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Integrated Petroleum Systems Controls on Fluid Distribution, Migration, and Liquids Variability in the Montney–Doig Hybrid Play

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Objectives/Scope

The aim of this research is to highlight an incompletely recognized oil family and source rock in the Montney Formation within the broader context of the Montney–Doig hybrid petroleum system, where hydrocarbon generation, migration, and accumulation are decoupled from simple stratigraphic and thermal maturity frameworks. We show that topset Montney-reservoired oils, sampled from 22 wellbores near the Alberta–British Columbia border (~56° N), were likely generated and subsequently migrated up-dip from inferred bottomset Montney source rocks that are presently overmature for oil generation. The range of source rock maturity is reflected in the oils, with greater maturity differences between early and late oil perhaps suggesting more geologic time for oil charging. By integrating oil and gas geochemistry, biomarker and isotope systematics, and regional stratigraphic and structural context, this study incorporates new geochemical observations into existing petroleum systems models and further refines our understanding of fluid heterogeneity and migration processes within the Montney–Doig interval.

Theory / Method / Workflow

Whole oil gas chromatography, terpenoid biomarker distributions (GC-MS), and bulk stable carbon isotope compositions from SARA fractions were determined for the 22 Montney-tested oils and compared to over 400 Western Canada Sedimentary Basin oils using hierarchical cluster and principal component analyses (e.g., Zumberge et al. 2016). These Montney oils were also analyzed by GC-MSMS (whole oil injection) to determine thermally dependent alkyl aromatic ratios, traditional biomarkers, C40 aromatic carotenoids, and diamondoids. In addition, Montney reservoir cores and cuttings from five of these wells were assessed for source rock potential, using Leco TOC, programed pyrolysis, and solvent extraction with subsequent biomarker/carbon isotope analyses.

These data are interpreted within the Montney–Doig petroleum systems framework, in which prior work indicates hydrocarbon generation during deep burial followed by structural inversion, uplift, and differential cooling that facilitated hydrocarbon migration (e.g., Wood et al. 2021). Within this context, the geochemical analyses evaluate evidence for a previously under-recognized Montney-sourced oil family and multiple, non-equivalent maturity signals consistent with multi-stage charge and extended migration histories, underscoring the role of migration timing and pathways in fluid distribution.

Results, Observations, Conclusions

GeoMark and others have previously typed other Montney-reservoired oils from different WCSB fields to the well-known Middle Triassic Doig (e.g., Riediger et al., 1990 and Riediger 1997) or

Lower Jurassic Gordondale source rocks. These new Montney-reservoired oils occupy a unique position in principal component space compared to other WCSB oil families. This suggested a primary Montney source facies that was later validated with extracts collected from Montney core samples. (Figures 1a, 1b & 1c)

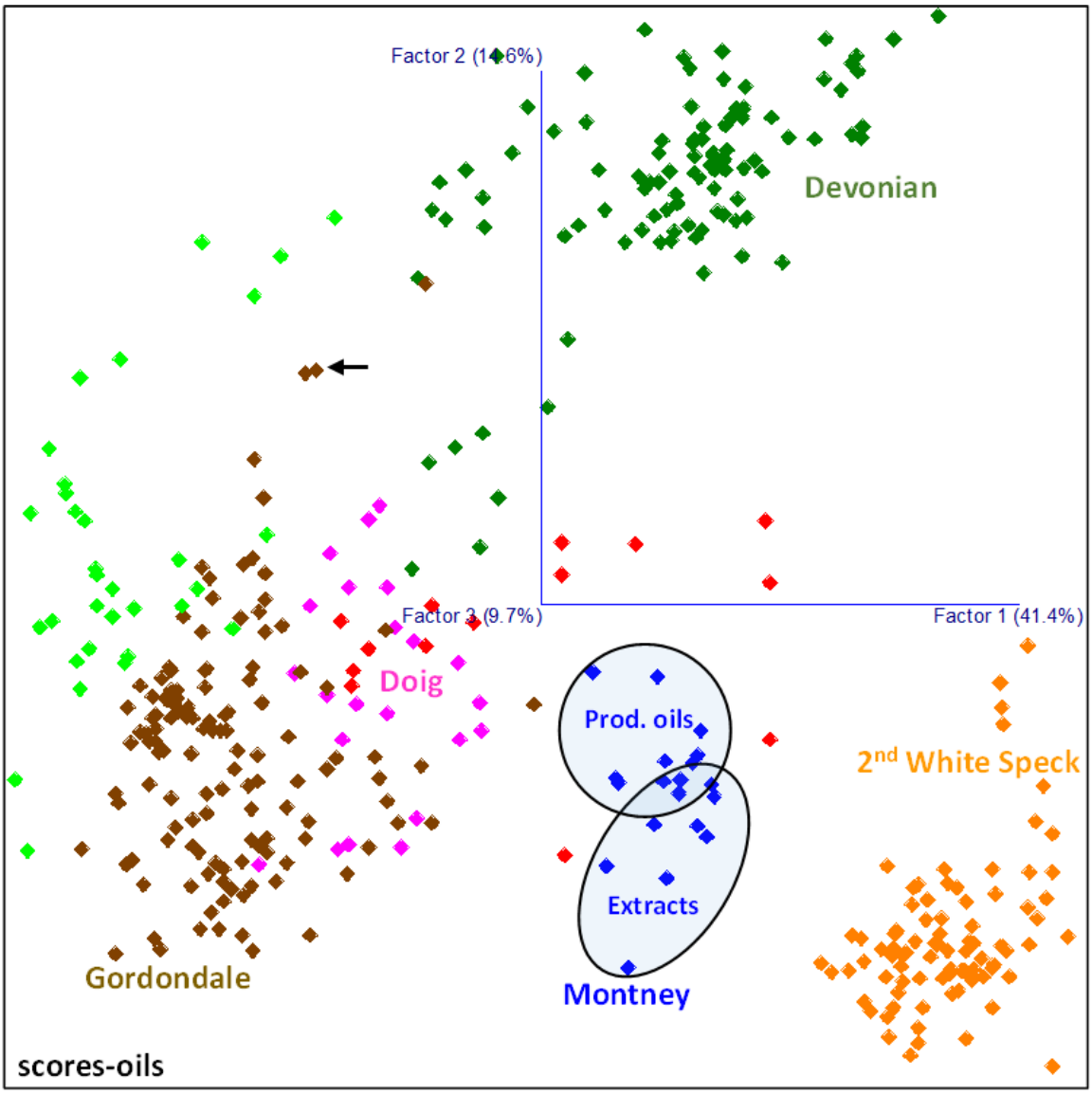


Figure 1a. Principal component scores of ~400 WCSB oils indicating a unique Montney-sourced oil family (blue). Other Montney-reservoired oils often type to the Doig or Gordondale source rock oil families (maroon and brown). The arrow shows duplicate oil samples.

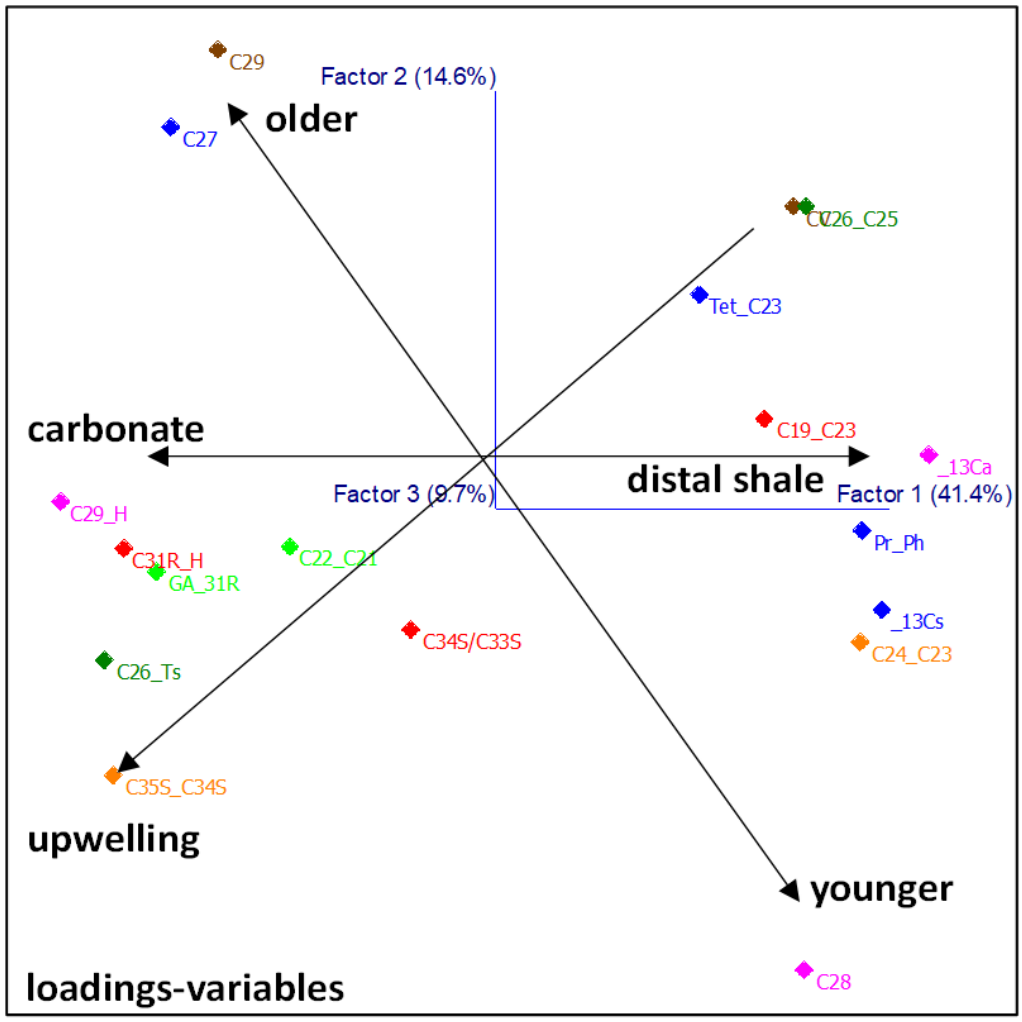


Figure 1b. Principal component loadings showing the biomarker and carbon isotopic ratios used in determining the WCSB oil families. Positive Factor 1 values point toward distal marine shale source rocks while negative values indicate carbonate-rich source rock lithologies. Higher C28 steranes suggest younger source rock ages (e.g., Upper Cretaceous), and higher C26/Ts terpane ratios imply source rock deposition under the influence of persistent upwelling conditions. Montney-sourced oils tend to have higher Pr/Ph ratios and more positive $\delta^{13}C$ isotope compositions than Doig-sourced oils.

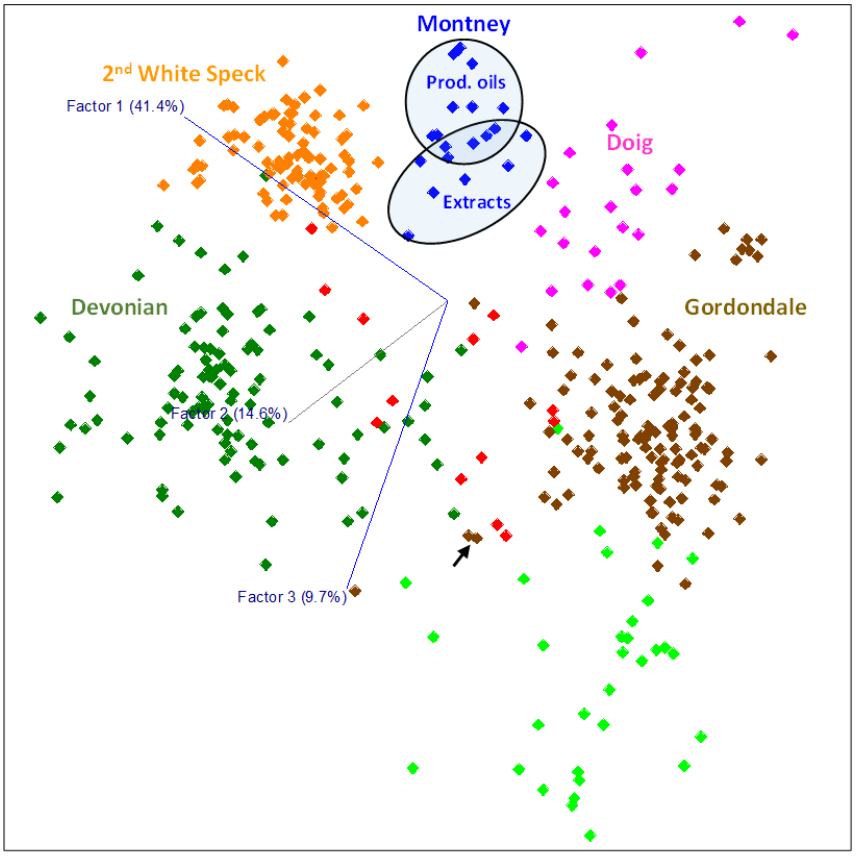


Figure 1c. Rotated principal components shown here represent 65% of the total data variation. Unique Devonian Keg River oil compositions were not included in these PCA iterations. The arrow shows the same duplicate oil samples as in Figure 1a.

The Gordondale and Doig-sourced oils clearly plot separate from these new Montney oils, and are independent of a mixing line, indicating these Montney oils represent a new, and previously not fully recognized oil family. Oil terpane biomarkers suggest a type II marine distal shale source facies deposited under the influence of persistent upwelling. Saturate and aromatic sterane ratios are consistent with a Triassic age.

Early oil, rich in heavy-end biomarkers, migrates first with oil vitrinite reflectance equivalence based on biomarkers (VREB) representing the source maturity during early expulsion. With continuing burial, expulsion and migration, lighter hydrocarbons (lean in biomarkers) mix with the early oil. This subsequent maturity signal, VREQ (based on alkyl aromatics), represents the mid-range composition. Although there is a good correlation of VREB to VREQ, the absolute values are only equivalent at the higher range (ca 1.15% VRE) (Figure 2) while at lower maturities, the difference between VREB (0.85%) and VREQ (1.05%). This suggests that the timing of charge from the source rock to the reservoir spans a long maturity window, from mid oil to wet gas generation. Excess amounts of thermally stable diamondoids present in reservoired Montney oil (from oil cracking to gas down-dip) may imply a higher-than-expected GOR.

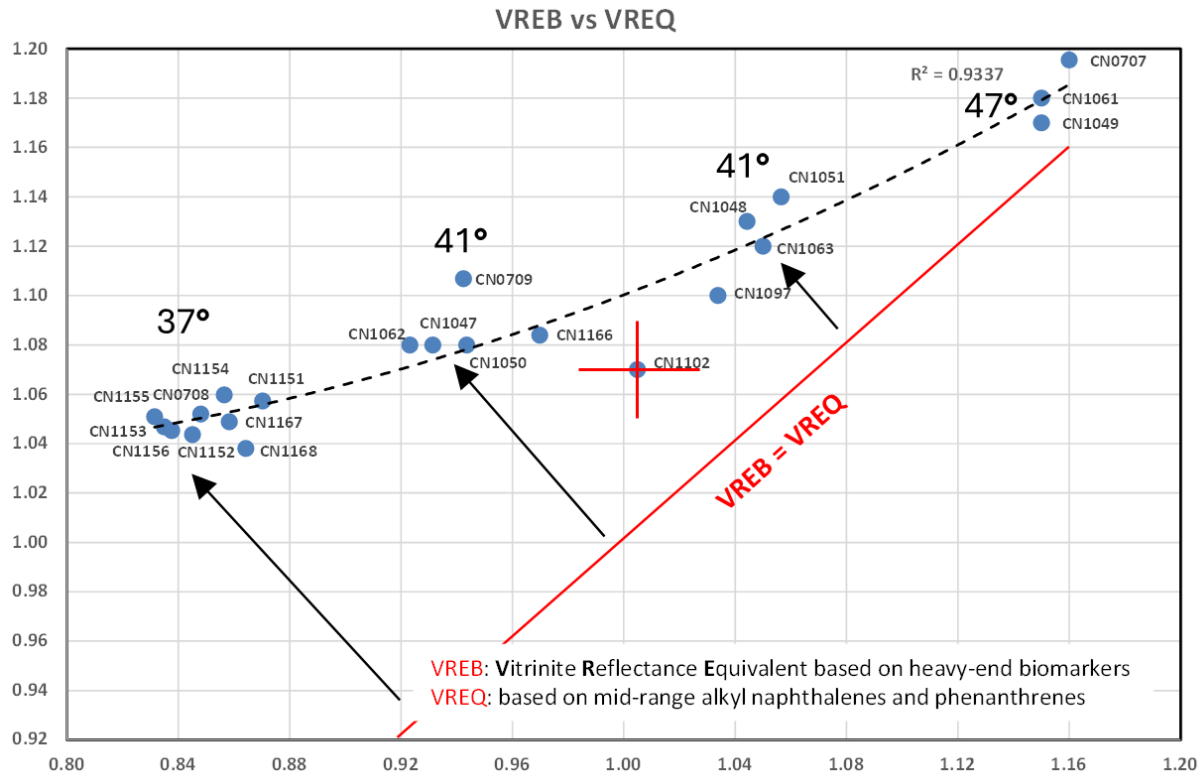


Figure 2. Early generated oil, rich in heavy-end biomarkers, migrate first with calculated oil VREB representing the source rock maturity as the oil is expelled (i.e., primary migration). As the source rock continues to expel oil at higher maturities with continued burial, lighter migrating hydrocarbons (lean in biomarkers) mix with the early oil along migration pathways or in the reservoir. This second maturity signal, VREQ, represents a mid-range composition (e.g., methyl phenanthrenes). Comparing VREB to VREQ for Montney generated oils, there is a good second order correlation, with the difference decreasing with increasing maturity. Oil CN1102 is an outlier since it was sourced from the Doig. Average API gravities are shown for each group. The range of source rock maturity (arrows) is reflected in the oils, with greater maturity differences between early and late oil perhaps suggesting more geologic time for oil charging up-dip Montney reservoirs. Red bars represents the standard error for VREB and VREQ.

In lighter colored Montney oils, where sterane and terpane biomarkers have been thermally degraded, pristane/phytane vales from gas chromatography along with stable carbon isotope compositions of the saturated hydrocarbon fraction (from SARA separation), can often determine the source of the light oil (Figure 3). Montney-sourced oil usually has higher Pr/Ph values and more positive carbon isotope values (enriched) than Doig-sourced oils.

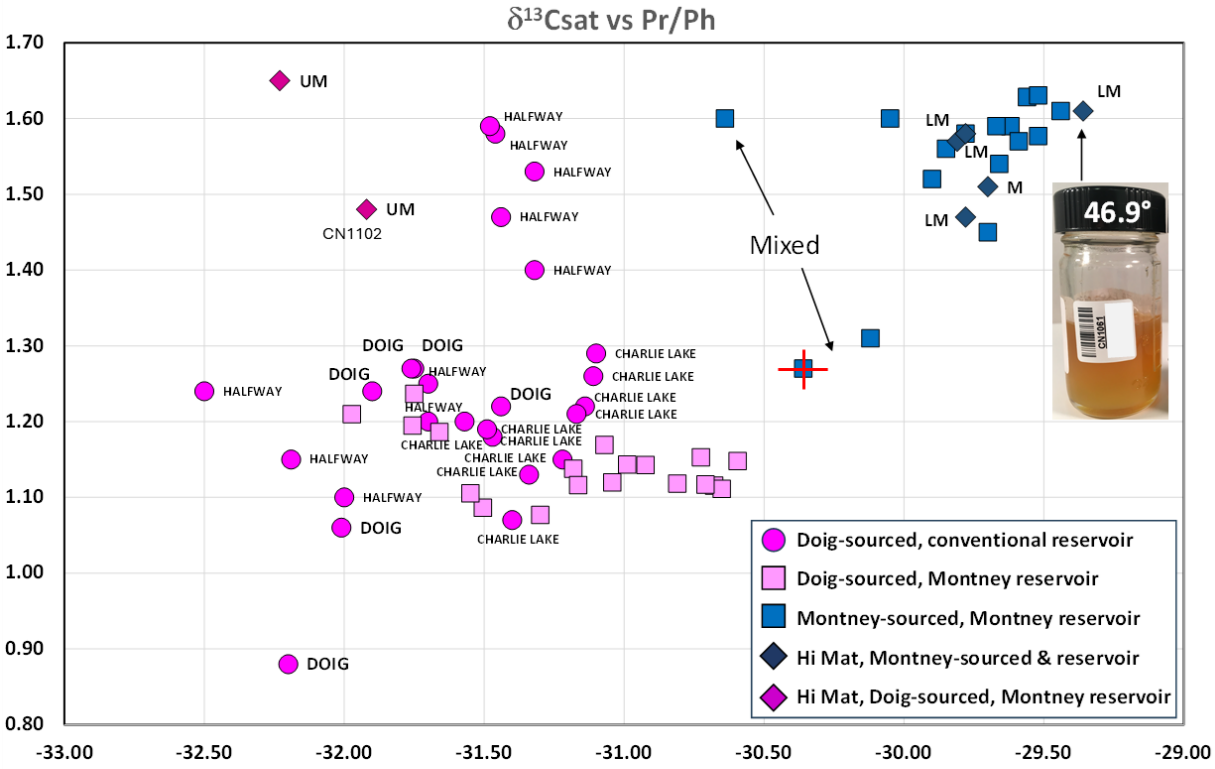


Figure 3. Two oil geochemical parameters, pristane to phytane ratio and the carbon isotopic composition of the C15+ saturated hydrocarbon fraction, usually distinguish Montney from Doig source rocks. The Halfway reservoir, just above the Doig source, contains oils with higher Ph/Pr ratios while the younger Charlie Lake reservoir oils have lower ratios. This may reflect the Pr/Ph variation between the lower Doig phosphatic facies and the upper Doig shale facies. These two variables are especially useful in typing higher maturity oils which lack the full suite of biomarkers to use PCA. In the few 'Hi Mat' samples here, the Lower Montney reservoir's oil was generated from the Montney while the upper Montney reservoir contains Doig-sourced oil. Red bars represents the analytical precision: ± 0.025 for Pr/Ph (peak heights) and ± 0.05 for δ^{13}Csat ‰.

Montney core samples (1,800-1,915 m depth) contained between 0.62 to 1.3% TOC and 2,000 to 5,000 ppm extracted saturate & aromatic hydrocarbons, far above the expected concentration for local oil generation. Vitrinite reflectance equivalent values from pyrolysis Tmax temperatures (VRET) indicate a local maturity level of only 0.67-0.76%, significantly below the VREB determined from extracted biomarkers (0.84-1.09%) which is consistent with migrated oil. Extracted oil maturity increased dramatically in one core (well 100/05-13) over only 100 m (Figure 4) suggesting different Montney zones were charged separately over geologic time with migrating oil from deeper source horizons. No significant mixing was evident in these relatively closely spaced core extracts. This interpretation conforms to Watt et al. (2022) Montney reservoir observations farther to the north in a higher maturity regime, where oil has converted to

pyrobitumen, and differences in gas isotope compositions indicate a stratified oil column with no vertical mixing. However, in other regions, Montney rocks may have some source potential interbedded with the reservoir facies (e.g., Becerra et al., 2024). Rudra et al. (2024) analyzed a number of organic-rich Doig and low TOC (~1%) Montney core extracts from Alberta for biomarkers and isotopes, but the few produced fluids were too mature to contain useable biomarkers. Their Lower Montney carbon isotopes from core extracts, however, were enriched with respect to Doig extract isotopes, consistent with our results.

Well	Depth m	ppm HC	%VREB	%VRET	%TOC
100/05-13	1,815	4,325	0.84	0.72	0.81
100/05-13	1,845	2,200	0.86	0.76	1.29
100/05-13	1,896	5,066	1.00	0.62	0.99
100/05-13	1,915	4,308	1.09	0.63	1.04
100/13-07	1,800	3,204	0.84	0.76	0.97
100/13-07	1,806	4,817	0.86	0.67	0.64
100/13-07	1,814	3,599	0.84	0.67	0.62

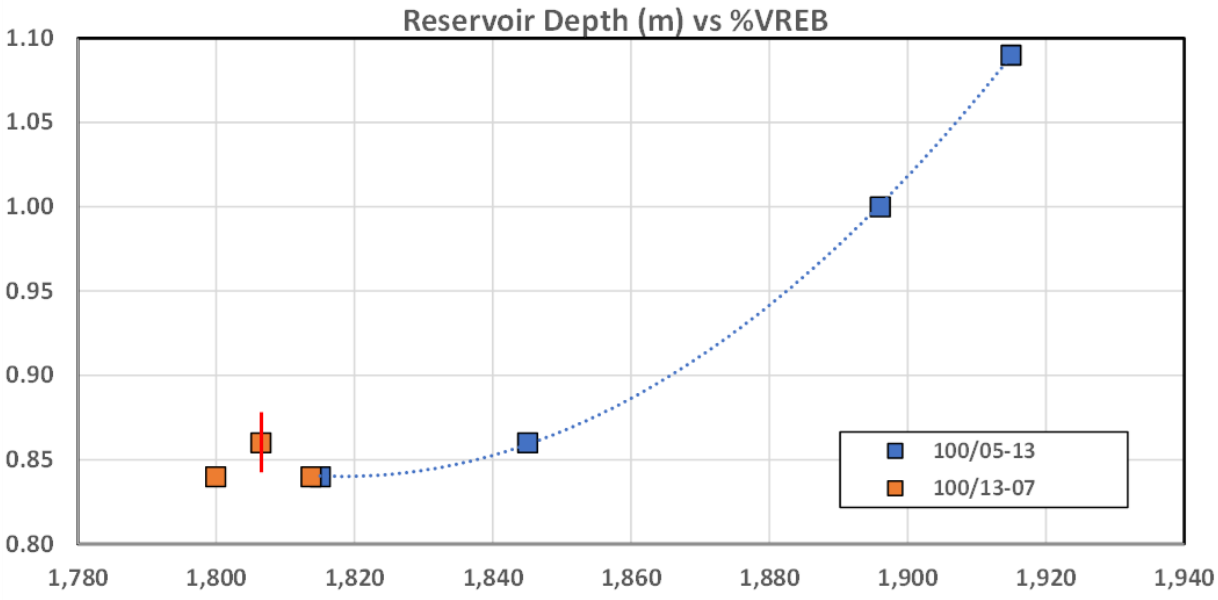


Figure 4. The high concentration of solvent extracted hydrocarbons and small TOC values from Montney core samples strongly indicate the presence of migrated oil. In addition, oil maturity (VREB; based on biomarkers) is significantly higher than host rock maturity (VRET; based on pyrolysis Tmax) which is also consistent with migration. Furthermore, extracted oil maturity increases dramatically in the 100/05-13 core over just 100 m. Reservoir zones were charged separately over geologic time with migrating oil from deeper source horizons with no/little mixing between these horizons. Deeper Montney water-based mud cuttings (up to 4,500m) from three other wells show similar trends. Red bar represents the standard error for VREB (± 0.02).

Novel/Additive Information

Aspects of the organic geochemistry of Triassic source rocks and oils have previously been reported, and conjectures regarding black oil migration within the Montney, from Bottomset source rocks (presently over mature) to Topset reservoir facies, have been proposed (Euzen et al., 2021 and Wood et al., 2022). Our new Montney oil family based on biomarkers and, especially, carbon isotopes, unique from Doig-sourced oils, demonstrates that up-dip Montney reservoirs can be charged with Montney source rock facies in addition to younger Doig-generated oil, essentially confirming the previously more speculative play. Large differences in Montney-reservoired oil maturity signals suggest a greater source rock maturity range with potentially more geologic time available for oil reaching the reservoir (Figure 5). Evaluation of produced gas composition (Figure 6) and formation water chemistry could offer additional, underutilized lines of evidence that can further constrain migration pathways, charge timing, and fluid connectivity, strengthening an integrated petroleum systems interpretation. These findings should empower operators to derisk up-dip, Montney step-outs or provide geologic support for unexpected oil volumes.

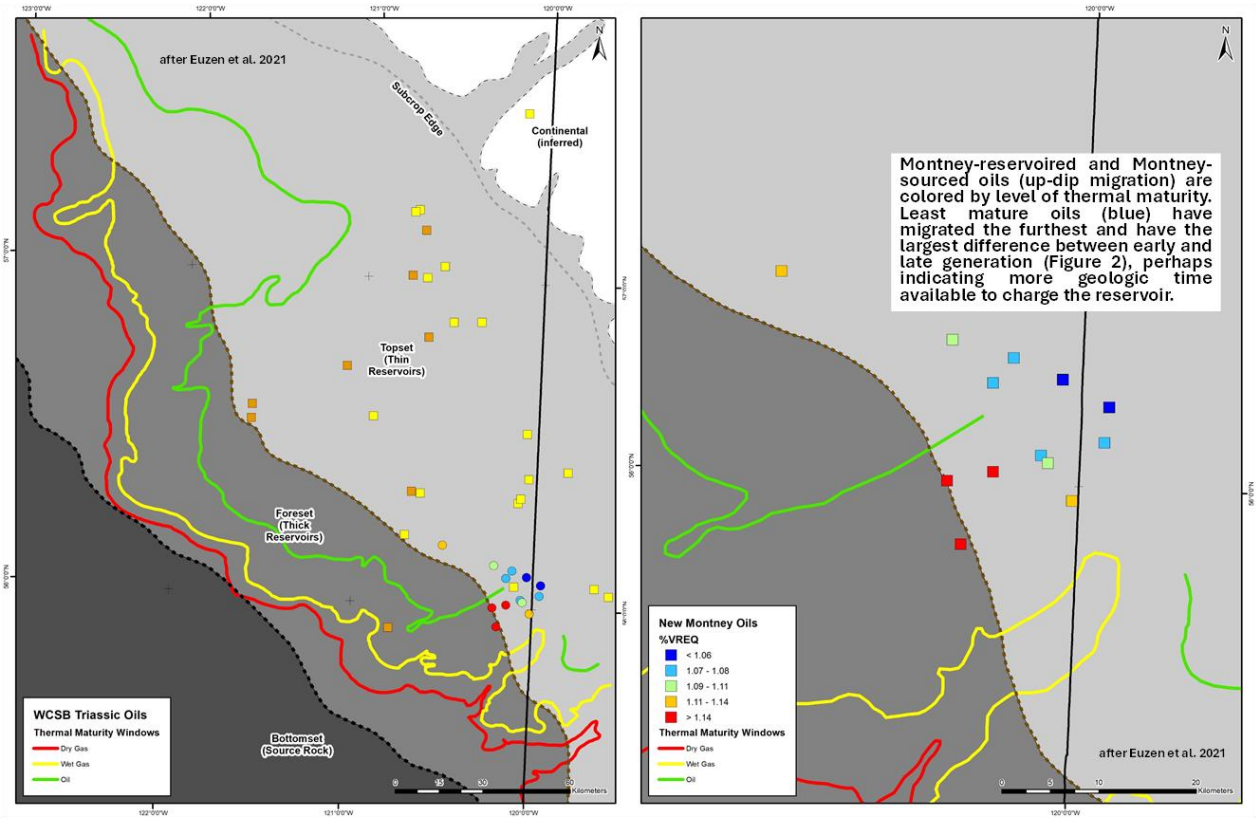


Figure 5. Here we show the general location of Triassic oil samples using the background Montney Topset reservoir to Bottomset (potential Montney source rock) notation and present-day zones of thermal maturity shown by Euzen et al. 2021. The map on the left shows oil locations as yellow & tan squares, mostly produced from conventional Upper Triassic Halfway and Charlie Lake reservoirs sourced from the underlying Doig Formation. The map on the right is an enlargement showing the Montney-sourced oil maturity level which reflects the range of source rock maturity when the oil is expelled and migrated.

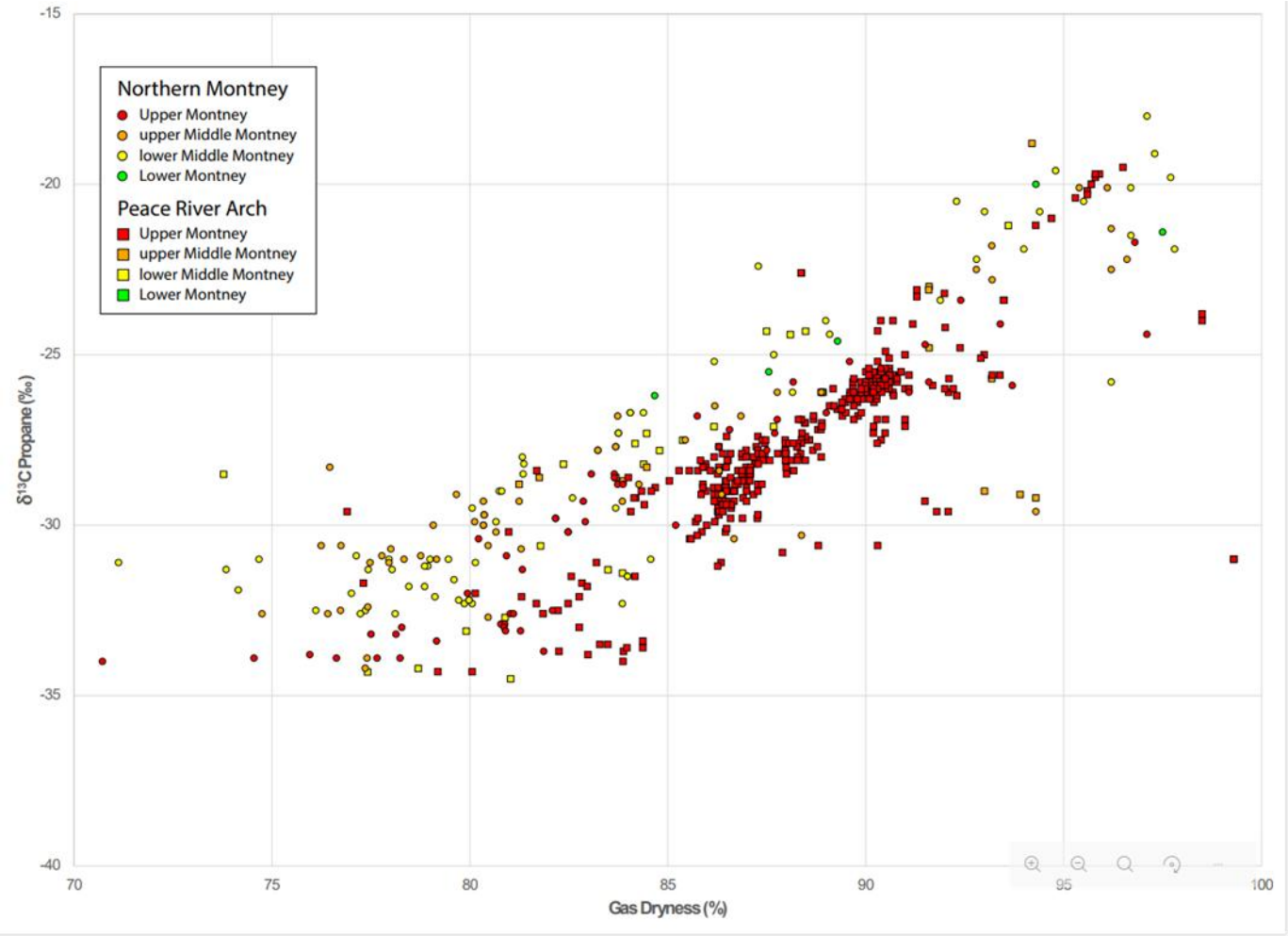


Figure 6. Here we show proprietary GeoMark Research gas data assigned to Montney Stratigraphy by Tristan Euzen, in which we have found strong evidence of stratigraphic controls on fluid distribution and resulting production outcome (both source and migration related). This illustrates the influence of stratigraphy in a cross-plot of d13C propane versus gas dryness of produced gas.

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