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NOT ALL OF THE NIKANASSIN
IS CREATED EQUAL
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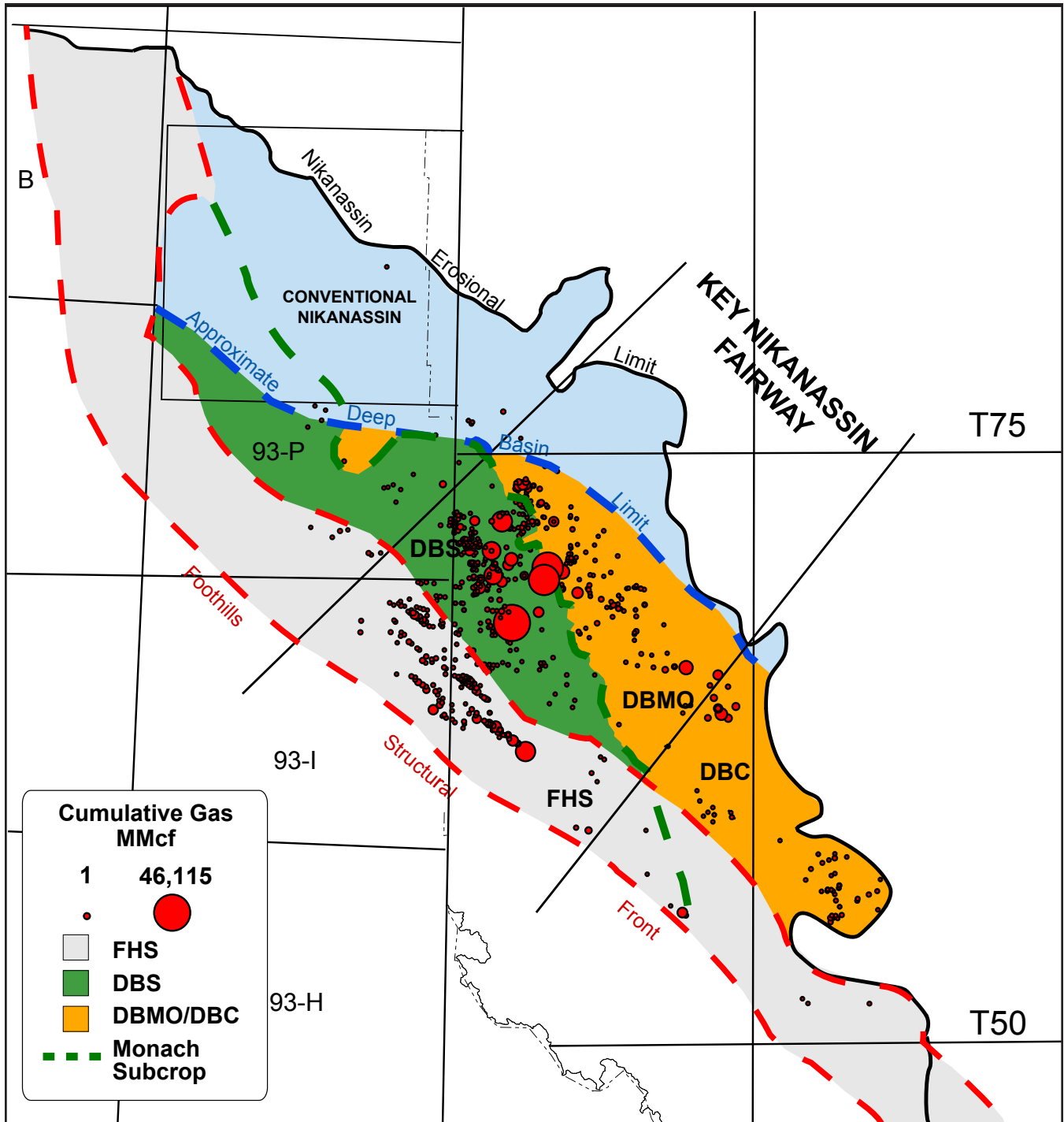
“Not All of the Nikanassin Is Created Equal”

A Choice Between Naturally Fractured High Deliverability Dry Gas vs. Deep Basin Liquids-Rich Gas

Executive Summary

- The Nikanassin Formation has the potential to become an important unconventional Deep Basin Resource Play in the Western Canada Sedimentary Basin.
- The Nikanassin is a proven Deep Basin unconventional tight gas sandstone play, with >950 Bcf produced to date.
- This report highlights three Nikanassin fairways (Figures 1 and 2) that demonstrate the best upside potential based on:
 - ◆ Initial deliverability (IP)
 - ◆ Estimated Ultimate Recovery (EUR)
 - ◆ Initial reservoir pressure and Liquids Yield
 - ◆ Calculated Internal Rate of Return % (IRR – Figure 3), Profit-Investment Ratio @10% (PIR) and Breakeven Supply Cost (BESC – Figure 4).
- The three geologically defined Nikanassin fairways that demonstrate the best upside potential are:
 - ◆ The Nikanassin Foothills High Deliverability Structured Fairway (FHS – Figure 1) is developed along a Southeast (SE) to Northwest (NW) trending belt, which runs parallel to the mountain front. The FHS is divisible into an inner Foothills fairway characterized by large-scale NW-SE trending anticlinal structures, and an Outer or Forefoothills fairway with smaller-scale structures. Nikanassin reservoirs are hosted within low permeability, naturally fractured tight sandstones from the Upper Nikanassin – Monach Formation and Lower Nikanassin Monteith formation (Figure 2). Nikanassin production within this fairway includes the Ojay – Narraway – Chinook Ridge areas. Companies actively licensing and drilling since January 2009 in this fairway include Conoco (COP-NYSE), Canadian Forest, a wholly owned subsidiary of Forest Oil Corp. (FST-NYSE), Shell (RDS.A-NYSE), Talisman (TLM-TSX), Daylight (DAY.UN-TSX) and Progress (PRQ-TSX).
 - Both the Inner and Outer FHS is characterized by:
 - High deliverability with IP (three-month average) = 3.7 (vertical wells) to 14MMcf/d (deviated wells)
 - EUR ~ 3.5 (vertical) to 7.1 (horizontal to highly deviated) Bcf/well
 - Commonly over-pressured with a low gas liquids content (<10 bbl/Mcf)
 - Calculated IRRs = 15–32%; PIR = 0.2–0.4; and BESC = \$3.47–4.26/Mcf.

Figure 1: Nikanassin Play Fairways Map With Cumulative Nikanassin Production

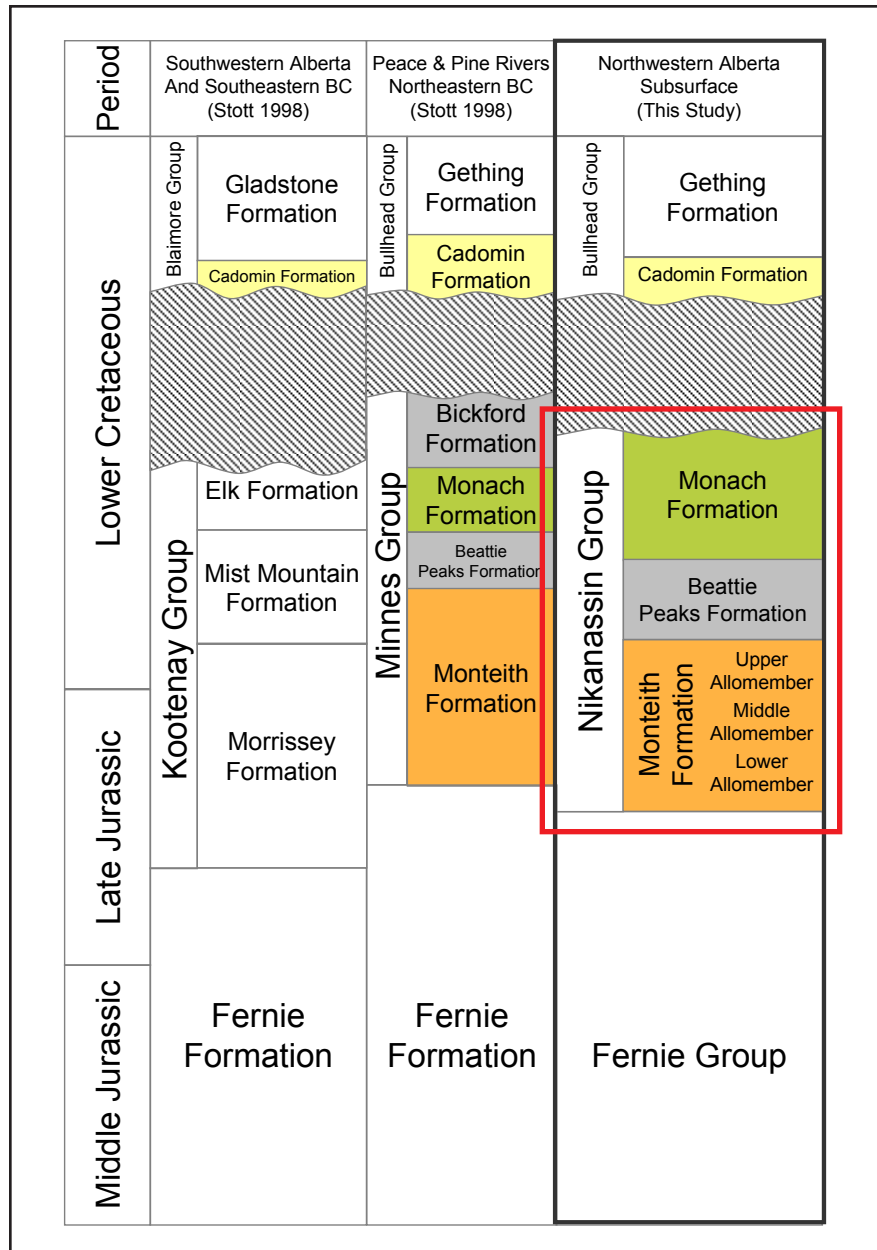


Source: BMO Capital Markets; Production data from GeoScout; Monach Subcrop limit – after Miles and Hubbard, 2010; Deep Basin Limit – after various published sources; Nikanassin subcrop limit – GeoScout and various published sources, Western Canada Sedimentary Basin Atlas, 2010

- ◆ The Upper Nikanassin Monach and Lower Nikanassin Montieth Deep Basin – Stacked Fairway (DBS – Figure 1) is developed within the Deep Basin with isolated small-scale structures. Nikanassin reservoirs are developed within locally fractured, low-permeability tight sandstones. The majority of DBS Nikanassin pools are located in the Elsworth – Wapiti – Bilbo – Red Rock areas. Companies actively licensing and drilling in this area since January 2009 include Conoco, Devon (DVN-NYSE), Daylight and NuVista (NVA-TSX).
 - The DBS Fairway is characterized by:
 - High deliverability with IP (three-month average) = 2.3 (vertical well) to 10 MMcf/d (horizontal well)
 - EUR ~ 3.5 (vertical) to 7.1 (horizontal to highly deviated) Bcf/well
 - Commonly under-pressured with a gas liquids content <10 bbl/Mcf in the western/deeper portion of the fairway, increasing to liquids-rich (~10 to 75 bbl/Mcf) toward the eastern side of the fairway
 - Calculated IRRs = 9–61%; PIR = 0.4–1.7; and BESC = \$2.25–4.68/Mcf
- ◆ The Nikanassin Deep Basin – Montieth Fairway (DBMO – Figure 1) exists eastward beyond the Monach subcrop edge, within the Deep Basin where only the Lower Nikanassin-Montieth is present. Nikanassin tight sandstone reservoirs are easily damaged due to immature reservoir mineralogy and an undersaturated nature, and commonly require specialized completion strategies. Where successful, the DBMO is most economic when commingled with uphole Cretaceous units. The top five companies actively licensing and drilling for the Nikanassin in this area since January 2009 include Encana (ECA-NYSE; ECA-TSX), Progress, Delphi (DEE-TSX), TAQA and Paramount (POU-TSX).
 - The DBMO Fairway is characterized by:
 - Lower deliverability with IP (three-month average) = 1.8 MMcf/d
 - EUR ~1.4 Bcf/well
 - Commonly under-pressured, with localized areas of overpressure, and a gas liquids content 10 to 75 bbl/Mcf
 - Calculated IRRs = 19–82%; PIR = 0.2–0.8; and BESC = \$3.02–4.23/Mcf.

The Nikanassin also has proven production in the Deep Basin Commingled (DBC) Fairway, south on trend of the main DBMO area, toward the Wild River area (Figure 1). In the DBC, the Nikanassin is characterized by a low net:gross reservoir and is not considered economically viable on its own at this time; however, the DBC can be an important secondary zone when commingled with uphole zones with multizone completions. This zone will not be a focus of this report.

Figure 2: Nikanassin Group Stratigraphic Framework – red box highlights section studied in this report



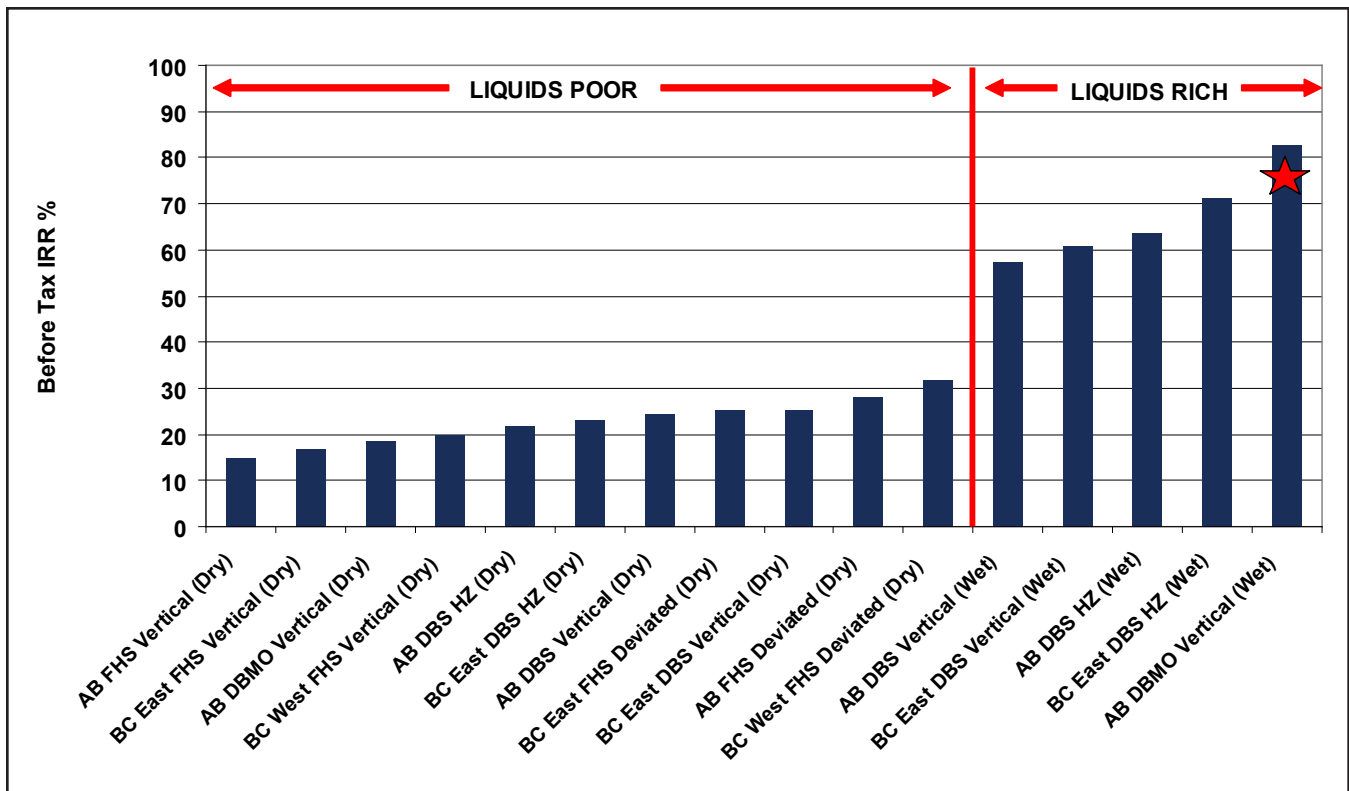
Source: after Miles and Hubbard, 2010

The key production and economic parameters that differentiate the value between the various Nikanassin Fairways include: Initial Production (IP), Estimated Ultimate Recovery (EUR), Liquids Content and Capital costs. These parameters allow for the calculation of Internal Rate of Return (IRR – Figure 3) and Breakeven Supply Cost (BESC – Figure 4). In terms of Average 30-Day IP, the FHS Highly Deviated wells are the largest (~10.4 MMcf/d), followed by DBS HZ wells (~6 MMcf/d), FHS vertical wells (2.9 MMcf/d) and DBMO/DBS vertical wells (1.5-1.7 MMcf/d). Nikanassin EURs vary from 7.1 Bcf/well for FHS Highly Deviated wells, ~3.5 Bcf for FHS vertical wells, ~ 3.1 Bcf for DBS and ~1.4 Bcf in the DBMO fairway.

The Before Tax Internal Rate of Return ratio (IRR %) varies considerably across the different fairways and political jurisdictions because of cost and royalty/tax burdens. Figure 3 shows the comparison of before-tax IRR % across the various type curves/fairways studied in this report. The highest IRRs are found in the DBMO Vertical (wet or high liquid content – see Figure 5) fairway (83%), followed by BC East DBS Vertical (wet), BC East DBS HZ (wet), AB DBS Vertical (wet), and AB DBS HZ (wet) 50–60% IRR. The common variable for these +50% IRR wells is the value that comes from the presence of high amounts of gas liquids in the production stream. The key risks are being able to manage potential reservoir damage and underpressured nature of these reservoirs, and to obtain high enough deliverability to effectively produce the liquids. After presence or absence of gas liquids, deliverability and time to payout are the next most important criteria. The Alberta and BC FHS deviated wells have IRRs of 20–32%. DBS wells with low liquid content have IRRs of ~25%.

The Nikanassin can be divided into four main fairways: 1) FHS = Foothills High Deliverability Structured Fairway; 2) DBS = Deep Basin – Stacked (Upper Nikanassin Monach and Lower Nikanassin Montieth) Fairway; 3) DBMO = Deep Basin – Montieth Fairway; and 4) DBC = Deep Basin Commingled Fairway.

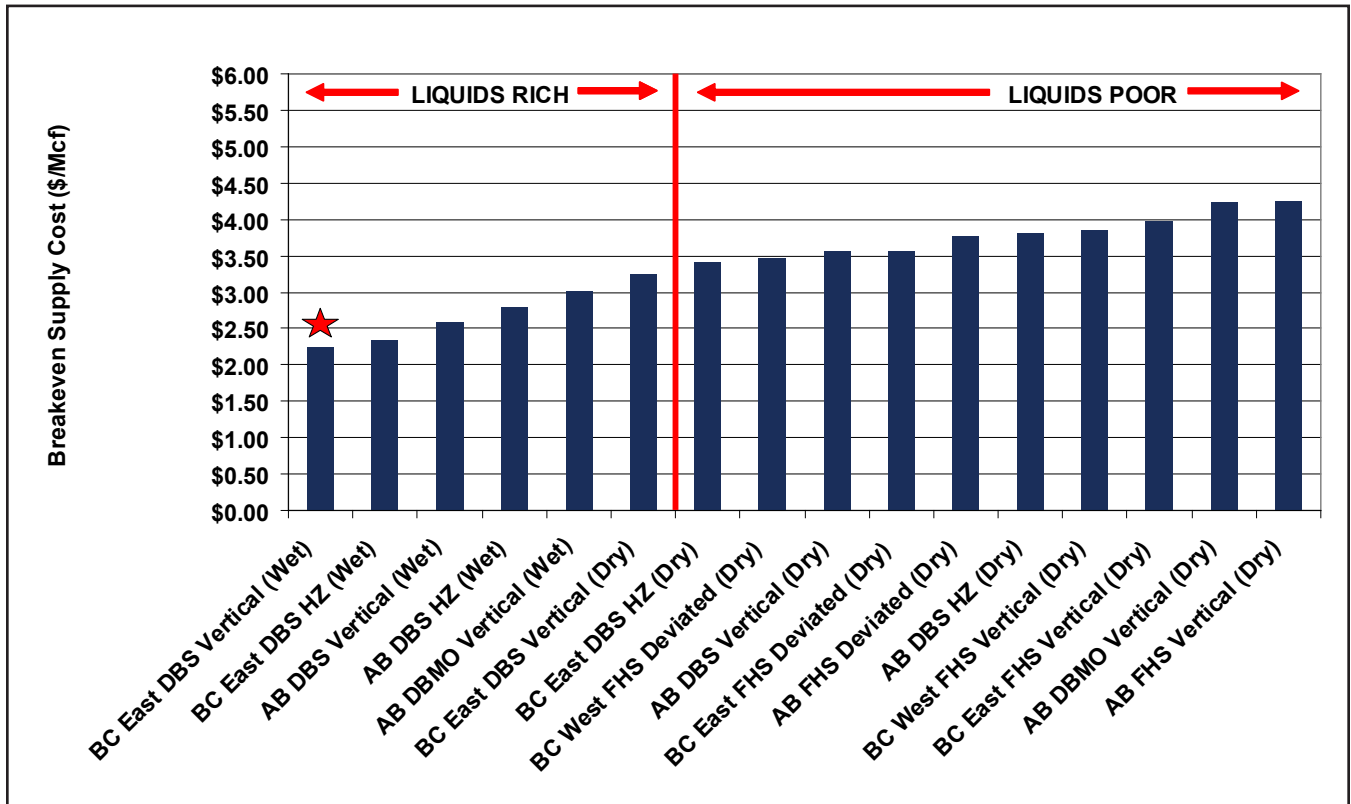
Figure 3: Before-Tax IRR % by Fairway Type Well



Source: BMO Capital Markets

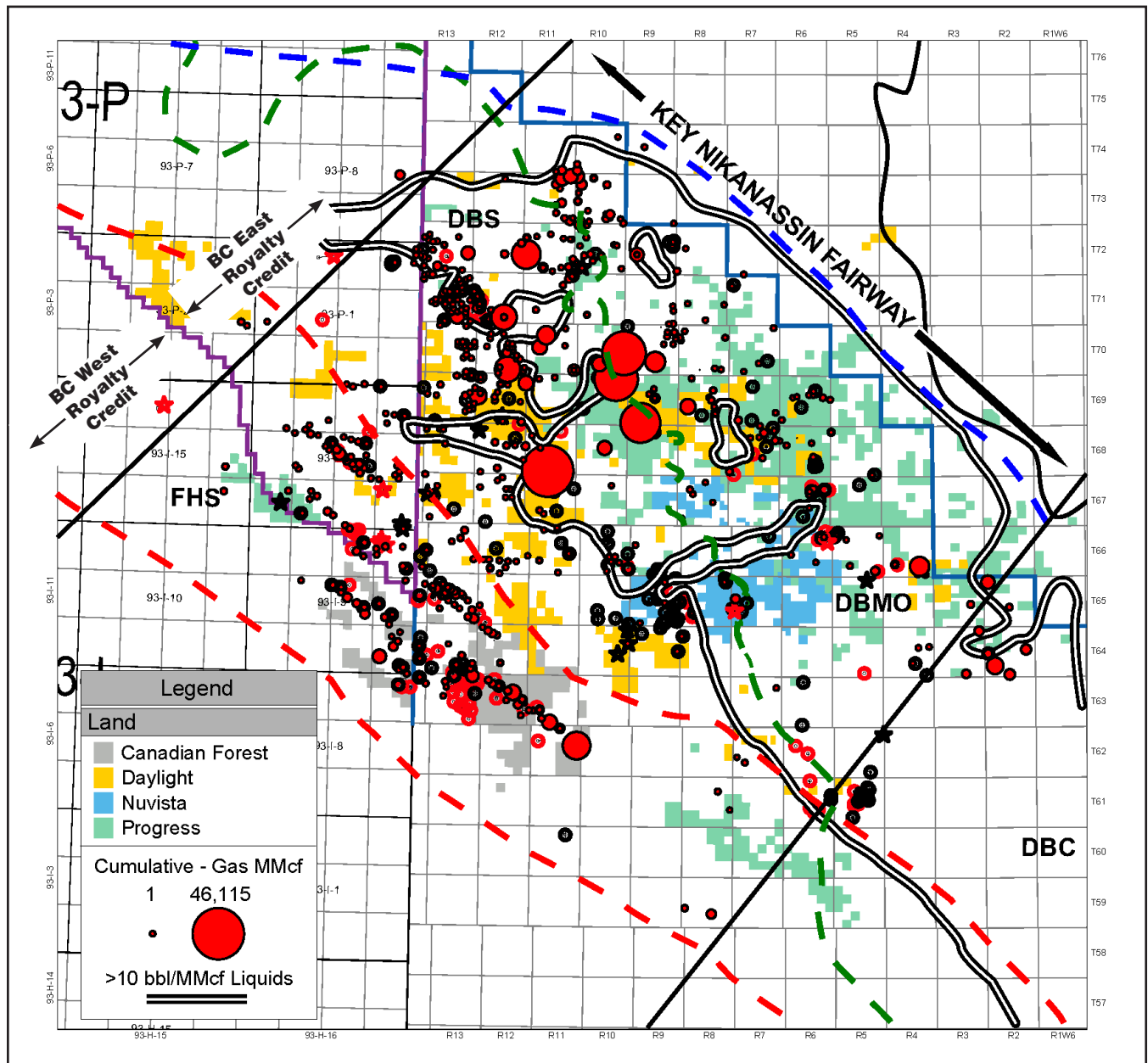
Figure 4 shows the Breakeven Price @10% (\$/Mcf) across the various type curves/fairways studied in this report. Play types and fairways toward the lower end of the Breakeven Price include the liquids-rich DBS and DBMO (sub \$3.50/Mcf). It is interesting to note that the best Breakeven Price for FHS and “dry” plays require >\$3.25/Mcf. Star represents best BESC play = BC East DBS Vertical with high liquids yield.

Figure 4: Breakeven Price (\$/Mcf) by Fairway Type Well



Source: BMO Capital Markets

Figure 5: Nikanassin Cumulative Production Map Showing Land Position of Canadian Forest, Daylight, NuVista and Progress in Relation to Nikanassin and Liquids-Rich Fairways (the position of the BC East and West royalty credit areas are divided by the purple line).



Source: BMO Capital Markets; Production data from GeoScout; Monach Subcrop limit – after Miles and Hubbard, 2010; Deep Basin Limit – after various published sources; Nikanassin sub-crop limit – GeoScout and various published sources, Western Canada Sedimentary Basin Atlas, 2010

Legend	
Drilled or Licensed since Jan 2009	
●	Vertical Drilled
★	Horizontal Drilled
●	Vertical Licensed
★	Horizontal Licensed

New evaluation methods applied to the Nikanassin to target “sweet spots” (e.g., 3D seismic to highgrade secondary structures with increased fracture permeability), new drilling (horizontal to highly deviated wells, underbalanced drilling) and completion technologies (e.g., multistage slickwater, oil and/or propane-based fracs) have increased the available area of stimulated rock volume (SRV) and improved IPs and EURs per well. Detailed mapping of the liquids content (Figures 5 and 43) has allowed for the identification of liquids-rich “sweetspots” approaching 50–75 bbl/MMcf have resulted in the Nikanassin being re-evaluated from a secondary “bail-out” zone to a potential primary “anchor-zone” target.

Certain companies have focused on the high deliverability dry gas fairways (FHS and western part of the DBS) where the ability to target structures that have increased natural fracture density has yielded higher IPs. An example is Shell, which utilized cutting edge 3D seismic and processing to image areas of increased fracture density that allows for improved placement of wells on structure. Canadian Forest’s strategy is to modify its completion processes and to utilize slickwater fracs from its experience in U.S. gas shales to improve SRV and increase deliverability. Other companies (e.g., Daylight, Progress, Pace/Midnight (PCE-TSX, not rated)) appear to be targeting via 3D seismic smaller-scale structures to define fractured sweet spots. Other companies have recently targeted the liquids-rich portion of the Nikanassin associated with the eastern DBS and DBMO (e.g., Progress, NuVista, Delphi, Artek (RTK-TSX, not rated)). In these areas the mitigation of reservoir damage during drilling and completion while keeping costs under control is the key to the economic viability of the play. While the Nikanassin in the DBS and DBMO is transitioning into a primary target, the ability to commingle with uphole Deep Basin zones is critical in the exploitation of the resource.

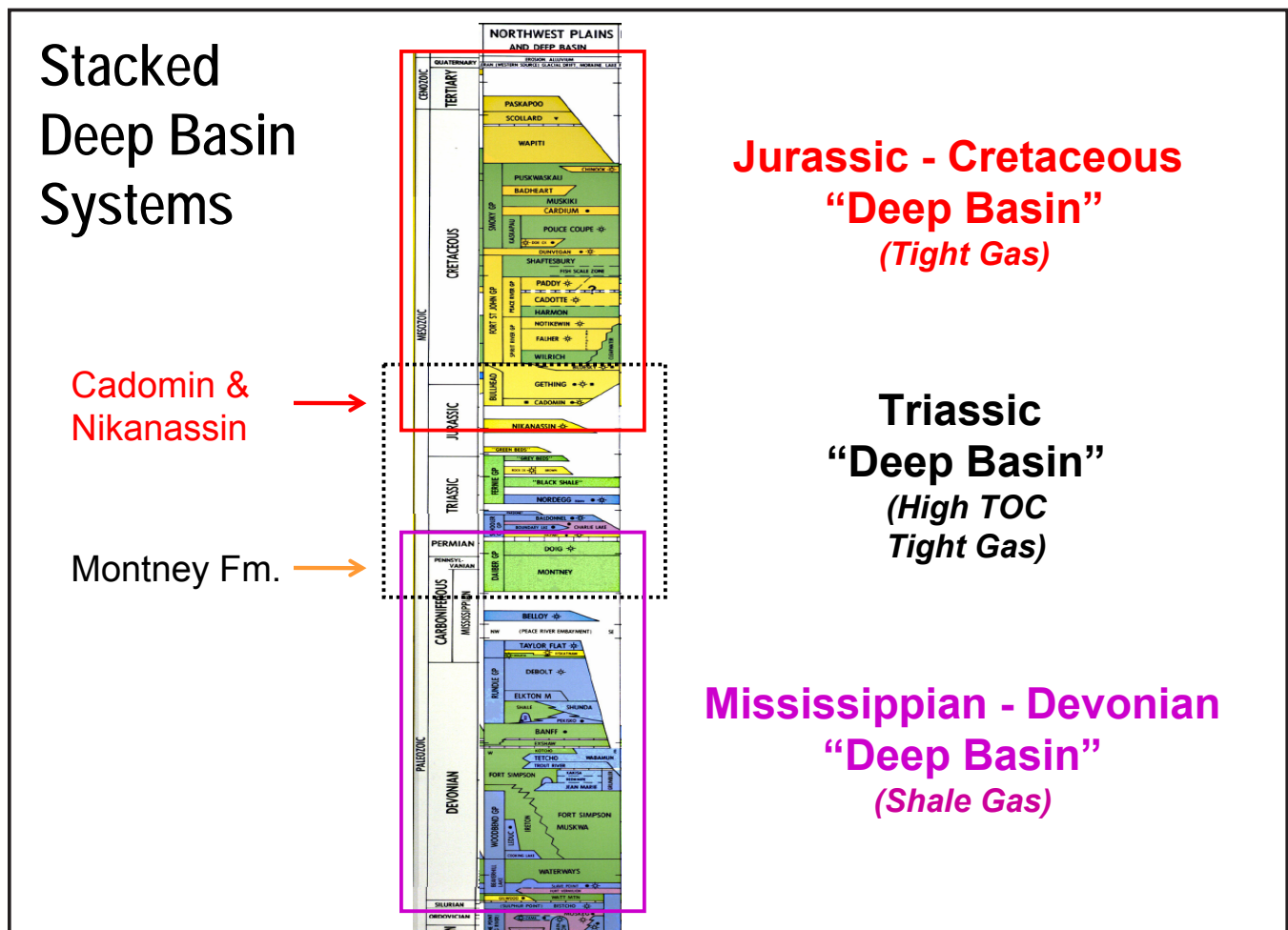
Four companies are highlighted, as they appear to represent the spectrum of play types and completion strategies presently being employed in the Nikanassin. Figure 5 is a composite land map showing the position of:

- Canadian Forest – a major E & P company focusing on Nikanassin Foothills High Deliverability Structured Fairway (FHS);
- Progress Energy – a company focused on both the Nikanassin Foothills High Deliverability Structured Fairway (FHS) and liquids-rich Deep Basin – Montieth Fairway (DBMO);
- Daylight Energy – a company focused on the lower liquid yield area of the Nikanassin Foothills High Deliverability Structured Fairway (FHS) and Deep Basin – Stacked Fairway (DBS), with some exposure to the liquids-rich Deep Basin – Montieth Fairway (DBMO); and
- NuVista – focused primarily on the liquids-rich Deep Basin – Stacked Fairway (DBS) and Deep Basin – Montieth Fairway (DBMO)

Introduction

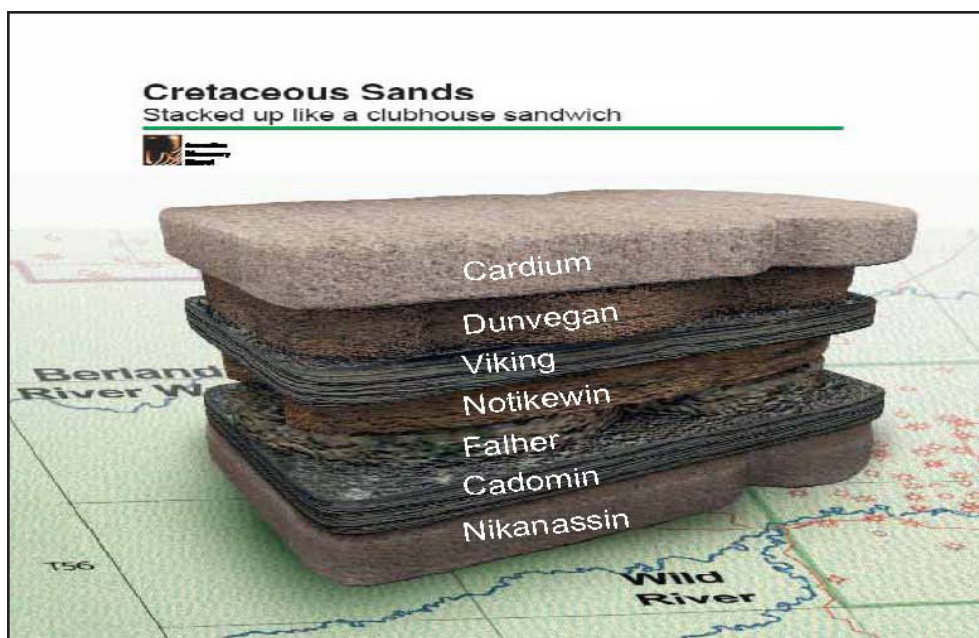
The Nikanassin Group appears to be developing into yet another exciting unconventional Deep Basin Resource Play in the Western Canada Sedimentary Basin (Figure 6). The Nikanassin was initially identified as one of the potential stacked Deep Basin tight gas zones in the early 1970s (Figure 7). The Nikanassin was interpreted to have a large original gas in place (OGIP), abnormal (both high and low) pressure areas, characterized by generally low permeability (generally <0.1md), and to be part of a continuous gas saturated system with little to no down-dip water (Masters, 1984). However, when vertical wells in the Nikanassin were completed with the technologies available at that time, the Nikanassin flowed at sub-economic rates in the range of 200–300 Mcf/day.

Figure 6: The Three Stacked Basin Centered Gas Systems in the Western Canada Sedimentary Basin (WCSB): 1) Jurassic-Cretaceous Deep Basin System – highlighting the position of the Nikanassin at the base of this system; 2) Triassic Deep Basin; 3) Mississippian – Devonian Deep Basin.



Source: Zaitlin and Moslow, 2005, 2006, 2008; Midnight/Pace Corporate Presentations

Figure 7: Schematic of Cretaceous-Jurassic Deep Basin Multi-Zone Potential, Highlighting the Position of the Nikanassin at the “Base of the Sandwich”

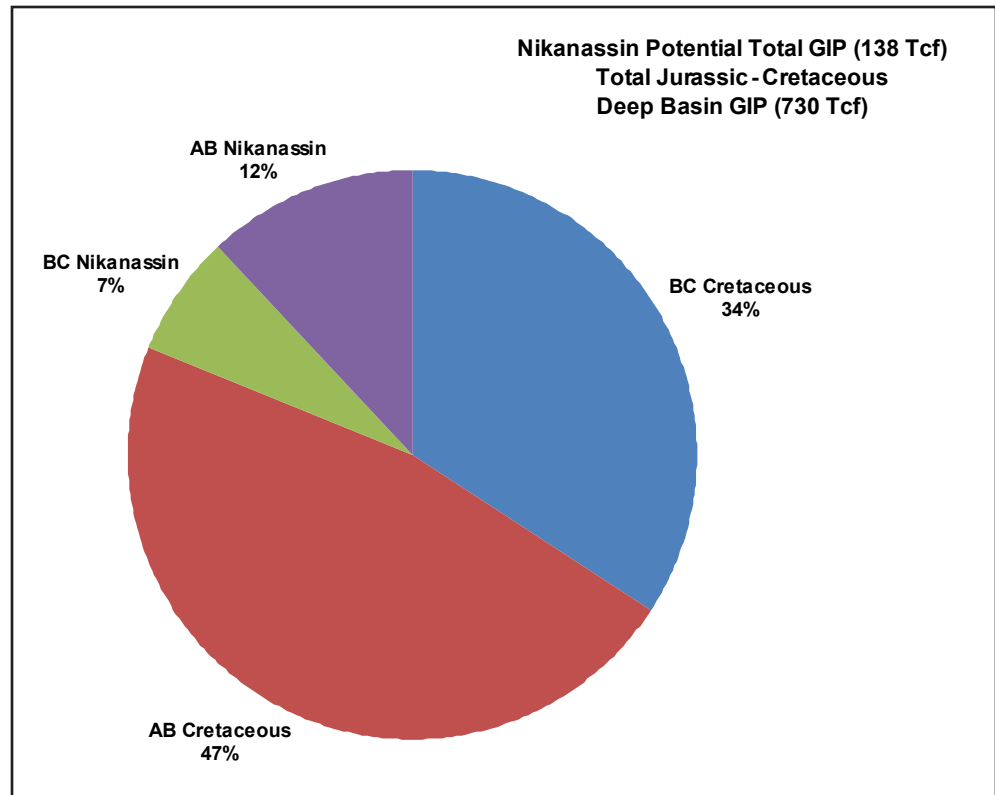


Source: Canadian Discovery Digest November/December, 2003

The Nikanassin was considered to be easily “damaged” as a result of its sensitivity to water-based fluids, immature mineralogy and clay rich (smectite and illite) lithology – though recent mapping indicates that this may be area specific. As a result, the Nikanassin was considered a secondary zone, suitable for potential commingling with uphole Cretaceous zones (Figure 7), rather than being a primary or anchor target. There was recognition that improved understanding of reservoir distribution, structure framework, petrophysical cutoffs and liquids content would be needed to effectively exploit the Nikanassin as an anchor or target zone. Therefore, the strategy for exploiting the Nikanassin had been to progressively downspace and target multiple uphole horizons, allowing for commingled production. This resulted in the deepening of many Deep Basin gas wells to capture incremental gas production from the Nikanassin and the formation of Development Entity #2 allowing commingling of multiple Deep Basin zones and well downspacing.

Because the Nikanassin reservoirs are commonly commingled with uphole zones and lack many wells with Nikanassin-specific long production histories needed to fully quantify their gas resource potential, attempts have been made to volumetrically quantify the contingent resource base. Resource base assessments indicate a significant potential contingent resource base for the Nikanassin (Figure 8). The British Columbia (BC) portion of the full Cretaceous Deep Basin is estimated to contain 125–250 Tcf Gas-in-place (GIP) (e.g., PRCL, 2003). The Nikanassin resource base was not evaluated separately; however, the authors estimated that the Nikanassin could contribute an additional 25–50 Tcf GIP. In Alberta, a more recent PRCL study calculated a total resource value for the Deep Basin of 430 Tcf GIP, with the Nikanassin contributing approximately 88.0 Tcf. Together, these studies estimate the Nikanassin to have between 112 and 138 Tcf GIP, approximately 19% of a total Jurassic – Cretaceous endowment of ~580–730 Tcf GIP. If these estimates prove out and technology develops to allow for the unlocking of this resource, the Nikanassin may develop into a world-class contingent resource that would rank well against many of the other tight gas resource plays being evaluated in North America today.

Figure 8: Estimated Nikanassin Potential Total Gas in Place



Source: BMO Capital Markets; utilizing PRCL/BC Assessment, 2003 and Hayes - CSUG Presentation, 2010

The Nikanassin in this report is considered to have four fairways (Figure 1):

- The Foothills High Deliverability Structured Fairway (FHS) is an area of large-scale structures characterized by high deliverability, overpressured dry gas hosted within naturally fractured low permeability tight sandstones from the Upper Nikanassin-Monach Formation (Figure 2). The Nikanassin in this fairway, which includes Ojay-Narraway-Chinook Ridge areas, can be considered a primary target. The top 5 companies actively licensing and drilling in this Fairway include Conoco, Canadian Forest, Shell, Talisman and Daylight.
- The Deep Basin – Stacked (Upper Nikanassin Monach and Lower Nikanassin Montieth) Fairway (DBS), is a transitional area of dry (<10bbl/Mcf) to liquids-rich (10–75 bbl/Mcf) commonly underpressured gas except in areas characterized by low relief structures, hosted within locally fractured, low permeability tight sandstones. The DBS Fairway includes the Elmworth-Wapiti-Bilbo-Red Rock areas. The top five companies actively licensing and drilling in this area include Conoco, Devon, Daylight, NuVista and Encana.
- The Deep Basin – Monteith Fairway (DBMO) is an area of lower deliverability, underpressured wet gas (10–75 bbl/MMcf). The thinness of the Nikanassin, underpressured nature and liquids in these tight sandstones require specialized completion strategies. Where successful, it is most economic when commingled with uphole Cretaceous units. The top five companies actively licensing and drilling for the

Nikanassin in this area are Progress, TAQA, Delphi, Paramount and Husky (HSE-TSX).

- The Deep Basin Commingled (DBC) Fairway occurs south of the main DBMO area (Figure 1). The Nikanassin in the DBC is very thin with low net: gross reservoir. The isolated ribbon sand nature encased in non-reservoir mudstones and coaly shales result in poor deliverability and small EURs/well and does not meet economic hurdles on its own; however, the Nikanassin in the DBC can be an important secondary zone when commingled with uphole zones with multizone completions, and is not a focus of this report.

This report will focus on determining where in the Nikanassin the best combination of economics and resource is developed, and which companies are best leveraged to capture this opportunity. The outline of this report will be:

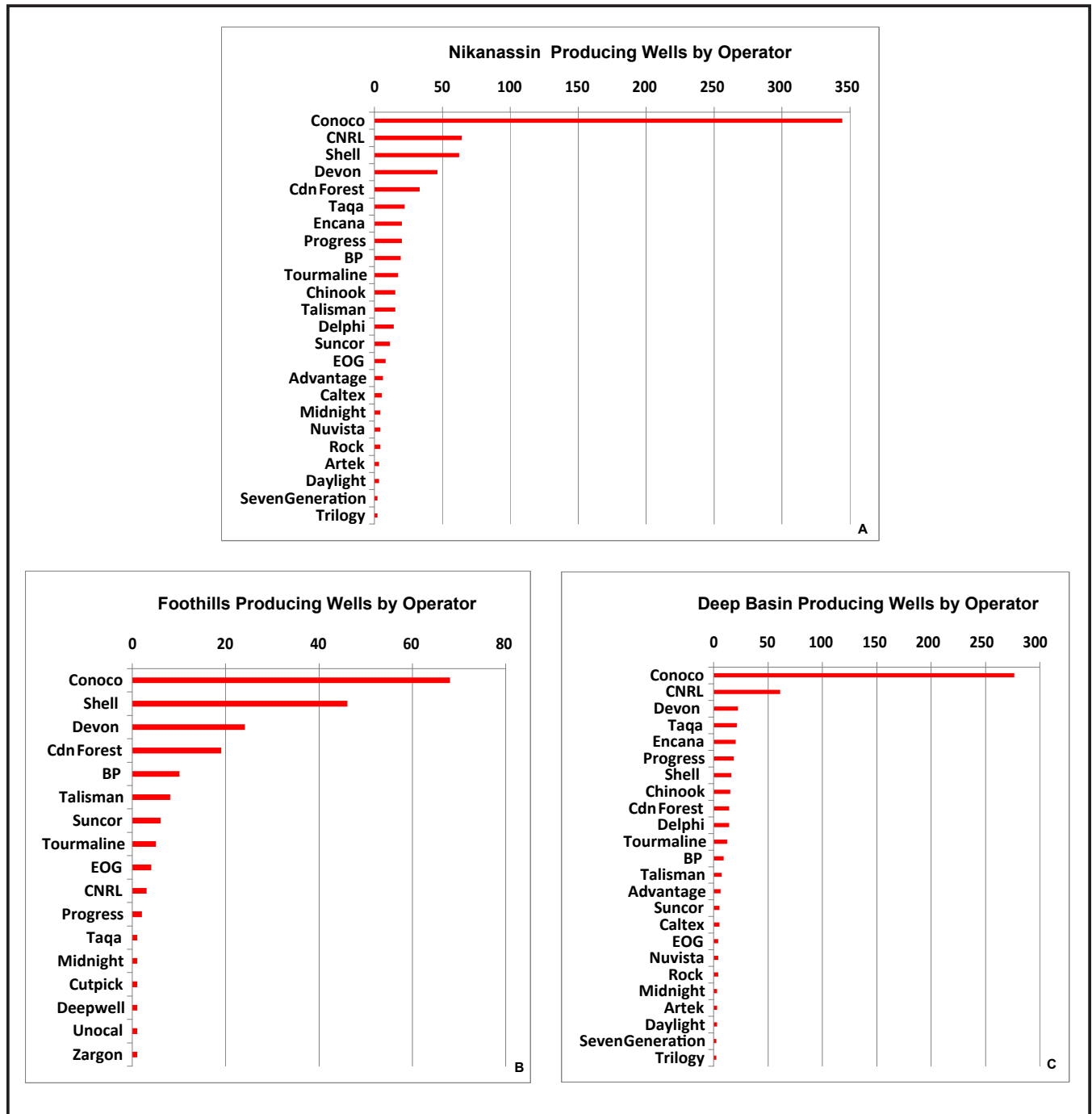
- An overview of the present activity, as well as geological, structural and stratigraphic controls on play fairway development
- Integration of production and reservoir parameters in order to develop economic scenarios associated with each of these play fairways
- Economic analysis of the specific play fairways.

Activity and Production

The Nikanassin is currently listed as a producing contributing zone in 762 wells within the WCSB. Conoco, Canadian Natural Resources (CNRL) (CNQ-TSX), Shell, Devon and Canadian Forest presently are the top five operators overall, with Conoco by far the leading operator of Nikanassin producing wells (Figure 9a). In the Foothills High Deliverability Structured Fairway (FHS), Conoco, along with Shell, Devon, Canadian Forest and BP (now Apache) are the top five current operators (Figure 9b). The implication is that large E&P companies with pre-existing Foothills exposure are the significant players with existing Foothills Nikanassin production. Nikanassin production in the Foothills has been successfully targeted on large-scale structures where extensive fracturing exists. Smaller and intermediate operators not normally known for Foothills exploration are also shown in Figure 9b to have production in the Foothills area (e.g., Tourmaline, Progress, and Midnight/Pace).

In the Deep Basin (DBS, DBMO, DBC), Conoco again is the main operator in the Nikanassin, with CNRL, Devon, TAQA and Encana rounding out the top five (Figure 9c). Other large- to medium-sized companies targeting secondary structures with increased fracture density and increasing deliverability include Progress, Shell, Canadian Forest, Daylight and Pace/Midnight.

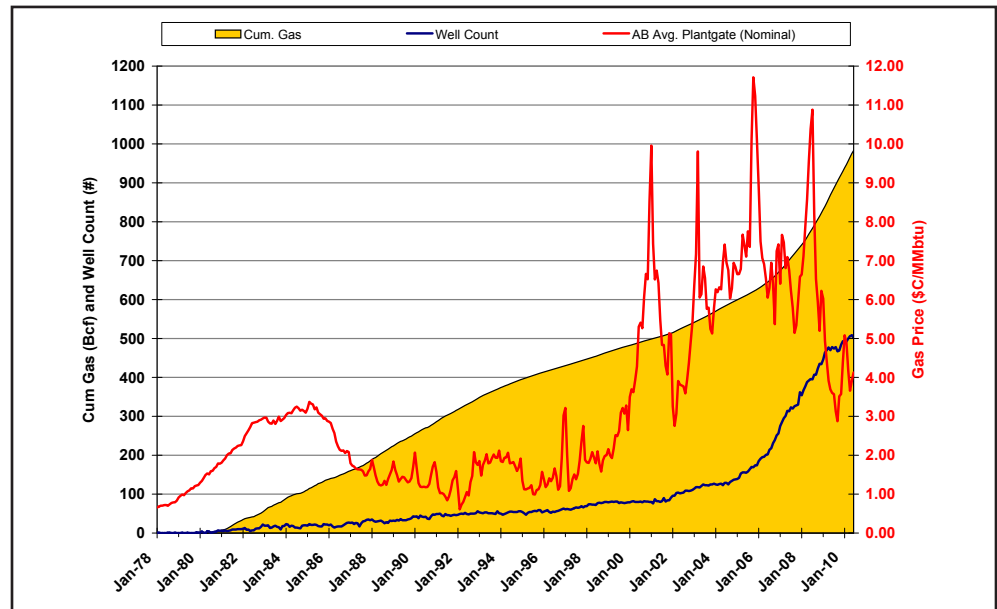
Figure 9: Nikanassin Producing/Operator Organized by: 9a- All Nikanassin Producing Wells by Operator; Figure 9b: Nikanassin Producing Wells in the Foothills Area (FHS) by Operator; Figure 9c: Nikanassin Producing Wells in the Deep Basin Area (DBS) by Operator.



Source – BMO Capital Markets; Data from GeoScout

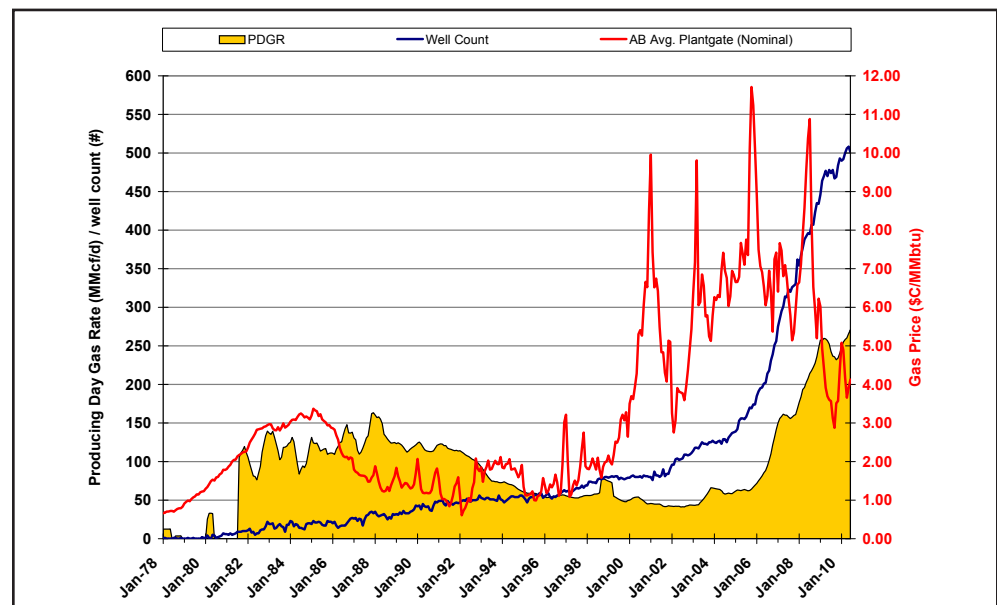
A Cumulative Production/well count and gas price versus time graph and a Rate/well count and gas price versus time are presented in Figures 11a and 11b. Approximately 500 of the 762 productive wells are in the focus area, with the remainder being in the southern commingled area near Wild River. Cumulative gas production from the Nikanassin is approaching 1 Tcf to date, with a present day production rate of ~250/MMcf/d. Producing day gas rate from the Nikanassin was in decline from 1988 to 2004 (~170/MMcf/d to ~50/MMcf/d). The Nikanassin was a minor secondary productive zone between the mid 1970s and early 2000s; however, the number of producing Nikanassin wells has increased dramatically since 2002. Note the time lag between the increasing gas price (~2000), the increase in well count starting in 2002, and the ramp-up in production and rate from 2006 to the present.

Figure 11a: Cumulative Nikanassin Production/ Well Count and Gas Price vs. Time



Source: BMO Capital Markets; Data from GeoScout

Figure 11b: Nikanassin Producing Rate/Well Count and Gas Price vs. Time



Source: BMO Capital Markets; Data from GeoScout

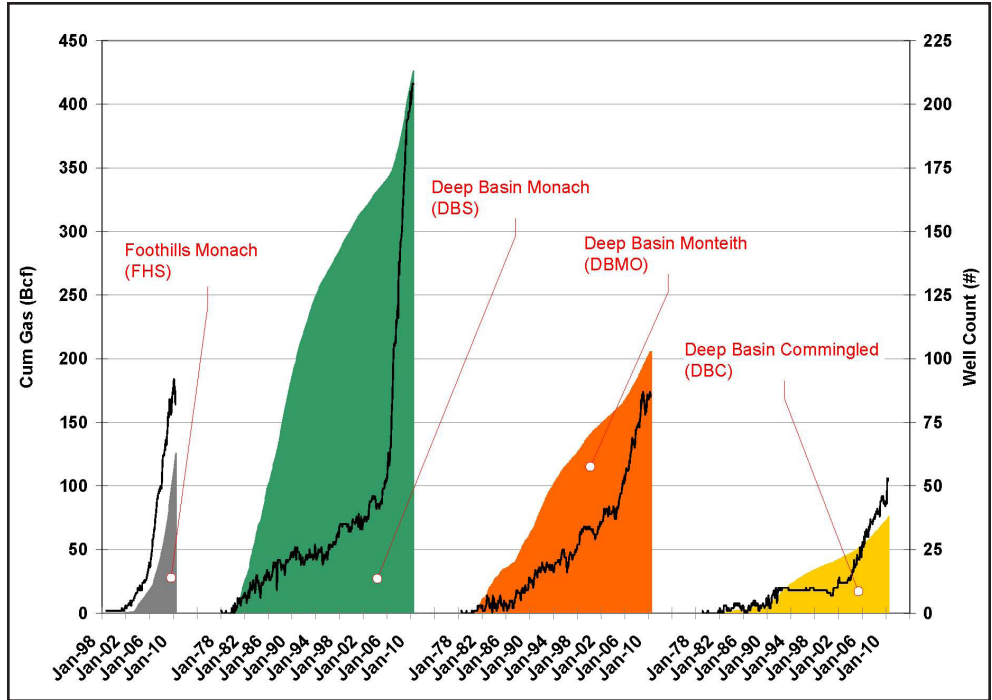
Cumulative Production/well count versus time graph are presented in Figures 12b. These plots demonstrate the variation in play maturity across the Nikanassin. In examining Figure 12, the Deep Basin Nikanassin was initially produced in the 1970s, whereas Foothills Nikanassin first began to be produced ~20 years later in the late 1990s. Within the Deep Basin, the DBS Fairway has produced ~425 Bcf, followed by the DBMO (~200 Bcf+) and the Deep Basin Commingled (DBC) area (~75 Bcf). However, data from the area is difficult to analyze due to multizone completions. FHS fairway cumulative production is ~125 Bcf, but began 20 years later in the late 1990s. The largest ramp-up in relative activity in the last 10 years in the Nikanassin has been in the FHS, followed by the DBS, DBMO and DBC.

The Cumulative Rate/well count versus time graph are presented in (Figures 12b) that the highest Nikanassin production area today is from the FHS (150 MMcf/d), followed by the DBS (~90 MMcf/d), DBMO (~35 MMcf/d) and DBC (<20 MMcf/d). Note that the DBS, DBMO and DBC show two populations, with a peak rate production in the late 1980s to early 1990s and a second peak since the mid-2000s. This is attributable to the low gas price environment between the late 1980s and early 2000s, and the decrease in drilling. A simple analysis of recent total rate: well count indicates that the best rate:well count ratio occurs in the FHS (~1.9), followed approximately equally by DBS (~0.42) and DBMO (~0.44) and then the DBC (0.33).

There has been a significant increase in recent licensing and drilling activity targeting the Nikanassin. Figure 13 shows the numbers of wells rig released or licensed since January 2009 for the Nikanassin. The top five companies with activity in the Nikanassin include Conoco, Devon, Encana, Daylight, and Progress.

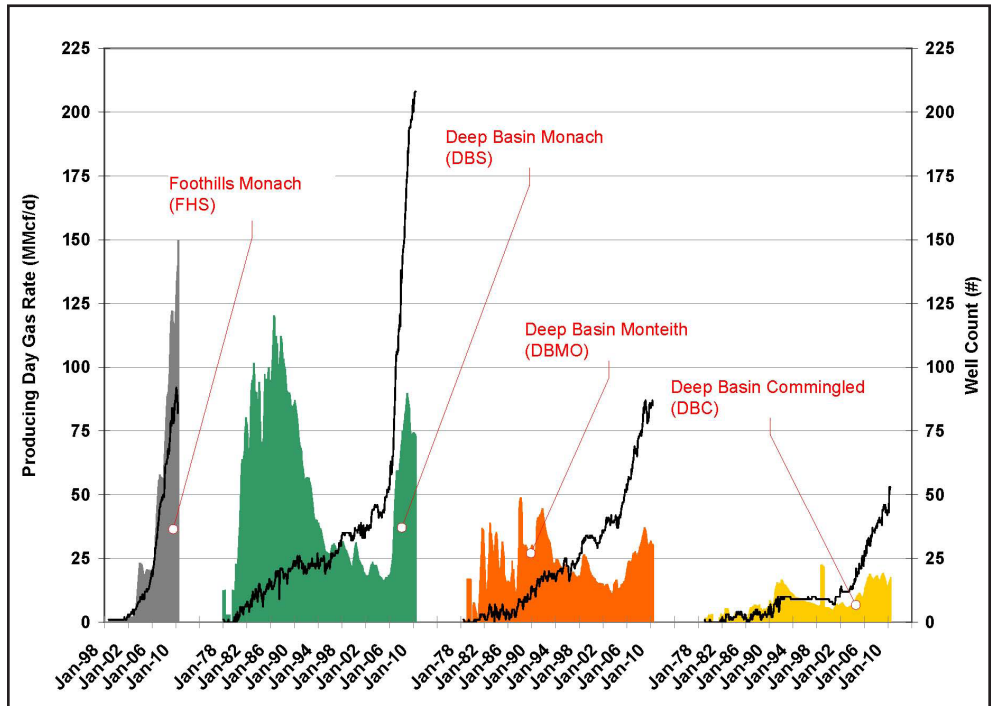
Conoco, Canadian Forest, Shell, Talisman and Daylight have been the most active in the FHS fairway (Figure 14a). Conoco, Devon, Daylight, NuVista and Encana have had the most wells rig released or licensed from January 2009 in the Deep Basin (Figure 14b). To the east in the Deep Basin – Monteith (DBMO) sub-area Progress, TAQA, Delphi, Paramount and Husky have begun activity in the Nikanassin since January 2009 (Figure 14c).

Figure 12a: Nikanassin Cumulative Production and Well Count vs. Time for the Four Main Play Fairways Shown in Figure 1



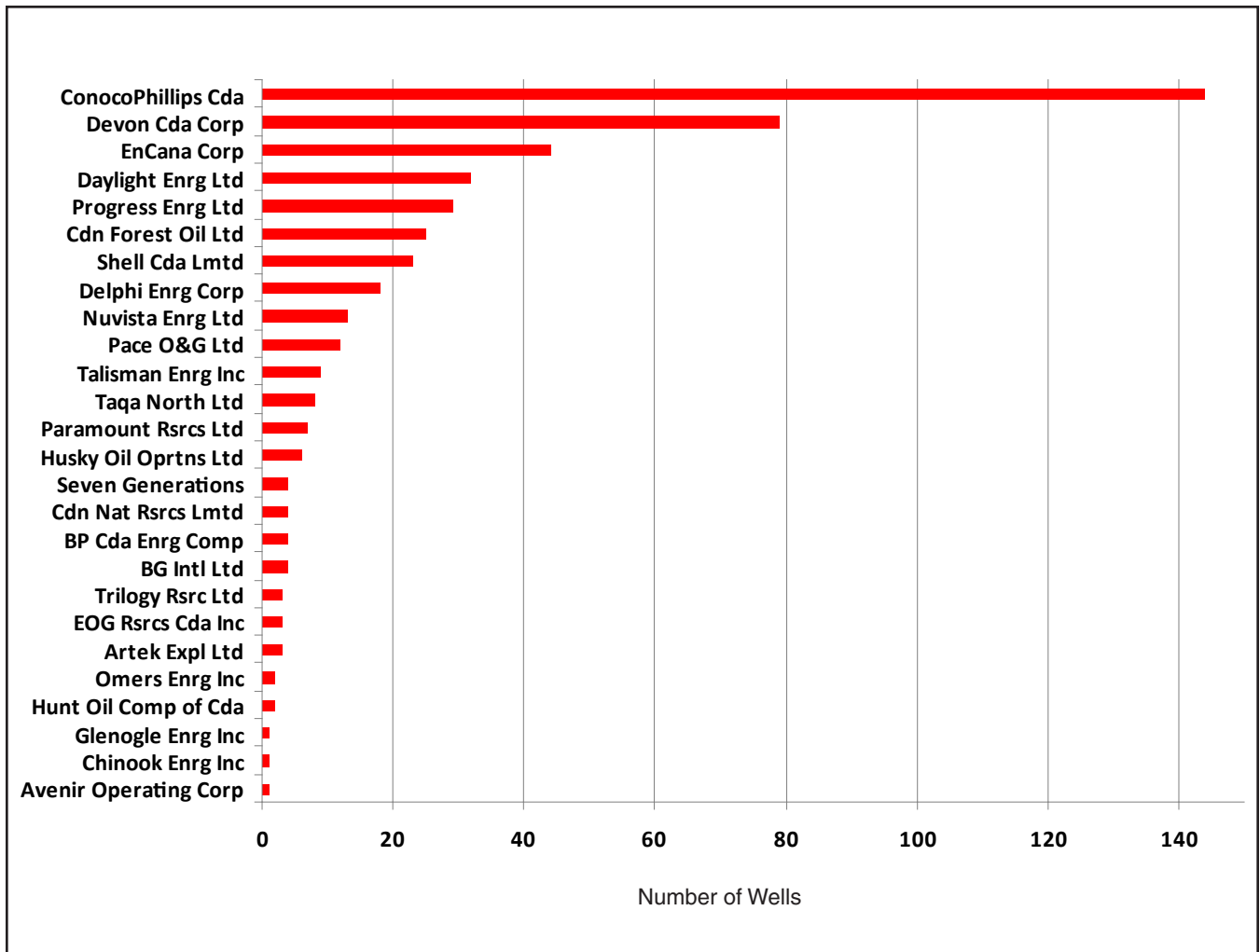
Source: BMO Capital Markets; Data from GeoScout

Figure 12b: Nikanassin Production Rate and Well Count vs. Time for the four main play fairways shown in Figure 1



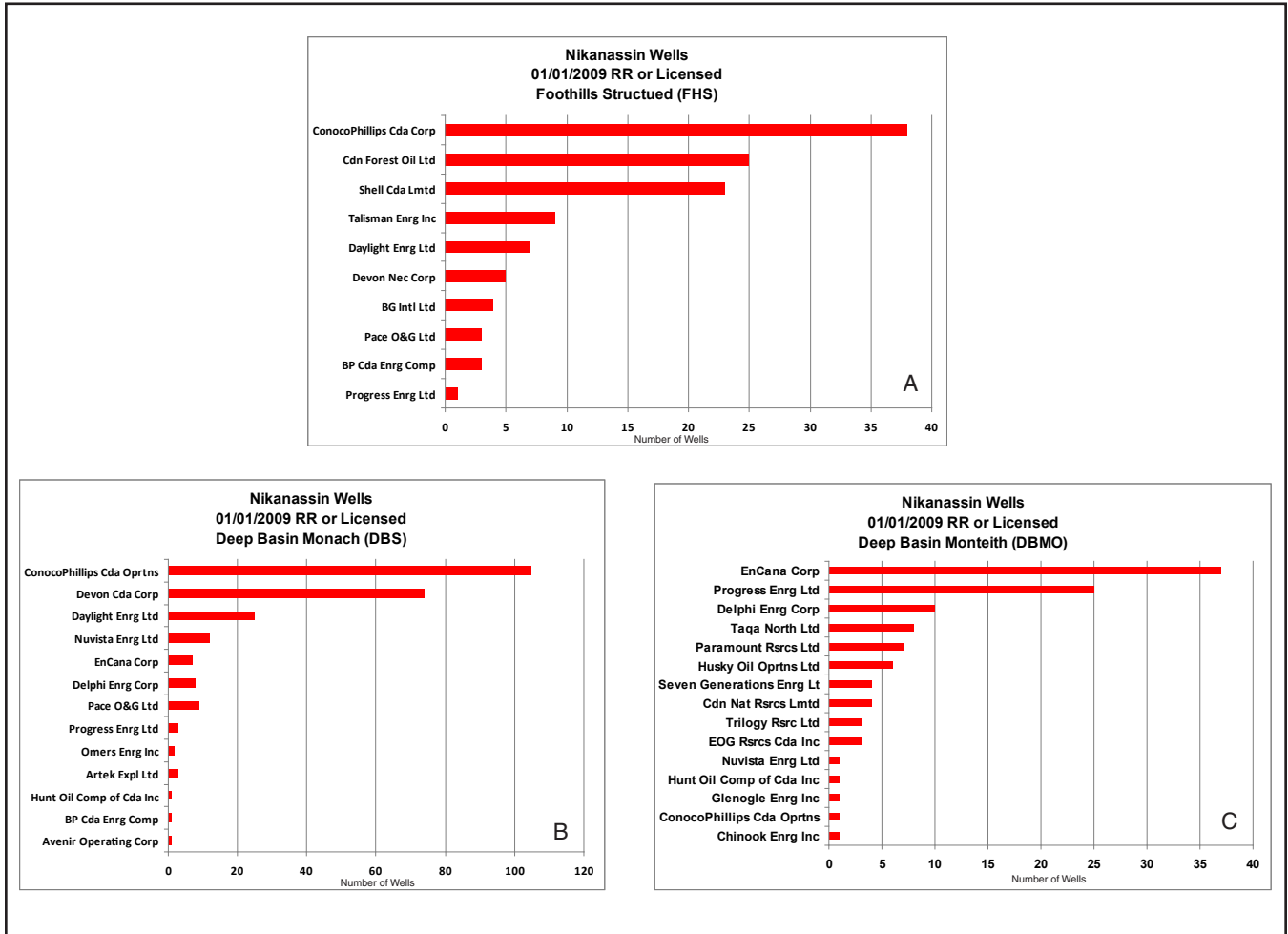
Source: BMO Capital Markets; Data from GeoScout

Figure 13: Nikanassin Wells Rig Released or Licensed Since January 2009



Source: BMO Capital Markets; Data from GeoScout

Figure 14: Figure 14A: Nikanassin Drilling Activity in the Foothills Deep Basin Area (FHS) by Operator; Figure 14B: Nikanassin Drilling Activity in the Deep Basin Area (DBS) by Operator; Figure 14C: Nikanassin Drilling Activity in the Deep Basin Monteith Area (DBMO) by Operator.

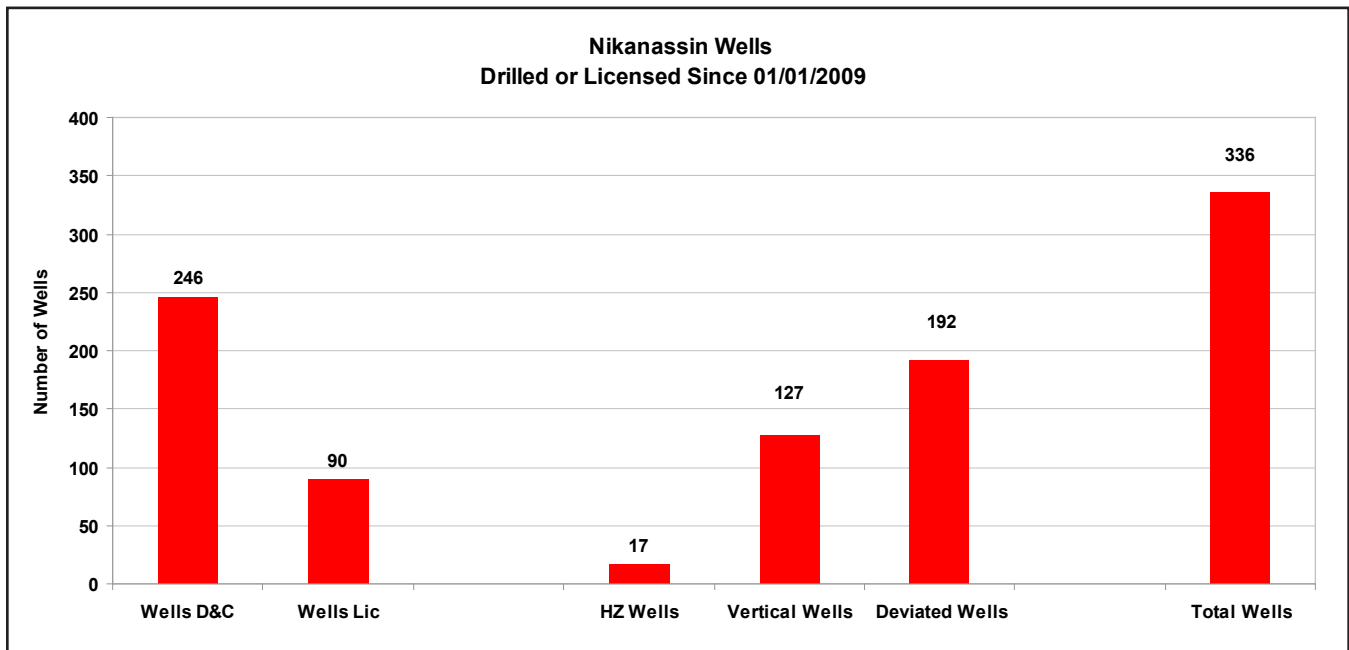


Source: BMO Capital Markets; Data from GeoScout

An analysis of the 336 wells that have been drilled or licensed for the Nikanassin since January 2009 indicates 246 have been drilled with no production data yet available and 90 wells have been licensed but not yet drilled (Figure 15). The majority of the 336 wells were licensed as either vertical (127) and/or deviated (192), with 17 wells classified as horizontal. Figure 16 shows the distribution of wells spatially across the FHS, DBS and DBMO Fairways.

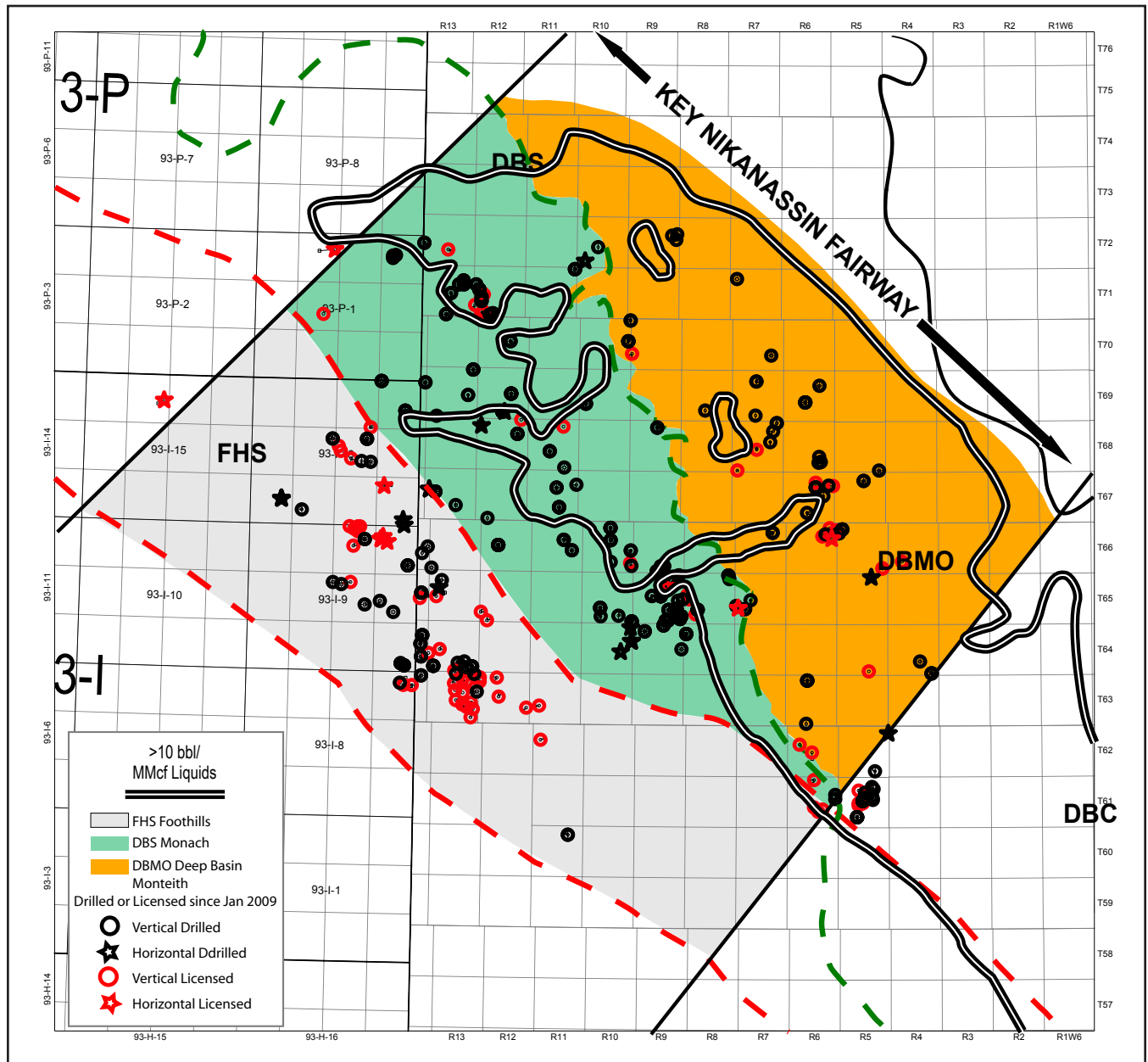
We consider the increase in activity, production and drilling rate to be a factor of both gas/liquids pricing AND the advent of new technology that has increased deliverability, potential recovery factors and lowered cost structures. These factors have also allowed the Nikanassin to become a primary target rather than just a secondary or “bail-out” zone.

Figure 15: Breakdown of Nikanassin Drilling Activity by Well Type From January 2009 to Present



Source: BMO Capital Markets; Data from GeoScout

Figure 16: Map of Wells Rig Released or Licensed Since January 2009 in Relation to Nikanassin and Liquids-Rich Fairways



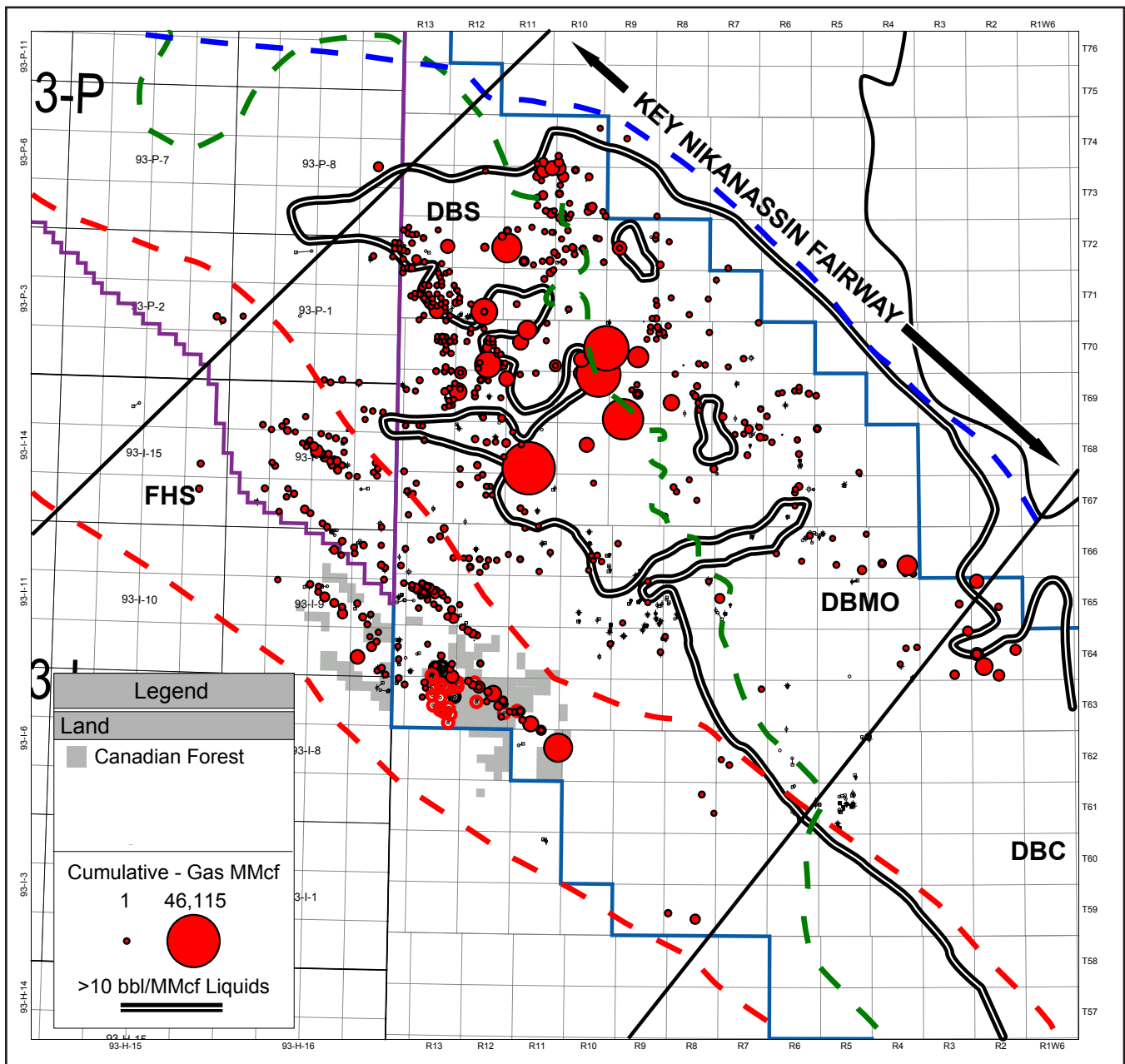
Source: BMO Capital Markets; Data from GeoScout

Key Company Activity

Canadian Forest

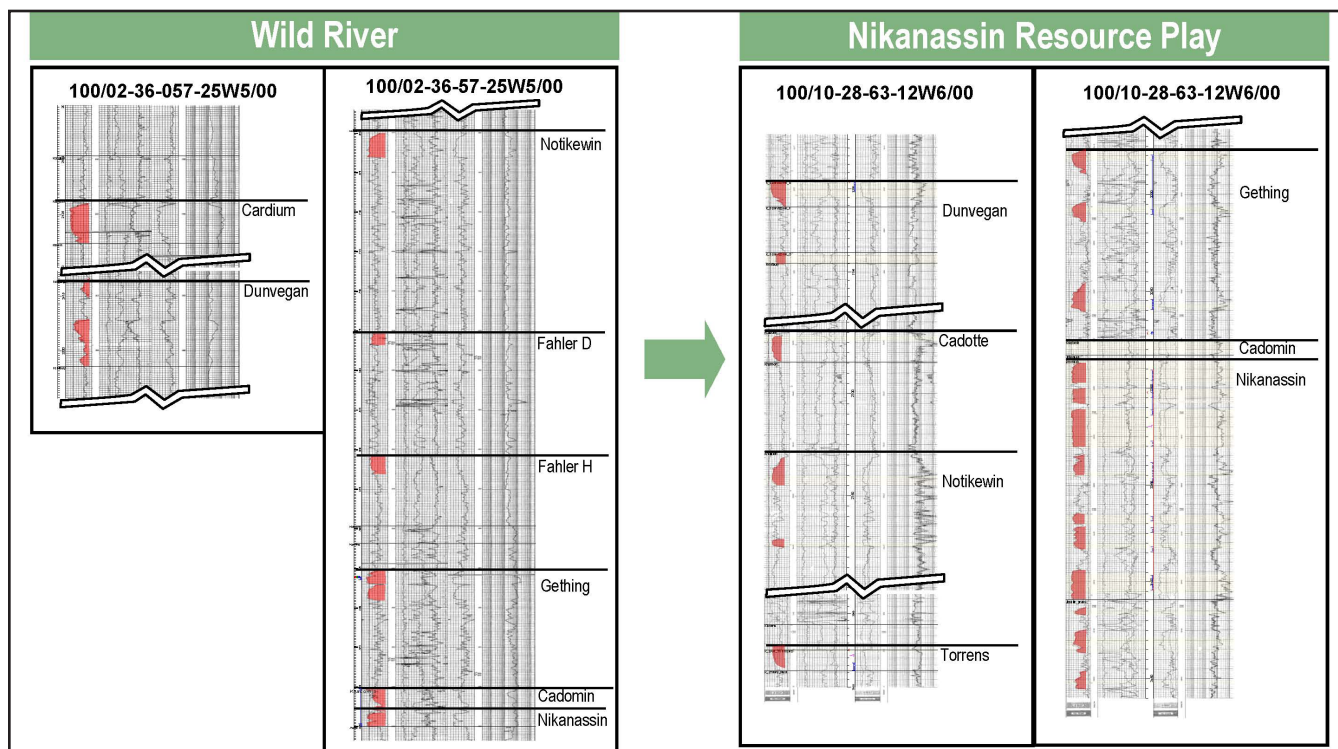
Canadian Forest's recent disclosure of its 27-well program in the Narraway - Ojay FHS Fairway area for the Nikanassin is indicative of the recent increase in drilling activity targeting high deliverability dry-gas in high accommodation areas (Figures 17 and 18).

Figure 17: Canadian Forest Land Position in Relation to Nikanassin and Liquids-Rich Fairways



Source: BMO Capital Markets; Canadian Forest Corporate Presentation, September, 2010; GeoScout

Figure 18: Comparison of a Canadian Forest Low Accommodation Nikanassin Well From the Wild River Area (DBC Fairway) Exhibiting Thin Lower Nikanassin Monteith With Multiple Uphole Stacked Deep Basin Reservoirs vs. High Accommodation Upper Nikanassin (Monach) in the Foothills Structured (FHS) Fairway Demonstrating the Increase in Nikanassin Section – highlighted red zones indicate potential pay



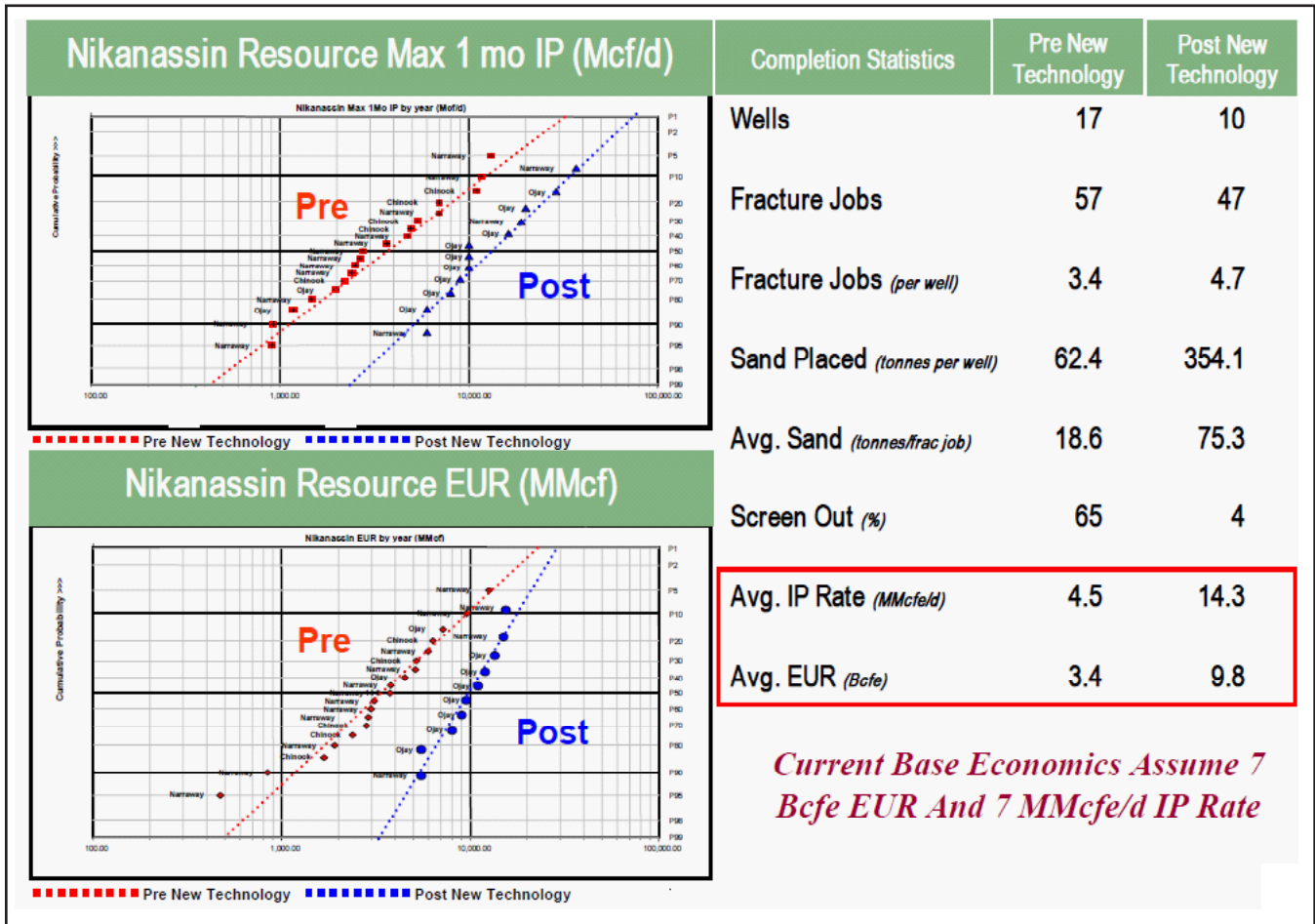
Source: Canadian Forest Corporate Presentation, September, 2010

Canadian Forest’s Nikanassin Foothills program demonstrated an increase in average IPs from 4.5 to 14.3 MMcfe/d with an increase in average EUR from 3.4 to 9.8 Bcfe per well (Figure 19). Canadian Forest attributed these improved results from:

- 1) Targeting areas of high-density fractures and thick gas saturated reservoirs to exploit natural fractures along the crest and forelimb area of the structures (Figure 20);
- 2) Changes in their drilling (highly deviated and horizontal wells) utilizing “Managed Pressure” (i.e., underbalanced) drilling; and
- 3) Completion practices (high density multi-stage slickwater fracs with large tonnage per well) to increase the effective stimulated rock volume (SRV) to exploit natural fractures.

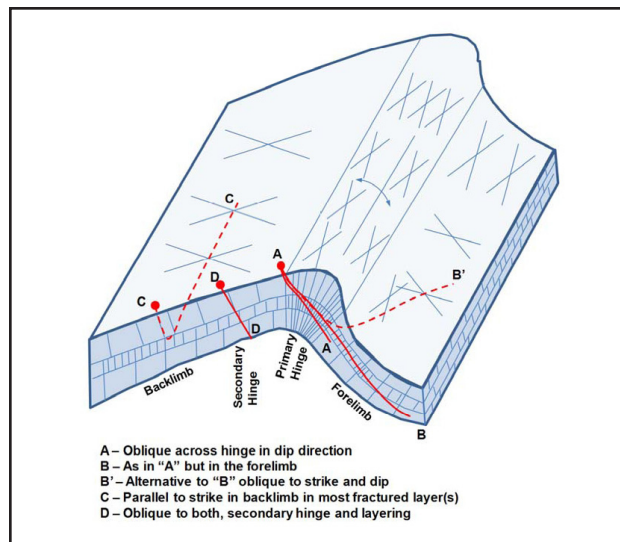
Canadian Forest is targeting the Foothills Nikanassin with highly deviated directional wells and has decreased its drilling time from 77 days to 33 days while lowering drill cost to \$4.7 million from \$8.6 million (excluding completion and access) (Figure 21). Canadian Forest reports that its first well drilled with improved technology produced >5 Bcfe in 11 months with an average rate of 15 MMcfe/d. This is an example of a company focusing in the Nikanassin Foothills High Deliverability Structured Fairway (FHS) characterized by thick, tight, naturally fractured high net: gross overpressured reservoirs. Gas saturated sandstones exist off-structure, but to date there is no positive indication of economically producible hydrocarbons off structure.

Figure 19: Canadian Forest Nikanassin Results From Ojay – Narraway Area in the FHS Fairway



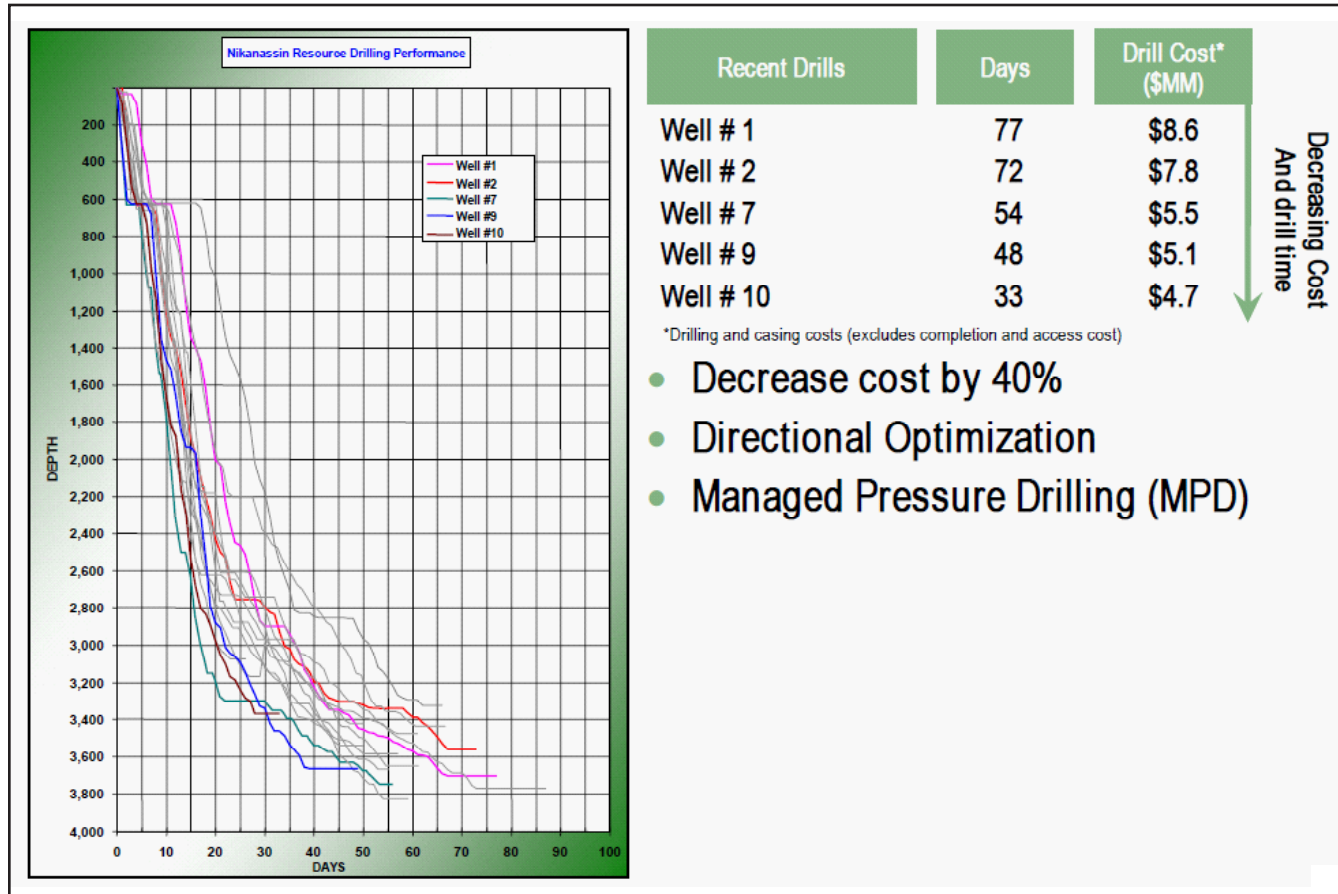
Source: Canadian Forest Corporate Presentation, 2010

Figure 20: Schematic Diagram of a Typical Asymmetric Fold Depicting Fracture Patterns With High Graded Optimum Well Paths Analogous to the Structures in the Foothills Structured Area (FHS) and Deep Basin – Monach (DBS)



Source: Solano et al., SPE Paper 132923, Fig 19, 2010

Figure 21: Canadian Forest Nikanassin Drilling Performance Over Time – From Ojay – Narraway Area

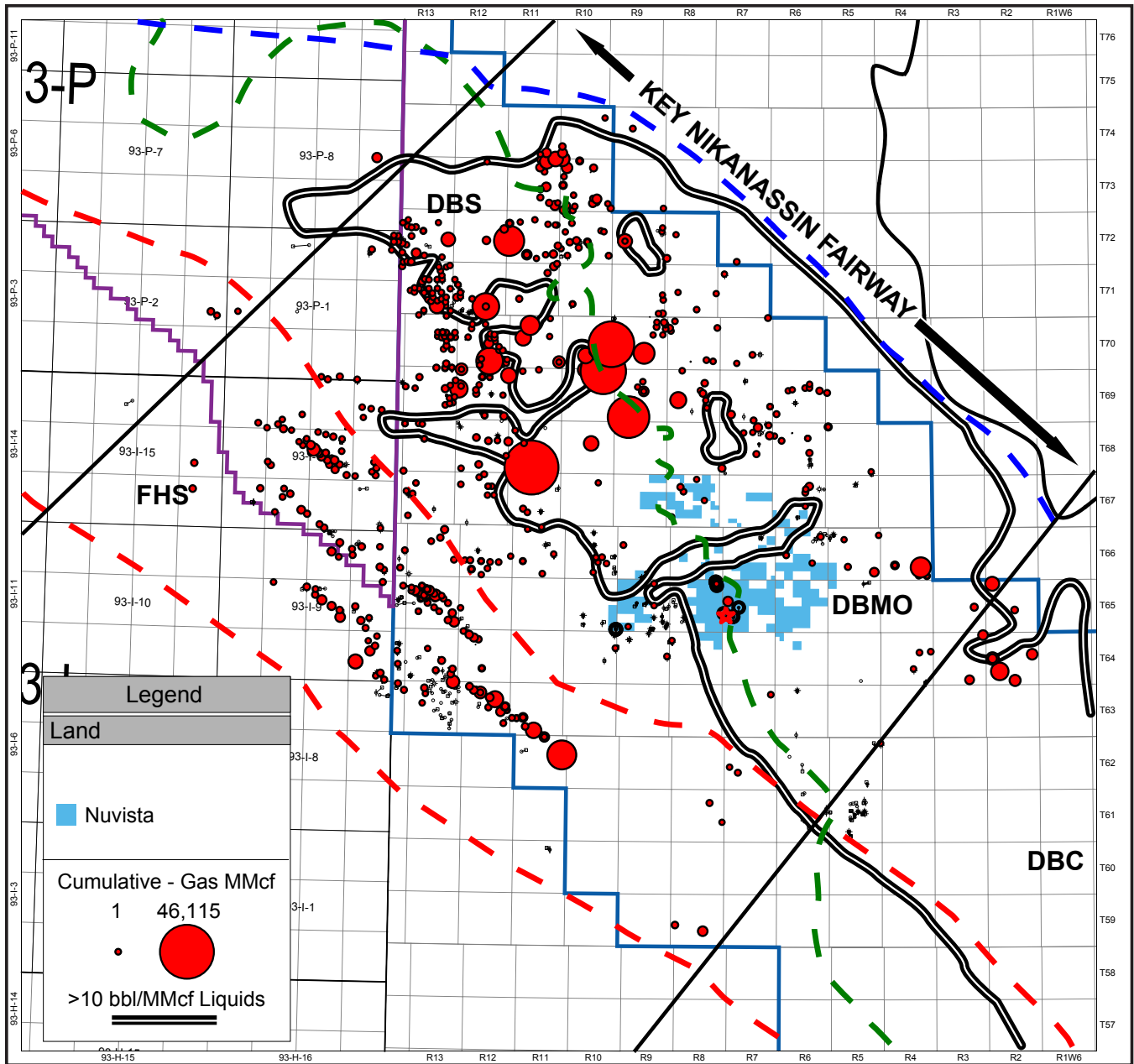


Source: Canadian Forest Corporate Presentation, 2010

NuVista

NuVista is an example of a company that has significant exposure to Nikanassin liquids-rich gas in both the DBS and DBMO areas (Figure 22). NuVista has participated in nine vertical wells during the last 18 months with initial production rates of 0.5–2.0 MMcf/d per vertical well and EURs ~1.7. NuVista has targeted seven wells (six vertical and one horizontal well) for 2010 in the heart of the liquids-rich fairway, estimated to contain >50bbl/MMcf and 3–5 Bcf /well EUR. NuVista is targeting: i) the DBS Monach in areas where net gross interval is >20m; ii) overpressured; and iii) an effective top seal exists between the Nikanassin and overlying potentially wet Cadomin. NuVista initially experimented with hydrocarbon (propane) based fracs; however; it is now utilizing (24–48 ton per stage) slickwater fracs. In order to exploit the EUR, future plans include the potential downspacing of verticals to four wells section and consideration of horizontal drilling. NuVista has successfully increased its net Nikanassin land position in Wapiti to approximately 185 gross sections with an average working interest of 86%.

Figure 22: NuVista Land Position in Relation to Nikanassin and Liquids-Rich Fairways.



Source: BMO Capital Markets; NuVista Corporate Presentation, 2010; GeoScout

Along trend to the north, Delphi and Artek are other examples of companies operating in the liquids-rich Nikanassin fairway. Delphi has announced the results of a three-vertical-well program targeting the liquids-rich area of the Nikanassin/multizone program having IPs ~1.9MMcf/d and ~190 bbl/d of liquids. Artek has announced similar results utilizing Gasfrac (propane) completion techniques.

Daylight Energy

Daylight Energy has extensive Nikanassin rights in the liquids-rich Deep Basin Monteith (DBMO), in addition to Deep Basin (DBS) and outer Foothills (FHS) areas (Figure 23). Specifically, it has >200 sections in the Foothills and western Deep Basin portions of the Nikanassin Fairway targeting the Monach (and Monteith) in the liquids-poor Deep Basin – Foothills transitional area (Figure 23). The Nikanassin section in the FHS/DBS is approaching 400–500m in thickness, with the Upper Nikanassin Monach reaching 150–250m. Competitor wells penetrating Upper Nikanassin Monach in the FHS/DBS have sandstone bodies that can reach 140m in this area. Secondary structures may enhance fracture permeability.

Daylight has announced results of its first 700m Nikanassin Horizontal well, which tested >7MMcf/d in the Elmworth area. This well tested >7MMcf/d from 700m horizontal leg with seven fracs. Daylight utilized microseismic to monitor frac growth and was able to verify significant vertical frac propagation increasing the stimulated rock volume (SRV).

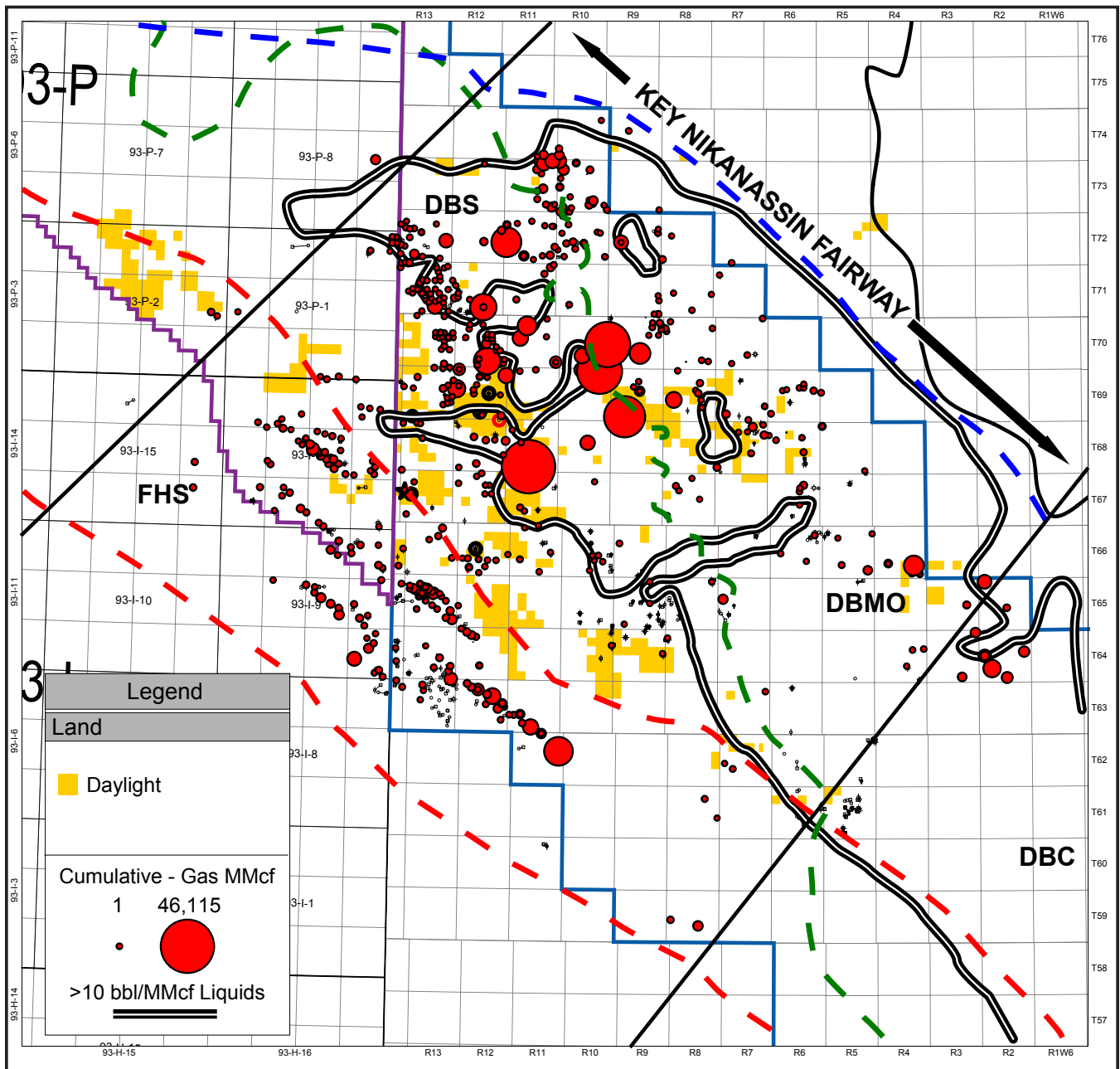
Daylight estimates that a type well in the DBS/FHS will have a 30-day IP of ~10 MMcf/d, declining to 4.8 MMcf/d in the first year, with an estimated EUR of 10 Bcf due to its lands being in the high accommodation areas of the Nikanassin. Daylight is considering utilizing various completion and drilling techniques to optimize Nikanassin production including underbalanced oil-based drilling followed by the “slickoil” fracs, and potentially decreasing well spacing from 1–2 wells to 4–8 wells when the price environment allows. Potential OGIP is 40+Bcf/section. Daylight is also planning slickwater fracs with 500m³ water, 100 ton low concentration high strength ceramic proppant with intervals variation of between 50m and 150m.

Progress Energy

Progress Energy considers the Nikanassin a base asset in the Deep Basin and Foothills (Figure 24). Progress Energy drilled 13 wells (12.5 net) in Q1 in the Gold Creek/Wapiti area, and is focused on further developing the Nikanassin play. Progress co-developed the use of a SlikPro(TM) fracture stimulation technique, utilizing an oil based frac in which they use ~500m³ oil and ~500m³ water with a low concentration of strengthened proppant to mitigate potential reservoir damage issues. This technique has increased the productivity of the Nikanassin zone, changing it from marginally economic to, in many cases, justifying wells that target only the Nikanassin. The economics of these wells are further enhanced by targeting multiple uphole producing horizons in the DBMO area. Progress has utilized 3D seismic to identify areas of better natural fracture development and micro-seismic to monitor effectiveness of the completions.

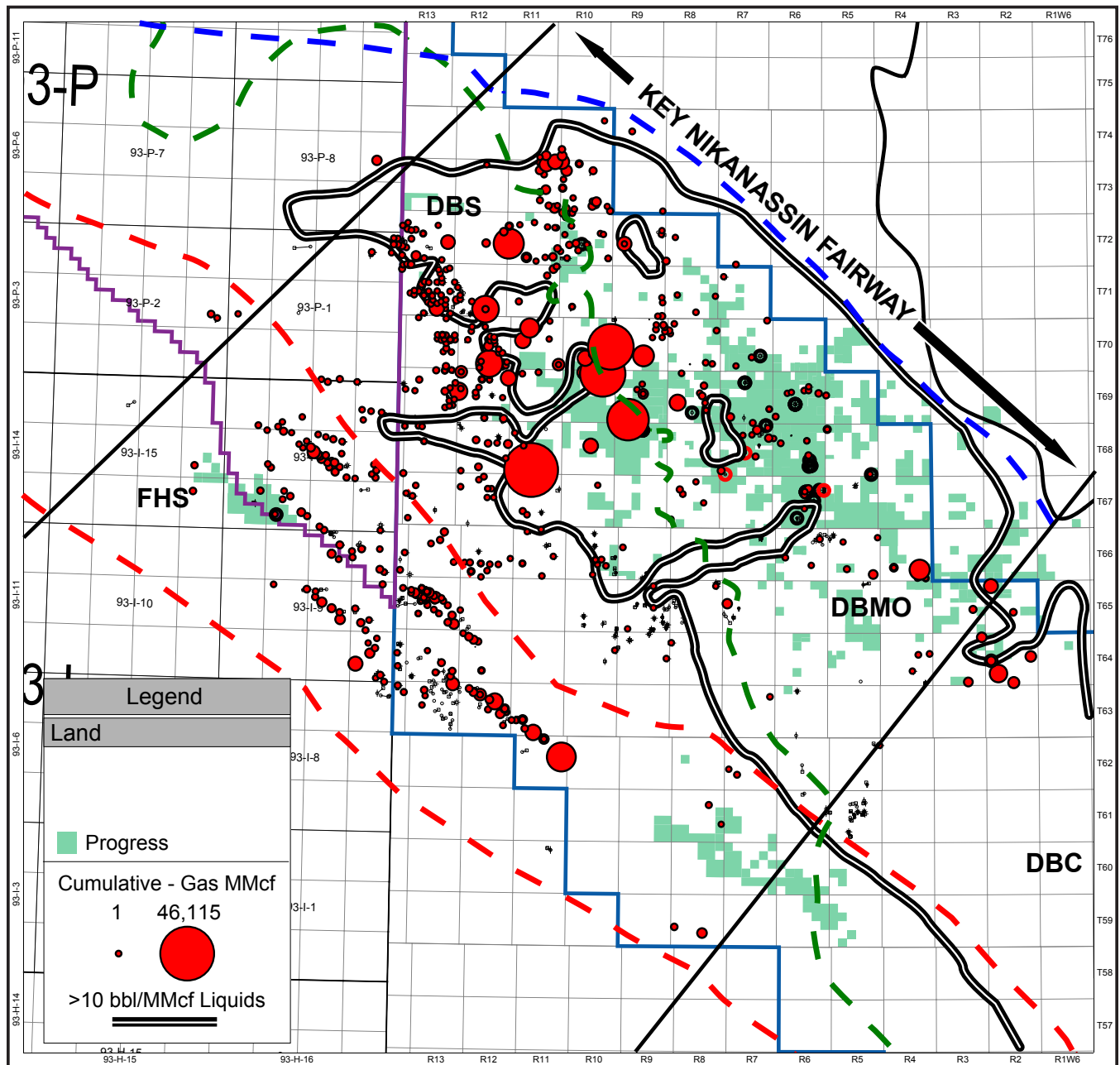
Since February 2008, Progress has drilled 22 wells in the Gold Creek/Wapiti core area with the Nikanassin as the primary target. The Nikanassin zones that were fracture-stimulated using SlikPro(TM) have yielded test rates averaging 2.5 MMcf/ per day. Progress has been able to achieve economic rates from a zone long considered uneconomic to drill. As a result, many wells in the Gold Creek/Wapiti area have Nikanassin pay that was left unperforated and that now present recompletion and new drill opportunities. Progress' Nikanassin and commingled production has grown significantly from less than 500 boe/d in early 2008 to approximately 6,000 boe/d currently.

Figure 23: Daylight Energy Land Position in Relation to Nikanassin and Liquids-Rich Fairways



Source: BMO Capital Markets; Daylight Corporate Presentation, 2010; GeoScout

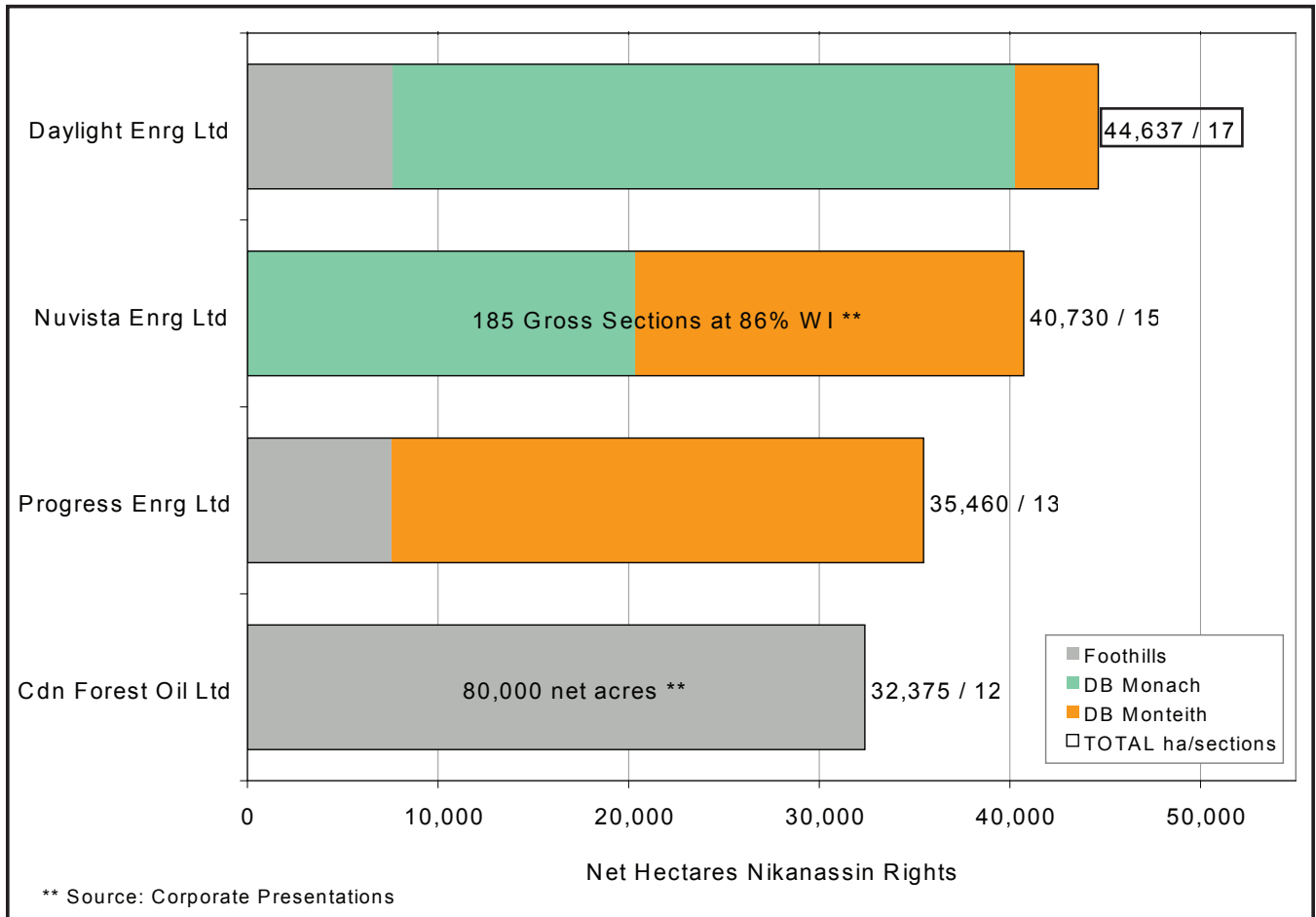
Figure 24: Progress Land Position in Relation to Nikanassin and Liquids-Rich Fairways



Source: BMO Capital Markets; Progress Corporate Presentation, 2010; GeoScout

Figures 5 and 25 present the composite land position for Daylight Energy, NuVista, Progress Energy and Canadian Forest across the FHS, DBS and DBMO fairways. These companies hold material land positions across the major play fairways and are actively drilling the various Nikanassin play types described in this review.

Figure 25: Key Company Land Holdings (44637 ha/174 sections)



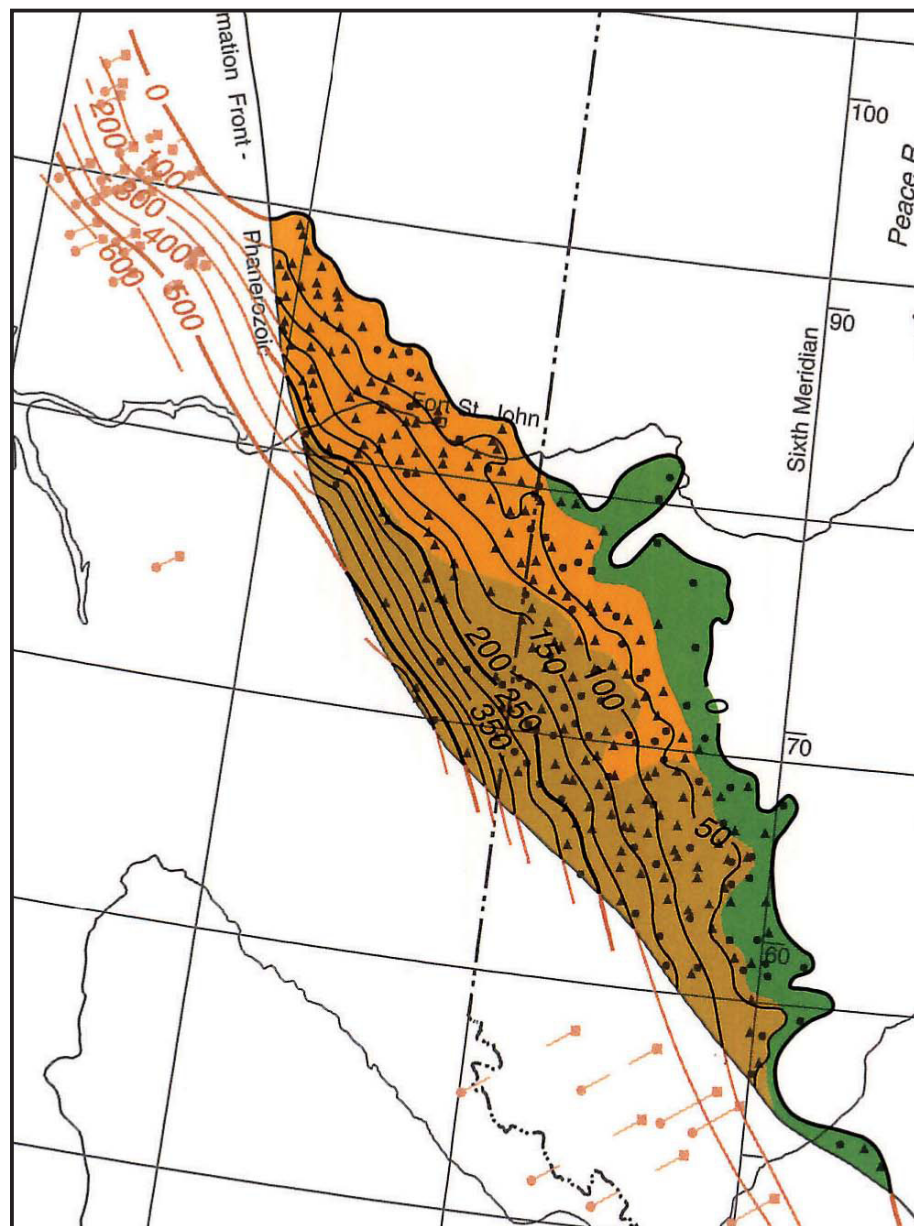
Source: BMO Capital Markets; Various Corporate Presentations; GeoScout

Geological Background

Stratigraphic Fairways

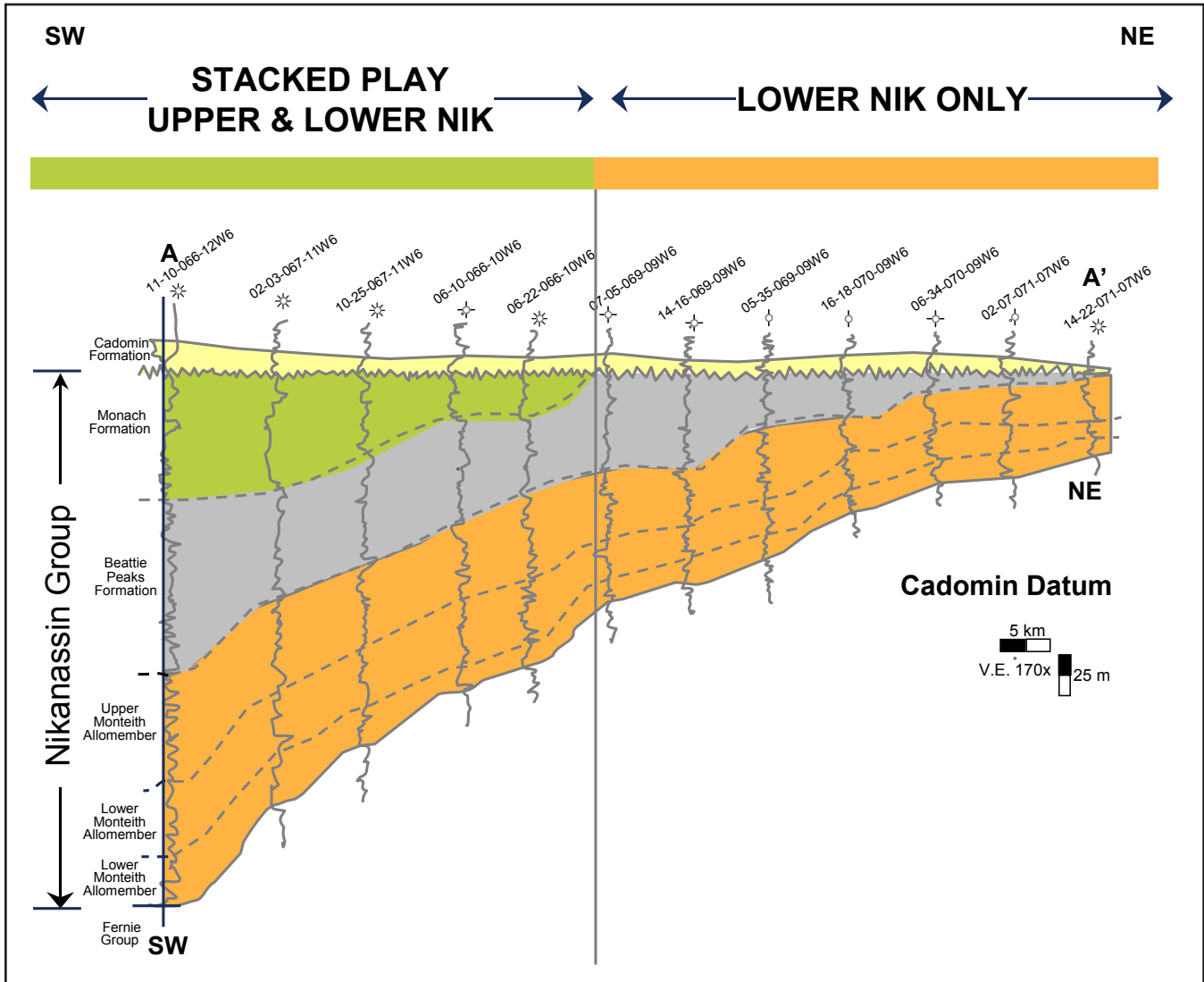
The Nikanassin Group is developed between the marine shales and siltstones of the Fernie Group and is erosionally overlain by a basin-wide angular unconformity associated with the base of the Lower Cretaceous Cadomin Formation (Figure 2). The Nikanassin forms part of a westward thickening wedge of sediments deposited in a north-south trending fore-deep parallel to the western mountain front. The Nikanassin thickens from a subcrop on the east of the study area to >500m near to the western edge with the foothills (Figure 26). Burial depths range from ~1,000m in the Plains, to >3,500–4,000m in the Foothills.

Figure 26: Isopach and Lithofacies of the Kootney/ Nikanassin/Minnes/ Deville/Success



Source: WCSB Atlas

Figure 27: A Type NE to SW Nikanassin Group Cross-Section



Source: modified after Miles and Hubbard, 2010

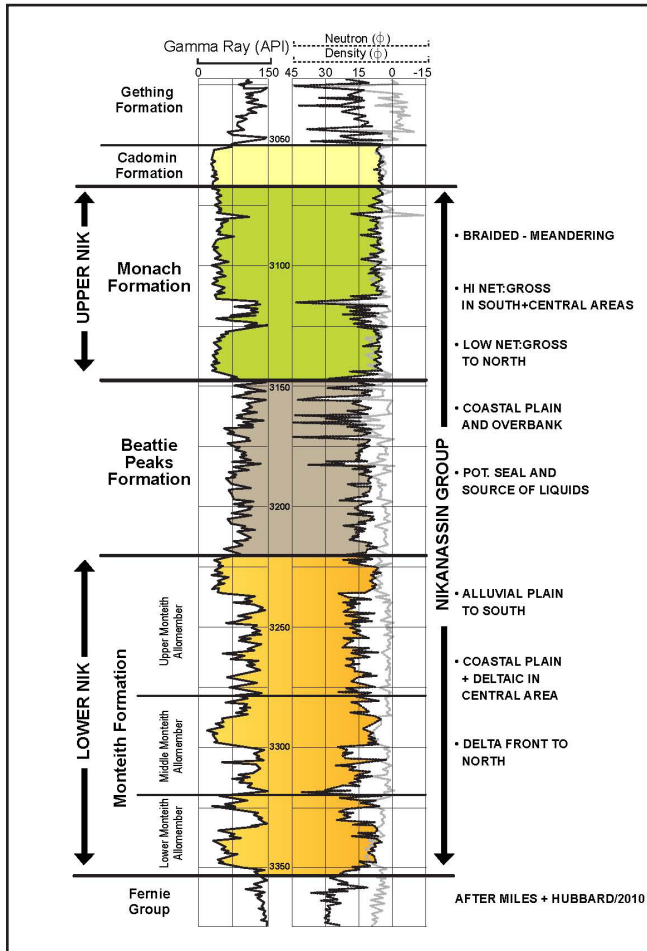
The stratigraphy of the Nikanassin Group has been subdivided into three formations, from youngest to oldest (Figures 2 and 27):

- Monach Formation (Upper Nikanassin)
- Beattie Peaks (Middle Nikanassin),
- Monteith Formation (Lower Nikanassin)

Figure 28a shows a Nikanassin type well and Figure 28b is an idealized chemostratigraphic characterization of the units. Chemostratigraphy is the characterization of strata based upon changes of elemental concentrations through time. Typically, it enables objective characterization and correlation of lithostratigraphic units, but usually provides resolution beyond that available from lithostratigraphic characterization based on wireline log response. The changing values of the ratios shown in the Nordegg–Cadomin sequence

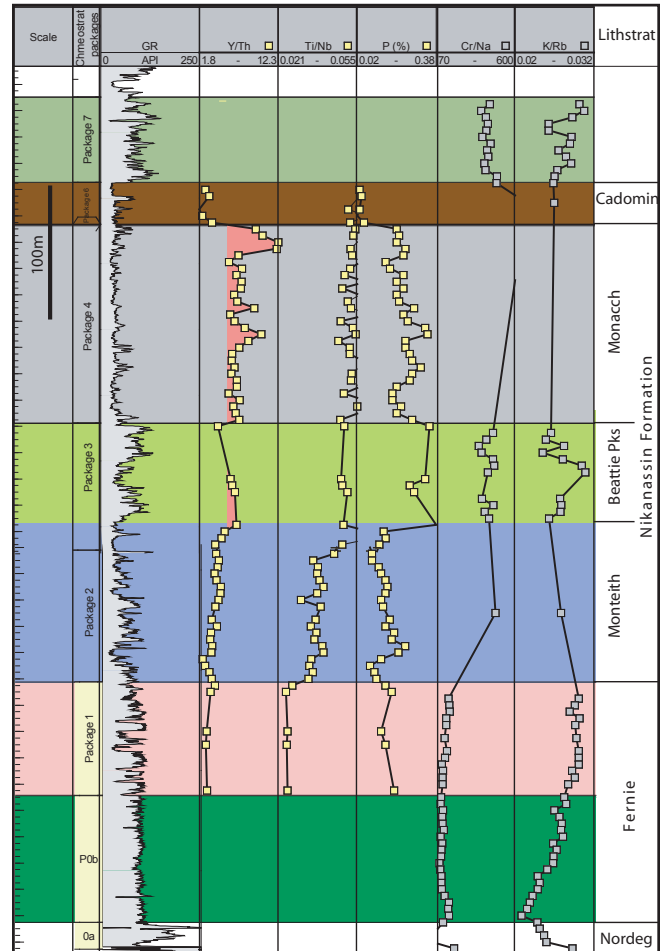
reflect changes in the source of sediment (Y/Th, Ti/Nb and P = changes in heavy minerals; Cr/Na = mafic minerals vs. plagioclase; K/Rb = K feldspar changes) during deposition. These changes form the basis for a correlation that extends for tens of kilometres.

Figure 28a: Nikanassin Type Well



Source: modified after Miles and Hubbard, 2010

Figure 28b: Nikanassin Type Chemostrat Well Displaying Characterization of the Various Formations



Source: courtesy of K. Ratcliffe; Chemostrat Inc.

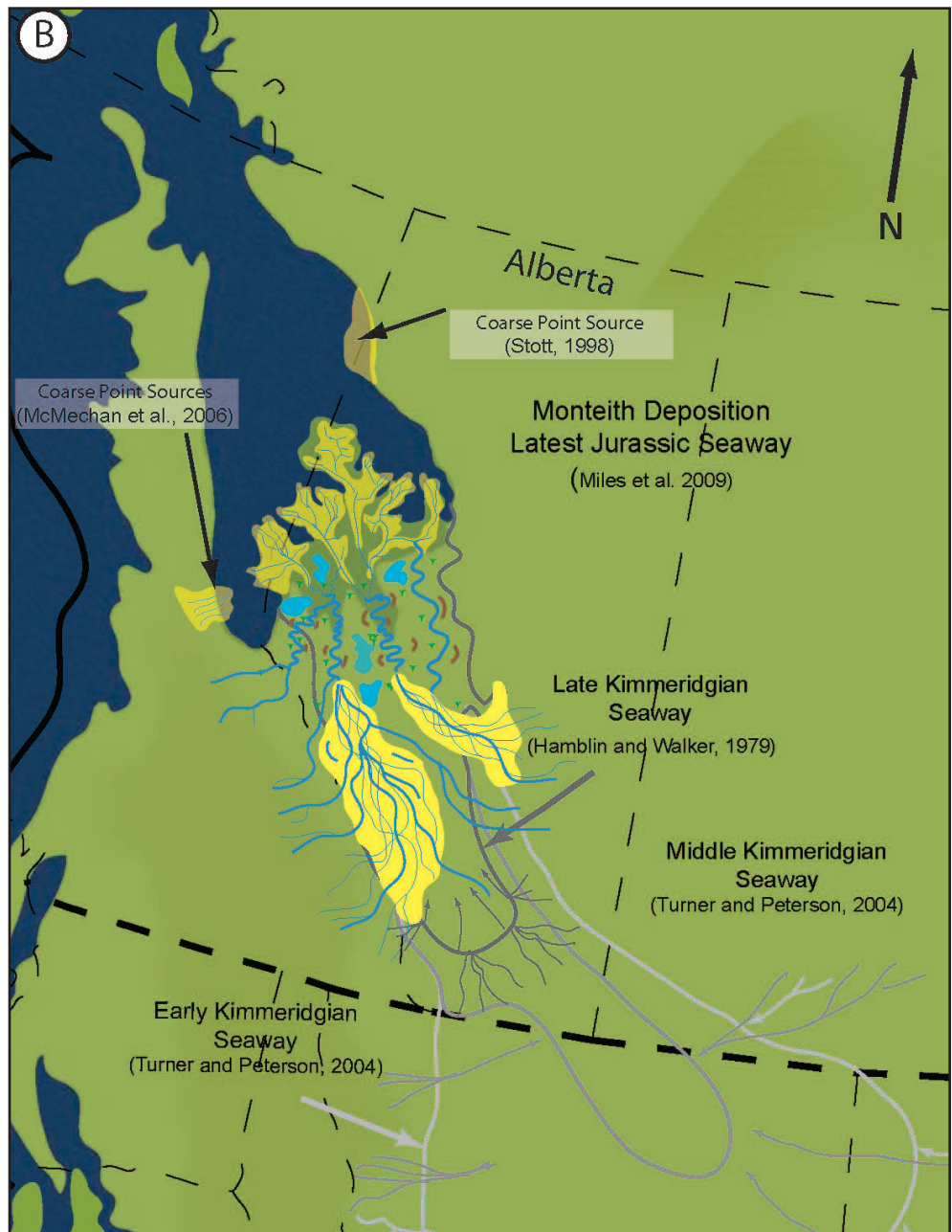
The Nikanassin is sub dividable into two main stratigraphic play fairways (Figure 1):

- 1) The Upper Nikanassin (Monach) Formation stacked with the Monteith Formation) occurring in both the Deep Basin (DBS) and Foothills Structured (FHS) Areas; and
- 2) The Lower Nikanassin (Monteith Formation only) in the eastern Deep Basin (DBMO) and commingled areas (DBC).

Lower Nikanassin–Monteith Formation

The Lower Nikanassin–Monteith Formation was deposited as a series of northward flowing fluvial and coastal plain to deltaic deposits (Figure 29). The Lower Nikanassin–Monteith Formation thickens to the west and southwest (Figure 27). Isopach thickness of the Lower Nikanassin–Monteith Formation to the east of the Beattie Peaks erosional edge represents a partial thickness, as the Lower Nikanassin–Monteith is strongly affected by erosional truncation associated with the sub-Cadomin unconformity. The northwest limit of the Lower Nikanassin–Monteith is interpreted to represent the major depositional edge of the deltaic system with offshore marine mudstones.

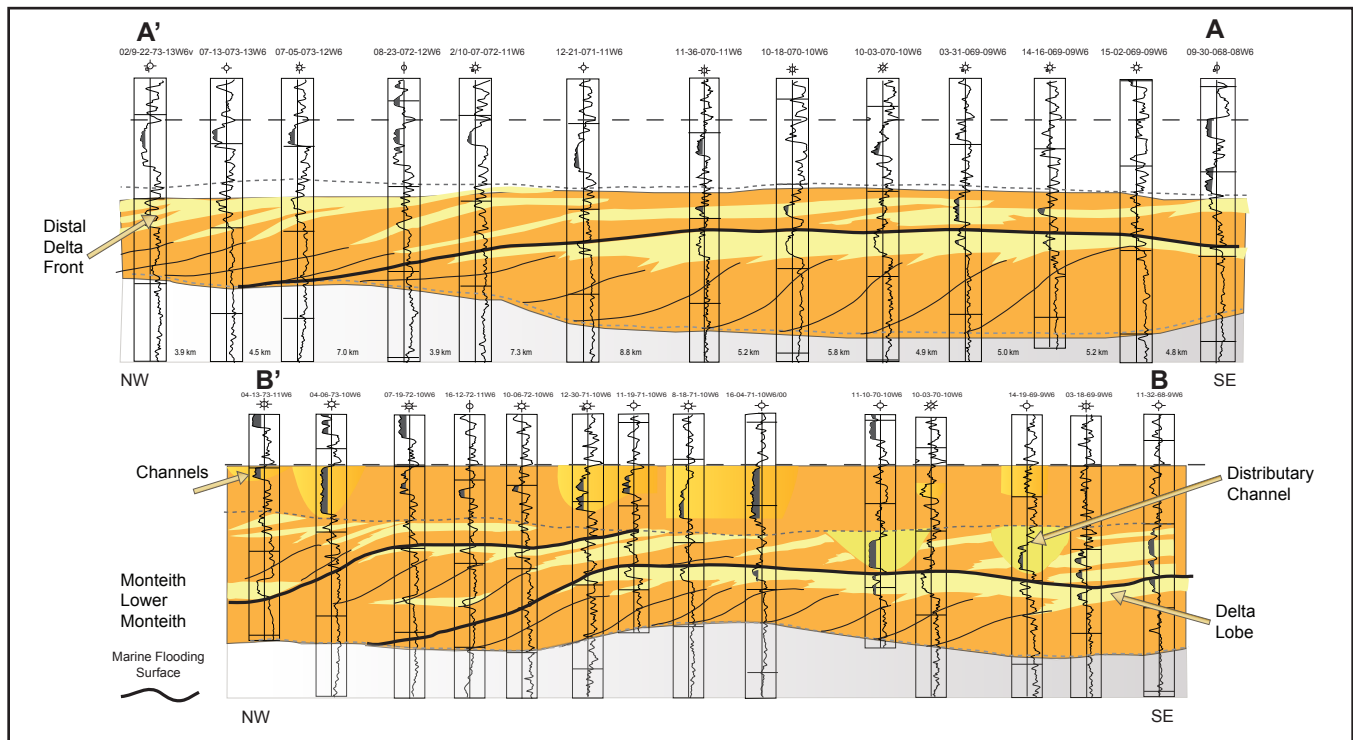
Figure 29:
Paleogeographic Reconstruction of the Lower Nikanassin (Monteith Fm) Depicting the Southeast to Northwest Progradation of the Nikanassin From Fluvial to Deltaic to Offshore Depositional Environments



Source: after Miles and Hubbard, 2010

Figure 30 represents two NW-SE cross-sections through the Lower Nikanassin (Monteith) displaying the offlapping geometry of Lower Nikanassin Monteith deltaic deposits. The Monteith displays a south-to-north transition from fluvial channel and off-channel deposits through a series of stacked deltaic lobes northwestward into offshore marine mudstones. Reservoir geometry also exhibits a transition from isolated “ribbon” sandstones encased in muddy to coaly alluvial plain deposits, to sheetlike deltaic lobes crosscut by distributary channel deposits, transitioning into bioturbated non-reservoir offshore interbedded mudstones and siltstones. The area with the best net:gross reservoir sandstones are within the SW-NE belt representative of the progradational extent of the Lower Nikanassin deltaic deposits. (Figures 1, 29 and 30).

Figure 30: Two NW-SE Cross-Sections (A-A' And B-B') Through the Lower Nikanassin (Monteith) Depicting the Geometry of Lower Nikanassin Deltaic Deposits Varying From Stacked Sheet Like Deltaic Lobe Sands Grading Into Offshore Mudstones (Nonreservoir) Cross-Cut by Distributary Channels



Source: after Miles and Hubbard, 2010

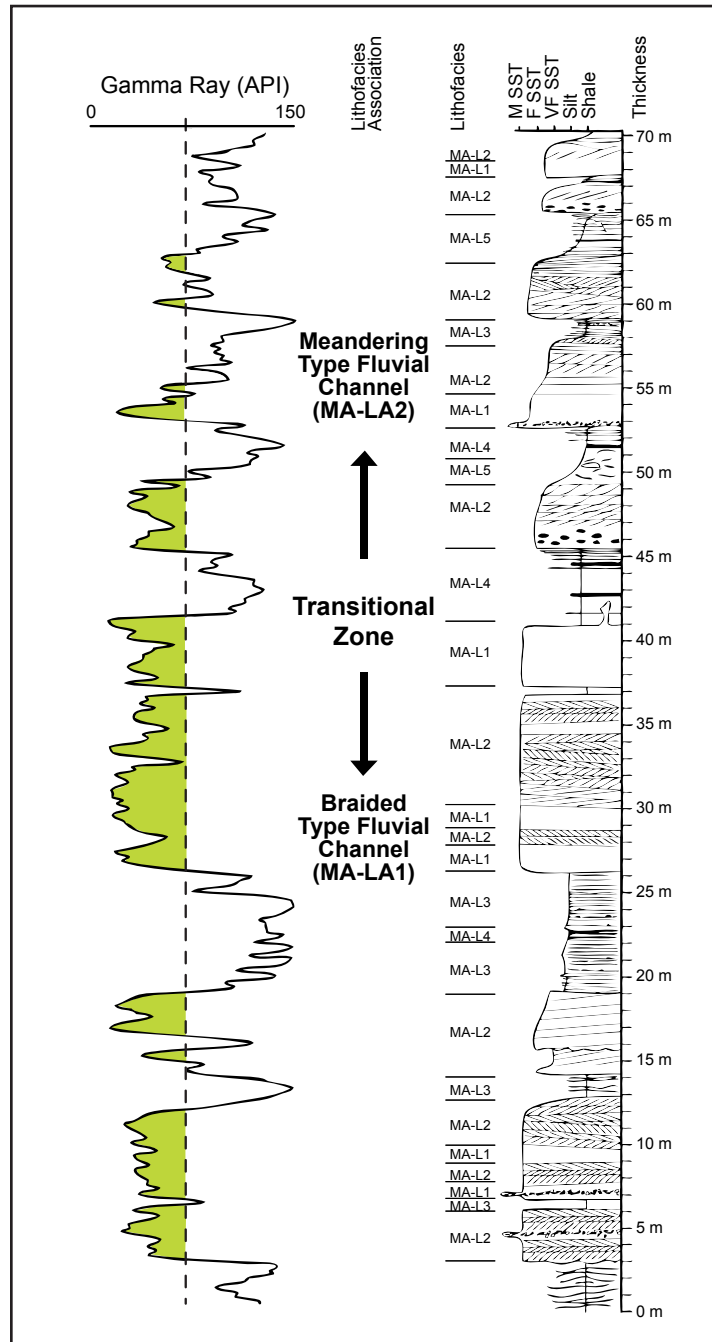
Middle Nikanassin–Beattie Peaks Formation

The Middle Nikanassin–Beattie Peaks Formation (Figures 2, 27 and 28) comprises a sequence of interbedded shales and siltstones with occasional thin sandstones. Toward the south, the unit becomes highly carbonaceous to coaly. The Beattie Peaks coals are considered to be a potential source rock for the liquids-rich gas in the system. These sediments are interpreted to have been deposited in a deltaic or coastal plain environment. The thickness of the Beattie Peaks Formation increases from 0m in the east at its erosional edge to >100m in the west-southwest. The Beattie Peaks Formation may be an important seal between the Lower Nikanassin Monteith and the Upper Nikanassin Monach Formations (Figures 27 and 28)

Upper Nikanassin–Monach Formation

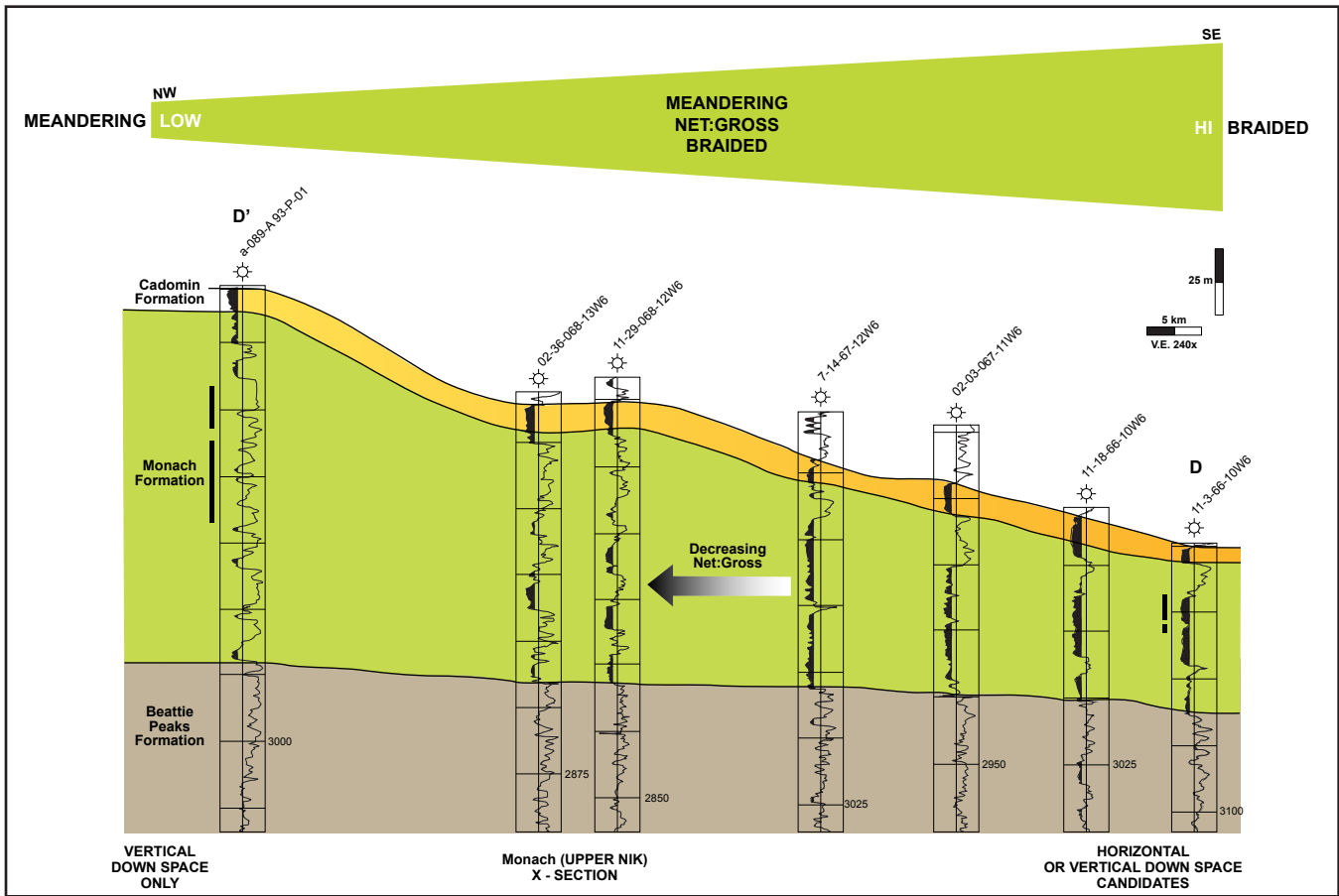
The Upper Nikanassin–Monach Formation (Figure 2, 27 and 28) comprises thick sandstone packages (up to 250m thick) deposited in a widespread southeast to northwest fluvial system. The Monach consists of both meandering and braid plain deposits (Figure 31). Where the Monach is meandering, isolated fining upwards ribbon sandstones are encased in fine grained overbank material resulting in a low net:gross thickness ratio (10–40 %). In areas of braided fluvial deposits, the Monach can be characterized by extremely high net sandstone to gross thickness ratio (80–100%) (Figure 32).

Figure 31: A Detailed Type Log of the Upper Nikanassin Monach Fm Exhibiting Basal Blocky Braided Fluvial Sands and Upper Fining Upward Meandering Fluvial Sands



Source: after Miles and Hubbard, 2010

Figure 32: Northwest to Southeast Cross-Section Through the Upper Nikanassin (Monach) Depicting the Change From High Net:Gross Braided Fluvial Deposits to Low Net:Gross Meandering Deposits. Dark zone indicates potential pay.



Source: after Miles and Hubbard, 2010

Structural Fairways

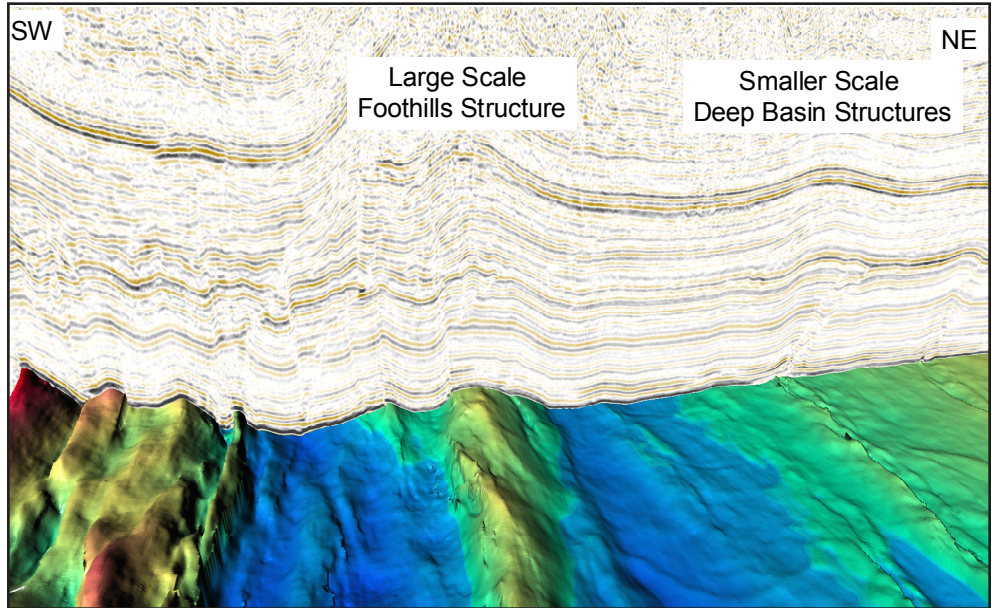
The Nikanassin can be differentiated into two distinct structural style fairways: Foothills Structural (FHS) vs. Deep Basin (DB) Play Fairways (Figure 1).

The Foothills Structural play area (FHS) forms a long narrow fairway composed of large scale anticlinal structures situated at the outer or leading edge of the Foothills, parallel to the mountain front (Figures 33a and b). Wells drilled off structure are generally non-productive. Multiple zones are fracture-stimulated and commingled. These larger-scale structures create an increased fracture density and enhanced productivity. Recently, companies such as Shell and Canadian Forest have been applying sophisticated geophysical techniques to estimate fracture orientation and density. Several wells at Chinook Ridge have produced >3.5 Bcf. Examples of producing pools in the FHS include Chinook Ridge, Narraway, Ojay, Grizzly, and Hiding Creek.

Structures become more subdued and merge into the Deep Basin to the east (Figure 33a). Examples of producing pools in the DBS include Glacier, Sinclair, Elmworth, Noel, Redrock and Bilbo. The major difference between the emerging Deep Basin Structural

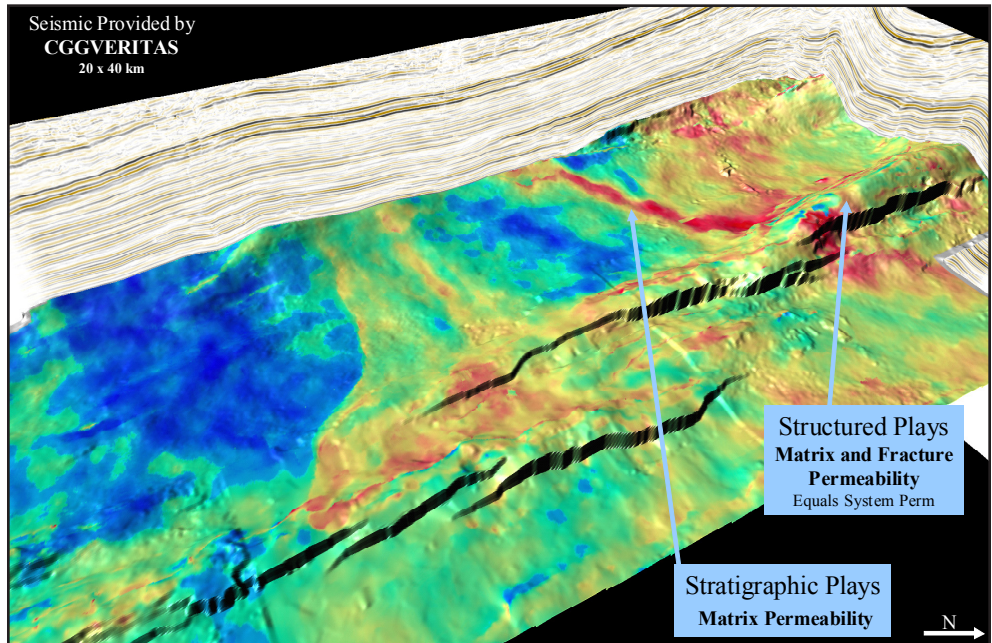
Fairway and the established Nikanassin Foothills Structural Play is that the Deep Basin structural play (DBS) is characterized by more subdued structures and significant areas that do not display enhanced permeability due to natural fracturing.

Figure 33a: SW-NE Dip Oriented Seismic Line Extraction Across the Foothills (FHS) to Deep Basin (DBS) Structural Fairways Exhibiting the Change From Large Scale Foothills Structures vs. Secondary Deep Basin Structures



Source: Boettcher, Thomas and Oz, 2009; Courtesy of M. Thomas

Figure 33b: SW-NE Dip Oriented Seismic Line Extraction Across the Foothills (FHS) to Deep Basin (DBS) Structural Fairways Exhibiting Secondary Deep Basin Cross Cutting Structures



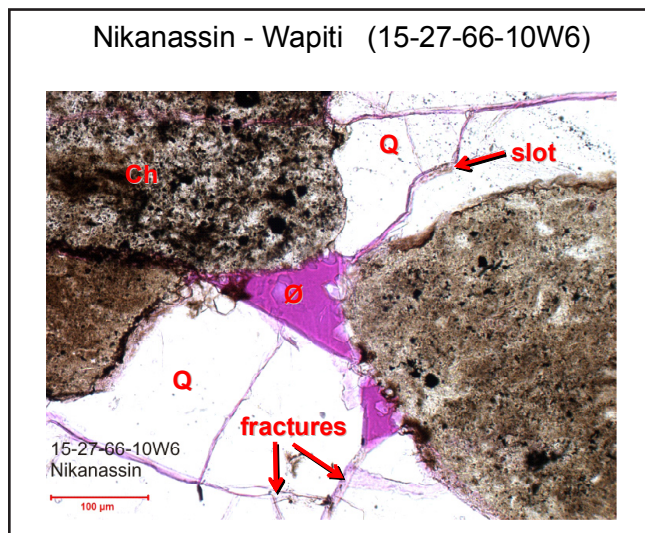
Source: Boettcher, Thomas and Oz, 2009; Courtesy of M. Thomas

Exploration and development of multi-zone reservoirs in both the FHS and DB require detailed subsurface mapping integrated with 3D seismic. The low-permeability sandstones are gas charged both on and off structures. The ultimate prize is the ability to design an effective drilling and completion program that will unlock unstructured areas allowing for economic rates of gas production. It is unclear whether this technology is being pursued today. Further to the east and south, the DBS Fairway becomes less structured so that the play develops into the Deep Basin–Jurassic–Cretaceous commingled play (DBC) fairway (e.g., Tourmaline, Talisman and Canadian Forest at Wild River). In this area almost every section has or can be downspaced to 2–4 wells per section as part of the ERCB Development Entity #2. By drilling to the Nikanassin Formation, up to 10 uphole reservoir intervals are evaluated.

Reservoir Properties

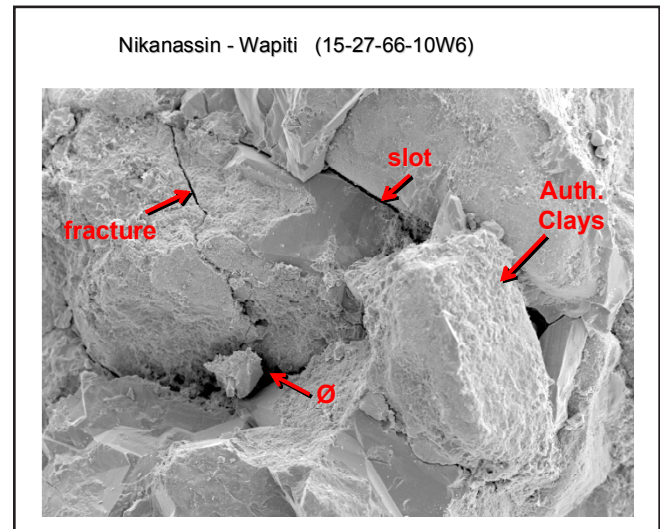
Nikanassin reservoir sandstones primarily consist of fine- to medium-grained poorly sorted, highly compacted litharenites, composed primarily of quartz, chert and sedimentary rock fragments (Figure 34a and 34b). Reservoir quality is often very poor, being pervasively cemented and brittle. Pores are generally small and isolated – most primary porosity has been destroyed, and little solution porosity has developed. Conventional core analysis porosity values are generally up to 6%, while permeabilities are 0.1 md or less. Where the Nikanassin is productive, however, core and thin-sections show extensive fracturing.

Figure 34a: Nikanassin Thin Section Showing Quartz (Q) and Chert (Ch) Lithology, and Main Porosity Styles – Intergranular Porosity (\emptyset), Fracture Porosity and Slot Porosity



Source: Zaitlin and Moslow, 2005, 2006, 2008; Midnight/Pace Corporate Presentations

Figure 34b: Nikanassin Scanning Electron Microscope Image (SEM) of the Same Thin Section in Figure 36a Showing at a Higher Magnification Intergranular Porosity (\emptyset), Fracture Porosity, Slot Porosity and Authigenic Clays



Source: Zaitlin and Moslow, 2005, 2006, 2008; Midnight/Pace Corporate Presentations

The Three P's: Pressure, Porosity, Permeability

A review of 76 Nikanassin producing pools allows for an evaluation of key reservoir attributes. Figure 35a is a graph of average pool porosity vs. depth. Nikanassin average pool porosity ranges from 4–16%. A clear trend of decreasing porosity with depth is shown, with higher porosity (~10–16%) in the shallower pools (~6,000 ft) whereas deeper pools >10,000 ft have porosity ~4–8%. Figure 35d is a graph of pool porosity vs. depth in the FHS fairway only. Average pool porosity ranges from 4–9%. Figure 35c is a graph of average pool porosity vs. depth in the DBS fairway only. Average pool porosity is 6–12%. Figure 35b is a graph of average pool porosity vs. depth in the DBMO fairway only. Average pool porosity is 9–16%. An interesting trend occurs below 8000 ft in Figure 35b in which porosity improves from 8.5–12.0% and may indicate secondary reservoir enhancement and dissolution with depth (DBMO).

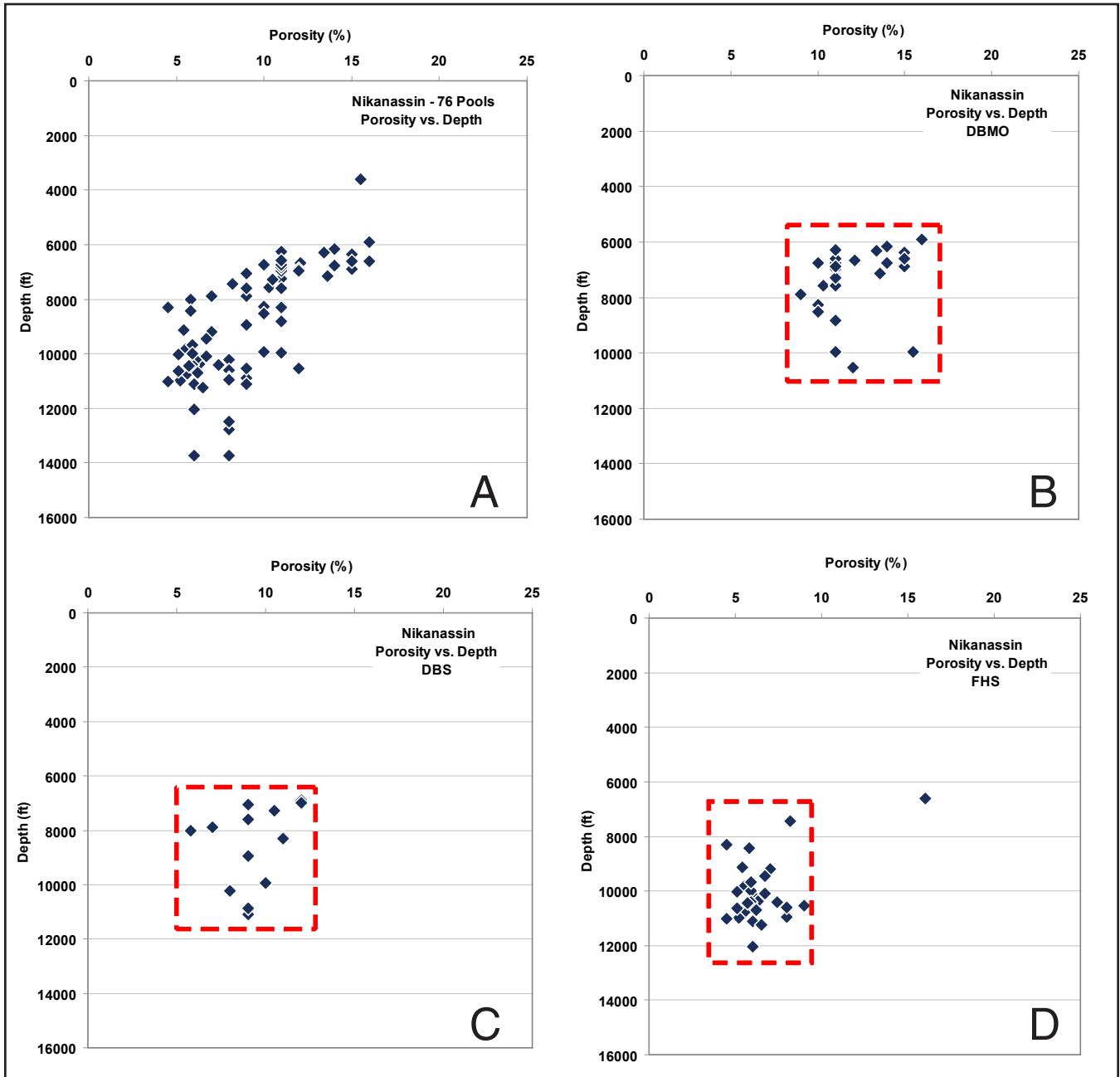
Figure 36 a-d are graphs of initial reservoir pressure vs. depth from the 76 defined Nikanassin pools with available data. Figure 36a is a graph of initial reservoir pressure vs. depth. A normal pressure gradient line of 0.43 psi/ft is included against which to evaluate individual pool pressures. Two populations of pressure vs. depth occur – a group below (to the left) of the 0.43 normal gradient line that are considered underpressured vs. a group of pools to the right or above the 0.43 pressure gradient line that are indicative of overpressured pools. A key component of Deep Basin systems are abnormal pressures (either +/-). Underpressured pools will have lower OGIP, whereas areas of increased overpressure can have higher OGIPs.

Figure 36b of pressure vs. depth clearly indicates that the majority of pools in the DBMO fairway are predominately underpressured; however, a few pools plot out as overpressured. These are probably indicative of small-scale structures within the DBMO fairway.

Figure 36c of pressure vs. depth clearly indicates that pools in the DBS fairway are predominately underpressured – and along with the Nikanassin's immature mineralogy and clay rich (smectite and illite) lithology may be the reason for its high susceptibility to reservoir damage and poor deliverability.

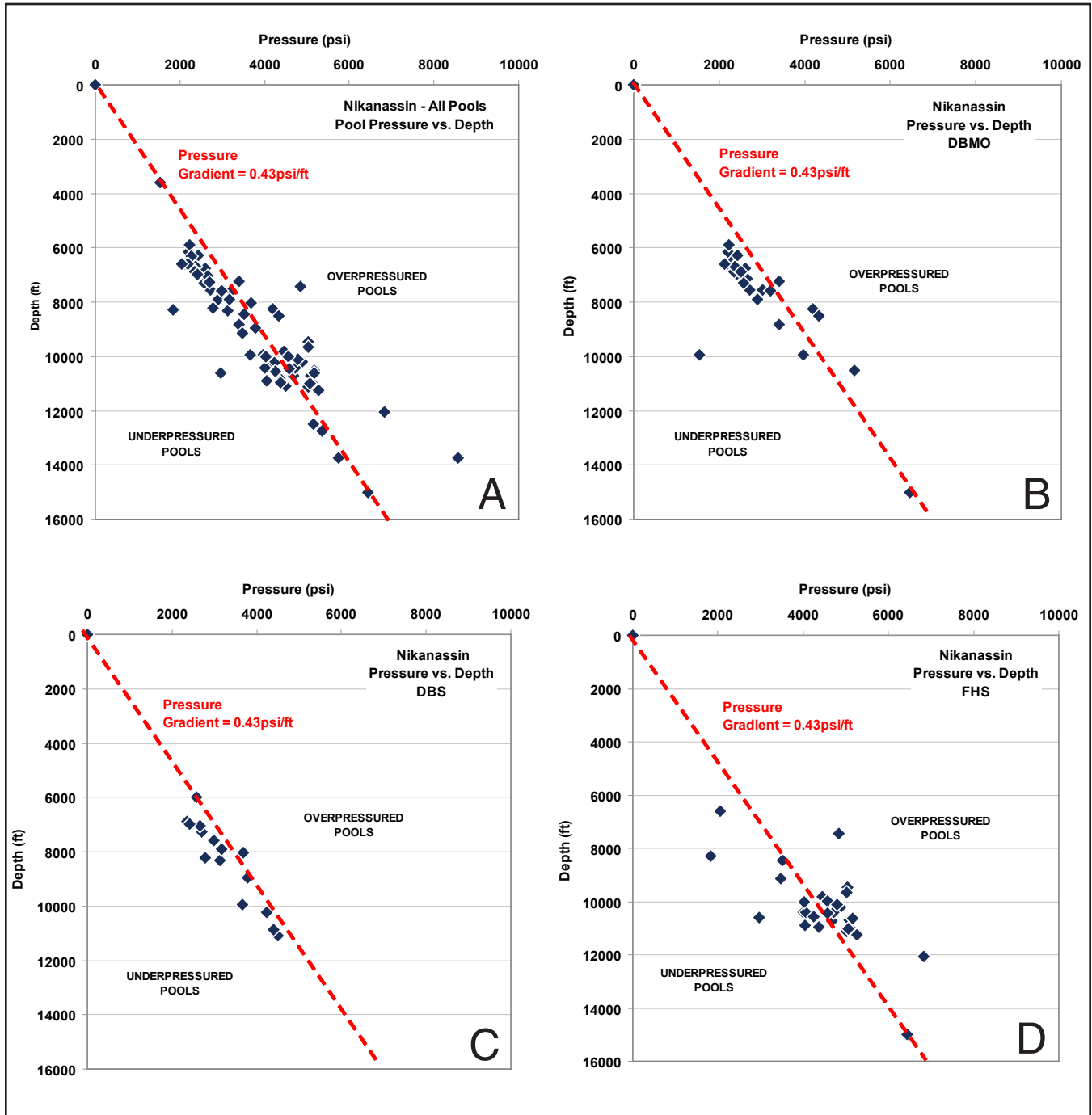
Figure 36d is a graph of initial reservoir pressure vs. depth in the FHS fairway. Again, a normal pressure gradient line of 0.43 is included against which to evaluate individual pool pressures. Two populations of pressure vs. depth occur – a group below (to the left) of the 0.43 normal gradient line that are considered underpressured vs. a group of pools to the right or above the 0.43 pressure gradient line that are indicative of overpressured pools. The underpressured pools are interpreted to have developed due to breaching of the top seal during structuring and uplift. The overpressured pools are associated with Ojay, Chinool Ridge and Narraway and are an important component to the higher IPs and EURs associated with those pools.

Figure 35: Averaged Porosity vs. Depth From 76 Defined Nikanassin Pools:
Fig 35A: All Nikanassin Pools; Figure 35B: DBMO; Figure 35C: DBS; and Figure 35D: FHS



Source: BMO Capital Markets; Data from GeoScout

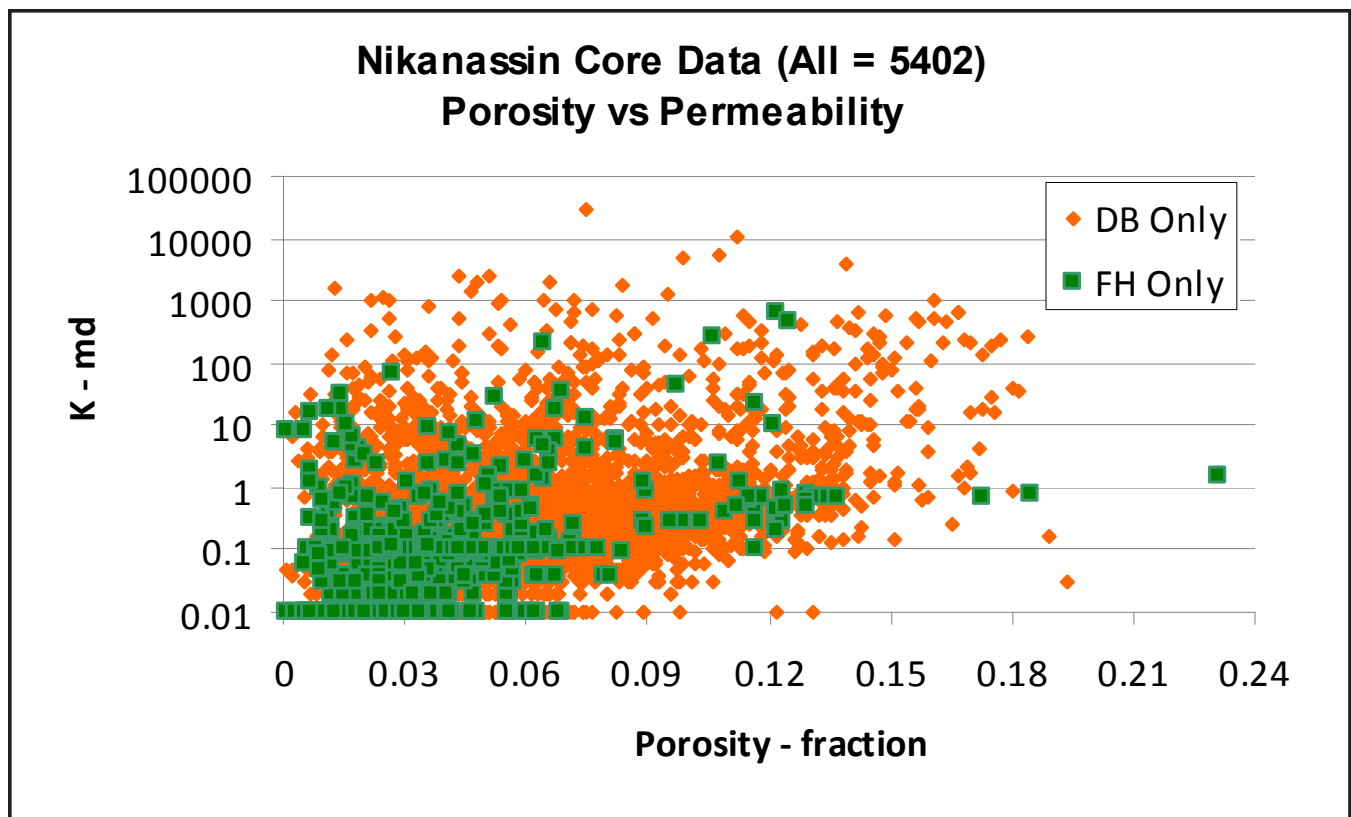
Figure 36: Averaged Porosity vs. Depth From 76 Defined Nikanassin Pools:
 Fig 36A: All Nikanassin Pools; Figure 36B: DBMO; Figure 36C: DBS; and Figure 36D: FHS



Source: BMO Capital Markets; Data from GeoScout

Figure 37 is a graph of porosity (fraction) vs. permeability (k-md) for Nikanassin cores subdivided aerially into the Foothills structural area (FH) and Deep Basin area (DB). The significant scatter of points is indicative of reservoir quality heterogeneity that exists in the Nikanassin. The Foothills (FH) porosity ranges from 0–8%, with some outliers to 13%. Permeability ranges <0.01–1.0 md with a second population between 1.0md and 100 md. In comparison, the Deep Basin Porosity–Permeability data exhibits a greater degree of scatter. Porosity ranges 0–19%, and permeability 0.01–1000+ md.

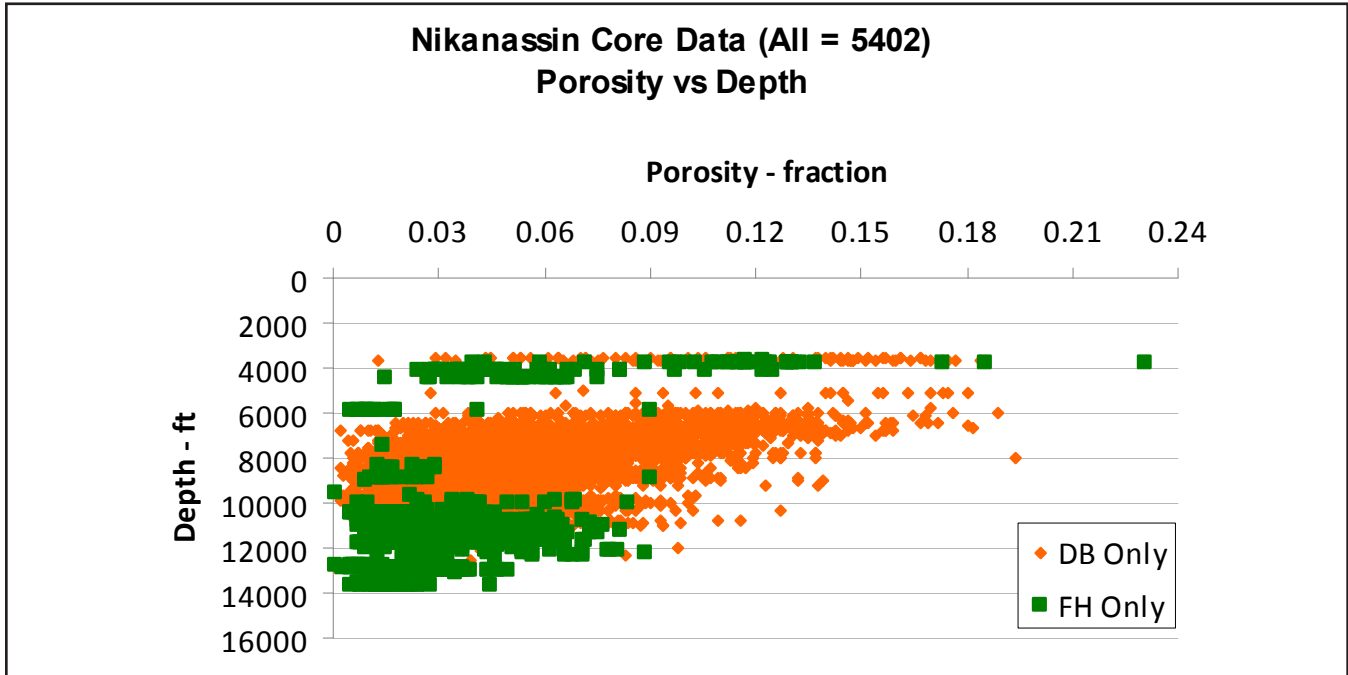
Figure 37: Nikanassin Core Porosity vs. Permeability



Source: BMO Capital Markets; Data from GeoScout

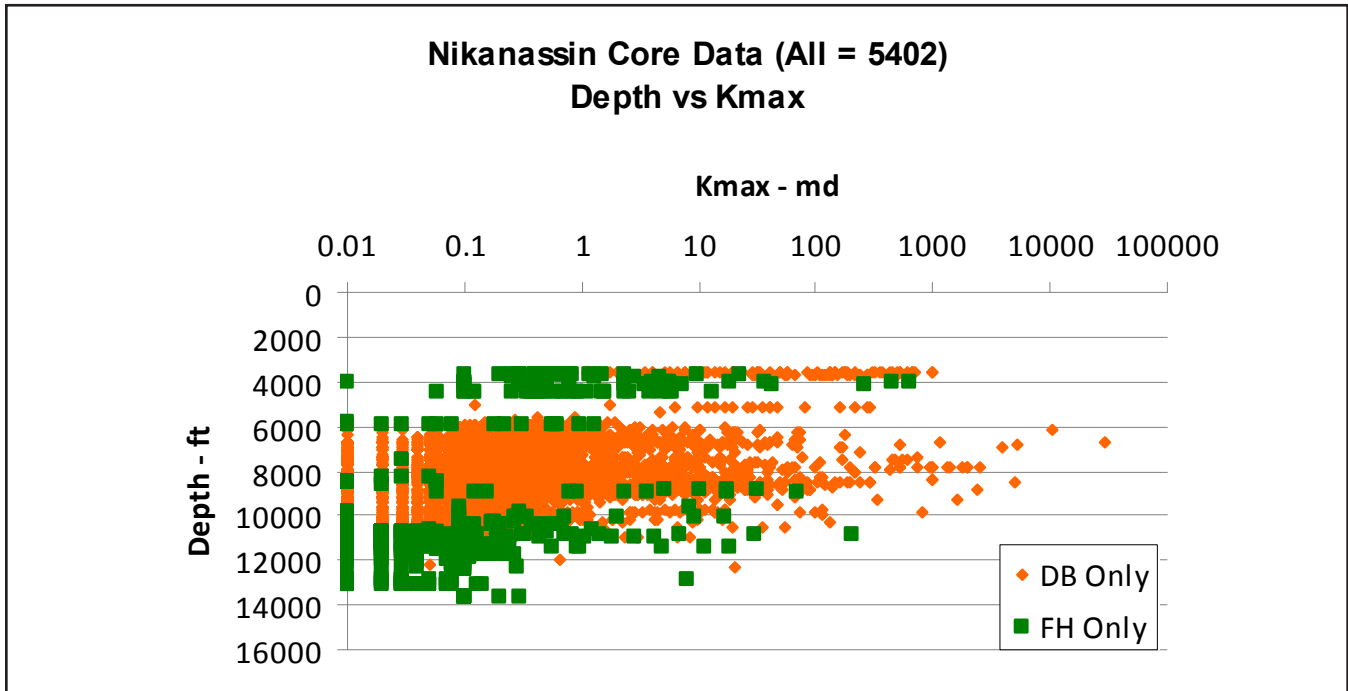
Figure 38 is a plot of porosity vs. depth for the available Nikanassin core data (5402 points). Porosities vary for the Foothills Nikanassin (FHS: 0–9%) at depth, whereas in more shallow uplifted structures the porosity range is 2–23%. Deep Basin cores have porosity between 0.5% and 19%. A key observation is that the range of porosity decreases in the Deep Basin with increasing depth. Figure 39 is a plot of permeability vs. depth for Nikanassin cored wells. The deeper Foothills Nikanassin cores have significantly lower permeabilities than the Deep Basin.

Figure 38: Nikanassin Porosity vs. Depth for Cored Wells



Source: BMO Capital Markets; Data from GeoScout

Figure 39: Nikanassin Permeability vs. Depth for Cored Wells



Source: BMO Capital Markets; Data from GeoScout

Figure 40 is a summary table of the Nikanassin reservoir parameters extracted from an analysis of the average pool data set supplemented by core. From this data, we can interpret the Nikanassin to span the spectrum of play types from tight gas reservoirs (<1md), unconventional gas reservoirs (1–10 md) and conventional reservoirs (>10md). Figure 41 is a summary of the Pool Averaged Mean EUR, Volumetrics and Well spacing assuming a 70% Recovery Factor (RF).

Figure 40: Mean Reservoir Parameters (based on Reservoir Pool Averages)

	FHS	DBS	DBMO
Mean Depth (m)	3,066	2,682	2,227
Pay thickness (m)	18.5	9.6	7.6
Porosity (%)	6.5	9.5	12
Formation Temp (R)	671	647	628
Compressibility (Z)	0.996	0.892	0.879
Pressure (psi)	4,438	3,262	2,803
BG or 1/FVF	236	201	180

Source: BMO Capital Markets; Data from GeoScout

Figure 41: Summary of the Pool Averaged Mean EUR, Volumetric and Well Spacing Assuming a 70% Recovery Factor (RF)

	FHS Vt Type Well (per well)	FHS Dev. Type Well (per well)	DBS Vt Type Well (per well)	DBS Hz Type Well (per well)	DBMO Vt Type Well (per well)
Mean IP (3-month avg.)	2.9	10.4	1.5	5.8	1.7
Mean EUR (Bcf)	3.5	7.1	3.1	6.2	1.4
Volumetric OGIP (Bcf/section)	18.4	18.4	12.5	12.5	11.3
Volumetric EUR (Bcf/section; 70% RF)	12.9	12.9	8.8	8.8	8.0
Number of wells per section	3.7	1.8	2.8	1.4	5.7

Source: BMO Capital Markets; Data from GeoScout

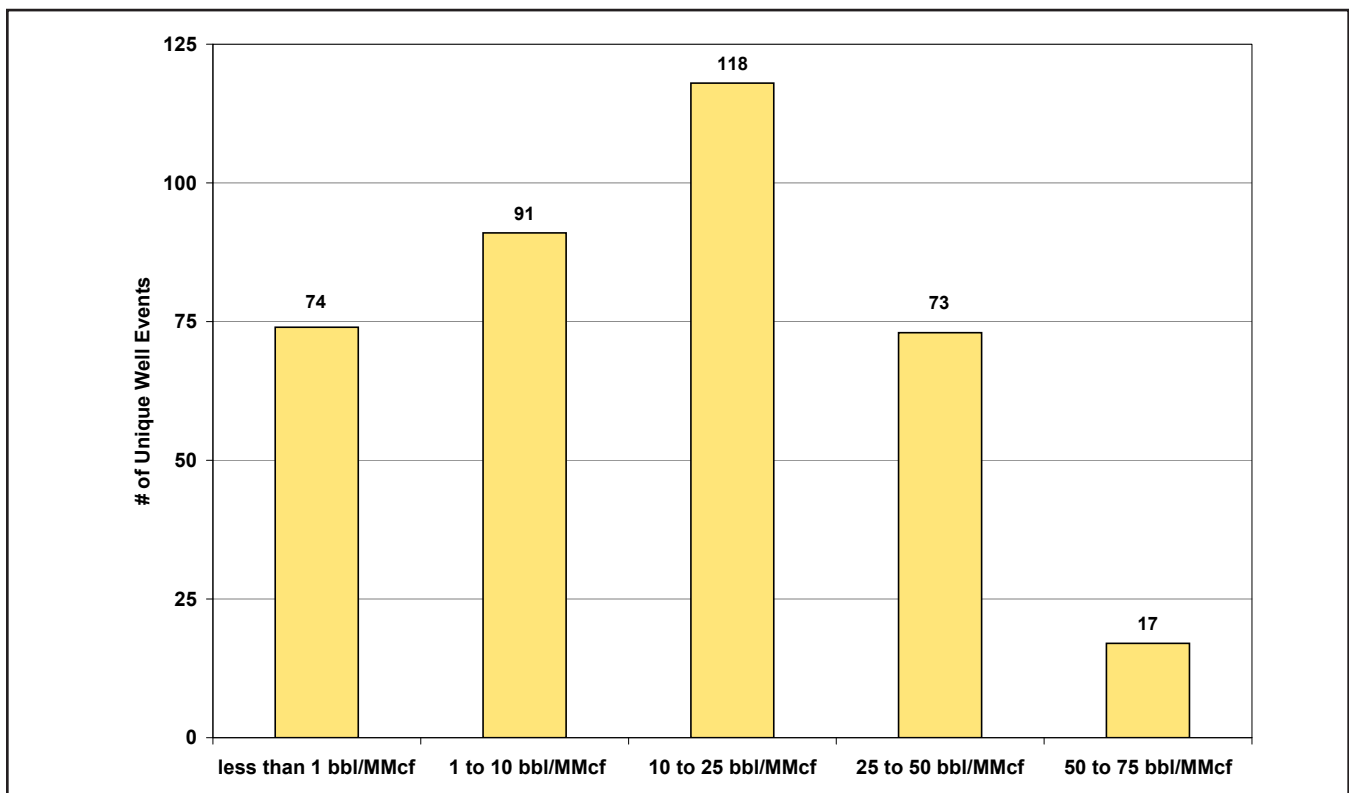
Liquid Yield Determination

All public gas analyses from wells within the three Nikanassin regions (FHS, DBS, DBMO) were evaluated. The DBC was not part of this evaluation. These analyses were then used to calculate the high-cut liquid yield with recovery factors for deep-cut components as follows: C3 = 75%, C4 = 90%, C5+ = 95%.

This list was compared with an initial database of wells to match the gas analyses with any reported liquid production. This resulted in a list of 373 unique well events, of which 14 also had reported liquid production from the Nikanassin. The calculated deep-cut yields were added to the produced liquids where applicable, to determine a total liquid yield. The distribution of these liquid yields is shown in Figure 42 and mapped in Figure 43.

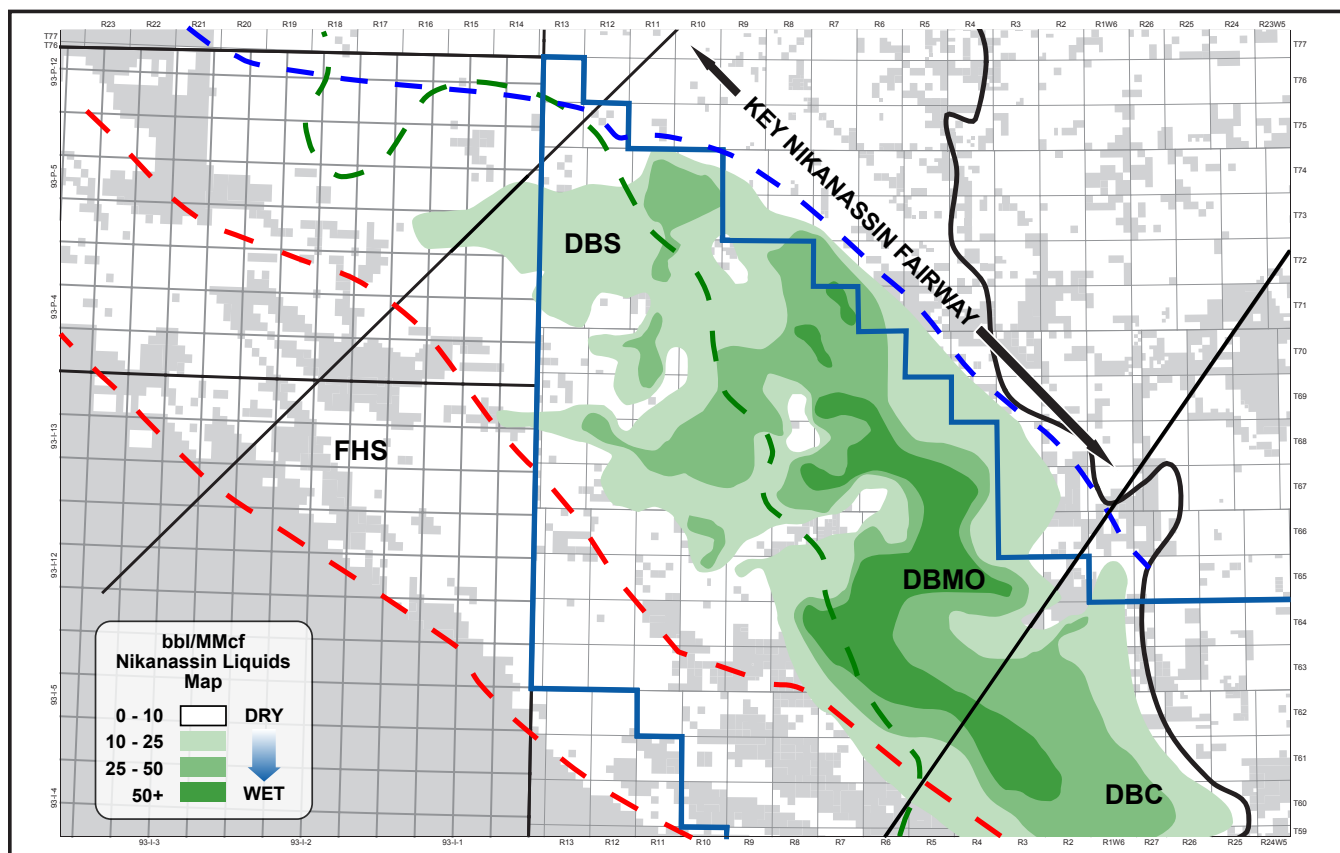
The results show that the Nikanassin liquid yields vary in the Deep Basin from 0–75 bbl/MMcf with the majority of the samples showing values from 10–50 bbl/MMcf. Many of the samples in the liquid yield database are from wells that have no production from the Nikanassin but were Drill Stem Tested (DST) or flow tested. As such, based on the location of the liquid fairways shown in Figure 43, it was determined that a conservative, base-case value for liquid yield in the Foothills Nikanassin is approximately 5 bbl/MMcf, whereas in the Deep Basin Monach and Monteith, the base-case yield is 10 bbl/MMcf. In addition, due to the likelihood of encountering varying levels of liquid yields, economic sensitivities were run against each base case type well at 0 bbl/MMcf and 50 bbl/MMcf.

Figure 42: Range of Nikanassin Liquid Yield Calculated From Available Gas Analysis and Liquids Production



Source: BMO Capital Markets; Data from GeoScout

Figure 43: Liquids Yield Map in Relation to Nikanassin and Liquids-Rich Fairways



Source: BMO Capital Markets; Data from GeoScout. Grey lands indicate open Nikanassin rights.

Companies that appear to be targeting Nikanassin liquids-rich areas (Figure 43) include Delphi, NuVista, Artek and Progress Energy.

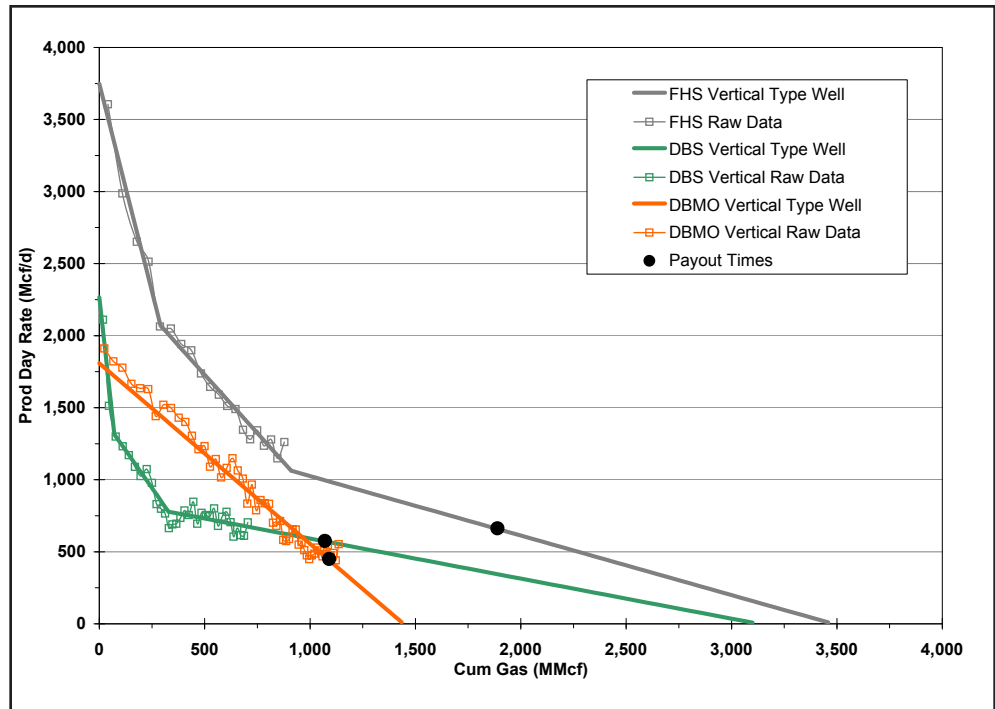
Nikanassin Type Well Construction

A) Vertical

All Nikanassin (single zone only) producing wells in the map area were selected and then sorted based on the four geographic regions: 1) Foothills Monach (FHS) – 101 wells; 2) Deep Basin Monach (DBS) – 229 wells; 3) Deep Basin Monteith (DBMO) – 133 wells; and 4) Deep Basin Monteith (DBC) – 94 wells.

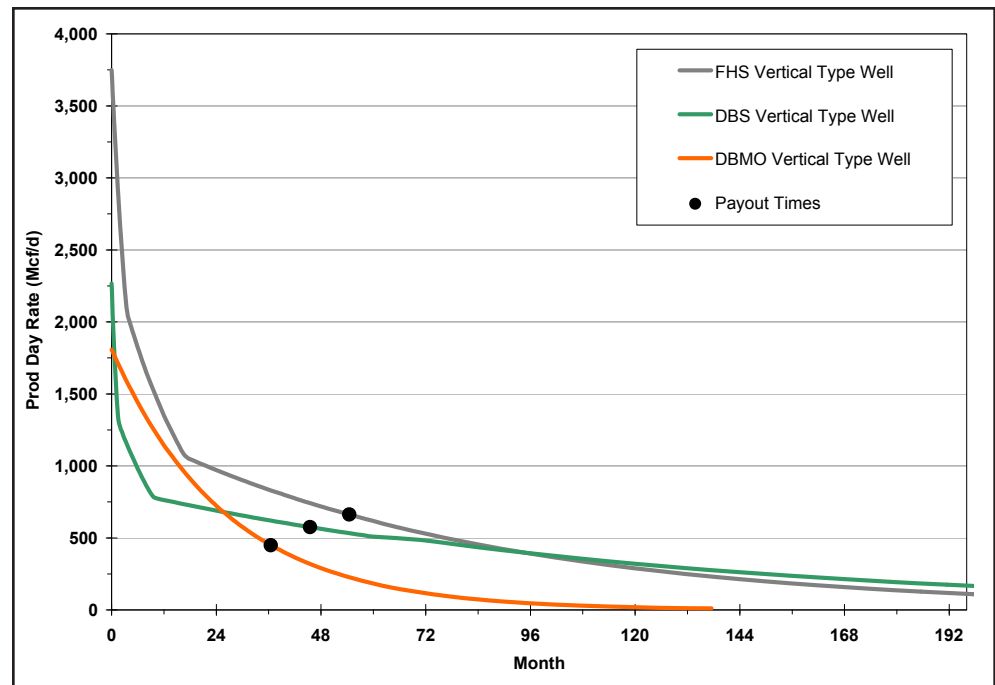
In each case, the best-fit decline curve was determined using Value Navigator to estimate the estimated ultimate recovery (EUR). This EUR and the Producing-Day Rate data was then used to develop a segmented, exponential decline curve. As shown in Figure 44a, the exponential decline curves in the FHS and DBS are characterized by a three-segment decline, whereas the DBMO type curve is characterized by only one exponential decline segment. Figure 44b shows the same curves on a rate-time plot. Both figures 44a and 44b also show the respective payout locations for each curve. Referring to figure 44b, the DBMO type well pays out first at 37 months, followed by the DBS at 46 months and the FHS at 55 months.

Figure 44a: Calculated Nikanassin Vertical Type Curves (Rate vs. Cumulative production) for the FHS, DBS, DBMO/DBC Fairways with Number of Wells, EUR, and Time to Payout



Source: BMO Capital Markets; Data from GeoScout

Figure 44b: Calculated Nikanassin Type Curves (Rate vs. Time) for the FHS, DBS Fairways With EUR, and Time to Payout. A DBMO Well Achieves Payout in 37 Months, DBS Well in 46 Months and a FHS in 55 Months.



Source: BMO Capital Markets; Data from GeoScout

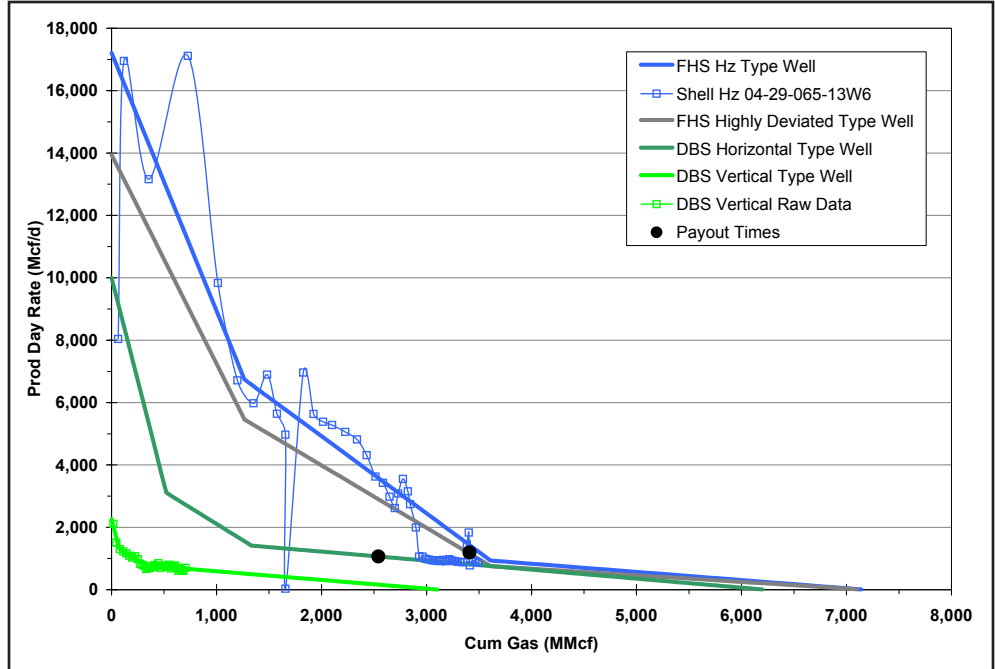
B) Horizontal/Deviated

There was only one horizontal well in our data set that had sufficient history to build a type curve (Shell Hz ChinookR 4-29-65-13W6). Using the same methodology as the vertical type curves, a three-segment horizontal type-curve was developed with an initial rate of 17 MMcf/d and an EUR of 7.1 Bcf (Figure 45a). However, the most current industry activity targets the Foothills Monach with highly deviated wells, which perform similarly to the horizontal well. Canadian Forest Oil states that the average, instantaneous rate for wells in this area is 14 MMcf/d with an EUR of 7.0 Bcf. The economic runs for the FHS highly deviated wells are based on the type well shown in Figure 45b with an instantaneous rate of 14 MMcf/d and EUR of 7.1 Bcf. These figures also show the respective payout locations for the horizontal and highly deviated type wells. The FHS deviated type well pays out first at 30 months, followed by the DBS horizontal type well at 60 months.

Since there were no horizontal wells in the DBS with sufficient production history, it was assumed that the EUR for a horizontal well in this region would be some multiple of the vertical Nikanassin wells. The EUR for a vertical well here is 3.1 Bcf and the volumetric estimate is 12.5 Bcf (OGIP). Typical tight-gas plays use a vertical to horizontal multiplier of three to five times EUR. In this case, a horizontal well with a multiple of this magnitude would result in a recovery factor of 74% to >100% for one well per section. A more reasonable estimate is two times the vertical EUR, resulting in a horizontal EUR of 6.2 Bcf and a well density of 1.7 wells per section.

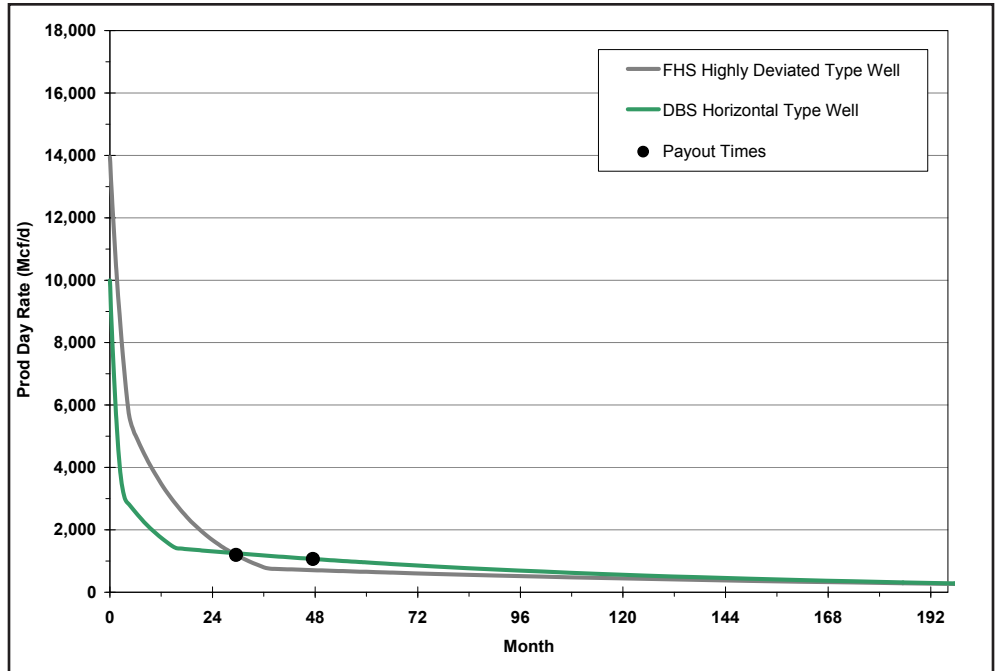
For the DBMO, the vertical type curve is purely exponential. This suggests that the formation will deliver its gas effectively with vertical wells only, and the extra expense of drilling horizontal wells is unnecessary (assuming acceleration does not significantly impact economics – see Figure 55).

Figure 45a: Nikanassin FHS Vertical and Horizontal/Highly Deviated Type Wells (Rate vs. Cumulative Production) Demonstrating the Potential Increase From 3.5 Bcf to 7.1 Bcf EUR/well From Vertical to Horizontal/Deviated Type Well in the FHS Fairway.



Source: BMO Capital Markets; Data from GeoScout

Figure 45b: Nikanassin FHS Vertical and Horizontal Type Wells (Rate vs. Time) Demonstrating the Potential Increase from 3.5 Bcf to 7.1 Bcf EUR/well From Vertical to Horizontal/Deviated Type Well in the FHS Fairway.



Source: BMO Capital Markets; Data from GeoScout

Economic Results

Capital Cost Assumptions

An average TVD for each region is shown in Figure 46. The average drilling time for each region was also determined as follows: Analysis of drilling reports suggests that drilling from surface through the Nikanassin occurs at an average rate of 114m/day. The assumed depths for each case were then divided by 114m to determine an average number of days required to drill and case each well. Total costs from drilling reports were used to determine the average daily cost to drill and case each well. In this case, the result was \$62,000 per day. For example, as shown in Figure 46, the average depth of a Deep Basin Monach (DBS) well is 2,682m, so the assumed drill and case costs were calculated as follows: $2,682\text{m} / 114\text{m/d} * \$62,000/\text{d} = \$1.5\text{ million}$.

Figure 46: Type Well Parameters Utilized in the Economic Analysis of the Nikanassin Fairways

	FHS		DBS		DBMO
	Vertical	Highly Deviated	Vertical	Horizontal	Vertical
Instantaneous IP (MMcf/d)	3.7	14.0	2.3	10.0	1.8
3-Month IP (MMcf/d)	2.9	10.4	1.5	5.8	1.7
EUR (Bcf)	3.5	7.1	3.1	6.2	1.4
Liquid Yield (bbls/MMcf)	5	5	10	10	10
RLI (years)	2.8	1.6	4.6	2.1	2.2
Well Cost (\$MM)	4.9	8.1	3.0	7.0	3.0
TVD (m)	3,066	3,066	2,682	2,682	2,227
MD (m)	3,066	4,066	2,682	3,682	2,227

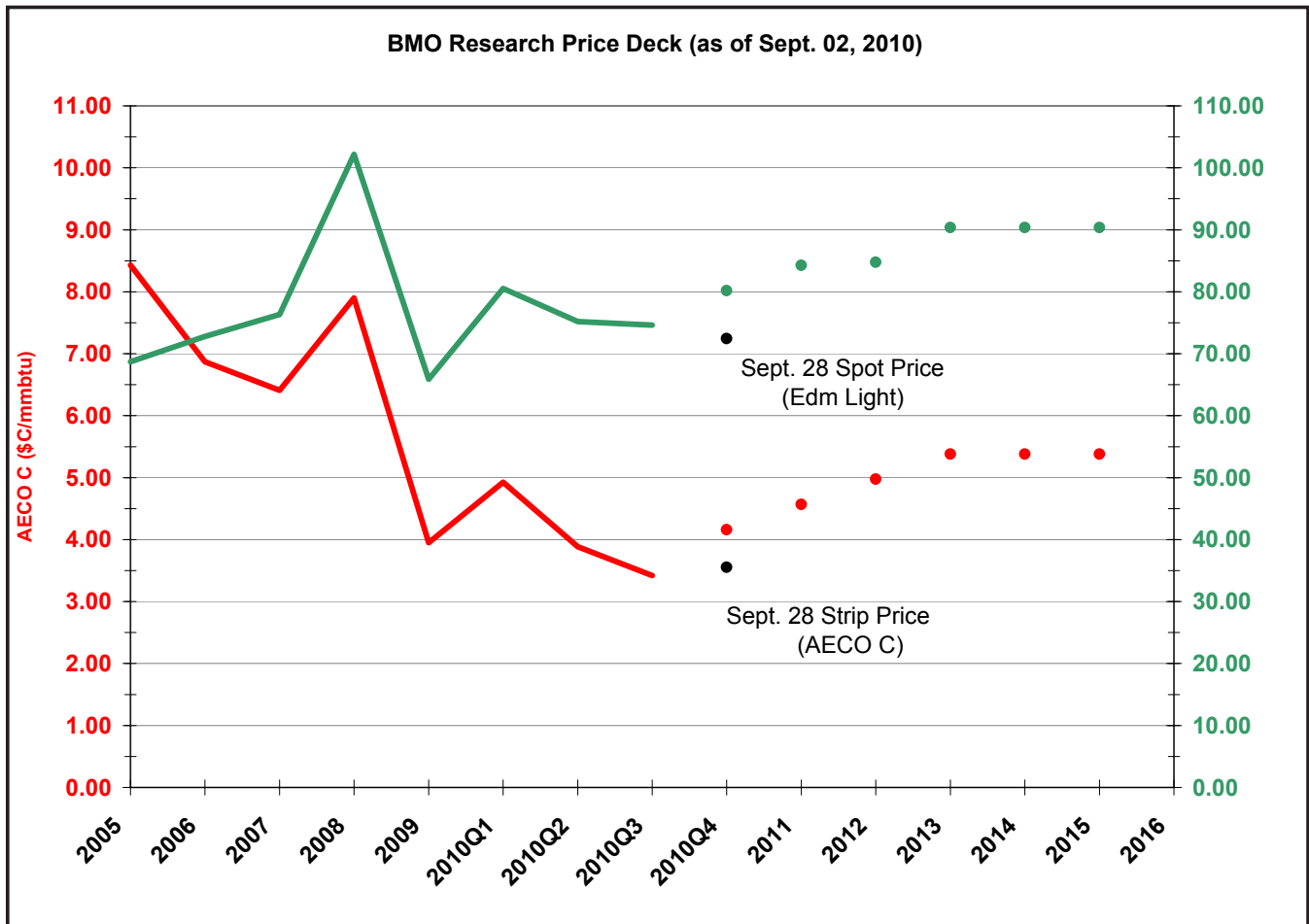
Source: BMO Capital Markets; Data from GeoScout; various Corporate Presentations

Recent completion programs in the Nikanassin are using slick-water, fracturing isolated intervals. Vertical wells have used 5T to 20T per interval while horizontal and highly deviated completions use 50T to 70T per interval. It was determined that 5T to 20T slick-water fracs on average cost \$150,000 each, while 50T to 70T fracs on average are \$250,000 each. Wellsite equipment and tie-in costs were assumed to be \$600,000 for all locations.

Pricing Assumptions

Each of our type well cases was run using the BMO Research September 2, 2010, price deck (Figure 47) assuming an effective date of January 1, 2011. For NGLs, a liquid yield was applied that resulted in an average liquid production, rather than separating the components into C3, C4, and C5+. A price differential of -C\$15.88/bbl was applied to the Edmonton Light price to determine a liquid price. This price differential was determined as the actual average price discount for NGLs to Edmonton Light.

Figure 47: Price Deck Utilized in the Economic Analysis



Source: BMO Capital Markets

Royalty Considerations

There were five base-case scenarios selected that represent the most likely outcomes from development of the Nikanassin. Each of the sub-regions has significant historical production through vertical wells, while emerging development is taking place with either highly deviated wells (in the Foothills) or horizontal wells (in the Deep Basin). In the Foothills, the productive portion of the Nikanassin is layered such that the wellbores essentially “snake” through a highly deviated trajectory. This is important because the Government of British Columbia makes a clear distinction with drilling credits available for horizontal and vertical wells. The FHS highly deviated well is considered to be a vertical well in BC. However, in the Deep Basin, horizontal wells are technically considered horizontal with wellbores that are greater than 80° from the vertical. These types of wells are being used in the Lower Nikanassin (Monteith) but are not necessary in the Upper Nikanassin (Monach). As such, our five base cases consist of one vertical type well in each region, plus a highly deviated well in the FHS, and a horizontal well in the DBS.

Another significant variable in the economic results are the drill credits. The Nikanassin spans the Alberta-British Columbia border, and also spans the British Columbia East-West area for its Deep Gas Well Program. FHS type wells occur in all three regimes (Alberta, B.C. East, B.C. West), while the DBS occurs in two (Alberta, and B.C. East) and the DBMO only occurs in Alberta.

The base program in Alberta for new wells is a maximum royalty rate (NWRR – New Well Royalty Rate) of 5% subject to a volume or time limit. Vertical wells pay a maximum of 5% to a volume of 500 MMcfe of gas equivalent production or 12 months, whichever comes first. Horizontal wells have the same criteria except that they have an 18-month limit.

In addition, there is a substantial drilling credit that can be applied to the royalties payable in Alberta (NGDDP – Natural Gas Deep Drilling Program). For gas wells with a true vertical depth of at least 2000m, the credit is calculated according to the measured depth beyond 2000 m. These credits can reduce the royalties payable to less than the maximum 5% but they do run concurrently with the NWRR.

In B.C., the base royalty rates tend to be lower than Alberta’s base rates, but its Deep Gas Well Program provides credits that vary greatly depending on which side of the East-West line it falls (Figure 5). The credit applied when drilling in the west section is approximately two times greater than for a well drilled in the east section. For example, in our study, the FHS fairway spans all three royalty regimes. Looking at the vertical FHS type well, the drilling credit in Alberta is \$0.7 million, while it is \$0.9 million in East B.C., and \$2.2 million in West B.C. (see Figure 48). However, B.C. also makes a clear distinction with how the credit is applied to vertical wells versus horizontal wells. For the FHS highly deviated type well, the drilling credit applied in Alberta considers the measured depth of the well, regardless of its horizontal status. In B.C., this type of well is considered vertical, so only its true vertical depth is considered. This results in a credit of \$2.4 million in Alberta, \$0.9 million in East B.C., and \$2.2 million in West B.C. The assumed drill credits, resulting royalty rates, and economic results are shown in Figure 48.

Figure 48: Summary Table of the Economic Results

	Foothills (FHS)		Deep Basin Monach (DBS)				Deep Basin Monteith (DBMO)	
	Vertical	Highly Deviated	Vertical	Vertical (High Liq.)	Horizontal	Horizontal (High Liq.)	Vertical	Vertical (High Liq.)
Instantaneous IP (MMcf/d)	3.7	14.0	2.3	2.3	10.0	10.0	1.8	1.8
3-Month IP (MMcf/d)	2.9	10.4	1.5	1.5	5.8	5.8	1.7	1.7
EUR (Bcf)	3.5	7.1	3.1	3.1	6.2	6.2	1.4	1.4
Liquid Yield (bbls/MMcf)	5	5	10	50	10	50	10	50
RLI (years)	2.8	1.6	4.6	4.6	2.1	2.1	2.2	2.2
Well Cost (\$MM)	4.9	8.1	3.0	3.0	7.0	7.0	2.9	2.9
Operating Costs (\$/mcf)	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
AB Drill Credit (\$MM)	0.7	2.4	0.4	0.4	1.4	1.4	0.1	0.1
1st-Year Royalty Rate (%)	2.4	2.6	2.6	3.4	2.7	3.5	2.6	9.0
Before Tax NPV @10% (\$MM)	0.8	3.0	1.8	4.5	2.8	8.5	0.4	2.5
Before Tax IRR (%)	14.9	28.0	24.3	57.3	21.8	63.7	18.7	82.7
Profit Investment Ratio (Capex/NPV10)	0.2	0.4	0.6	1.5	0.4	1.2	0.1	0.9
Realised Break-Even Price (\$/Mcf)	4.26	3.78	3.57	2.58	3.81	2.78	4.23	3.02
BC East Drill Credit (\$MM)	0.9	0.9	0.3	0.3	0.9	0.9	na	na
1st-Year Royalty Rate (%)	0.0	5.4	0.0	5.0	0.6	5.9	na	na
Before Tax NPV @10% (\$MM)	1.1	2.7	1.9	5.3	3.1	10.3	na	na
Before Tax IRR (%)	16.7	25.1	25.2	61.0	23.0	71.3	na	na
Profit Investment Ratio (Capex/NPV10)	0.2	0.3	0.6	1.7	0.4	1.5	na	na
Realised Break-Even Price (\$/Mcf)	3.97	3.58	3.26	2.25	3.42	2.34	na	na
BC West Drill Credit (\$MM)	2.2	2.2	na	na	na	na	na	na
1st-Year Royalty Rate (%)	0.0	0.0	na	na	na	na	na	na
Before Tax NPV @10% (\$MM)	1.6	3.4	na	na	na	na	na	na
Before Tax IRR (%)	19.9	31.8	na	na	na	na	na	na
Profit Investment Ratio (Capex/NPV10)	0.3	0.4	na	na	na	na	na	na
Realised Break-Even Price (\$/Mcf)	0.32	0.42	na	na	na	na	na	na

Source: BMO Capital Markets

Liquid Yields

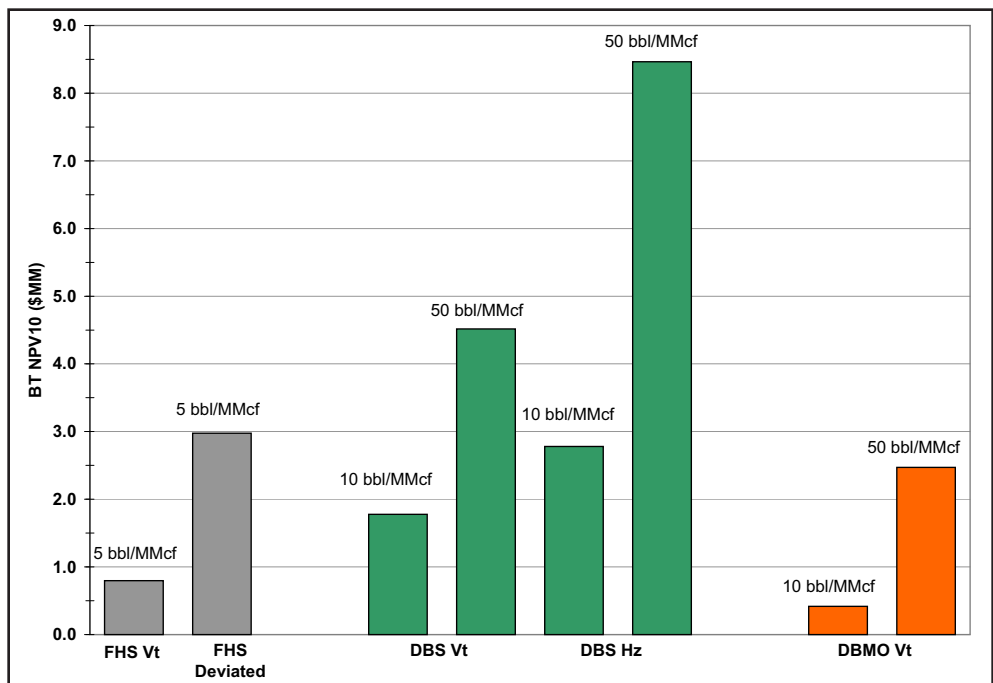
Since there is a liquids-rich fairway throughout the DBS and DBMO regions, the type wells here were evaluated with a liquid yield sensitivity. The FHS region was found to have liquid yields that were <10 bbl/MMcf, so a high-yield case here is not a likely outcome. Type wells were evaluated with liquid yield sensitivities of 0 bbl/MMcf and 50 bbl/MMcf to determine the impact this has on the economics parameters.

All of the relevant parameters that were used in each case are shown in Figure 48 along with the results. The focus of the following discussion and all related plots is primarily on the economic results of the Nikanassin in Alberta (outlined in red). This is because Alberta is the only jurisdiction that contains all of the type wells. The economic results in the two B.C. jurisdictions are presented in Figure 45 and are discussed briefly later. Figure 48 shows the Before Tax Net Present Value at a 10% (BT NPV10) discount rate for each type well case. The results of the high liquid yield assumption are shown because this sensitivity resulted in the greatest impact to the economic results. The FHS type wells are not presented with a high liquid yield, because the liquid analysis suggests that it is unlikely to encounter high yield in this region. As shown in Figure 49, all of the cases provide a positive BT NPV10.

Figure 50 shows the internal rate-of-return (IRR). The chart shows that the best return on capital invested will come from the Deep Basin high liquid yield wells, while the best return among the low liquid yield cases is the FHS Highly Deviated wells. In particular, the best IRR is with the DBMO high liquid yield well. The profit-investment ratio (PIR) (Figure 51) shows the same pattern with the Deep Basin, high liquid yield wells giving the best PIR. However, with this parameter, the DBS provides a better PIR than the DBMO. This is consistent with the fact that the DBS case has a much higher BT NPV10 than the DBMO case, even though the DBMO provides a better IRR.

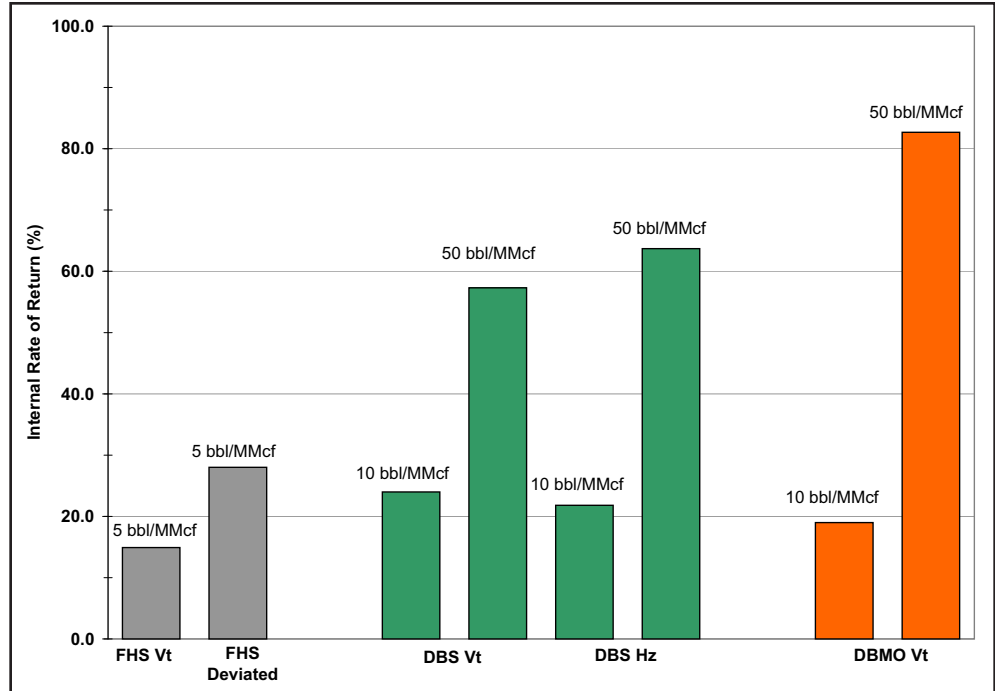
In addition, a breakeven price analysis was run for each case using the same price deck (Figure 52). That is, the ratio of oil-to-gas for 2011 is 17:1 (WTI = US\$85/bbl, HH = US\$5.00/mmbtu) so the resulting breakeven supply cost price (BESC) assumes a liquid price that is determined from this ratio. The resulting value represents a realised price, that is, there has been no accommodation for transportation costs, quality (Btu) adjustments, finding, development, & acquisition (FD&A), or general and administrative (G&A) costs. The price was determined using the “Supply Cost” report in Value Navigator. This uses an iterative procedure to determine the gas price that gives the project a \$0 BT NPV10. Again, this analysis shows that the best projects (which require the lowest breakeven price) are the Deep Basin, high liquid yield cases, both vertical and horizontal.

Figure 49: Calculated Net Present Value (NPV) @ 10% vs. FHS, DBS and DBMO Fairways and Well Type



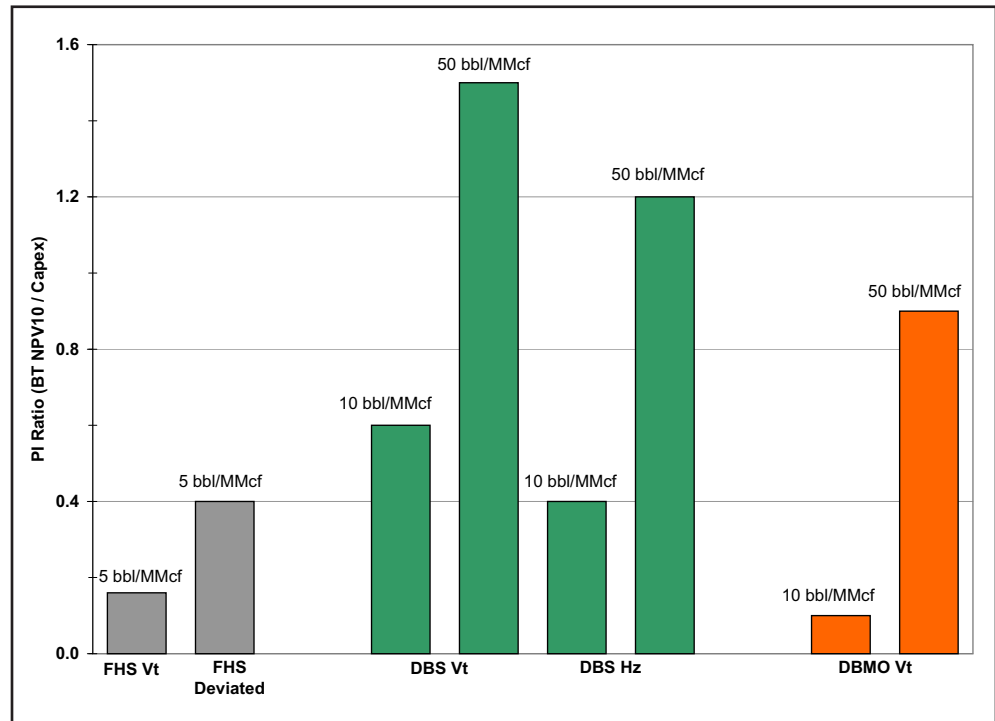
Source: BMO Capital Markets

Figure 50: Calculated Internal Rate of Return (IRR) vs. FHS, DBS and DBMO Fairways and Well Type



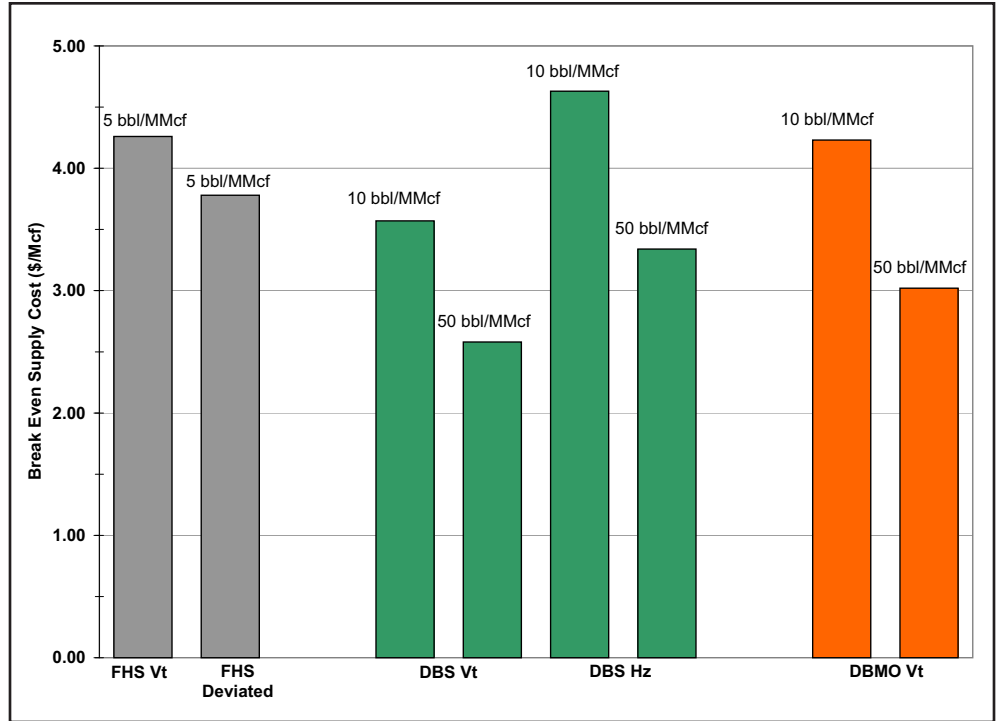
Source: BMO Capital Markets

Figure 51: Calculated Profit – Investment Ratio @ 10% (PIR) vs. FHS, DBS and DBMO Fairways and Well Type



Source: BMO Capital Markets

Figure 52: Calculated Breakeven Supply Cost (BESC) vs. FHS, DBS and DBMO Fairways and Well Type

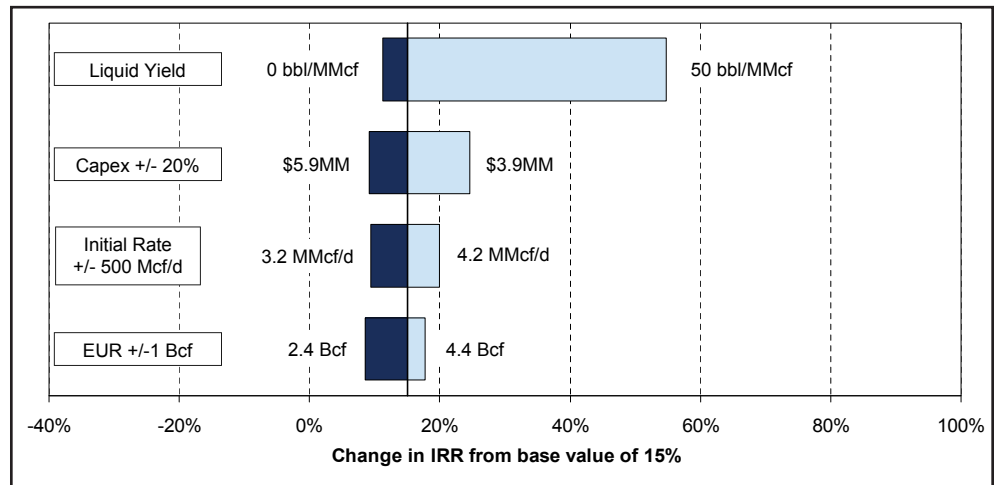


Source: BMO Capital Markets

Tornado Plots (Economic Sensitivity Analysis)

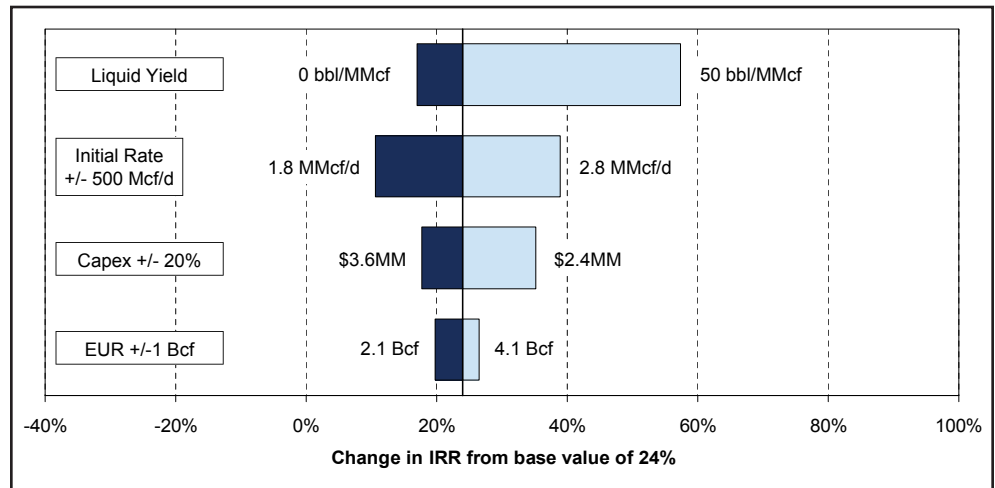
There are four input parameters used in the economic cases that are most likely to affect the outcome. These are: 1) Liquid Yield; 2) Capital Expense; 3) Initial Rate; and 4) EUR. Figures 53-57 highlight the impact of these four parameters on the economic base cases. In each case, the liquid yield has the biggest impact on the economic outcome. For example, the DBS Vertical Type well has a base IRR of 24% with 10 bbl/MMcf to a 57% IRR with 50 bbl/MMcf. Conversely, the EUR is generally the input parameter that least impacts sensitivity on the type wells. The exception to this is the DBMO, where the EUR is the second most important variable. However, this type well has one of the lowest RLI at 2.2 years, and the lowest EUR at 1.4 Bcf, so any change to the EUR will have a greater impact than it will on type wells with longer RLIs.

Figure 53: IRR Sensitivity FHS Vertical



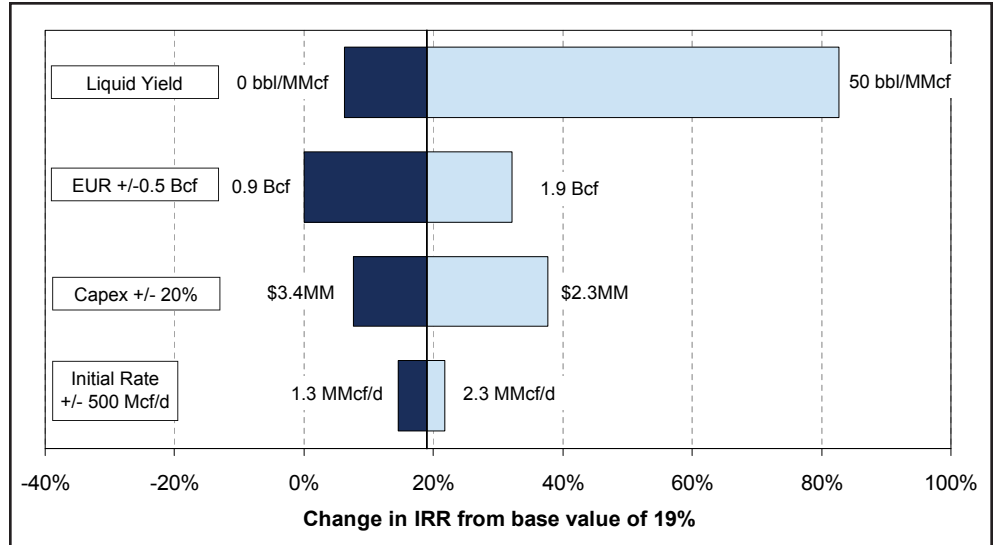
Source: BMO Capital Markets

Figure 54: IRR Sensitivity DBS Monach Vertical



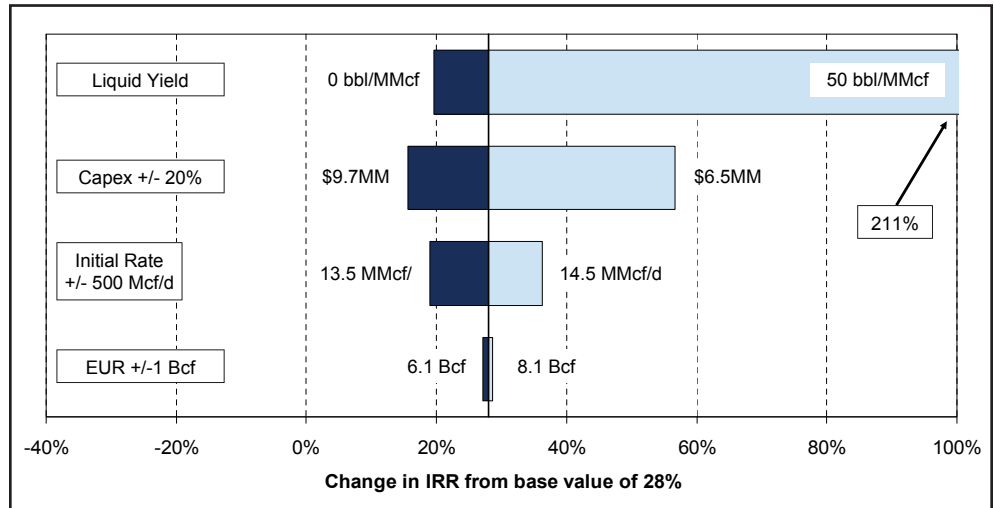
Source: BMO Capital Markets

Figure 55: IRR Sensitivity DBMO Monteith



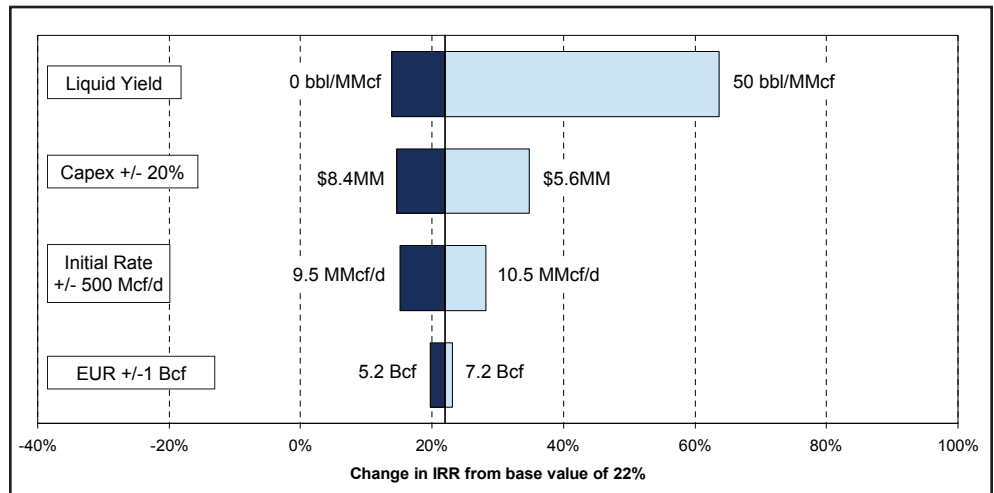
Source: BMO Capital Markets

Figure 56: IRR Sensitivity FHS Highly Deviated



Source: BMO Capital Markets

Figure 57: IRR Sensitivity DBS Monach Horizontal

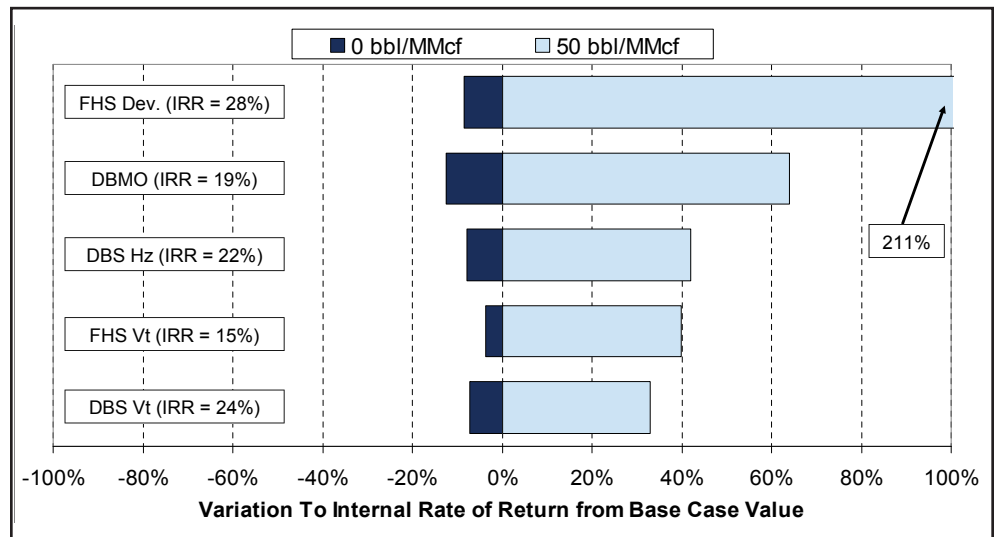


Source: BMO Capital Markets

Figures 58 – 61 demonstrate the impact of the sensitivity variables on the five base type wells. Initial rates were modified in each type well as follows: the instantaneous rate was adjusted up or down, while keeping the slopes of the first two segments constant. In other words, the initial rate for the starting point of each decline segment was adjusted by the same amount. Figure 58 (IRR vs. Liquid Yield) demonstrates the impact of liquid yield on the IRR for each type well. However, while a FHS deviated well is the most impacted by the liquid yield, high liquid yields are unlikely in this area.

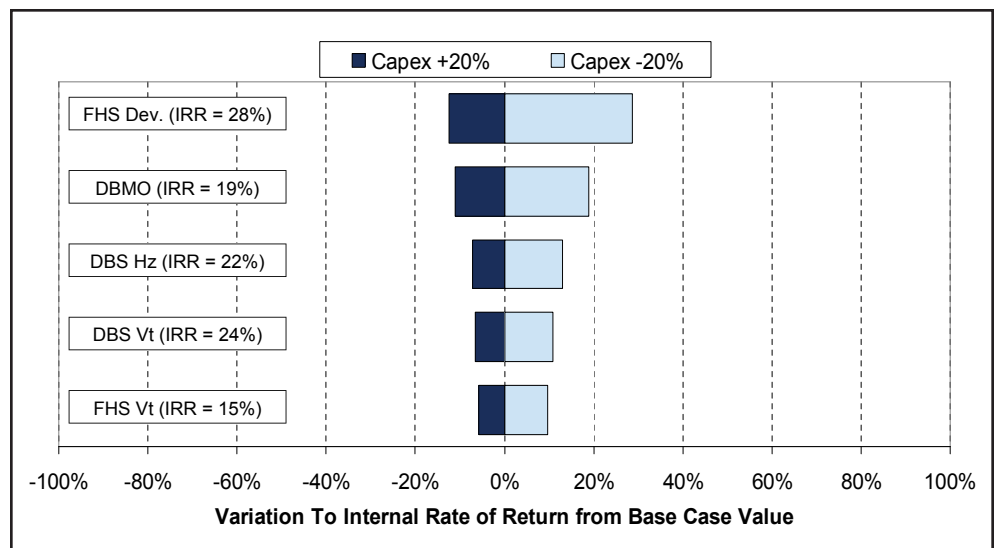
Figure 59 (IRR vs. CAPEX) shows the impact of varying the capital requirements of each type well. All the type wells were impacted significantly by capital expenditures, implying that adjustments to capital expenditures will have more significant impacts on economic results than either IP or EUR.

Figure 58: IRR Sensitivity to Liquid Yield



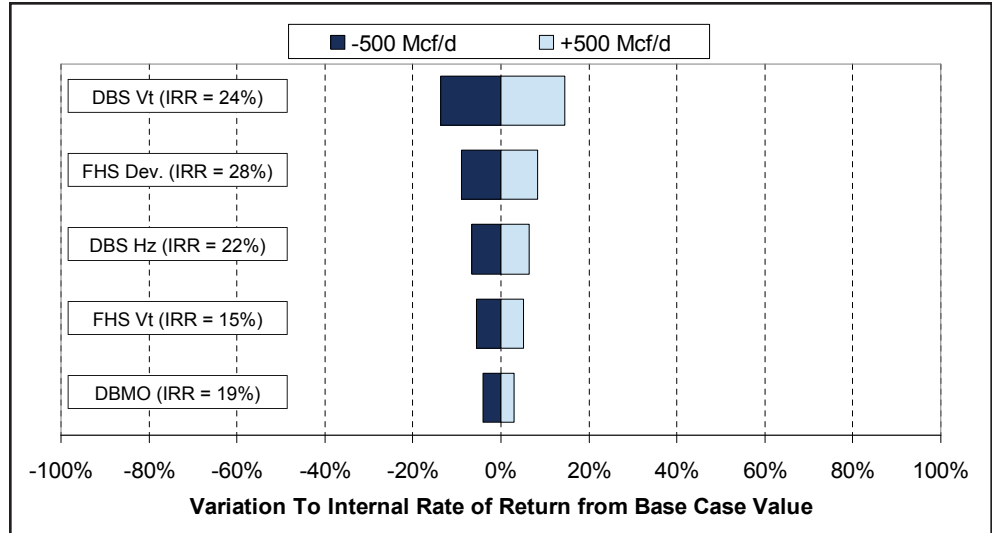
Source: BMO Capital Markets

Figure 59: IRR Sensitivity to Capex



Source: BMO Capital Markets

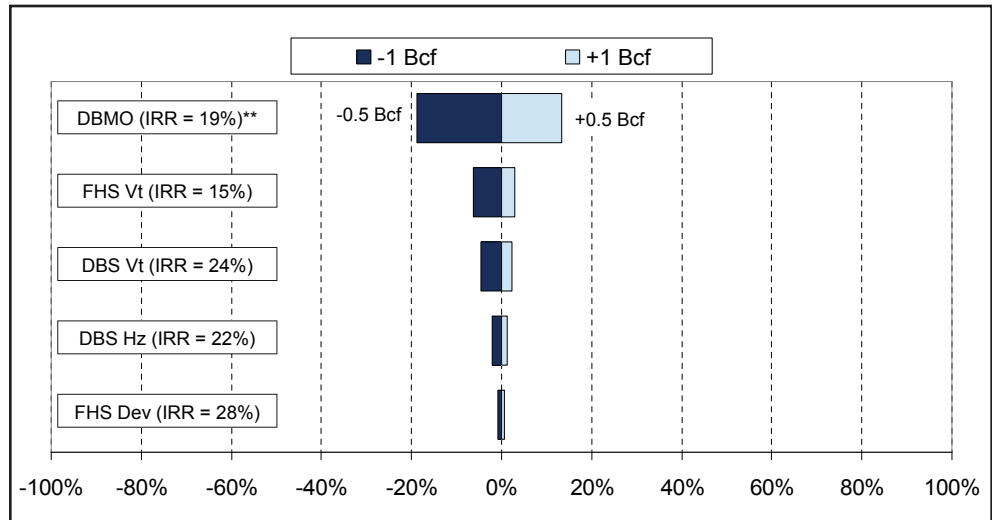
Figure 60: IRR Sensitivity to Initial Rate



Source: BMO Capital Markets

Figure 61: IRR Sensitivity to EUR

** DBMO used a sensitivity of +/- 0.5 Bcf. All other cases used +/- 1.0 Bcf.



Source: BMO Capital Markets

Variation in the IP of each type well is shown in Figure 60. The effect of variations in the IP is to accelerate or decelerate the reserve recovery (since the EUR is held constant). The IRR of the DBS Vertical well is most sensitive to variations in IP. In this situation, increasing the IP of this well by 500 Mcf/d increases the IRR from 24% to 39%. This reason for this can be seen in the reserve life index (RLI): in this case, the RLI decreases to 3.7 years from 4.6 years, which shows that the reserve recovery has been accelerated, thus increasing the NPV. Similar results are shown for each type well.

Figure 61 (IRR vs. EUR) shows the impact to the rate of return as the EUR is adjusted from its base case. Each of the type curves was adjusted by +/-1 Bcf, except for the DBMO. Since the EUR on this type well is 1.4 Bcf, it is unreasonable to vary its EUR by this much so a sensitivity of +/-0.5 Bcf was used instead. In each case, the EUR was adjusted accordingly simply by moving the end point of the final decline segment. That is, the first two decline segments were left untouched and only the final segment was adjusted. The effect of this is to demonstrate the impact to the NPV by the tail portion of the reserves. As previously mentioned, the DBMO case shows the greatest sensitivity to this variable. Conversely, the case that is least sensitive to changes in its EUR is the FHS Deviated well. In general, it is expected that the NPV of wells with higher RLIs will be less impacted by the tail of their reserves than wells with shorter RLIs. The important point to note is that, in general, the sensitivity to EUR is not as significant to the economics as the sensitivity to other input variables.

Summary and Conclusions

- The Nikanassin Formation has the potential to become an important unconventional Deep Basin Resource Play in the western Canada Sedimentary Basin.
- The three geologically defined Nikanassin fairways that demonstrate the best upside potential are:
 - ◆ The Nikanassin Foothills High Deliverability Structured Fairway (FHS – Figure 1) characterized by:
 - High deliverability with IP (three-month average) = 3.7 (vertical) to 14MMcf/d (deviated)
 - EUR ~ 3.5 (vertical) to 7.1(horizontal to highly deviated) Bcf/well
 - Commonly over-pressured with a low gas liquids content (<10 bbl/Mcf)
 - Calculated IRRs = 15–32%; PIR = 0.2–0.4; and BESC = \$3.47–4.26/Mcf.
 - ◆ The Upper Nikanassin Monach and Lower Nikanassin Montieth Deep Basin – Stacked Fairway (DBS – Figure 1) characterized by:
 - High deliverability with IP (three-month average) = 2.3 (vertical) to 10 MMcf/d (horizontal)
 - EUR ~ 3.5 (vertical) to 7.1 (horizontal to highly deviated) Bcf/well
 - Commonly under-pressured with a gas liquids content <10 bbl/Mcf in the western/deeper portion of the fairway, increasing to liquids-rich (~10 to 75 bbl/Mcf) toward the east of the fairway
 - Calculated IRRs = 9–61%; PIR = 0.4–.7; and BESC = \$2.25–4.68/Mcf

- ◆ The Nikanassin Deep Basin – Montieth Fairway (DBMO – Figure 1) characterized by:
 - Lower deliverability with IP (three-month average) = 1.8 MMcf/d
 - EUR ~1.4 Bcf/well
 - Commonly under-pressured, with localized areas of overpressure, and a gas liquids content 10 to 75 bbl/Mcf
 - Calculated IRRs = 19–82%; PIR = 0.2–0.8; and BESC = \$3.02–4.23/Mcf.

The key production and economic parameters that differentiate the value between the various Nikanassin Fairways include: Initial Production (IP), Estimated Ultimate Recovery (EUR), Liquids Content and Capital costs. These parameters allow for the calculation of Internal Rate of Return (IRR) and Breakeven Supply Cost (BESC – Figure 4). In terms of average 30-day IP, the FHS Highly Deviated wells have the largest IPs, (~10.4 MMcf/d), followed by DBS HZ wells (~6 MMcf/d), FHS vertical wells (2.9 MMcf/d) and DBMO/DBS vertical wells (1.5–1.7 MMcf/d). Nikanassin EURs vary from 7.1 Bcf/well for FHS Highly Deviated wells, ~3.5 Bcf for FHS vertical wells, ~3.1 Bcf for DBS and ~1.4 Bcf in the DBMO fairway.

The Before Tax Investment Rate of Return ratio (IRR %) varies considerably across the different fairways and political jurisdictions because of cost and royalty/tax burdens. Figure 3 shows the comparison of Before-Tax IRR % across the various type curves/fairways studied in this report. The highest IRRs are found in the DBMO Vertical (Wet or high liquid content – Figure 5) fairway (83%), followed by B.C. East DBS Vertical (wet), B.C. East DBS HZ (wet), AB DBS Vertical (wet) and AB DBS HZ (wet) with 50–60% IRR. The common variable for these +50% IRR wells is the value that comes from the presence of high amounts of gas liquids in the production stream. The key risks are being able to manage potential reservoir damage and underpressured nature of these reservoirs, and to obtain high enough deliverability to effectively produce the liquids. After presence or absence of gas liquids, deliverability and time to payout is the next most important criteria. The Alberta and BC FHS deviated wells have IRRs of 20–32%. DBS wells with low liquid content have IRRs of ~25%.

The analysis presented in this report clearly demonstrates that “**Not All of the Nikanassin is Created Equal**”. Presently, the choice in the Nikanassin is between targeting naturally fractured high deliverability dry gas in the FHS and western DBS fairways versus Deep Basin liquids-rich gas toward the subcrop edge of the DBS and into the DBMO fairway. When the technological issues with reservoir sensitivity can be overcome in the off-structured position in the DBS and FHS areas, then the large resource base attributed to the Nikanassin will become a major tight gas sand resource play in the Western Canada Sedimentary Basin.

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