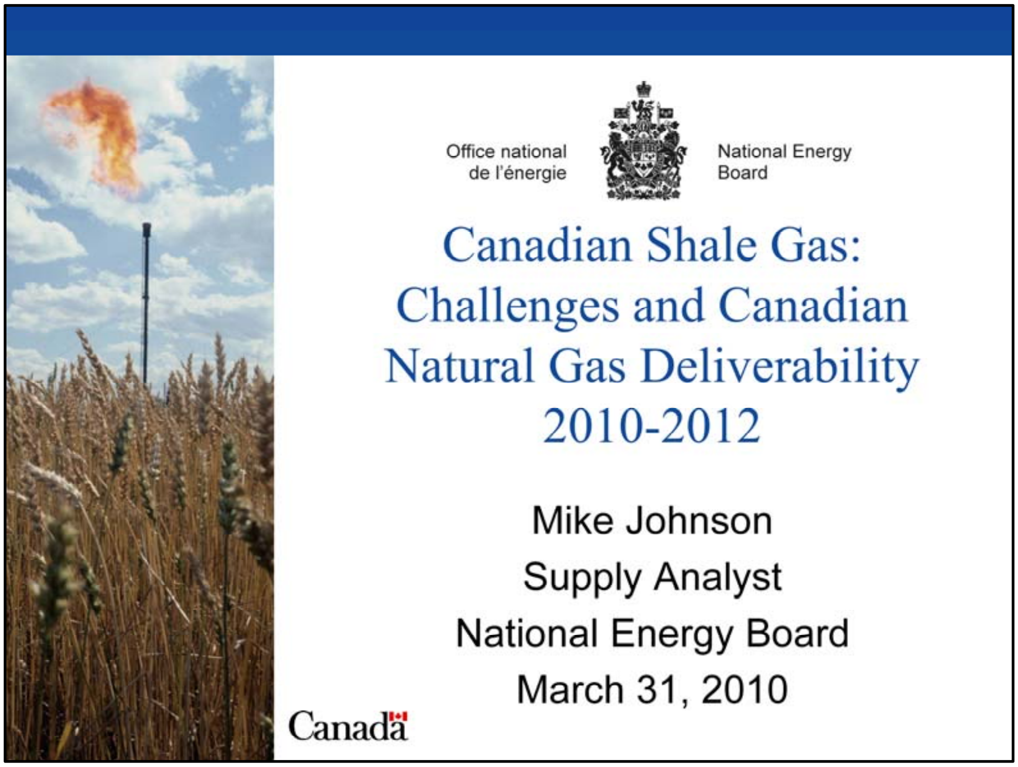
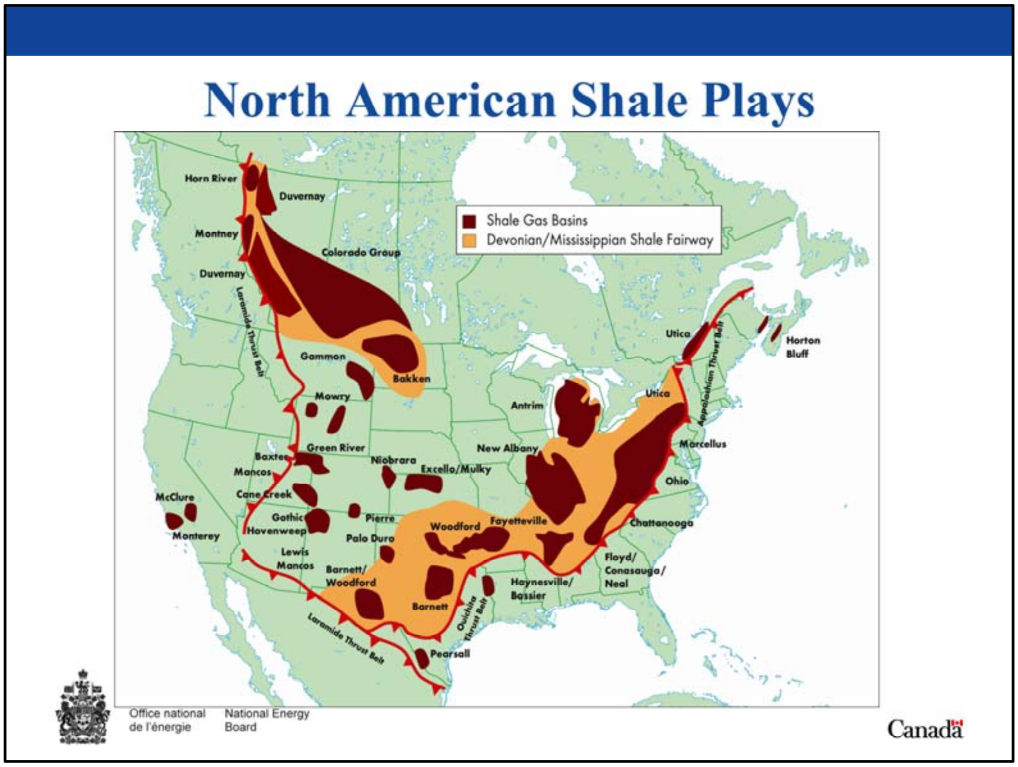


Part of the NEB's mandate, aside from our regulatory role in pipeline and electricity infrastructure, is to inform the public of energy matters and that's the reason I'm here today to discuss shale gas.

Just a warning: I'm a geologist by trade and not an engineer. Further, I'll be referring to a very recently published NEB publication (our Short Term Deliverability Report 2010-2012 was released this morning) put together by our Gas Team for which I had some input, but the lion's share of work was performed by others: namely Scott Treadwell, now at Macquarie, and Melanie Stogran and Paul Mortensen.

Importantly, much of what I discuss here today are opinions of my own and not necessarily shared by the Board. And, nothing of what I say here should be construed as pre-judging applications that are currently in front of us or that may come before us in the future. As the Board is a quasi judicial tribunal, it's the Board Members who make the decisions, not staff . And the Members will make their decisions based on the record of evidence before it on any particular application after carefully considering what all parties to the proceeding have to say.

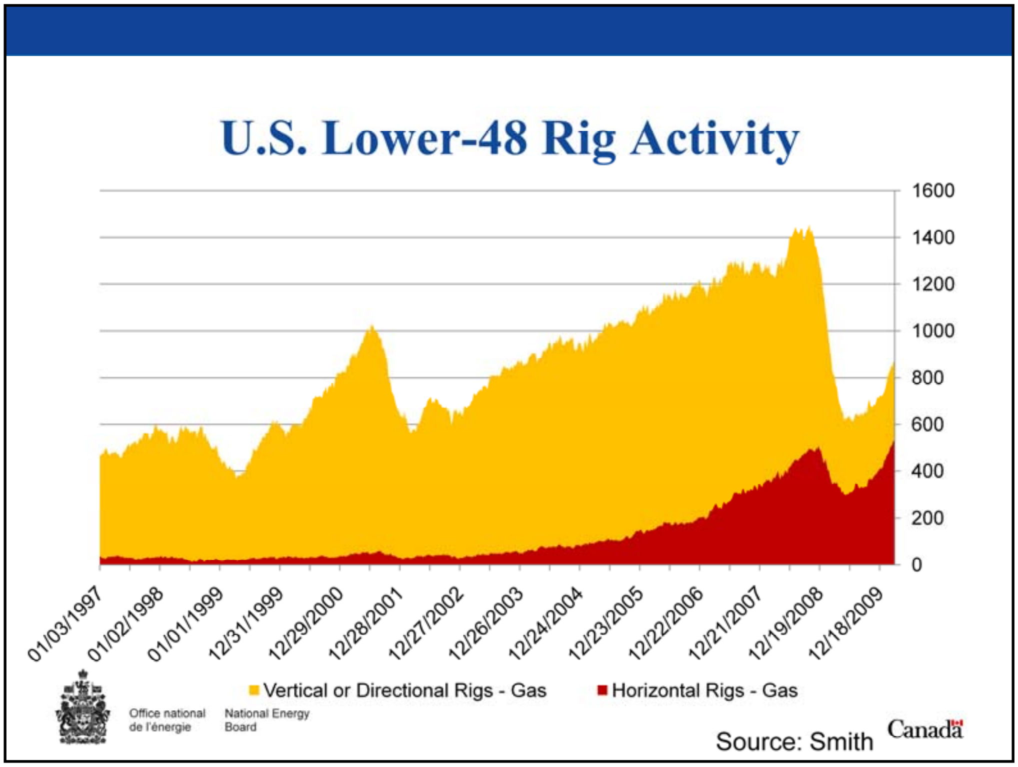


Historically, major shale gas development in the U.S .had been occurring in the Barnett Shale adjacent to Fort Worth TX over the past few years.

More recently, there has been significant activity in the Fayetteville, Woodford, Haynesville, and Marcellus shales. This had helped push U.S. production above 58 Bcf/d, a level not seen since the 1970s, although it's fallen back since then.

Canadian activity in shale gas, so far, appears to be restricted mostly to the Montney and the Horn River Basin. The Utica and Horton Bluff shales of Quebec and the Maritimes, respectively, are only in the experimental stage and there is no sales-gas production to date.

And how things change: we released a version of this map in November of 2009. Since then, the Duvernay Shale has been added to the Canadian shale gas family as some significant land-sale activity of December 2009 and March 2010 appears to have been focused on it.



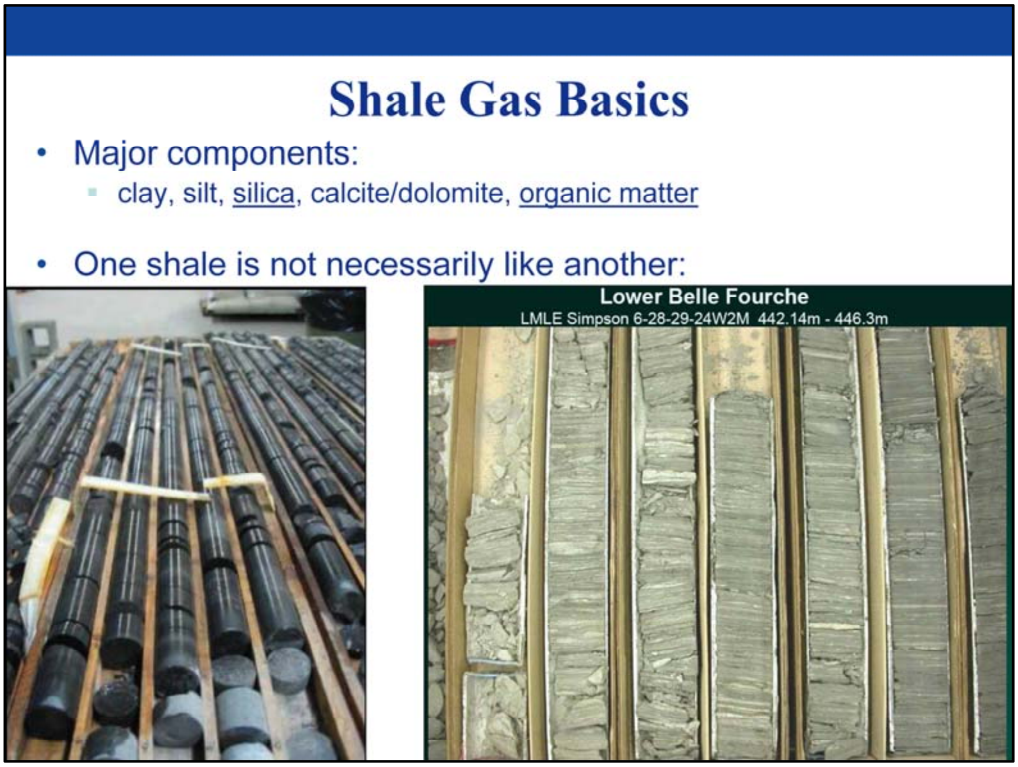
One indicator of this shift towards shale gas and how it has remained resilient in the face of low gas prices is the drilling activity in the U.S.

There has been a steady climb in the U.S. Lower-48 gas-targeted horizontal rig count since activity bottomed out in early 2009. Vertical drilling, however, has not shown much of a recovery.

By early March 2010, the number of horizontal rigs chasing gas in the U.S. surpassed the previous high of mid-2008. Now over 60% of those working rigs in the US targeting gas are drilling horizontally. Further, it appears that, even with a lower total rig count, this smaller fleet of active rigs is doing a significant job in tempering production declines.

Prices have improved from the sub US$3 prices of September 2009, which is likely responsible for some of the resurgence; however, there are other likely factors as well. Leases in the U.S. often have shorter terms than Canadian leases and require more drilling to be kept. Rather than lose leases, its widely suspected that operators have been choosing to drill uneconomic wells to maintain their land inventory. Unfortunately, what's being drilled to earn money and what's being drilled to keep land is near impossible to capture.

Finally, various reports indicate about 40% of North American natural gas production was hedged at over $6 for 2010, which would lessen the impact of low prices.

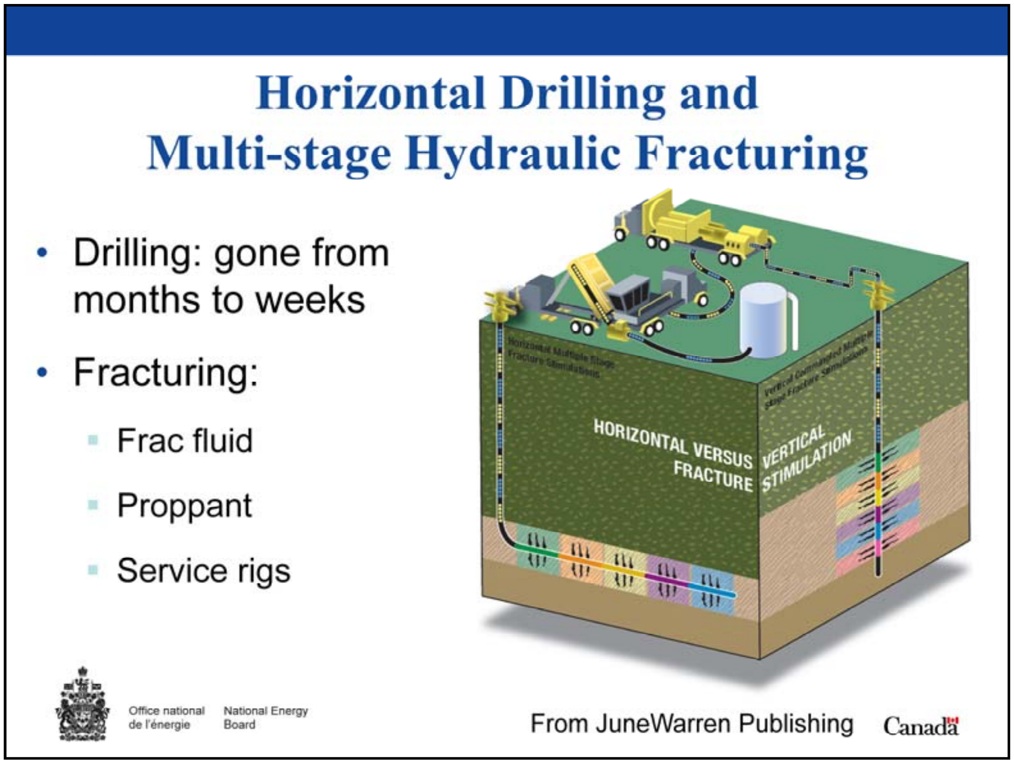


What is a shale? That depends upon who is defining it, but many consider it to be a fissile mudstone. Fissile refers to the rock's ability to break along old bedding surfaces, coming off in slabs or sheets or flakes, and mudstone refers to the grain size, that it's dominantly silt-sized or clay-sized sedimentary particles. Alberta regulations define shale as: "a lithostratigraphic unit having less than 50% by weight organic matter, with less than 10% of the sedimentary clasts having a grain size greater than 62.5 micrometres and more than 10% of the sedimentary clasts having a grain size less than 4 micrometres."

Needless to say, there are considerable variations to the components of shale. Typically, gas shales are silica rich (50 to 65% looked at as "optimal" as in the Barnett and the Muskwa Shale of the Horn River Basin), which makes them brittle and susceptible to hydraulic fracturing; however, some shales are relatively calcite rich (like the Utica Shale of Quebec), which is still brittle, but less so than silica. The Montney is more of a hybrid tight-sand/shale play, with a relatively high amount of sand and is filled with silt rather than having the bulk of its silica present as cement like in other shales. While the BC MEMPR considers the emerging Montney mudstone resource to be shale, the ERCB doesn't.

Then there is the source of gas in the shale: "thermogenic" gas was generated by intense heat and pressure when the shale was buried at great depths, where methane was essentially cracked from the organic matter. This same thermogenic process can also crack off larger hydrocarbons like oil and NGLs if the pressure and heat is less intense, which leads to some shales being liquids rich (such as in the Eagleford in Texas and the Montney to a lesser extent here or even oily as in some parts of the Barnett). Further, bury your shale deep enough and there is the potential to generate carbon dioxide, like in the Horn River Basin. In shallow shales (less than a km), there is potential for "biogenic" gas because temperatures can be low enough that bacteria can consume the organic matter and release methane as a byproduct. NGLs aren't typically generated with shallow gas. But, you can also have both if a deeply buried shale becomes shallow as it is unroofed. This is theorized to have occurred in the Antrim Shale of the Michigan Basin and might also be occurring in shallow sections of the Utica in Quebec, where one shallow test produced oil.

Finally, there is formation pressure. As the gas is generated, some escapes, but some doesn't, which leads to an internal buildup of pressure in the shale: overpressuring. This is important for several reasons. It helps with the frac, because pressures are already closer to the breaking point (it's theorized that conventional reservoirs are charged when gas and oil migrate out of these shales when pressures get so high that the rock fractures itself). Further, overpressuring means there is more gas packed into the rock, meaning larger gas in place, as well as the formation has a greater ability to push back some of the frac fluid that's been pushed into it and begin flowing. Many gas shales are overpressured (like the Montney and Horn River Basin); however, some aren't (like the Fayetteville, which is normally pressured).



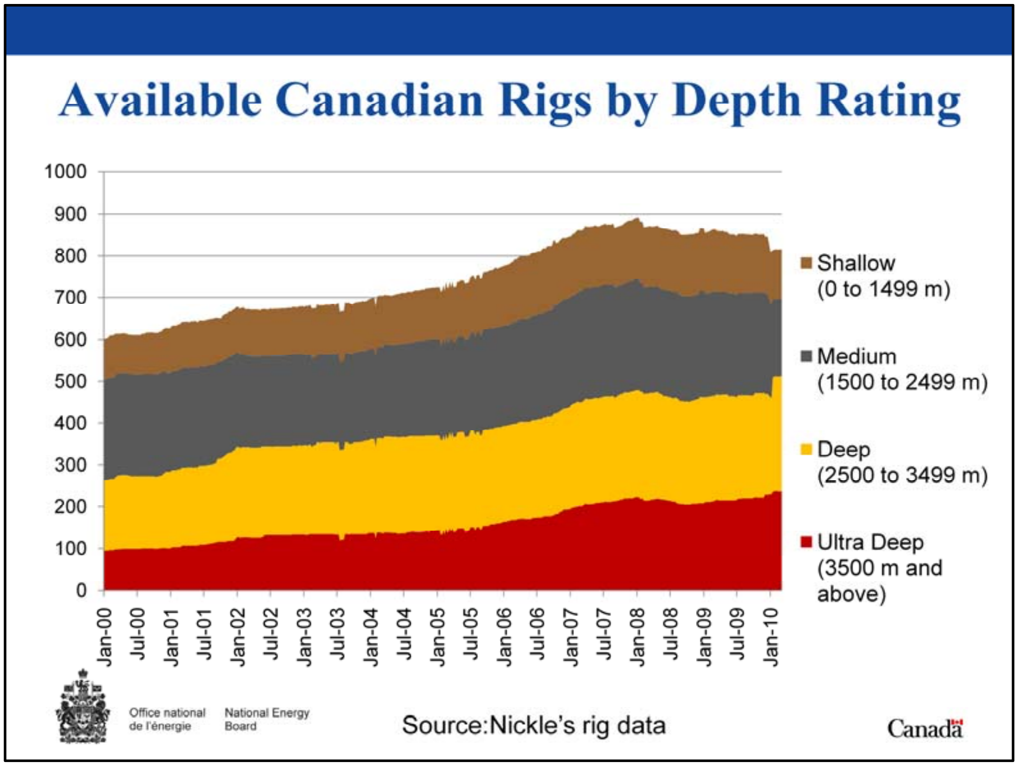
And, of course, there is one similarity that has apparently connected most of the shale-gas plays. The advancement and combination of two technologies that have been around for a *long* time and have made this shale-gas revolution possible: horizontal drilling and hydraulic fracturing.

Thanks to advances in drilling, deep wells with long horizontal reaches can be drilled in a few weeks versus the months that would have been required a few years ago and this time is shrinking as an increasing number of horizontal legs are drilled from a shared vertical borehole, saving more time. Many new Montney wells are taking just two to three weeks. In the Horn River Basin, operators are talking about drilling 18 wells from a single pad.

Thanks to advances in multi-stage hydraulic fracturing, operators can complete wells with between one to two fracs per day, thus putting a well with 15 fracced zones on production after only a week or two of stimulation. And service companies are pushing boundaries by increasing the number of fracs they can do per well, recently indicated to be 24 from what had only been twelve just two years ago.

But there are challenges. Significant amounts of raw material are required to stimulate shale-gas wells. Recent presentations from one operator indicate that about 1 million gallons of water is required for each frac stage in the Horn River Basin. Given that operators are planning to fracture more than 20 stages per well, approximately 20 million gallons of water would be required. Having said this, the same operator has also indicated that they are testing the use of brackish water recovered from shallower formations instead of fresh water, reducing their freshwater-use footprint. Further, in the Montney, carbon dioxide is commonly used in fracs along with water, reducing water usage there as well. There have also been recent attempts to recycle water recovered during flow testing from the Montney.

An important question, of course, is: how many drilling rigs are there capable of drilling these wells in western Canada?



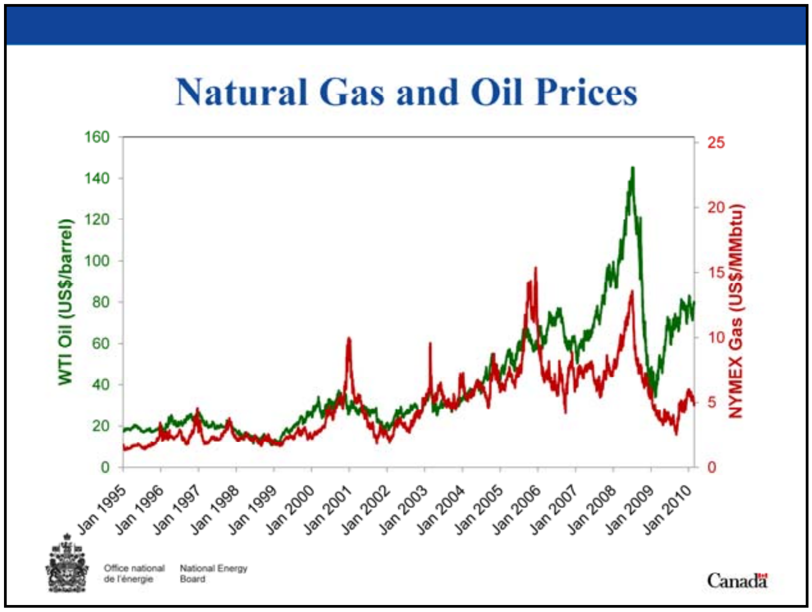
Overall, rig capacity in Canada has been shrinking after peaking at near 900 rigs in early 2008. By early 2010, that number had dropped to just over 800. The Devil is in the details, however.

While the number of Shallow and Medium rated rigs shrank, the number of rigs rated for Deep drilling and Ultra Deep has increased beyond their early 2008 highs. Currently, there are 223 rigs rated for drilling Ultra Deep wells and 275 for Deep wells. The number of rigs capable of drilling 3500 m can be considered those capable of drilling Montney horizontal wells based on well length. However, if a 3900 m cutoff is used instead of 3500, the number of Ultra Deep rated rigs falls by more than half to 108. The 3900 m number is important because that's the length of wells likely to be drilled in the Horn River Basin.

Through the 2010 winter-drilling season, Ultra Deep rated rigs were almost 75% utilized. This is exceptionally high for the years after 2006, where winter-drilling utilization was normally 65%. Further, while spare equipment may exist at 75% utilization, whether there are people to staff these spare rigs is another matter.

So, it's hard to say what will happen. Yes, the number of rigs capable of drilling these deep wells is growing; however rig utilization is still high. But what we're also seeing is operators drilling over-rated, with about 20% of Deep-rated rigs drilling long horizontals on average about 450 m longer than what they were rated for and it wasn't uncommon for some of this subset to be drilling near a kilometre or more over, especially in areas associated with Montney development. Thus, there may be more rigs available for drilling these long wells than based on raw ratings alone. Part of this is ratings are largely developed for TVDs and not necessarily measured depths including long horizontal legs. Finally, as discussed, the time required to drill these wells is shrinking, meaning more wells can be drilled with a single rig.

Of course, there may be other challenges.



Other challenges include competition for sets of shared resources because, after all, the upstream natural gas industry is not a closed system.

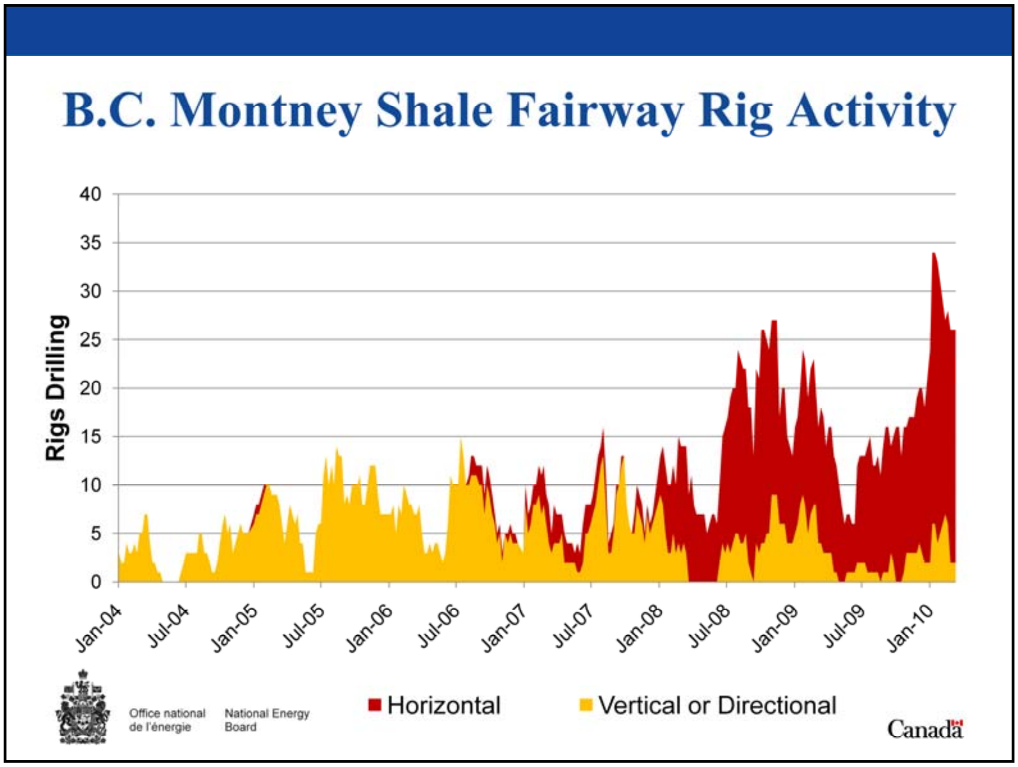
This is a plot of oil versus gas prices, converted for energy equivalence (~ about 6 Mcf of gas per barrel of oil)

Beginning in January 2006, there has been a disconnect between oil and North American gas prices per energy equivalence. Since early 2009, oil prices have risen towards $80/bbl while gas has remained in the $4-5/mcf range.

In other words, oil is being valued at 2 to 3 times the energy equivalent amount of gas and, since the beginning of March, the valuation has been above 3 times. Which, of course, encourages investment in oil over gas.

Thus, those chasing gas may lose out on capital that is steered towards oil.

Further, those chasing shale gas may find themselves competing for equipment with those chasing oil in the oil-based resource plays of the Bakken and the new Cardium, because shale gas and these oil plays essentially require the same technology: drilling rigs that can drill several kilometres of hole and completion equipment capable of multi-stage fraccing . However, as discussed, there may not be a large spare number of rigs to go around for any increase in activity, thus supply costs may rise. Putting those chasing gas at further disadvantage is that those operators chasing oil can likely afford to pay more for field equipment, which could raise supply costs further.



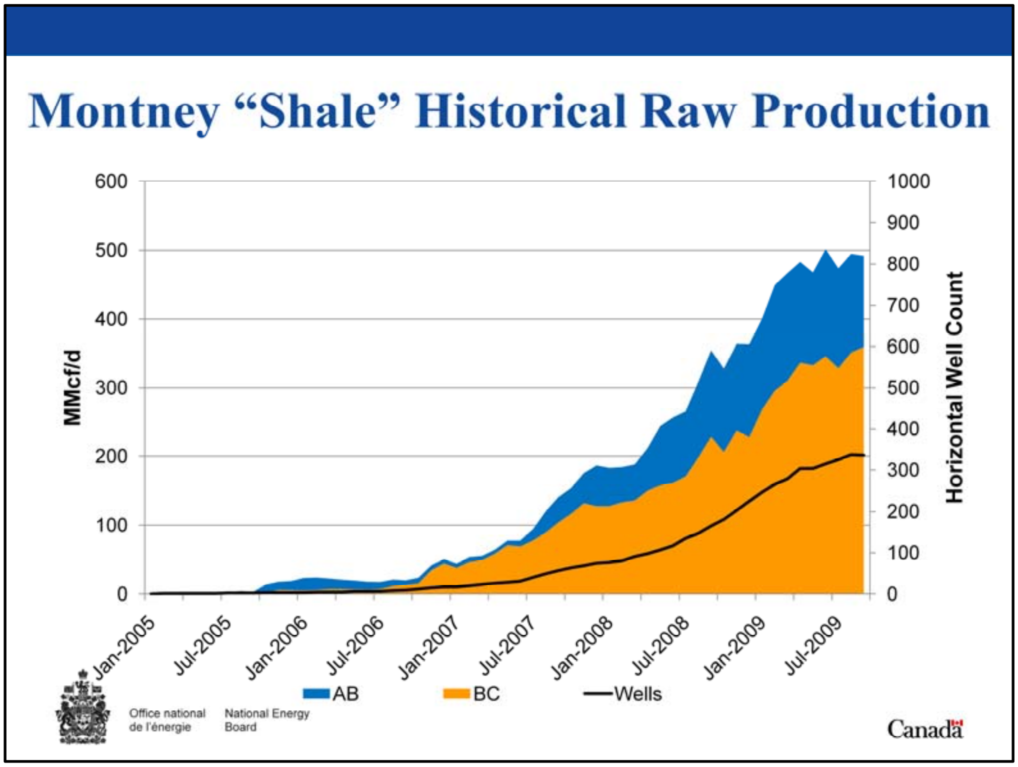
So what have we seen so far?

In the Montney, while activity in the summer of 2009 had been reduced compared to the summer of 2008, likely due to lower prices of the same time period, activity has since exceeded past highs by early 2010 with over 30 rigs drilling before Spring breakup.

There is also a significant reduction in vertical rigs, which indicates there is a shift away from experimentation and towards development.

Given the appearance that Montney activity has remained relatively robust whereas there has been a significant decrease in activity throughout much of the WCSB otherwise, it could be interpreted that Montney gas is profitable to exploit even at currently low prices and this is consistent with what some operators are saying. Another possibility is that operators hedged their production at higher prices.

Finally, to put these numbers into perspective, the Haynesville Shale had about 80 to 90 horizontal rigs drilling as of January 2010.

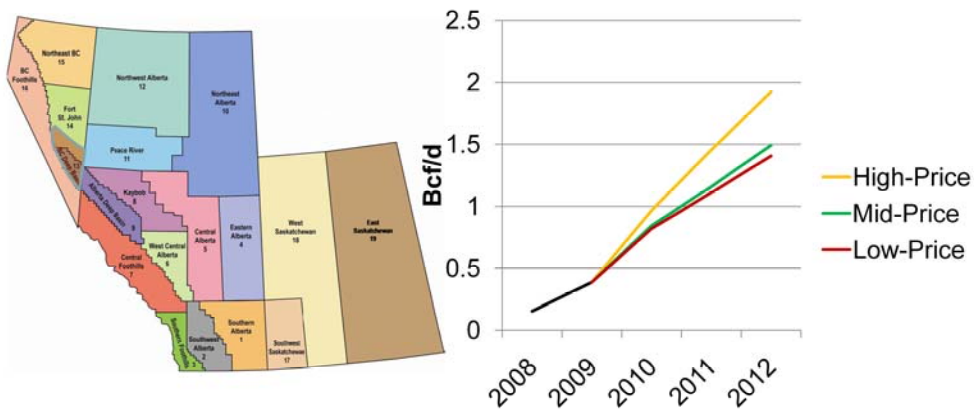


Historical production from Montney shale, keeping in mind that the ERCB doesn't consider Montney mudstone to be classified as shale like the BC MEMPR does.

As of September 2009, raw gas production from horizontal wells in the Montney had climbed to almost 500 MMcf/d from almost 350 wells. While British Columbia forms the lion's share of this, Alberta's production is growing as well.

Of importance: near half of Alberta's Montney horizontal-well production is classified as commingled, thus, from raw data, it can be difficult to attribute wells to the formations they're producing from.

Montney Deliverability



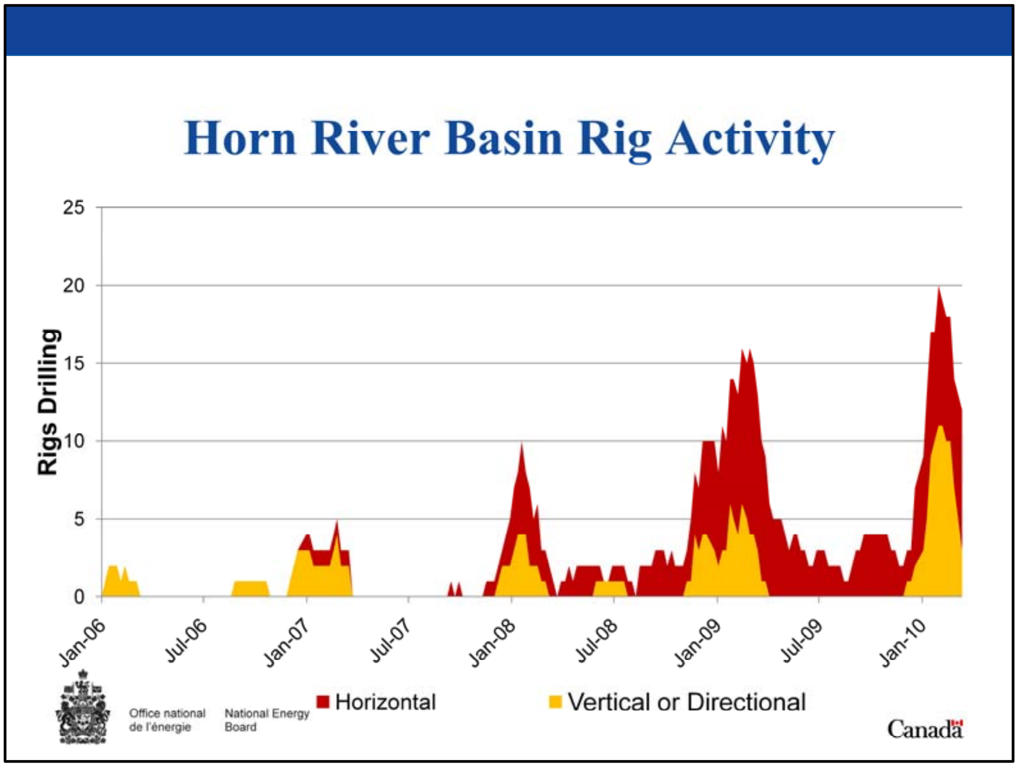
Price	2009	low			mid			high		
		2010	2011	2012	2010	2011	2012	2010	2011	2012
US$/MMbtu	3.70	4.25	4.75	5.25	5.50	6.00	6.75	6.50	7.00	7.75
Wells drilled	150	190	235	255	210	250	290	320	360	400

So what do we see going forward?

In terms of gas prices, the mid-case is based on a balanced market of increased demand during economic recovery and decreasing North American production in the short term. The low-case is essentially driven by a slow economy and little demand growth The high case is driven by robust economic expansion and LNG that can't entirely satisfy markets. In all three cases, price increases over the three years of the modeling are driven by increases in demand and cost escalation of development of the resource. Also, hedging of about 40% of the resource in 2010 has been taken into account and reduced variability in forecasts for that particular year.

The methodology for NEB production forecasts is relatively simple: based on expected exploration budgets and prices for gas, as well as how much it costs to drill wells, we estimate how many drilling days there are in a year and, from that, how many wells are drilled. Once you have the number of wells drilled, by using production profiles, we begin to estimate production.

For the Montney, using the prices set out in the table, we expect production growth in all price scenarios, reaching 1.5 Bcf/d by 2012 for the mid case. The high case would have production climbing to near 2 Bcf/d by 2012. The low case would be slightly less than the mid-case.



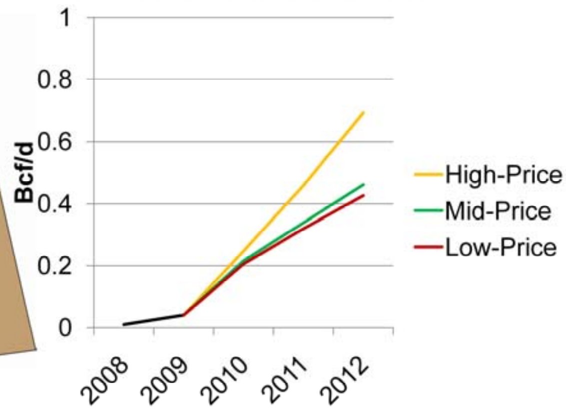
Horn River Basin rig activity has also remained relatively robust, albeit with a small twist: a surge in vertical rigs operating in the area has pushed the overall activity higher than in early 2009. If you look carefully though, the number of rigs drilling horizontally has actually slightly decreased.

There may be a few reasons for this drop in horizontal drilling. First, it's remote and the low gas prices moving into 2010 may not have been enough to spur significant development. Second, after strong activity in early 2009, where operators gathered significant amounts of technical information about drilling and completion methods, they may still be evaluating the data and deciding how best to best exploit the resource. The vertical drilling activity likely indicates the same thing: that vertical holes are still be drilled and tested before additional horizontal wells are drilled. Further, vertical activity potentially represents pilot holes from which multi-lateral horizontals might be drilled the following season.

There is also strong seasonality to the development of the resource, limiting it largely to the winter months so far. While some operators have announced plans for year-round drilling from all-season drilling pads, it's not particularly well reflected in this data. With the difficult logistics of transportation and onsite storage of considerable amounts of cement, casing, water, frac sand and other material over non-winter months, it will be interesting to see how plans for year-round drilling pans out in the future.

To put these numbers into perspective, again, the Haynesville Shale had about 80 to 90 horizontal rigs drilling in January 2010.

Horn River Basin Deliverability



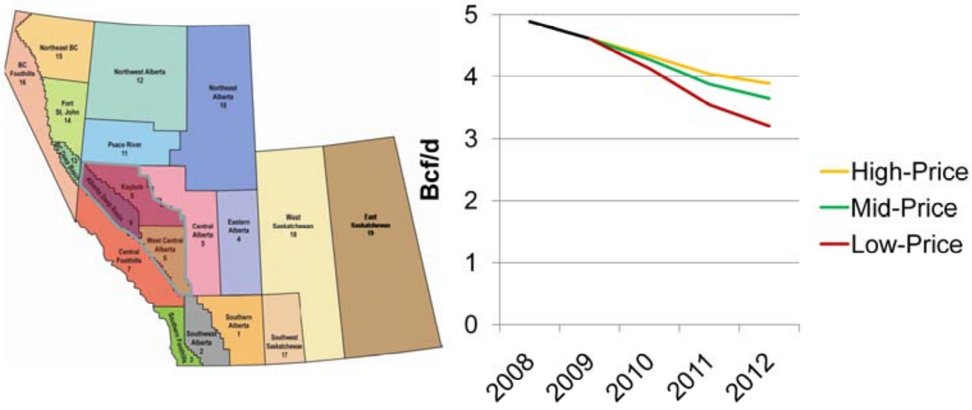
Price	2009	low			mid			high		
		2010	2011	2012	2010	2011	2012	2010	2011	2012
US$/MMbtu	3.70	4.25	4.75	5.25	5.50	6.00	6.75	6.50	7.00	7.75
Wells drilled	30	65	75	85	70	80	95	85	125	160

Like the Montney, in all three of our price forecasts we expect production to grow towards 2012. In our mid-case, we expect production to grow towards 0.5 Bcf/d and our high case indicates production may grow to just over 0.7 Bcf/d. Like the Montney, the low case is slightly less than our mid-case. It's hard to know if development will remain profitable at those low prices; however, industry will likely continue to drill the play to at least evaluate it so they can move forward with development if prices rise or costs fall to profitable levels in the future.

What else of importance is there in the Horn River Basin? The gas is very lean because the organic matter is so thermally mature (the basin was deeply buried). Further, the overcooking has also substantially increased the CO_2 content of the gas to about 10 to 15%. Our projection would indicate that, by 2012 in our mid-case, about 1.2 million metric tons of CO_2 per year would be produced along with the shale gas, about 1.5% of B.C.'s total CO_2 emissions.

There had been suggestions of carbon capture and sequestration in proposed gas-processing projects or additions to existing projects; however, these would have to be economic to move forward and without any form of carbon pricing or fiscal incentive, at currently low gas prices, it would be difficult to see these CCS proposals going forward.

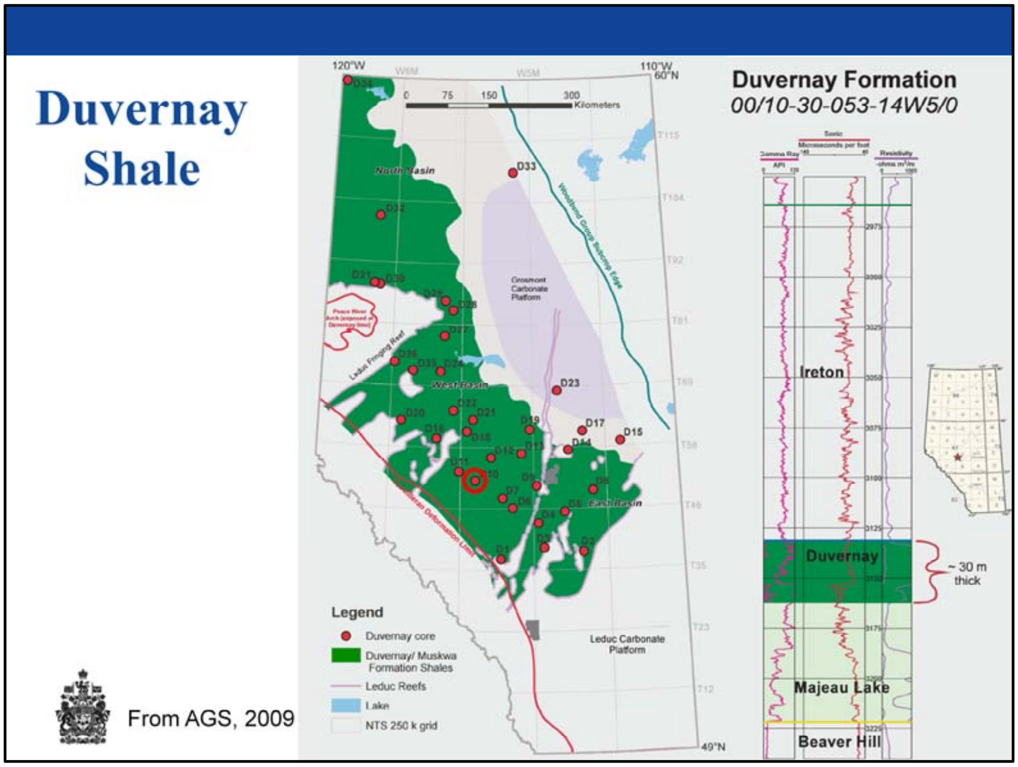
Deep Basin, Kaybob & West-Central Alberta



Price	2009	low			mid			high		
		2010	2011	2012	2010	2011	2012	2010	2011	2012
US$/MMbtu	3.70	4.25	4.75	5.25	5.50	6.00	6.75	6.50	7.00	7.75
Wells drilled		617	544	573	965	981	1009	1064	1123	1177

I’ve grouped the entirety of the Deep Basin area (all tight gas and conventional gas from the entire stratigraphic column) with Kaybob & West-central Alberta deliverability for a reason I’ll bring up in a moment. Here we see deliverability expected to trend downwards towards 2012 in all three cases.

Not included in this projection, however, is the Duvernay Shale, which spans almost the entirety of this area plus much of surrounding areas as well and which has recently become a focus for land-sale activity if speculation in the news is any indication. What might the Duvernay’s impact on deliverability be?

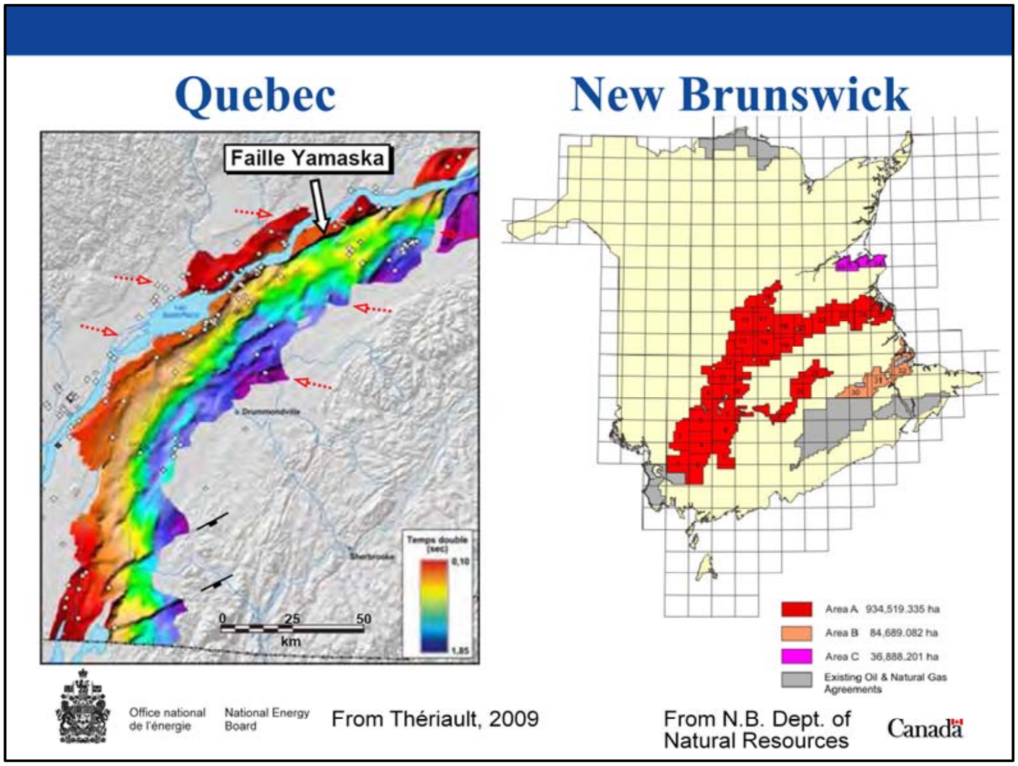


First off, just some general characteristics of the Duvernay. The Duvernay Shale was deposited as mud (the green stuff on the map) in the basins lying between Devonian reefs (the beige stuff) across much of western Alberta and extending into British Columbia – the Duvernay is actually the stratigraphic equivalent of the Muskwa shale which is the uppermost of the Horn River Basin shales being developed in NEBC. The big news of latest 2009 was the last Alberta December land sale where Duvernay rights in the Wild River sub-basin were snapped up for somewhere over $300 million. In particular, the Duvernay gets very deep towards the foothills: locally over 4000 m deep, though the type well above is "only" 3000 m deep. So, while prospective, this might be a challenging shale to develop simply because of its depth.

Further, Duvernay shale gas has the potential to be sour. Nearby Leduc and Swan Hills gas pools that were sourced from the Duvernay average about 20% sour gas. That doesn't necessarily mean that the Duvernay is going to be sour. There's a whole lot of extra geochemistry that goes on in these reefs with the mixtures of water and sulphate minerals and bacteria that may not occur in the shale next to them. But, sour gas is a possibility.

Regardless, the Duvernay's impact on Short-term Deliverability should be minimal towards 2012. It takes considerable time to drill, successfully experiment to achieve sustainable production, and then finally develop shale resources.

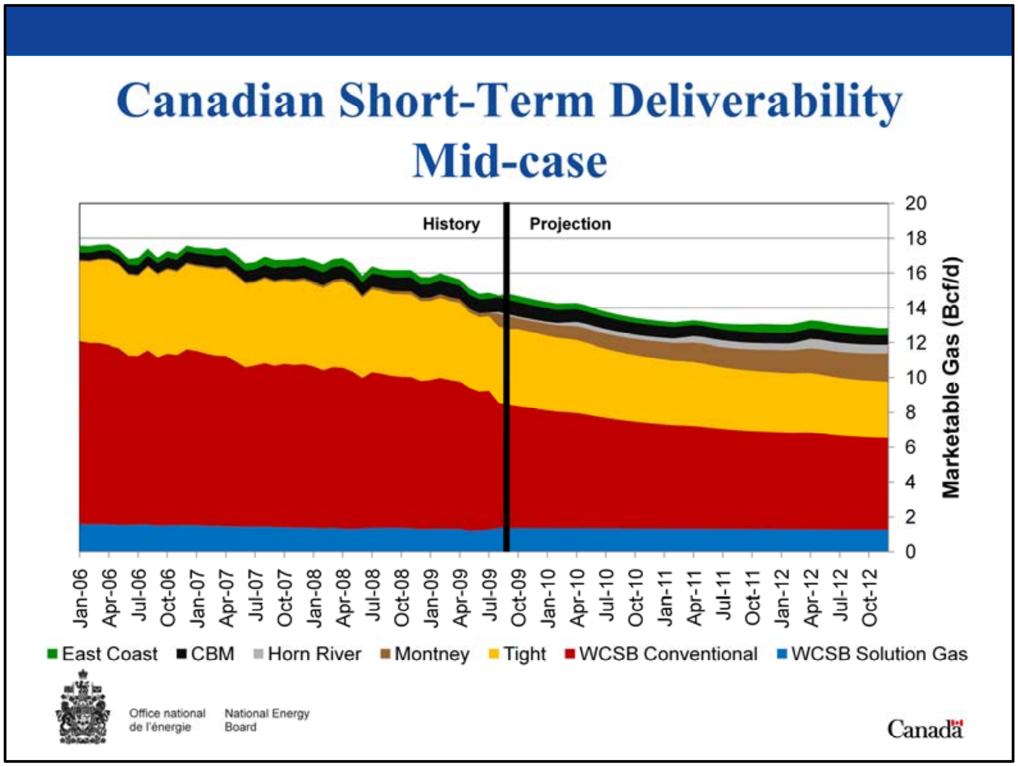
Finally, what about other Canadian shale gas prospects and how do they fit into deliverability?



There's been increasing buzz about the Utica Shale in Quebec with a recent report of a horizontal well with a production test that started flowing at about 12 MMcf/d before declining to 5 MMcf/d after three weeks. This is after a series of announcements of horizontal and vertical wells that flowed on the order of about 1 MMcf/d. In our Deliverability report, however, we don't have production from the Utica coming on until the beginning of 2011 and at only 10 MMcf/d in all three scenarios. While there is a considerable distribution network for natural gas in the area, a gathering network and facilities for gas processing have yet to be built. In particular interest for any potential gas-processing facilities is that the Utica appears to be liquids rich in a good part of the basin.

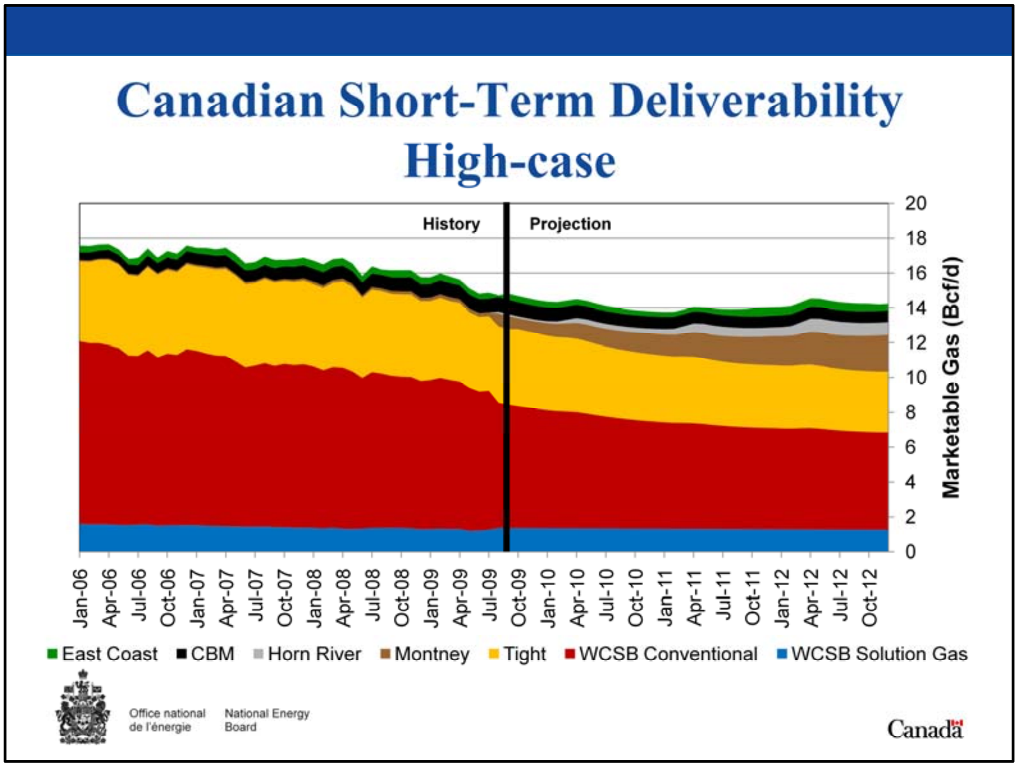
For the Horton Bluff shale in the Maritimes, there was a recent land sale that has largely slipped under the radar. On March 16, over 1 million hectares of petroleum rights were snapped up, some of which were contiguous with Corridor Resources Frederick Brook Shale property in which there was a recent test of about 4 MMcf/d and in which Apache Corp has taken a considerable interest. Southwestern Energy picked up areas A and B for $35.4 million and $11.5 million in spending commitments, respectively. This is their first foray of the large U.S. shale producer into Canada. Still, we don't expect any significant marketable production from the Horton Bluff within the time span of the Deliverability report given the early stage of evaluation.

As for gas contents in the Horton Bluff, what information there is so far indicates higher CO2 contents, though not as high as in the Horn River Basin. However, it's likely going to be complicated: Unlike western Canada, New Brunswick's sedimentary cover is very complicated because of rifting 300 million years ago, where pull-apart tectonics formed elongate troughs of thick sedimentation, including the shales, and other areas where there isn't any sedimentary cover at all. This segmentation also means that different areas have been buried very differently, even if they're close to each other, and the organic-rich rocks will have experienced different thermal histories, which likely means different gas compositions.

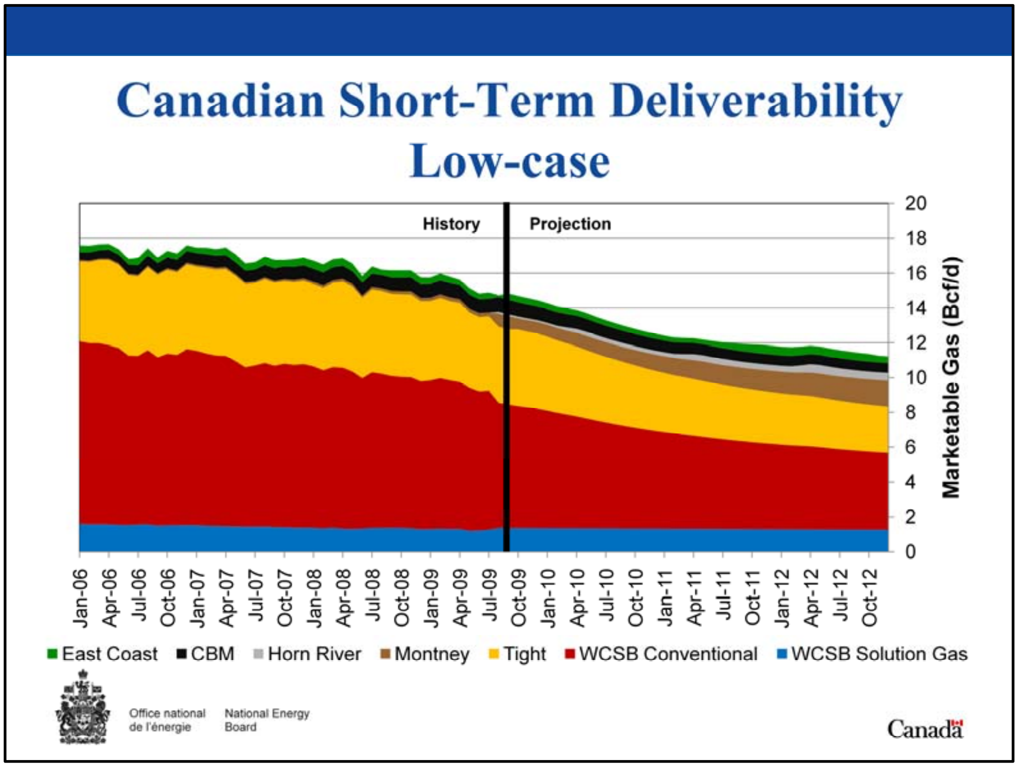


As for total Canadian deliverability, in our mid-case, where prices increase from $5.50 to $6.75 from 2010 to 2012, Canadian deliverability still declines overall. Production in the Montney and the Horn River Basin increases, but is not enough to offset declines in tight-gas and conventional-gas production. We even project CBM production to decline from 2010 to 2012, largely from decreased activity.

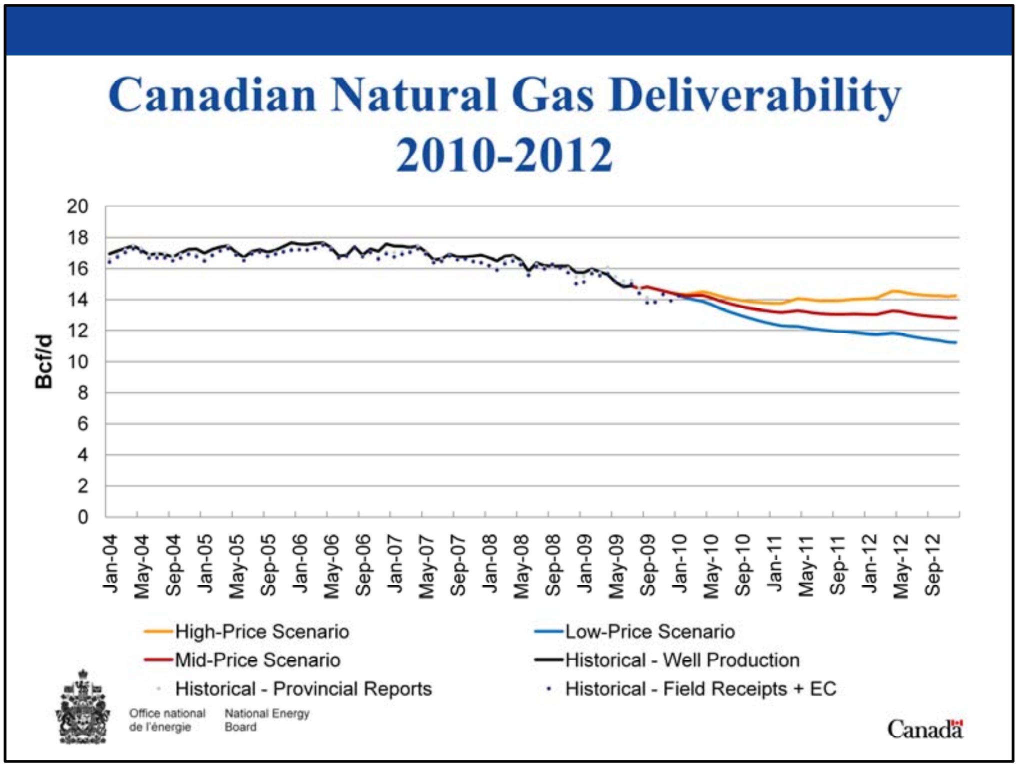
By 2012, in the mid-case, it is expected that Canadian production will be just less than 13 Bcf/d. WCSB production is expected to be 12.5 Bcf/d.



In our high case, where prices move from $6.50 to $7.75 from 2010 to 2012, overall Canadian deliverability bottoms out in late 2010 before rebounding to over 14 Bcf/d by the end of 2012. While tight gas and conventional gas and CBM production all shrink, the declines aren't as dramatic as in the mid-case scenario. Further, there is significant growth in Montney and shale gas production that overall help edge deliverability higher.



In the low case, where prices move from $4.25 to $4.75 from 2010 to 2012, Canadian deliverability shrinks to 11.2 Bcf/d by the end of 2012. Declines in conventional and tight gas production are expected to be significant and overwhelm production growth in the Montney and Horn River Basin.



Finally, here are the three cases compared. This should give you a good visual reference to our upper and lower bounds and the spread between them. Similar levels of production in 2010 are largely constrained by 40% of production being hedged at an average price of $6.15.

Notably, none of our short-term scenarios indicate that Canadian production will reach past highs, at least in the short term. And there's really not much to say other than what's been said on previous slides.

Conclusions

- Development of shale gas is going to have its share of challenges, but…
- Industry has shown signs of adapting
- Shale deliverability is expected to rise towards 2012 in all three price scenarios, but…
- Total Canadian deliverability declines in the Low and Mid cases while only the High case shows growth

Office national de l'énergie National Energy Board

Canada

Thanks for the free lunch!

Mike.Johnson@neb-one.gc.ca

"Canadian Short-term Deliverability 2010-2012" and other energy reports can be found at:

www.neb-one.gc.ca

Office national de l'énergie National Energy Board

Canada