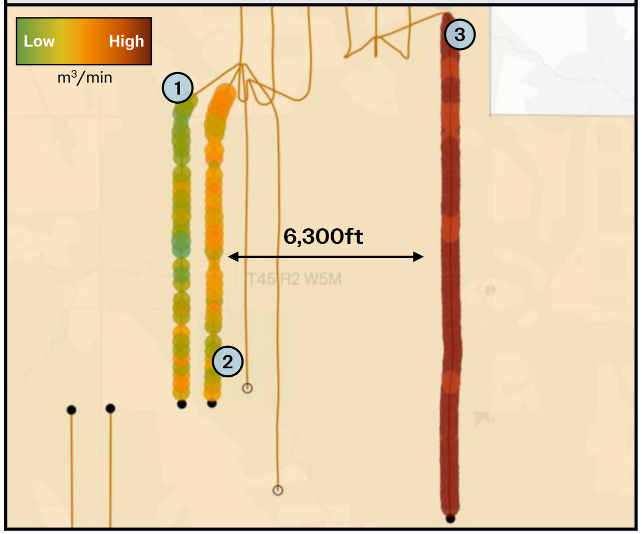


Duvernay Fracture Treatment Cost Analysis

While inflation has been the *thème du jour*, we wonder how much of that is simply due to longer laterals and bigger completions – i.e. cost inflation that is actively increasing EURs, leading to single-well F&D costs remaining relatively stable despite higher gross DCE&T costs. When we look at data compiled through the analysis of hundreds of Duvernay tour reports, we see that while average completion AFEs are ~75% higher, the inflation factor is typically overstated as stimulated stage counts are up ~50% since pre-COVID. Normalizing fracs to 45 stages, comparative completion costs are only up ~20%. But, at the same time, sand placed and water pumped is also up ~15% since pre-COVID. Call it a wash – we think inflation is real, but the productivity factor is up just as much. 1P F&D costs amongst Montney rich gas peers are up ~14% over 2019, for an annual inflation of ~2.5% – that's lower than the actual inflation rate!

Below we discuss how improved frac practices, while certainly more expensive, have earned their cost by delivering phenomenal well results. D&C improvements like this have offset services inflation, while also delivering more desirable inventory.

2-14.4: Baytex Frac Stage Map



Fracture Inflections Prove West Shale Basin Prospectivity

In 2024, Baytex demonstrated what a properly fracked well could deliver in the Pembina fairway. They delivered both consistently strong pumping rates, and a large increase in stage counts. To the left we show the stage-by-stage breakdown of 3 stimulations. The first two wells had low pumping rates and inconsistent stage placement. The third, and most economic well shows extremely strong pumping rates, and much tighter stage spacing. We believe that high pumping rates (>85Bbls/min), and a consistent completion are necessary to unlock the full potential in the Duvernay. This avoids frac channeling, and improves fracture complexity. Baytex has done a phenomenal job in the Pembina area.

These wells definitively prove that in the same geology; stage spacing and pumping rates can materially change EURs. The 3 generations of fracs were only executed ~6,300' apart, less than ½ the lateral length of a single well. While we still see (1) as producing an EUR of ~280,000Bbls, and (2) at ~350,000Bbls, we expect (3) will produce an EUR of almost 500,000Bbls – almost double the first generation frac. While the properly competed well cost ~30% more, we estimate the EUR improvement is 50-60%.

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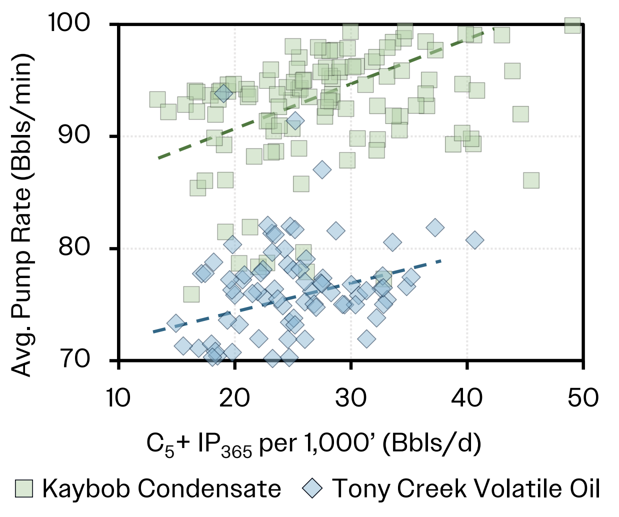
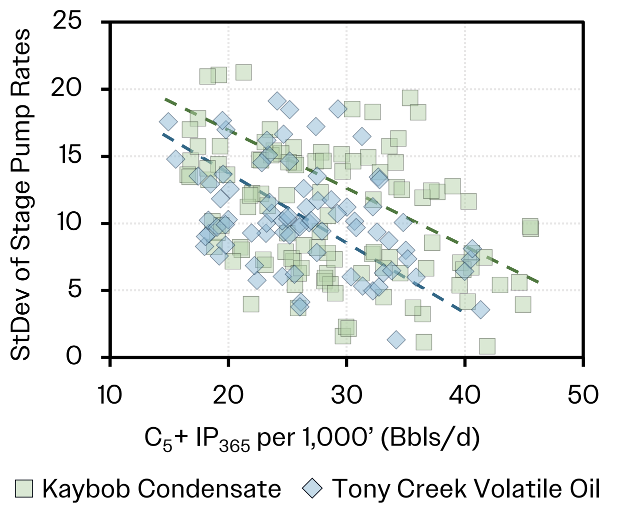
2-14.5: Frac Pumping Rate Scatter



High Pumping Rates Lead to Measurably Better Wells

Taking the frac investigation one step further, our multivariate analysis suggests that pumping rates (and breakdown pressure) are both important factors when improving Duvernay well results in similar geology. Logically, one underlying reason that pumping rates show a correlation with improved EURs, is that a more intense frac, with better pressure pumping equipment is more likely to stimulate the entire lateral proficiently; we've noticed that at Kaybob in pre-2021 wells, past ~9,000' of lateral length the effectiveness of the stimulation typically declines – though the correlation persists even when adjusting for lateral lengths. There is also the implication that a well executed frac, is a thoughtfully designed frac. Our findings also suggested that increasing fluid was a next step to improving EURs, though in our modelling, in the Pembina area we only saw increasing fluid per stage effectively improve EURs when proppant was also increased (i.e. Lbs/Bbl remained constant). Loading more friction reducer also had a statistically significant impact on EUR, suggesting there is possibly further upside to high-concentration friction-reducer fracs; which in theory should improve stimulation consistency along the lateral.

2-14.6: Frac Consistency Scatter



Pumping Consistency Shouldn't Be Overlooked Either!

For similar reasons as noted above; we also saw that more consistent fluid pumping resulted in better wells – i.e. when the standard deviation of stage pump rates is lower (less variation between stages), wells are *typically* better – though this correlation is noisier, it's directionally notable and fairly logical. Much like NCS fracs offer entry-point control, consistent pumping makes it such that entry point control is less important.

We noted that wells with more consistent pumping often saw increased contributions from the last ~30% of the lateral, but also a higher IP:EUR ratio, we think owing to improved proppant placement with a more uniform fracture network, and fracs that remain open for longer. Ultimately, when you've reached the limit of adding sand, and are looking to take Duvernay completions from "good" to "great" – high-tier pressure pumping equipment and well-planned fracs are crucial, especially in areas of worse mineralogy, like the West Shale Basin. When operating in poor mineralogy, we've also found that increasing the effective shot count along with very high pump rates can aid in delivering the "shatter" effect that doesn't happen otherwise in higher-clay rock.

Who's Next to Transact in the Oily Montney?

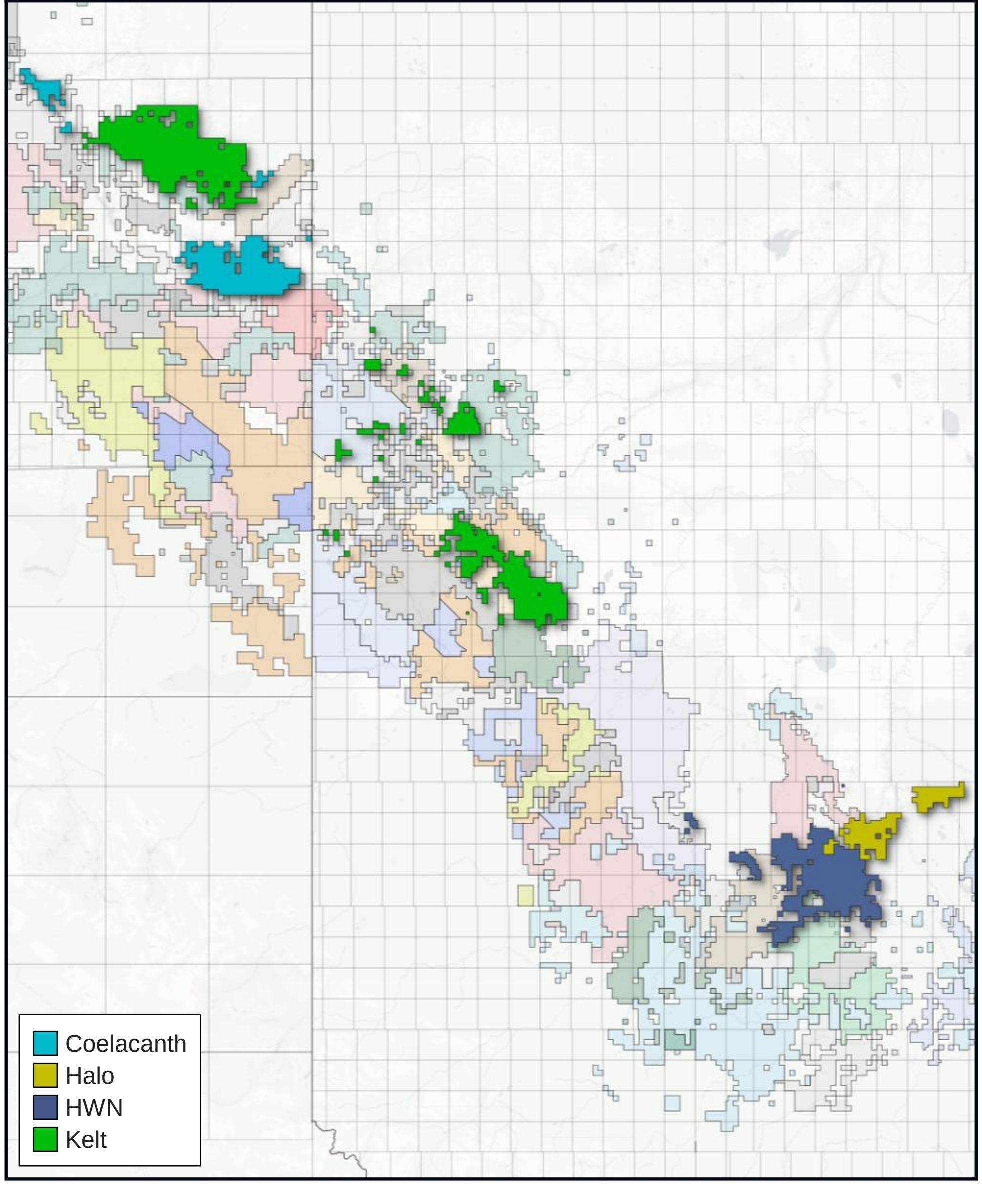
The updip oil fairway has seen major action over the last 3 years, with ARC, Hammerhead, Leucrotta, Pipestone, and Spartan all selling assets. Even Bonterra has joined the party with ~30,000 acres just to the east of Kelt's Wembley block, which has seen some very respectable well results (peak IP_{30}s of ~400Bbls/d).

As basin dynamics have changed with operators seeking scale the updip oil fairway has become a natural focus area for many – offering that scale; with upside to better fracs and exploration opportunities. Well economics are less sensitive to gas prices, DCE&T costs are lower, inventory is plentiful, and able to be organically acquired through the crown auctions.

Naturally, with downdip rich gas transaction valuations increasing (and AECO prices in the dumps), it'd be expected the asset builders that have focused updip over the past decade will seek to exit. Especially when considering only certain acquirers can ship downdip deals as accretive on an FY_1 basis when running economics using spot gas. We investigate 4 assets in various stages of maturity – Kelt Wembley is on the cusp of development mode, HWN is just implementing new fracs, Halo has drilled 2 pads and could bear a larger growth program, and Coelacanth has drilled various test wells and should soon have the infrastructure to support a larger growth ramp.

While updip assets typically have no more than 2 benches that can be viably codeveloped, they make up for that by generally being bigger, aerially. Our development framework for updip assets which are an order of magnitude more permeable than their downdip counterparts, favors single bench configurations. The semi-conventional nature of updip resource plays makes interactions between producing wells much more likely, and they aren't visible immediately. The high intensity fracs transforming updip assets simply aren't amenable to tight vertical spacing.

2-14.7: Select Greater Montney Updip Oil Focused Assets



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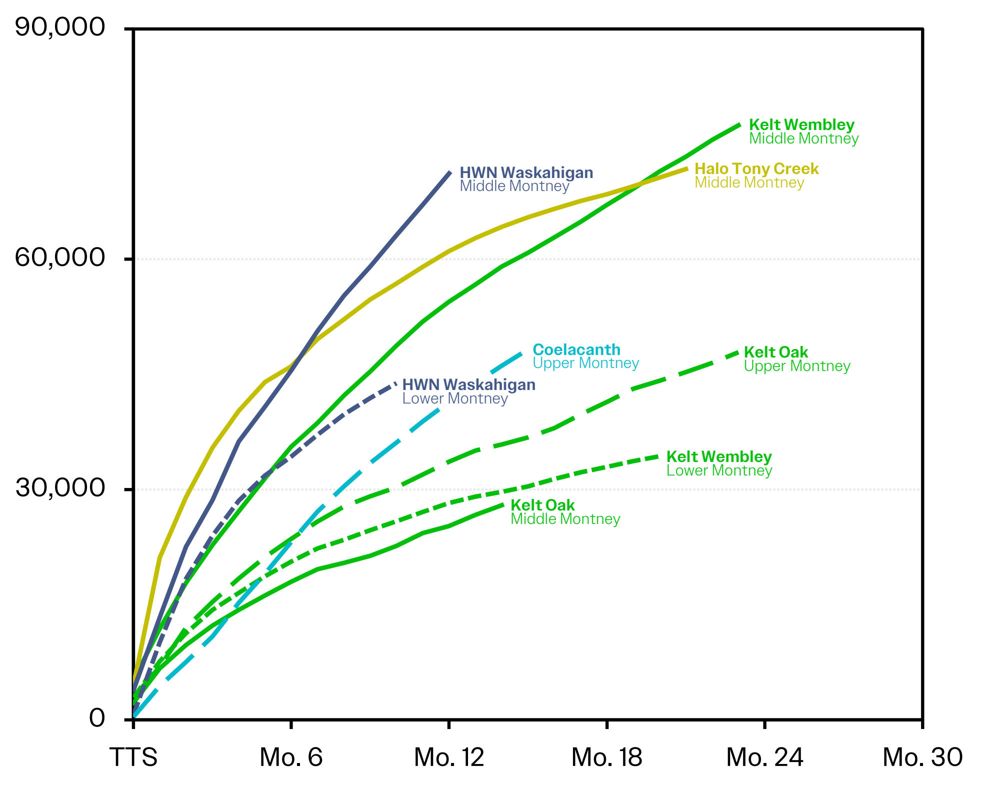
Well Performance and Growth History

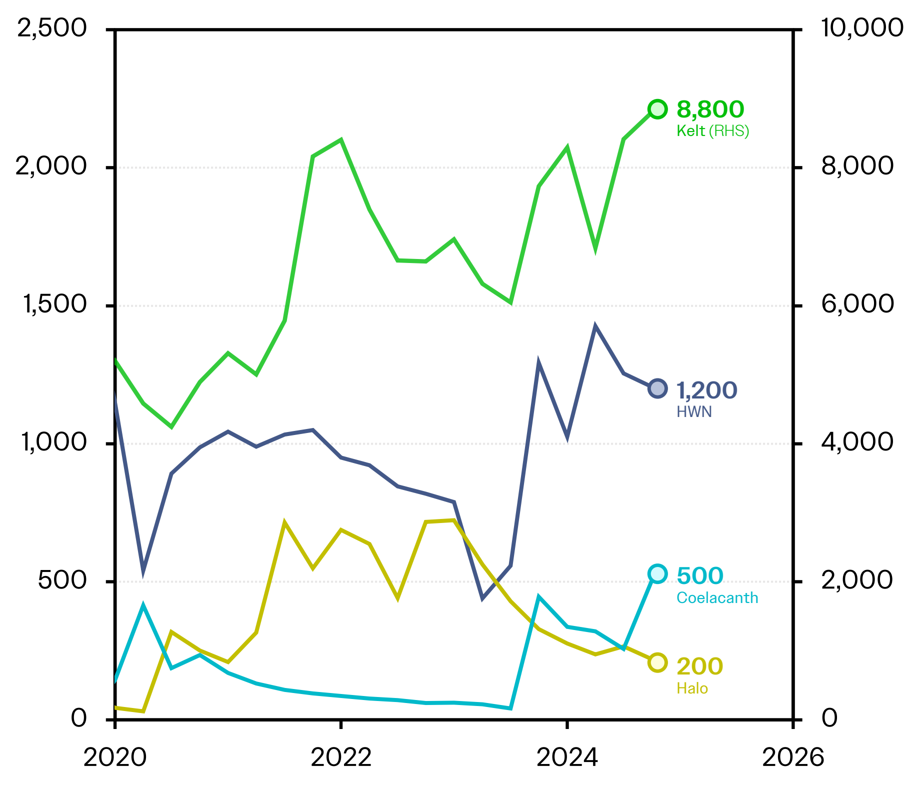
Most of the updip players have focused on growing volumes while delineating their asset(s). While Kelt and Coelacanth must build infrastructure from scratch at Oak and Two Rivers, respectively; Halo and HWN benefit to some extent from legacy Deep Basin and modern Duvernay infrastructure within their operating areas; and also benefit from more available NGTL meter space.

Kelt's assets win in terms of volumes, though HWN's Waskahigan wells are leading the pack in terms of cumulative oil in the first year, and we believe there's further upside on HWN's acreage. We think there is also upside to Kelt's Wembley results, but only if they switch to high intensity NCS completions – which would come at the cost of absolute inventory numbers, but would greatly improve single-well economics. Coelacanth and Halo Montney results are both early-stage, though promising.

2-14.8: Cumulative Raw Oil by Operator/Bench (Bbls)



2-14.9: Montney Oil Rates by Operator (Bbls/d)



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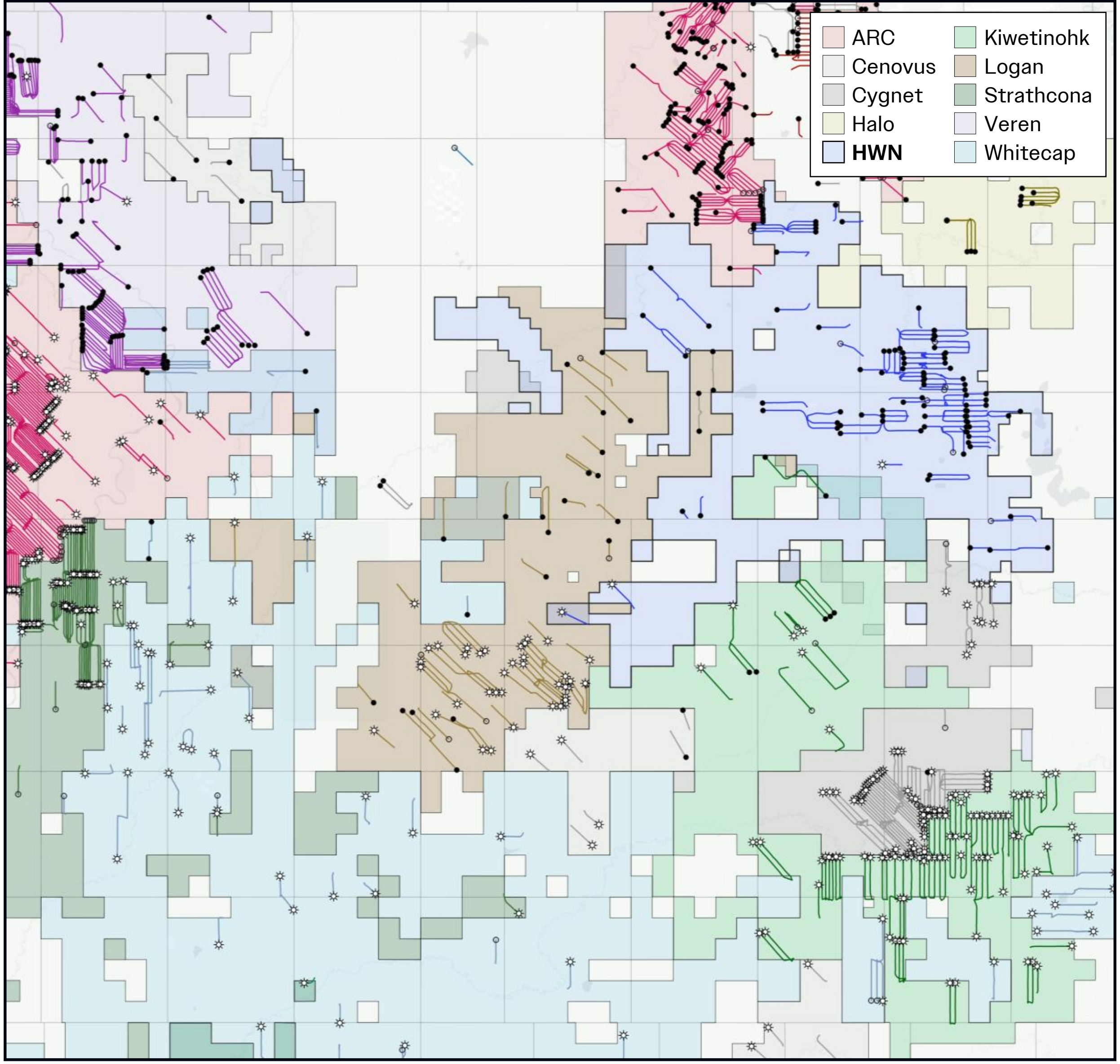
HWN Updip Montney Oil

A relatively new Montney player, HWN is a Carnelian backed E&P led by John Oberg. Despite an asset base that spans most of Alberta, HWN has managed to accumulate a massive Montney position in the Waskahigan oil window, which we are seriously constructive towards. Their initial wells have showed major improvements over legacy producers, owing to proper fracs with increased tonnage – key when transitioning from the conventional coquina and high-porosity features in the area; to semi-conventional – and not always done right. We think that HWN's Montney asset can consistently produce >315,000Bbl C_3+ wells. We see an inventory position of 370 locations, and despite the inconsistency of updip oil; we believe HWN's asset can support growth to 32,000BOE/d and maintain flat volumes for ~15 years, generating ~$250MM of field FCF annually. We like HWN's asset because there is less water risk than Ante Creek (though still elevated), with upside in lower benches.

HWN's other focus areas include Karr, where they produce the Dunvegan; and Lochend where the produce the Cardium. On an oil IP_{365} basis, HWN's Cardium wells are the 3rd the most productive in the play, beat only by Ricochet, and Whitecap.

At the corporate level, HWN has 800,000 acres of land (~200,000 unconventional), produces ~18,500BOE/d (~55% oil and NGLs), and has ~430 net unconventional locations.

2-14.10: Greater Waskahigan/Lator Montney Map

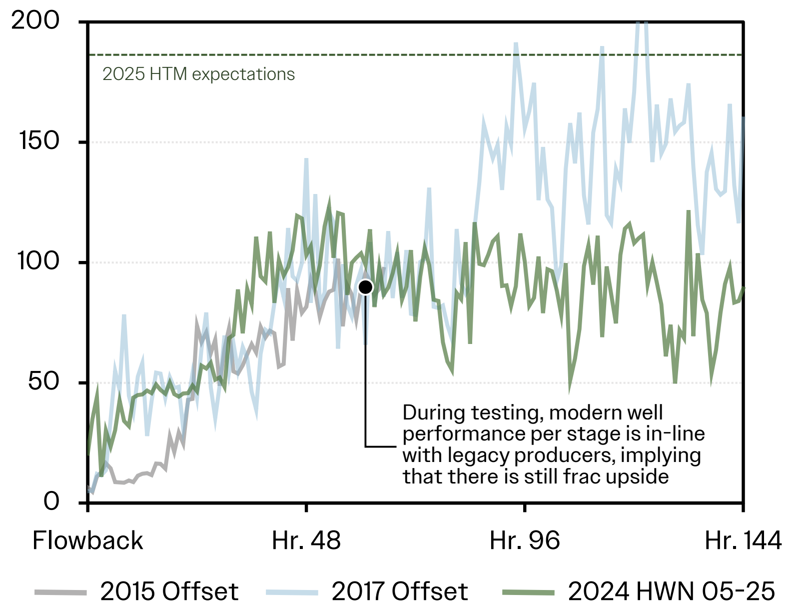


HWN Updip Montney Oil

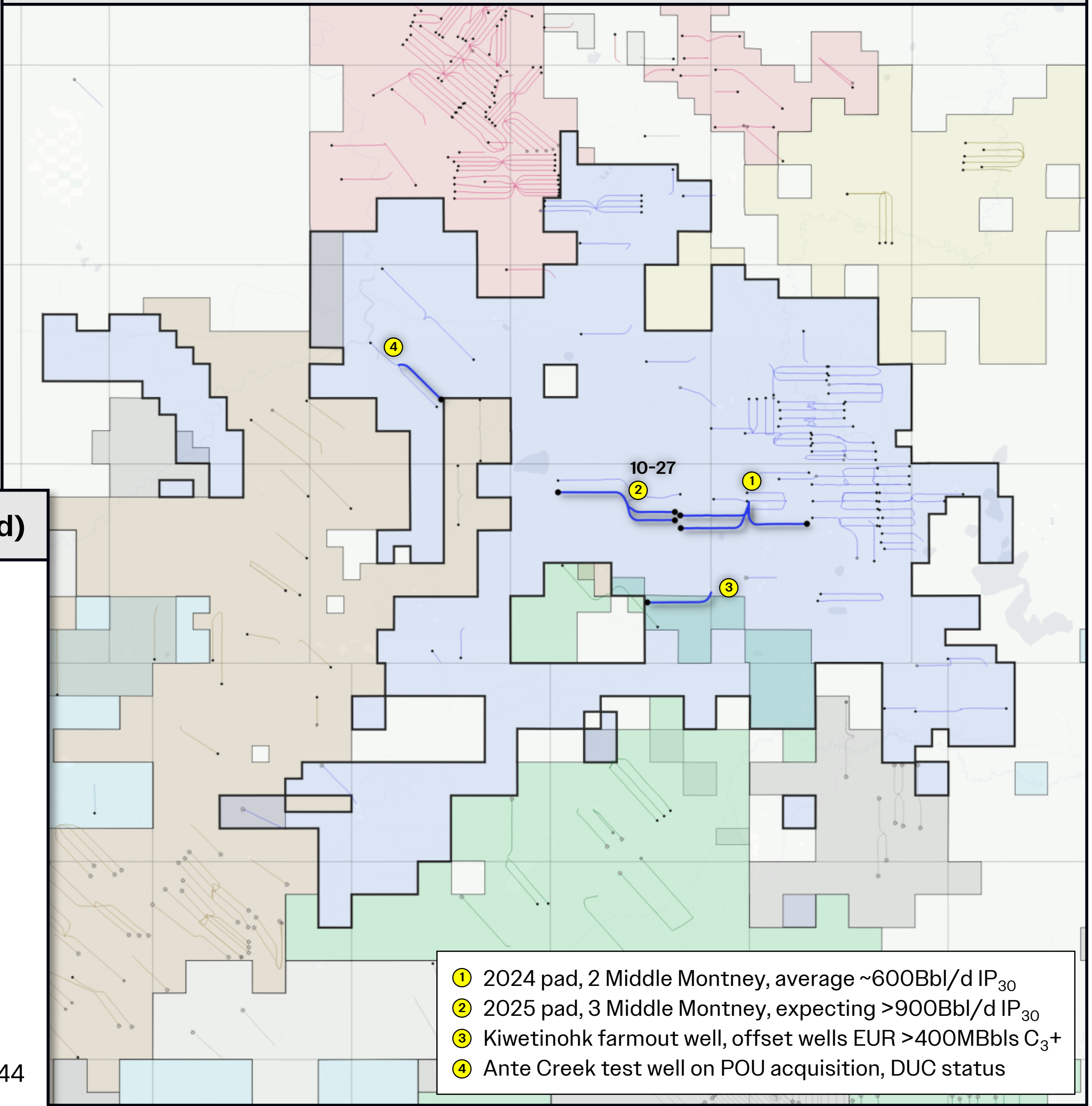
HWN's 2025 capital program plans for 7 wells, focused in the most promising oil-weighted areas.

Their 10-27 pad features 3 wells, all with varying length and stage configurations. Initial flowback rates from HWN's 05-25 success last year peaked at ~100Bbls/d/1,000', which was in-line with offset wells. Thus, we think there is even further upside to landing depth, and stage counts. Despite absolute IP_{30} improving with modern fracs, *IP_{30} per NCS stage have remained constant*, so we think HWN has yet to find the point of diminishing returns, though Logan has proven that it's <200 stages with their 05-11 well to the west. We're excited!

2-14.12: HWN Area Oil Test Rate per 1,000' (Bbls/d)



2-14.11: Waskahigan Area Montney Map



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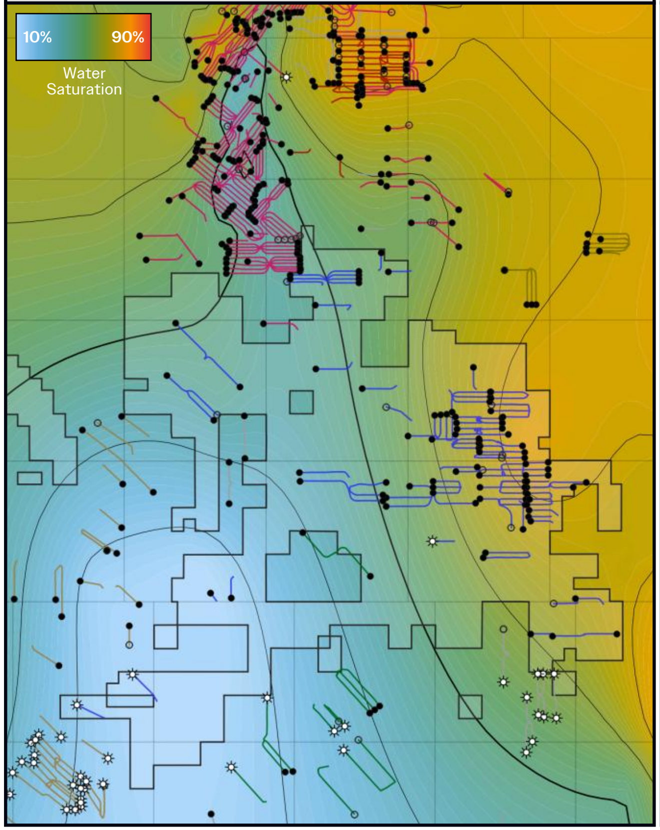
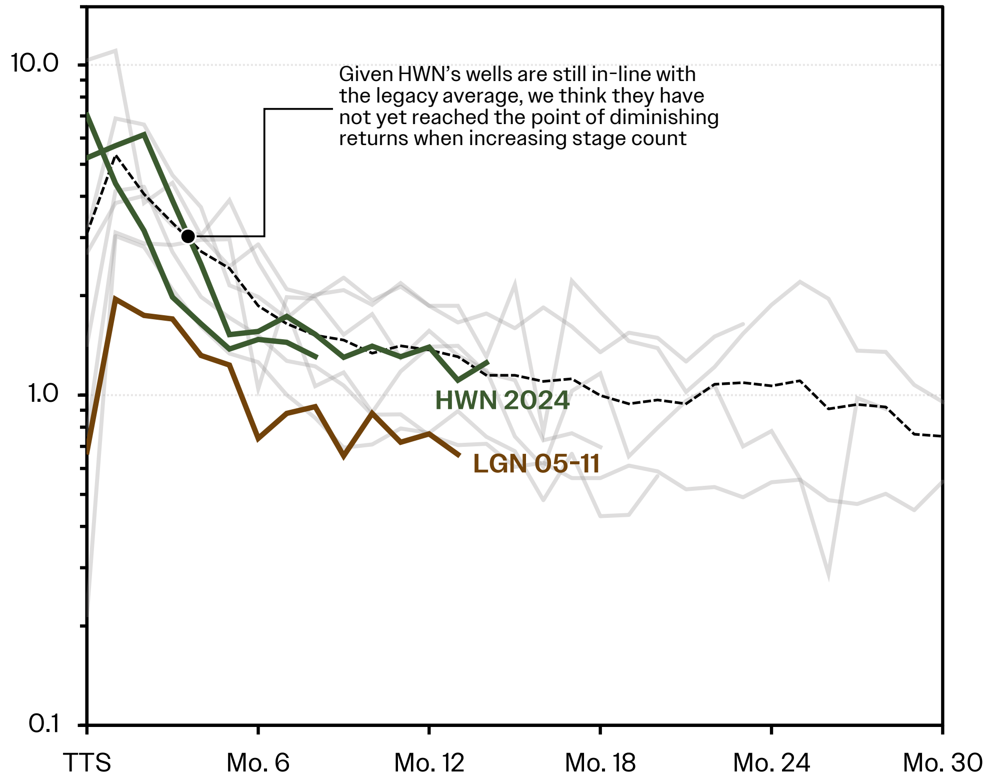
HWN Waskahigan Local Geology

Through farm-outs, small tuck-ins, and land sales, HWN has been able to push their Montney exposure to the south – generally a good thing as water saturation falls, pressure increases, and consistency of results generally improve. Notably, HWN does lie in a fairly unpredictable gas migration pathway, though the lower liquids content of the south gas inventory is somewhat offset by deliverability. To the east and northwest, water risk in the regional Montney increases substantially. While historical operators in the area typically targeted localized coquinas, or areas of ultra-high porosity (>10%), unconventional wells have accessed thicker sections of lower porosity and permeability resource with still abundant oil in place, but not viable through conventional production means. The NCS sliding sleeve frac has done a good job of 'combining' this pay into a package that can be produced with one horizontal well.

2-14.13: Water Saturation Map (10% C.I.)



2-14.14: Area Raw Oil Rate per Placed NCS Stage (Bbls/d)



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Kelt Wembley Updip Oil & Rich Gas

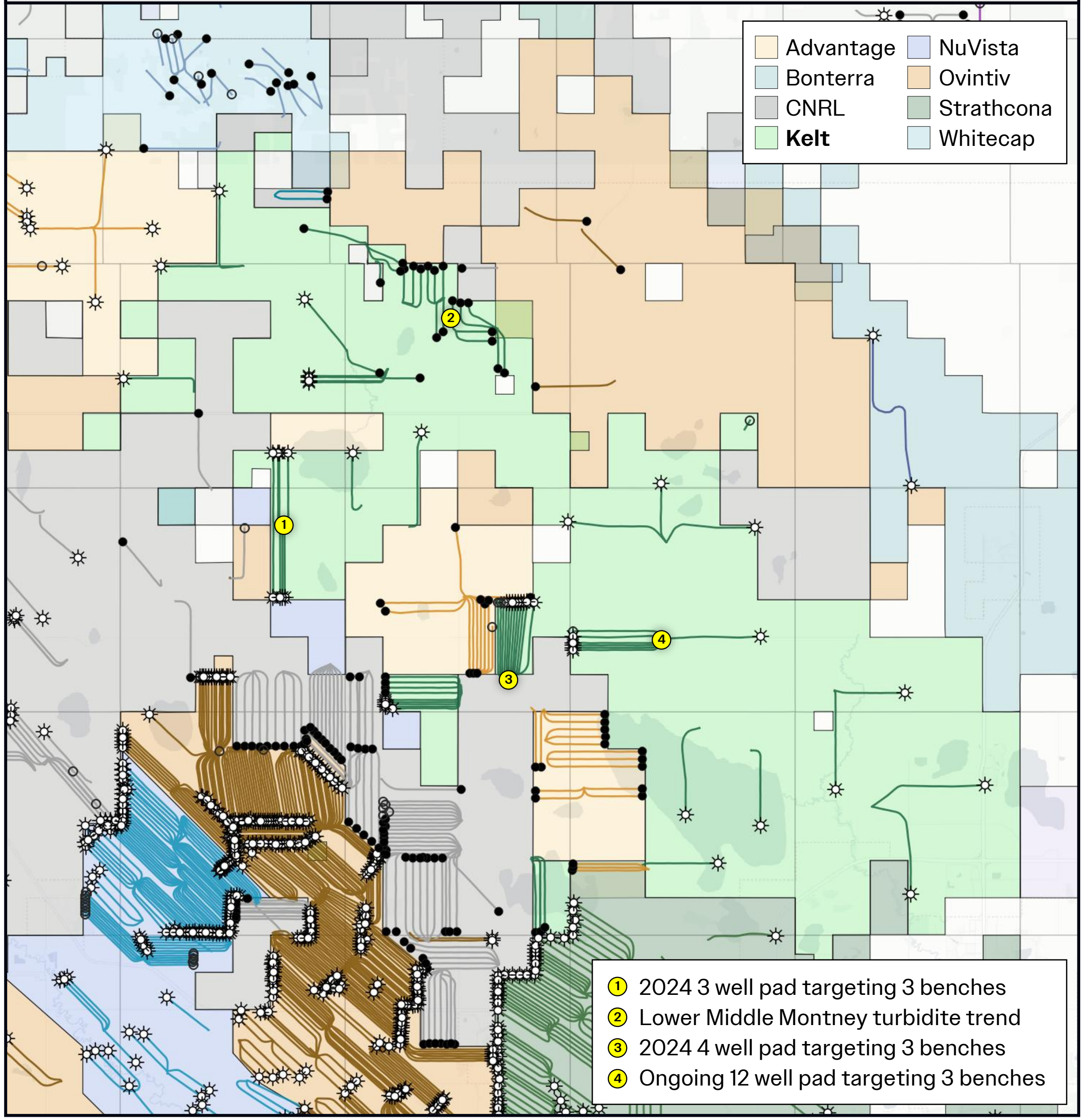
Kelt is an accomplished Montney player, with divested assets now producing some of the best wells in the play (Whitecap Lator, and Conoco Inga). This iteration of Kelt is focused on updip oil and condensate between Wembley and Oak.

Their Wembley asset shown to the right lies just outside of the Montney's overpressure line, with their recent development drilling focused on the deeper, higher pressured areas of their asset. Results from the Middle Montney intervals have been strong, though the Lower interval has lagged.

Kelt's development philosophy is interesting. They have communicated they intend to develop 3 benches throughout the asset at a time when best practices are moving towards wider spacing and larger completions. In the east of the asset, we think the semi-consistent porosity throughout the middle interval lends itself to single-bench development, with 2 bench development a better fit in the northwest. Kelt is currently developing Pipestone at 12-14 wells per section, which we believe is too tight, given they are no longer in the much less permeable condensate window. We've seen early indication of depletion effects on Kelt's operated 'cube' pads, and from offset operators that codeveloped 3 benches.

Offsetting (2) Ovintiv recently drilled a very solid Montney well, producing >130,000Bbls in 10 months online directly adjacent to Kelt's property. This well is targeting a localized turbidite, so clients should use caution when extrapolating these results to other areas of Kelt's property.

2-14.15: Wembley Area Montney Map

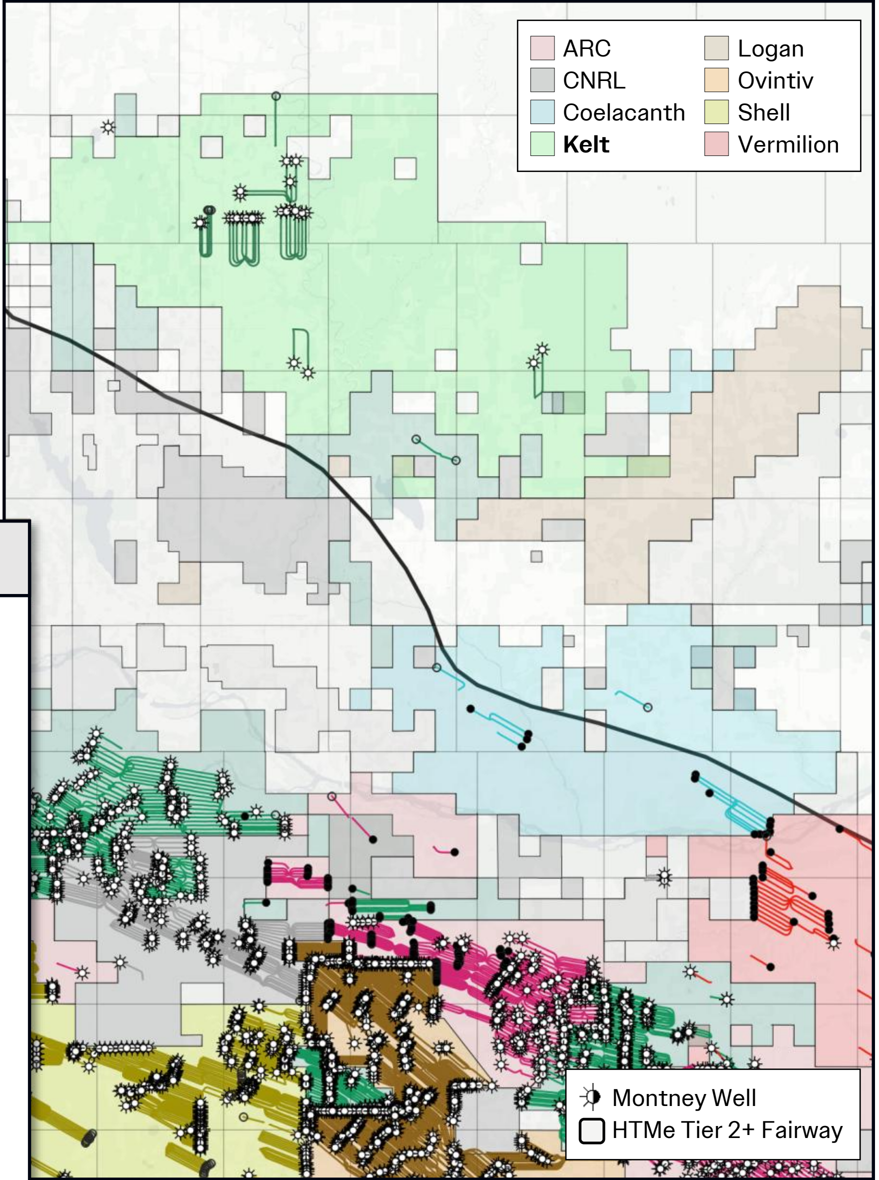


Kelt Oak Updip Rich Gas

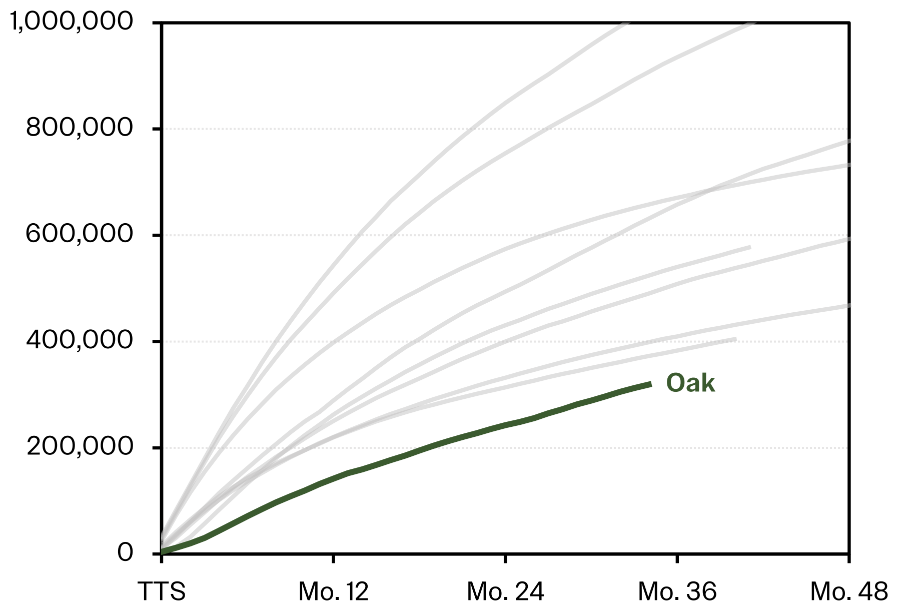
In 2025, Kelt is budgeting $14MM for a 3D seismic shoot, perhaps hinting they're gearing to sell Wembley. We think there's upside at Oak if they encounter a turbidite deposit (there are many instances to the west). Notably, on-strike with Oak, Tourmaline drilled an exploratory well at Zaremba in 2020 offsetting 3D seismic, it remains a DUC, though they have marked in their presentation it was an "oil discovery"...

While Oak has seen poorer results compared to their BC Montney peers, geologically, Oak is situated in the proximal offshore transition zone, which puts it in the most likely area to encounter these stochastic, yet extremely economic geological features. Core analysis intersecting the Montney is sparse in the area – so we think that Kelt's seismic shoot is an attractive risk/reward, especially combined with recent updip, turbidite, and conventional Montney oil success in Alberta.

2-14.16: Oak Area Montney Map



2-14.17: Kelt Oak Cumes vs. BC Montney Peers (BOE)



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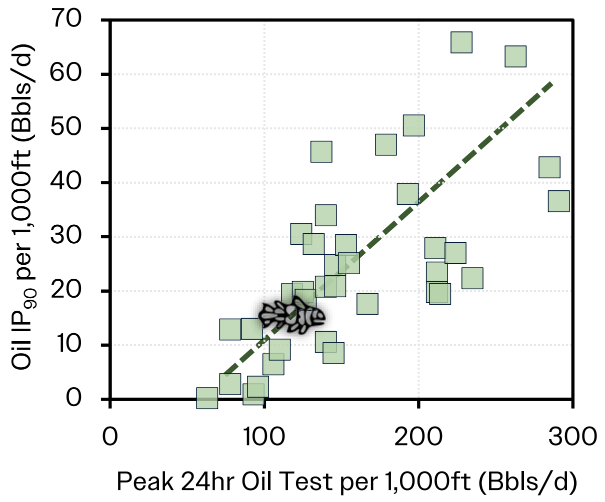
2-14.18: Local Oil Test Rates vs. IP_{90}

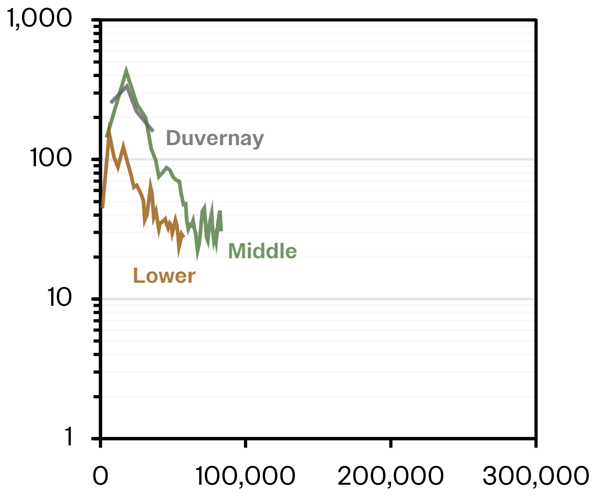


Coelacanth Updip Montney Oil

Coelacanth operates north of the Peace River, targeting light oil in the Upper and Lower Montney benches. While current production is low (<1,000BOE/d), they have a positive working capital position, and 9 suspended/rate restricted wells awaiting infrastructure. In late 2024, Coelacanth released Montney 24hr test rates averaging ~1,625BOE/d, which is an improvement over previous tests across their asset. Their Two Rivers 100/04-03 well had a peak 24hr test rate of ~400Bbls/d, and a peak IP_{30} of 150Bbls/d. At a 3:1 ratio, their new wells would map to a ~300Bbl/d IP_{30} – slightly lower than the Montney asset Coelacanth's predecessor Leucrotta sold to Vermilion in 2022. Notably, Coelacanth has only a handful of wells that have continually produced (due to infrastructure constraints), making it difficult to assess water risk, which is elevated moving updip.

Coelacanth's growth inflection is scheduled for mid-2025, when they complete their local field handling build out, and connect to 3rd party gas processing. The company plans to grow to ~15,000BOE/d by late-2027, at which point we estimate they will generate ~$140MM in run-rate annual FFO at strip AECO and flat spot liquids pricing.

2-14.19: Halo Oil Results (Bbls/d & Bbls)



Halo Exploration Updip Montney Oil and Duvernay Tight Oil

Halo has a smaller Montney asset, and a good sized Duvernay asset at Kaybob, both are currently being marketed by Peters & Co., Halo's management sees a pathway to grow to ~12,000BOE/d, with over 500 drilling locations. Halo's horizontal producers generally target the Middle and Lower Montney intervals. Their Middle Montney wells have seen very strong initial rates, though decline much faster than other Montney plays. We estimate that their Middle Montney wells will produce oil EURs of 130-140,000Bbls, or ~18Bbls/ft. Their best Middle Montney wells were completed using NCS sleeves with ~4.4MMLbs of sand and 40-45,000Bbls of freshwater; which is in-line with local completions.

Halo's first Duvernay well was drilled to 9,600' in length, and we estimate will produce an oil EUR of ~25Bbls/ft. Given the well's confidential status, we have no visibility as to the completion technique. While Halo has a large Duvernay footprint, it's outside of the core; though the industry has been slowly expanding the volatile oil window into areas with thinner pay. Recently, GMT has seen resounding success drilling on-trend with Halo, with their Duvernay wells seeing oil EURs >430,000Bbls, or ~34-38Bbls/ft.

Disclaimers and Disclosures

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