BOE Report Weekly Round-up
April 4th, 2025

As the world grits their teeth in response to unfolding trade wars, we're buckling down too and focusing on the only industry theme more important than decoding the impacts of tariffs – assessing if cyclic gas injection may work in the Duvernay.

Inside we look at Duvernay EOR potential before briefly discussing the inventory intricacies of certain Montney asset bases. We think that understanding breakevens, high-grading potential, true M&A desirability, and all other nuances of a company's opportunity set is increasingly important in a soft price tape. While we aren't sure what will come of tariffs – we're sure that owning anything but the highest quality companies is a recipe for disaster.

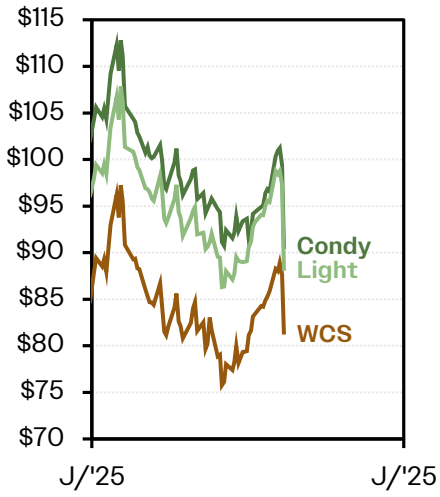
On days like today, we'd recommend a healthy dose of Toby Keith.

Rig Counts by Operator

Tourmaline Oil Corp. 13	veren 10	Baytex Energy Corp. 8	ARC Resources Ltd. 7	Whitecap Resources Inc 5
spur Petroleum Ltd 5	Obsidian Energy 5	tamarack valley energy 4	Paramount Resources Ltd. 4	Strathcona Resources Ltd 4
Peyto 4	Spartan Delta Corp. 2	Birchcliff Energy 2	HWX Headwater Exploration Inc. 2	NuVista Energy Ltd 2
kelt exploration 2	kiwetinohk energy 1	Logan Energy Corp. 1	Advantage Energy Ltd. 0	Bonterra. 0

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

WCS discount continues to narrow, reaching –US$9.10/Bbl

Westgate closes US$25MM senior secured loan

ConocoPhillips eyes sale of Oklahoma assets for >US$1Bn

Prairie Provident announces year end results

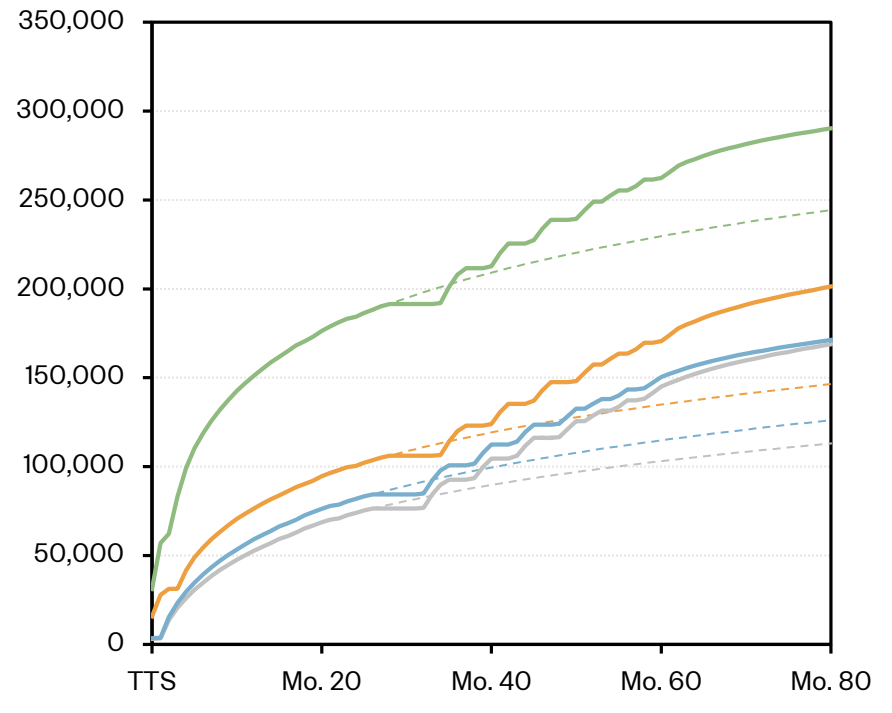
LNG Canada import cargo arrives

Tokyo Gas reaches Haynesville deal with Chevron

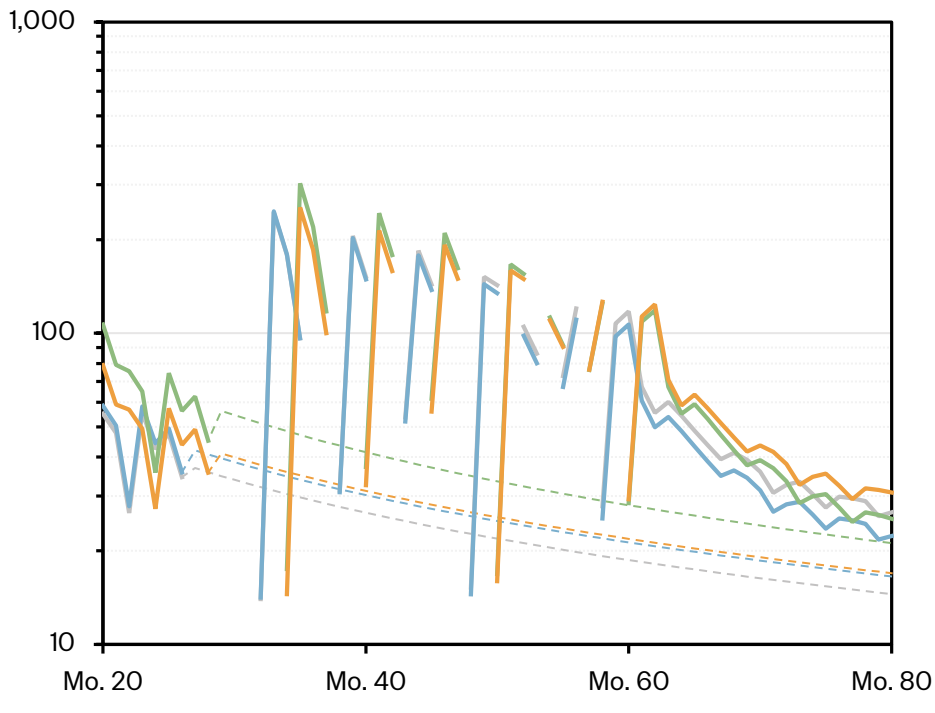
Can The Duvernay Huff-n-Puff? Kiwetinohk is Uniquely Positioned to Find Out

As Kiwetinohk readies themselves for a potential sales process – all eyes in the basin (2-3 people) fixate on South Simonette, wondering if a potential buyer may implement an EOR pilot. Kiwetinohk has historically communicated their intentions to implement an EOR trial, but it hasn't materialized. Kiwetinohk assets are uniquely positioned to trial huff-n'-puff in the Duvernay as they are the only operator in the overpressured gas window that owns 100% of the key infrastructure. Cyclic gas injection aims to repressurize the reservoir such that the heavy condensate molecules are absorbed back into the gas stream. During normal production, as reservoir pressure depletes throughout the life of a well, the condensate molecules 'dew' out of the gas stream, turning into a liquid that isn't transported to the surface efficiently. Cyclic gas injection has worked in the high-pressure condensate window of the Eagle Ford before, with EOG's Martindale pilot shown below. Similar to what Kiwetinohk is likely envisioning, they injected gas, shut the wells in and let them soak, then reproduced the "absorbed" condensate, before repeating multiple times. Their 3 year trial improved EURs by at least 50,000Bbls in all cases, without altering the decline curve of the well after the trial finished (i.e. adding, not accelerating reserves).

4-4.1: EOG Martindale EOR Pilot Oil Cumes (Bbls)



4-4.2: EOG Martindale EOR Pilot Oil Rates (Bbls)

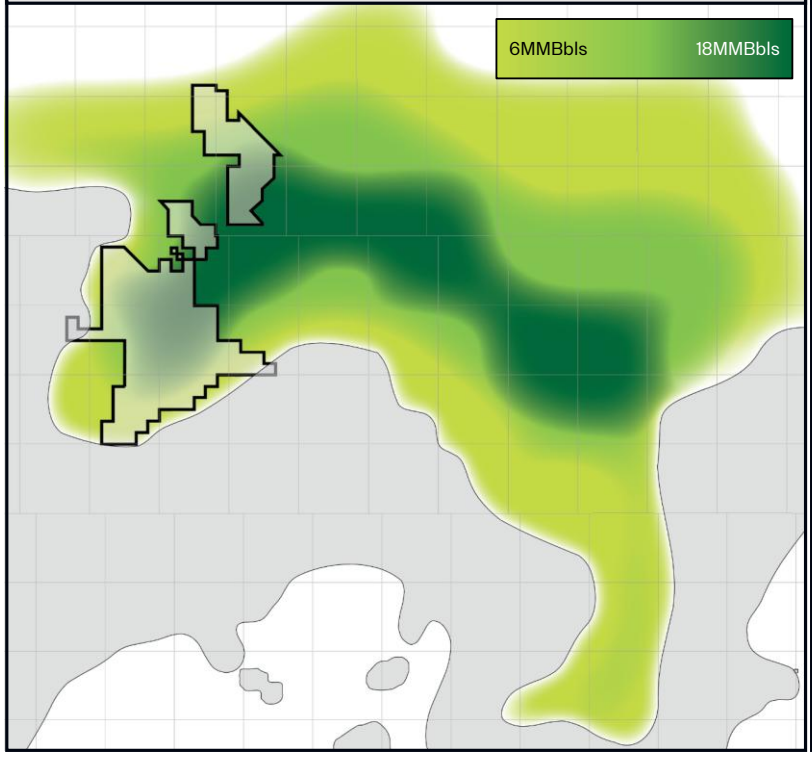


There is Compelling Evidence the Duvernay May be Amenable to Cyclic Gas Injection

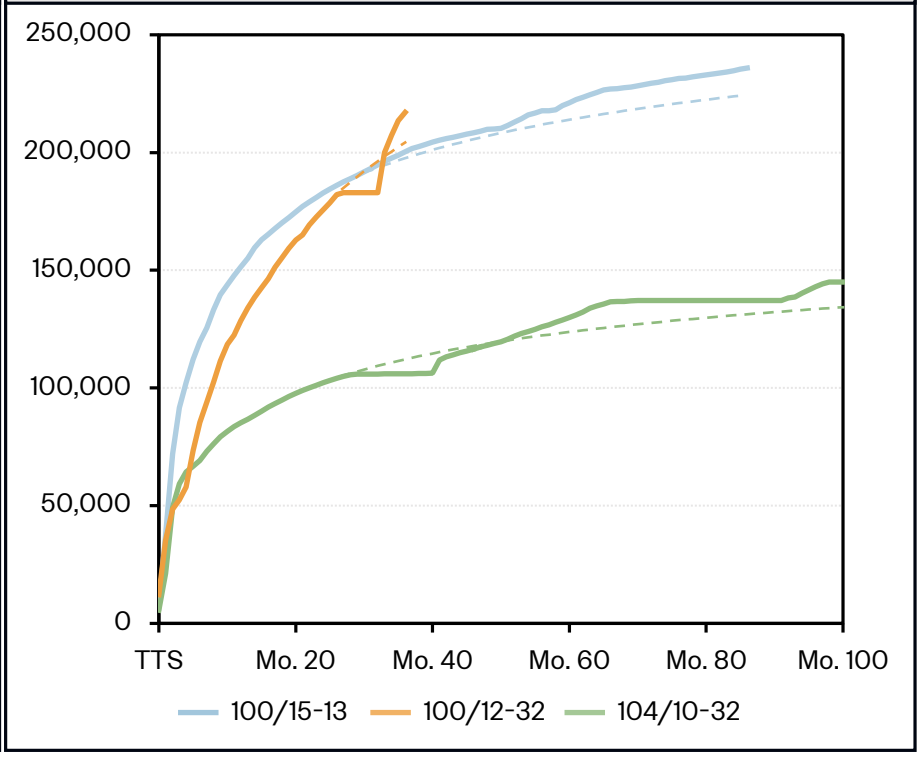
Kiwetinohk's wells are initially so great because the high formation pressure leads to extreme deliverability, as such, we have seen IP_{30} rates peaking at >3,000BOE/d, though liquids rates drop quickly as formation pressure depletes. This is no fault of Kiwetinohk (though we think they could be better with early-time choke management). With up to 10MMBbls of NGLs in place per DSU in the core of South Simonette, when critical pressure is reached the NGL recovery factor is only ~2.5%, climbing to ~6% over the well's life.

So we set out for anything that might confirm that repressurizing the Duvernay could lead to sustainably higher recovery factors (and that's without injecting lean gas). Luckily for us, there are many instances of wells being shut-in for >3 months – with COVID netting us a unique data set to work with. Shown below are a handful of Kiwetinohk's wells that saw a condensate EUR uplift after being shut-in for >90 days. Veren's 10-06 Waskahigan pad is another good example of this phenomenon, with condensate EURs >10% higher after a prolonged shut-in period. Clearly there's some promise here – we'd love to see a potential new operator give it a shot!

4-4.3: Kaybob Area NGLs in Place per Section



4-4.4: Select Duvernay Shut-in Well Condy Cumes (Bbls)



Efficient Markets Pricing Equities Right or Mispriced SMID Cap Opportunities?

Canada has lots of great unconventional inventory – though at times the thesis for Canadian E&Ps, especially as recounted by some commentators, becomes almost too indulgent, nearly untenable. Companies have one hundred million years of drilling locations, can privatize in weeks using free cashflow at just $40/Bbl WTI – and they give free puppies to every investor!

While Canada is not at the point of inventory degradation like the US – we think that some Canadian producers have fallen victim to the same mentality that plagued E&Ps in the early days of shale; overstating inventory potential. This gets lapped up and quickly parroted by industry proponents – much to our excitement, but also dismay. Not all Canadian inventory is created equal, though it's often presented as such. In the recent months, we've seen numerous people use the Ovintiv/Paramount transaction as a benchmark for what Canadian locations are worth – that is wrong. Very few assets in the basin come close to Karr, and this generalization, among many others, set dangerous expectations – both operationally, and in the equity markets.

Many Canadian E&Ps have good stories and can hold their own as businesses without sensationalizing their inventory picture (and in some cases, by their own doing). As we've discussed in prior BOE Report Round-Up notes – the disparity between inventory across Canada is palpable – and with companies often having multiple plays, and play styles, an intimate, and often forgone understanding of all local nuances is key. We don't think inventory figures should be taken at face value. And while we won't provide inventory estimates here, we will walk through some of our thinking, and the modelling that drives our internal estimates; especially where we think markets may be too generous. In many cases, results from delineation and codevelopment are wildly different – a phenomenon we haven't seen discussed much at all, especially as the theme-de-jour is owning assets on the cusp of maturing from delineation, to development. With these theses, we often see little accompanying geological analysis presented.

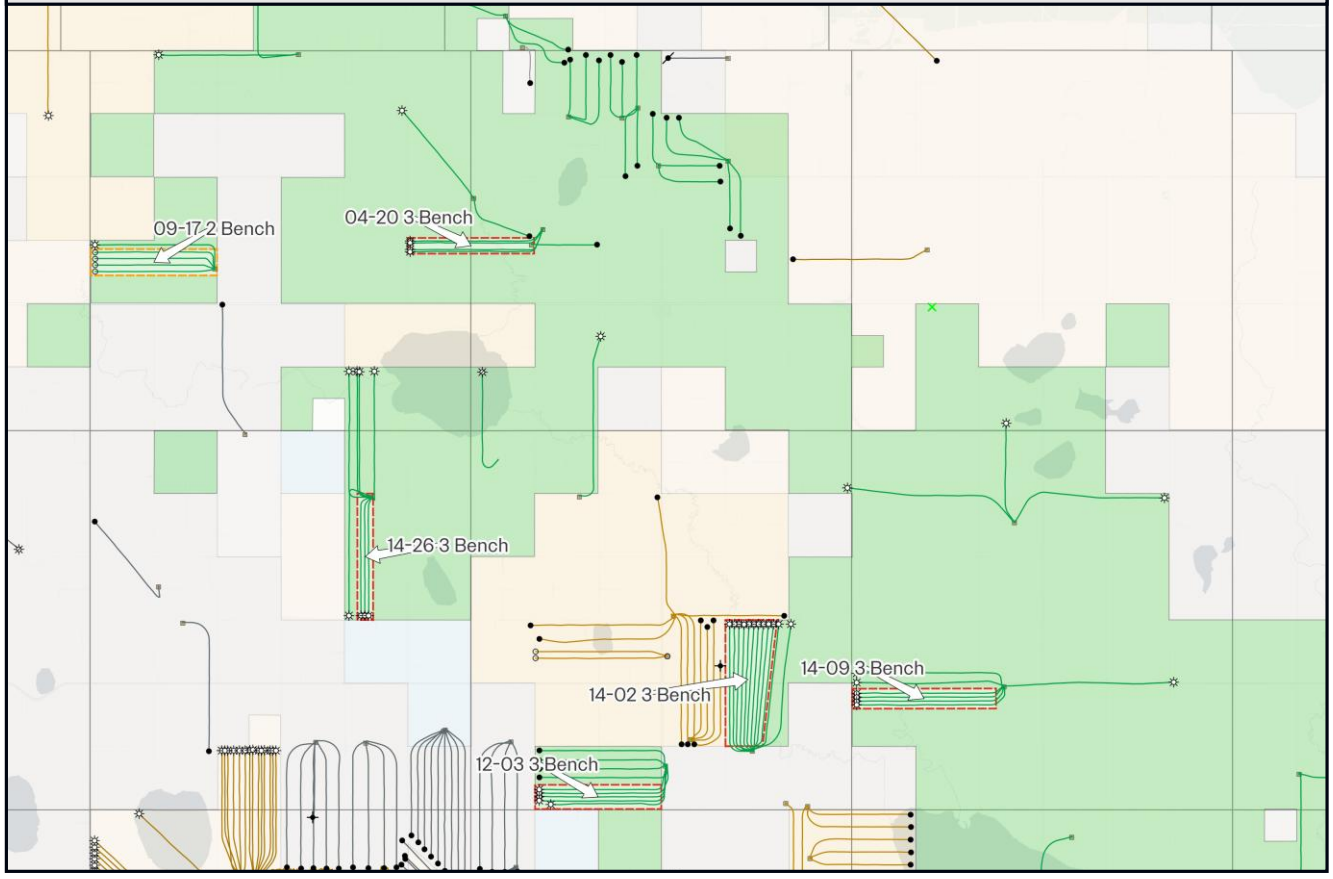
The Montney isn't a shale like the Permian; and while it's not chasing sand bodies like the Doig, or as conventional as the Charlie Lake where operators have to navigate sub-unconformities within broader unconformities – it's still a semi-conventional play. In the Permian, alternating sands, carbonates and shales (source rocks) differentiate flow units, with parts of the Delaware exceeding 1,000 meters in gross thickness (compared to the Montney's ~2-300 meters in the best parts of the condensate rich fairway). That is a lot more resource to exploit – and even in a 1,000m thick true unconventional pay package, operators still have parent-child issues. While less discussed in Canada, the conventional nature of the Montney (more permeable, with more homogenous lithology) means it's more susceptible to interactions between producing wells – especially wells with <100m of vertical distance between them. This is why we liked Veren, we thought their inventory numbers were very reasonable, and borderline conservative – we see the same with Whitecap today. Alternatively, there are certain operators that imply 3-4 development benches in the updip Montney – and while there may be 3-4 discrete intervals of porosity in certain parts of the Wembley/Valhalla/Progress complex – there are not 3-4 discrete flow units that can be codeveloped with little parent-child interaction.

Inside we discuses two SMID cap E&Ps, and select inventory nuances. As companies progress assets bound for the M&A markets – we think it's extremely important to understand and assess "what will/can a potential acquirer reasonably pay for" as opposed to what we see more often – "what does this company have they might be able to sell".

Kelt Axes the Lower Montney on 09-17, Widens Middle Montney Spacing

On their recently rig released 09-17 pad, Kelt skipped the Lower Montney, despite it being still pervasive in the area. This maps to 365m between wells on the same bench, wider than ~310-320m on 14-02 and 14-09. We think this is a positive development, as we expect that single well economics and capital efficiency will improve if they shift towards 2 bench development in the Middle Montney. Kelt has tested variation of a "cube" on their acreage, and we don't think they were successful. While 365m interwell spacing implies <600 drilling locations compared to Kelt's unrisked (excluding the Lower Montney) estimate of >800 – we think this is more consistent, more economic, and ultimately more desirable inventory.

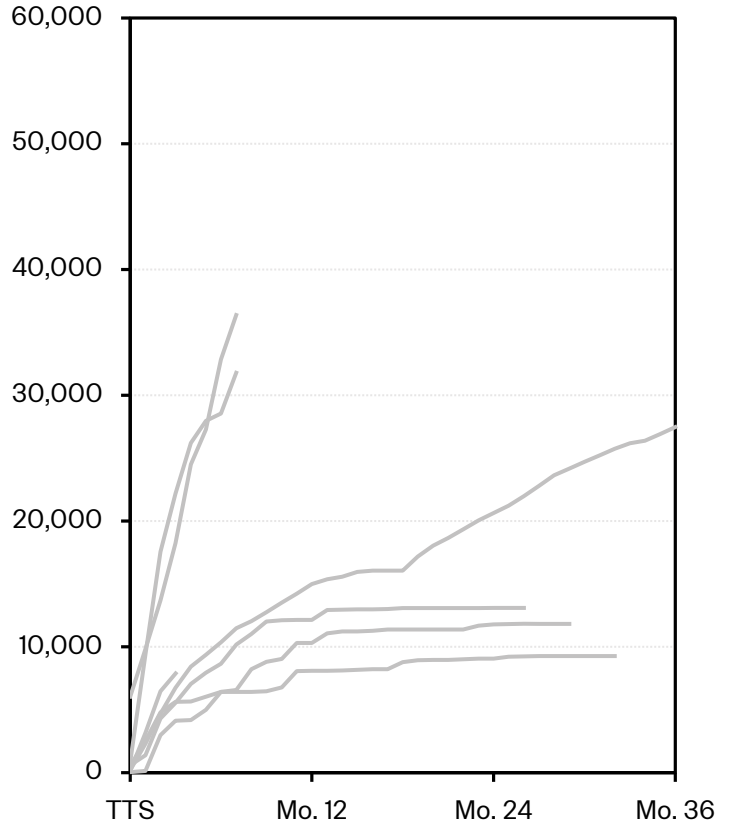
4-4.5: Kelt Wembley Codevelopment Project Map



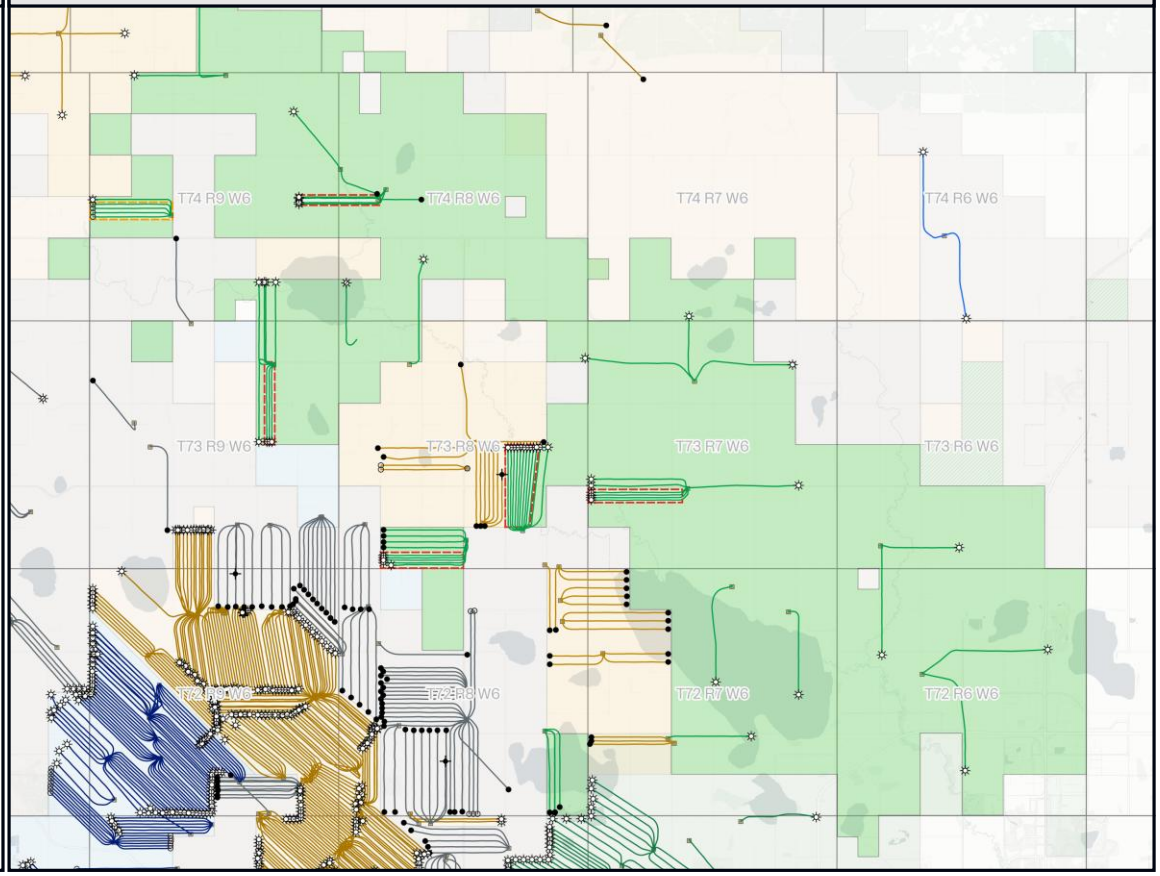
Excluding the Valhalla Turbidite, Wembley is Still Fairly Under-Delineated

Removing from the map the Lower Montney turbidite sequence in 74-8W6, the eastern parts of Kelt's assets haven't seen strong well results. Granted, Kelt's DCE&T costs are ~$8MM (including lease), which lowers the EUR hurdle, but even with their excellent cost structure, we don't think including the Lower Montney was economically defensible (shown below), nor do we think that the lower impact inventory to the east is highly desirable in an M&A scenario. Thus, we believe it's irresponsible to include >500 locations in any Wembley M&A build-out value. We think 4-500 locations is a good number that represents 2 benches in the Middle Montney with proper spacing, leaving some upside to the acquiring party vis-à-vis downspacing, and further Lower Montney delineation.

4-4.6: Kelt Lower Montney Oil Cumes (Bbls)



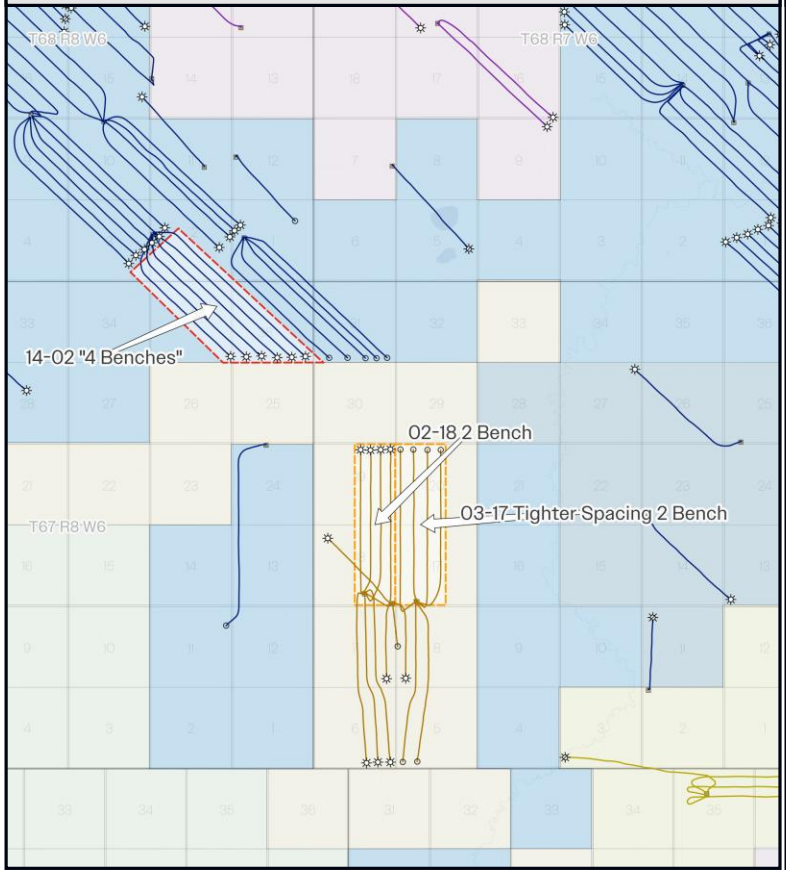
4-4.7: Kelt Greater Wembley Adjusted Asset Map



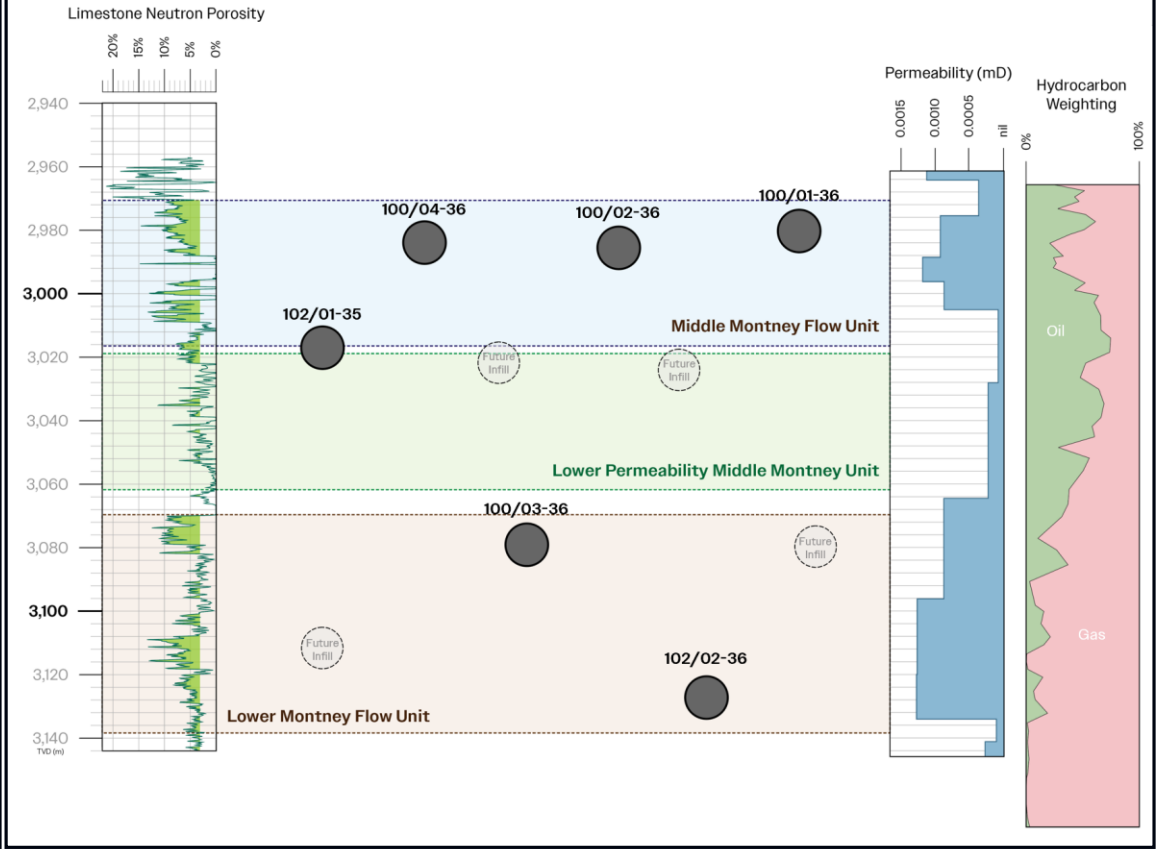
NuVista Trials 4 Benches at Wapiti, but are Results Conclusive?

Moving south to NuVista, at Wapiti, we wonder about the long-term viability of 3-4 bench development, especially as the company pushes west into the leaner gas window (then doubly so into the naturally leaner Lower Montney, as shown below). We've seen NuVista continue to press release strong well results, but those are, for all intents and purposes, unbounded wells. For example, the 14-02 pad we break down below only had 1 well in each bench besides the Upper Middle Montney, which had 3 wells. These delineation wells alter the reservoir, leaving behind infill inventory. To the south, Paramount developed just 2 benches at ~8-10 WPS. NuVista implies 12-14 WPS. For reference, we show the limestone neutron porosity track, clients can login to see the full log suite with more, calibrated, tracks.

4-4.8: NuVista South Wapiti Codev Projects



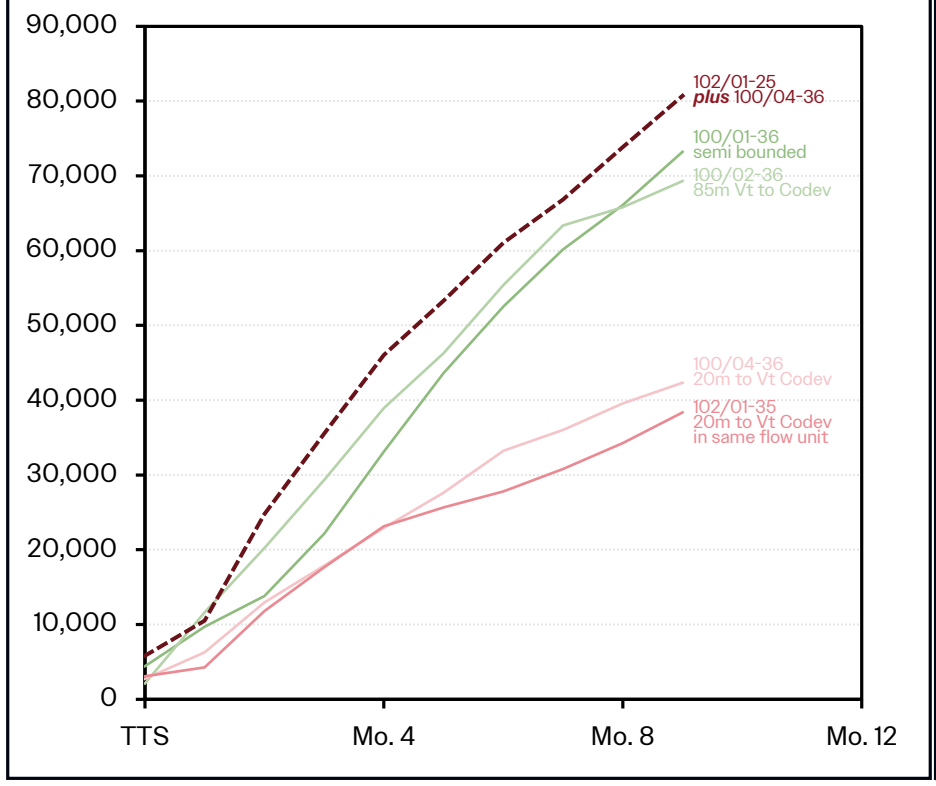
4-4.9: NuVista South Wapiti Type Log Section Spacing Cross Section



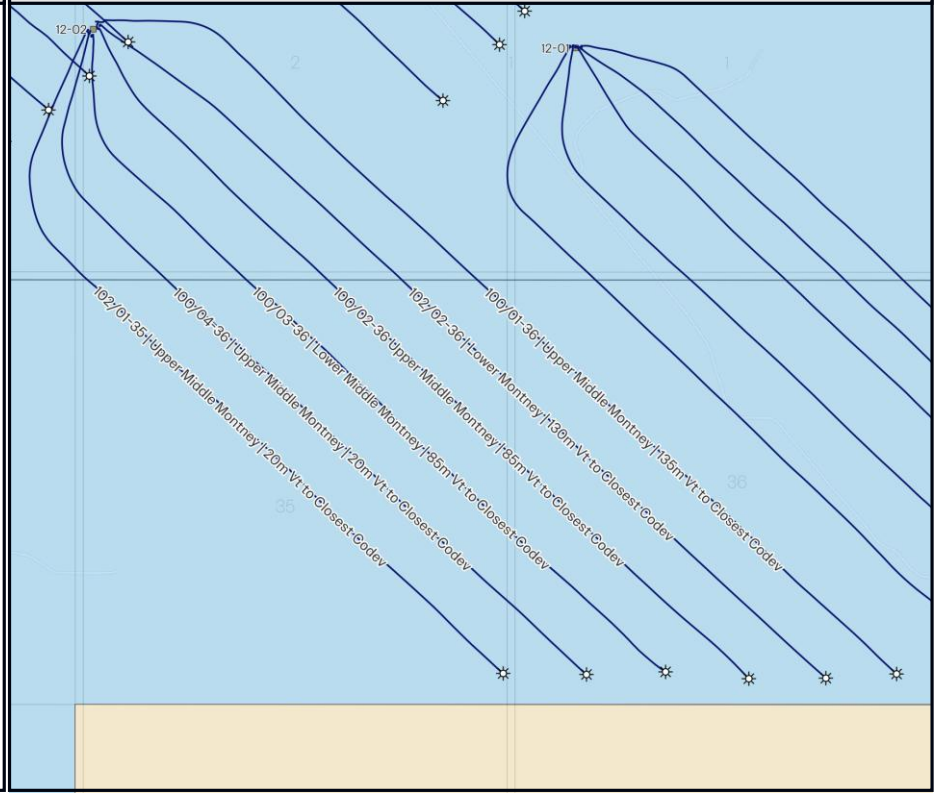
Early-Time Production Data Suggests Spacing is Still Too Tight

It's certainly not a compelling piece of evidence that on this pad, the unbounded Upper Middle Montney 100/01-36 well is performing in-line (<10% behind) the cumulative production from **both** the 102/01-35 and 100/04-36 wells. To us, this suggests that, while NuVista does highlight the low permeability lower Montney unit, it isn't an effective frac barrier, or they still aren't spacing wells wide enough. The Lower Montney wells with >100m of vertical spacing have performed okay, but we don't think these essentially unbounded wells provide enough data. The porosity transitions from liquids-filled, to gas-filled lower in the Montney section, so we think that liquids recoveries (and thus, economics) on a single-well basis will struggle greatly as NuVista densely develops the lower flow unit. While NuVista's Wapiti wells are very solid – they are leagues behind their core Pipestone inventory on a liquids production, and development density basis – but we think they can majorly upgrade Wapiti inventory by tweaking their spacing... at the expense of "stay-flat" years.

4-4.10: NuVista 12-02 Pad Key Condy Cumes (Bbls)



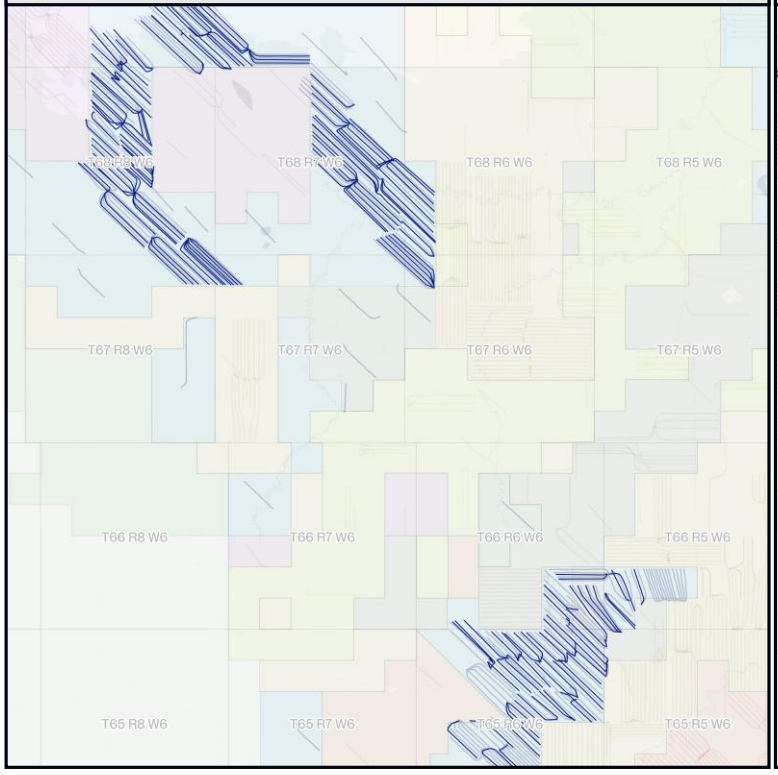
4-4.11: NuVista 12-02 Pad Lateral Breakdown



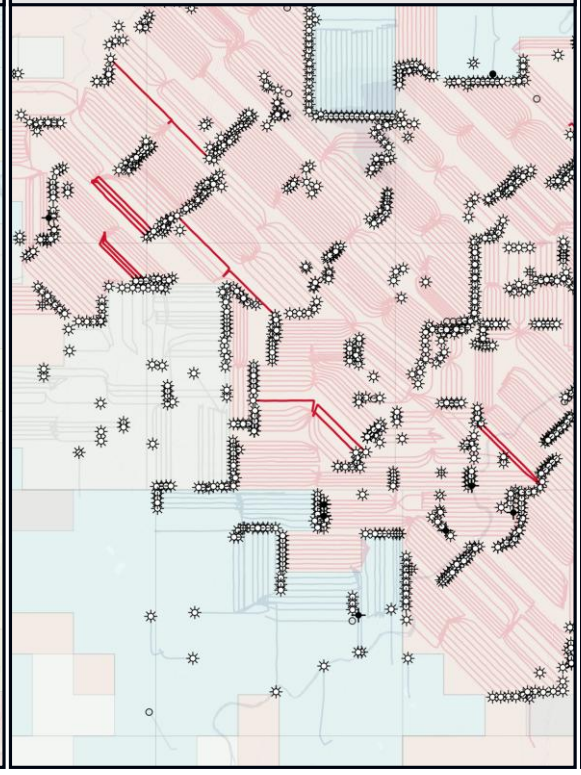
An Overexposure to Infill Inventory May Pose Future Problems

While our inventory bookings can vary greatly from company models, and reserve auditor bookings, we think that NuVista holds a disproportionately large number of infill locations compared to peers, almost 200 across their asset base – that's the only way we can come close to rationalizing the ~1,200 total drilling locations they claim to have. Below we show a map of infill locations that we book when configuring NuVista's assets in a potentially overcapitalized, 3-4 bench configuration. This is the only way we get to 1,200 sticks. We can lean on Kakwa to see what infill-heavy programs bring. Recall that ARC caught up on infill drilling in 2022 through 2023 before Attachie (link), which provides a useful data point. These infill/child wells, into previously affected reservoir while still fine wells, are notably worse than production from parent/codev wells, as shown below. As NuVista continues to drill "delineation" pads, essentially, only parent wells, they sterilize future acreage, making themselves less desirable from an M&A perspective. And assuming the economics and recoveries are what they claim to be, they're needlessly robbing themselves of future cashflow potential by avoiding codevelopment.

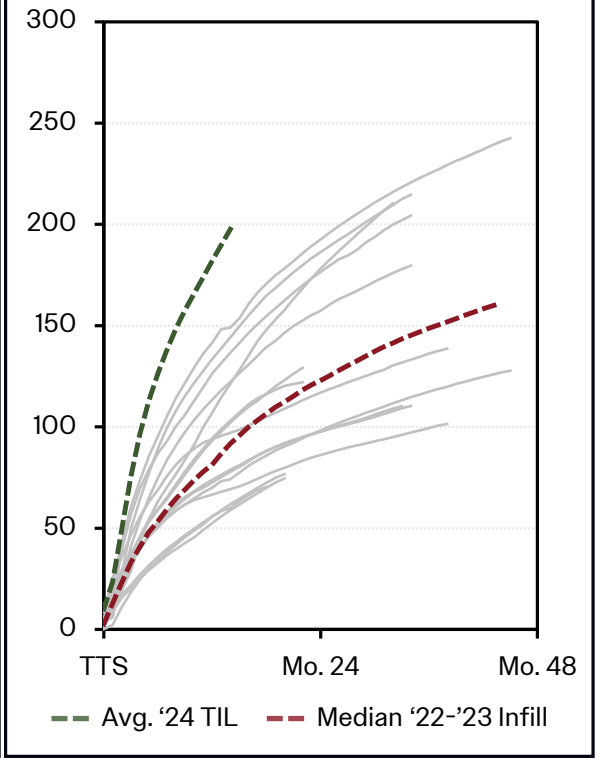
4-4.12: HTMe NuVista Infill Location Map



4-4.13: ARC Kakwa Infill Map



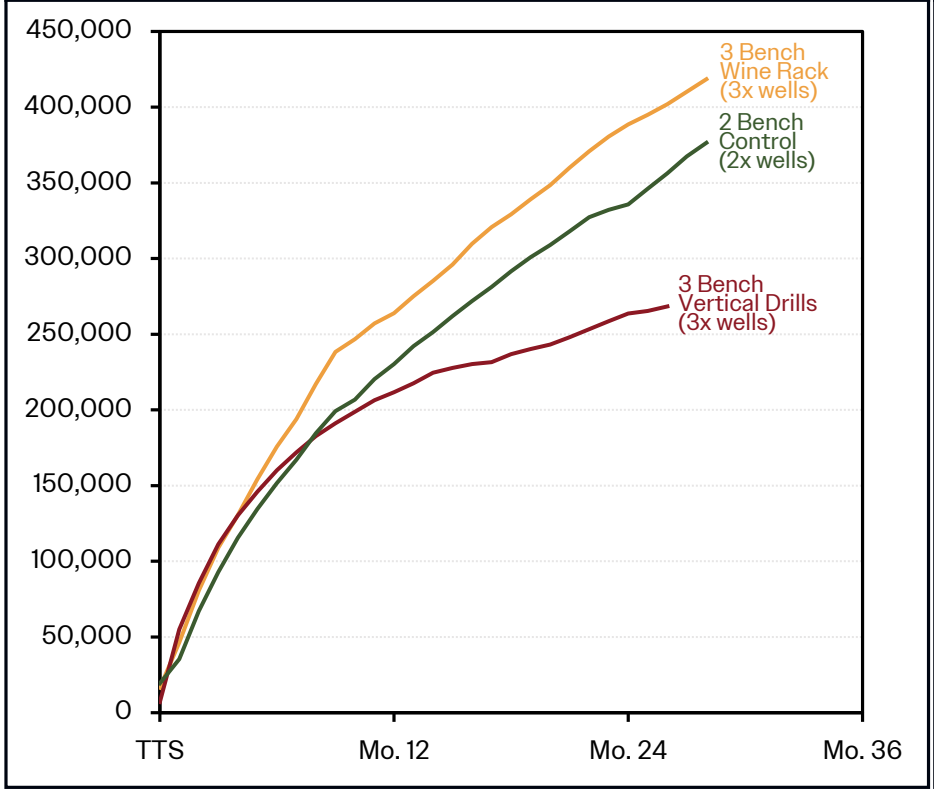
4-4.14: Infill Condy Cumes (MBbls)



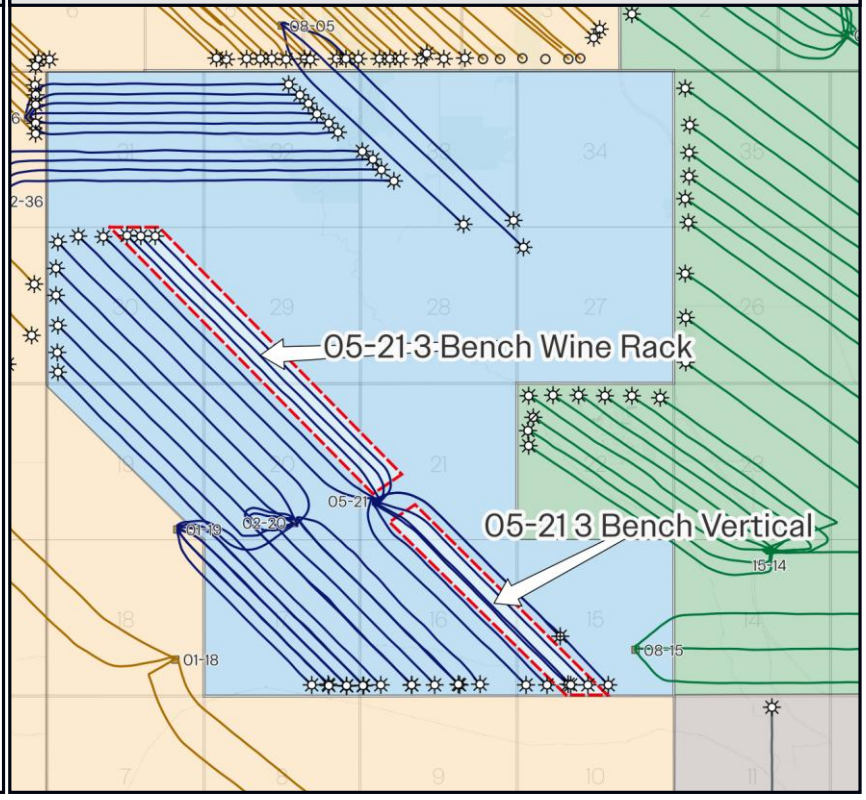
Pipestone South Sees Sequential Improvement, but is it Defensible?

Overall, we think Montney spacing is still evolving, and any valuation framework that doesn't justify their independently estimates inventory figures should be interpreted with caution. For example, the **two** semi-bounded wells on the Pipestone South 05-21S pad have performed in-line with the **four** bounded wells on the same pad (both sets of wells have produced ~450MBbls of liquids). While the wine rack spacing clearly outperformed the directly vertical spacing configuration (which says something about frac height growth), the outperformance compared to a 2-well control sample is marginal, with the incremental recovery likely <100,000Bbls of condensate. While investors are focused on the geological viability of certain benches, we are more concerned that Lower Montney economics may fall apart during codevelopment, especially with more than 2 intervals. We wonder if the slight performance improvement from wine rack spacing on 05-21N was enough to justify keeping the Lower Montney at South Pipestone given the weak incremental EURs.

4-4.15: Key Pipestone South Condy Cume Samples (Bbls)



4-4.15: Pipestone South Codev Map



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