Exhibit No. PNG-15

PNGTS Index of Customers;
TransCanada Contract Renewal
and
TransCanada's Western Canadian Sedimentary Basin

Myths and Realities – A Practical Guide
to the Potential of the WCSB

BROWN, WILLIAMS, MOORHEAD & QUINN, INC.
ENERGY CONSULTANTS

Index of Customers

Portland Natural Gas Transmission System - 159747872</< div>

	Pipeline Name		ID	Report Date	Original/ Revised			First Day of Calendar Quarter				Transportation MDQ Units	Storage MQ Units	Contact Person	Footnotes
	Shipper Name		Shipper ID		Affil	Rate Schedule	Contract	Contract Effecitve Date	Contract End Date	Contract Rollover Days	Negotiated Rate	Transportation MDQ	Storage MQ	Footnotes	
	Agent Name		Affiliate		Footnotes										
	Type	Point Name	Qual	Point ID	Zone Name							Transportation MDQ	Storage MQ		
	Nbr	Footnote													
H	Portland Natural Gas Transmission System		173	4/1/2010	O			4/1/2010				T	T	David J. Haag (603) 559-550	
D	Bay State Gas Company		69340214		N	T Transportati	FT-1997-001	3/10/1999	3/9/2019	3264	N	4900			
P	MQ	Dracut MA - TGP	29	272132	na							4900			
P	M2	Pittsburg Interconnect	29	247231	na							4900			
D	Bay State Gas Company		69340214		N	T Transportati	FT-1997-002	3/10/1999	3/9/2019	3264	Y	40600		o1	
P	MQ	Haverhill MA - TGP	29	255295	na							40600			
P	M2	Pittsburg Interconnect	29	247231	na							40600			
D	Northern Utilities		49286305		N	T Transportati	FT-1997-003	3/10/1999	3/9/2019	3264	N	1100			
P	MQ	Westbrook ME - Granite Stat	29	247227	na							1100			
P	M2	Pittsburg Interconnect	29	247231	na							1100			
D	Northern Utilities		49286305		N	T Transportati	FT-1997-004	3/10/1999	3/9/2019	3264	Y	33000		o1	
P	MQ	Westbrook ME - Granite Stat	29	247227	na							15100			
P	MQ	Eliot ME - Granite State	29	265954	na							4900			
P	MQ	Newington NH - Granite Stat	29	247229	na							13000			
P	M2	Pittsburg Interconnect	29	247231	na							15100			
P	M2	Pittsburg Interconnect	29	247231	na							4900			
P	M2	Pittsburg Interconnect	29	247231	na							13000			
D	DTE Energy Trading, Inc.		806708806		N	T Transportati	FT-1997-005	3/10/1999	3/9/2019	3264	N	30000			
P	MQ	Dracut MA - TGP	29	272132	na							30000			
P	M2	Pittsburg Interconnect	29	247231	na							30000			
D	TransCanada Gas Services		252302799		Y	T Transportati	FT-1997-006	3/10/1999	3/9/2019	3264	N	15000			
P	MQ	Dracut MA - TGP	29	272132	na							15000			
P	M2	Pittsburg Interconnect	29	247231	na							15000			
D	Wausau Papers of NH		802740753		N	T Transportati	FT-1997-007	10/1/1999	9/30/2019	3469	N	4600			
P	MQ	Groveton NH - Wausau Pap	29	253049	na							4600			
P	M2	Pittsburg Interconnect	29	247231	na							4600			
D	MeadWestvaco Corporation		1095041		N	T Transportati	FT-1998-002	3/10/1999	3/9/2019	3264	N	5000			
P	MQ	Rumford ME - Mead Oxford	29	253051	na							3000			
P	M2	Pittsburg Interconnect	29	247231	na							5000			
P	MQ	Dracut MA - TGP	29	272132	na							2000			
D	EnergyNorth Incorporated		194387015		N	T Transportati	FT-1999-001	11/1/1999	10/31/2019	3500	N	1000			
P	MQ	Dracut MA - TGP	29	272132	na							600			
P	MQ	Berlin NH - EnergyNorth	29	265955	na							400			
P	M2	Pittsburg Interconnect	29	247231	na							1000			
D	H.Q. Energy Service (U.S.) Inc.		24988722		N	T Transportati	FT-1999-002	3/10/1999	3/9/2019	3264	N	15000			
P	MQ	Dracut MA - TGP	29	272132	na							15000			
P	M2	Pittsburg Interconnect	29	247231	na							15000			
F	1	winter only contract													

Mainline Firm Contract Renewals for November 1, 2010

A total of **2,693** TJ/d of service under Mainline firm transportation contracts was scheduled for expiry on November 1, 2010. As of May 1, 2010, TransCanada received notice from Shippers to renew **1,856** TJ/d or **69 %** of the contract quantity scheduled to expire. Note that these contract quantities include firm service classes FT and STS for all paths (Long-haul and Short-haul).

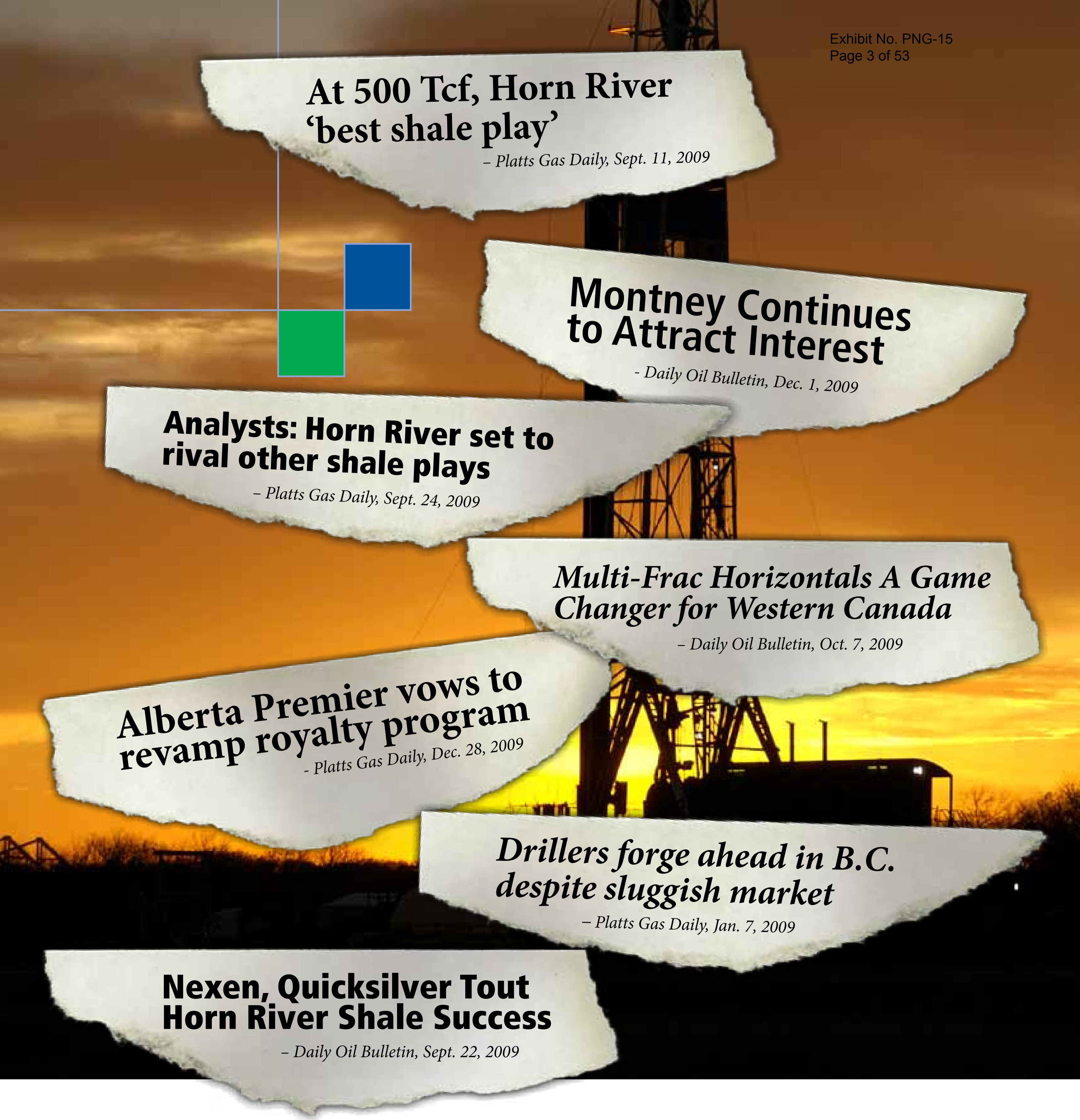
Additional details on renewals by path and zone category are set out in the following table.

If you require clarification or further information, please contact:

Norma Marchet, Contracts Analyst at (403) 920-6258 or
Barbara Miles, Manager Contracts & Billing at (403) 920-5780

MAINLINE RENEWALS EFFECTIVE May 1, 2010					
Path Type	**Zone**	**Eligible**	**Renewed**	**Non Renewed**	**Percentage Renewed**
Eastern Short Haul	Chippawa	205,805	146,120	59,685	71.00%
	Cornwall	10,300	10,300	-	100.00%
	East Hereford	73,887	-	73,887	0.00%
	Eastern	966,688	946,688	20,000	97.93%
	Philipsburg	-	-	-	0.00%
	Southwest	105,275	5,275	100,000	5.01%
	Subtotal	**1,361,955**	**1,108,383**	**253,572**	**81.38%**
Long Haul	Chippawa	10,593	10,593	-	100.00%
	Cornwall	13,570	13,495	75	99.45%
	East Hereford	19,108	-	19,108	0.00%
	Eastern	732,736	539,382	193,354	73.61%
	Iroquois	110,329	7,205	103,124	6.53%
	Napierville	8,580	8,580	-	100.00%
	Niagara Falls	113,033	-	113,033	0.00%
	North Bay Junction	-	-	-	0.00%
	Northern	29,524	16,327	13,197	55.30%
	NCDA	1,545	1,545	-	100.00%
	Philipsburg	2,306	2,005	301	86.95%
	Southwest	31,828	-	31,828	0.00%
	SSMDA	-	-	-	0.00%
	Western	-	-	-	0.00%
	Subtotal	**1,073,152**	**599,132**	**474,020**	**55.83%**
Western Short Haul	Emerson 1	-	-	-	0.00%
	Emerson 2	11,032	-	11,032	0.00%
	Manitoba	225,657	146,443	79,214	64.90%
	Saskatchewan	21,450	2,200	19,250	10.26%
	Subtotal	**258,139**	**148,643**	**109,496**	**57.58%**
Grand Total		**2,693,246**	**1,856,158**	**837,088**	**68.92%**

Quantities are Contract Demand in GJ/d. Data is as of May 3, 2010 at 0800h MDT. Western: Delivery west of station 41, to MDA, or to Emerson; Longhaul: Primary Receipt west of 41 or at Emerson and Delivery east of 41 and Emerson; Eastern: completely east of station 41 or Emerson.



Western Canadian Sedimentary Basin (WCSB)

Myths and Realities – A Practical Guide to the Potential of the WCSB

January 2010

TransCanada
In business to deliver

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The Western Canadian Sedimentary Basin: Game Changers and Tremendous Potential

The news? The WCSB has tremendous potential.

Factors leading to the recent production decline are either reversing themselves, or being offset by the significant game changing events that are providing new incentives for producers to step up to the plate and drill. And they are responding — many with significant commitments.

This book contains an aggregation of facts, knowledge, and views about the future of the Western Canadian Sedimentary Basin (WCSB). Consider it a practical guide to developing your own informed point of view.

Talk about bad timing.

In the face of tremendous American optimism for the potential of shale gas production across the United States, and the need to be more responsive and competitive than ever, the WCSB had its perfect storm. Recession, deflated gas prices, misaligned royalty structures (Alberta), rising drilling costs, and a strengthening Canadian dollar all led to a marked drop in production from the WCSB in 2008/2009 — and likely in 2010. Canadian pipeline tolls, driven by the volume decline, have risen dramatically.

The marketplace is responding with concerns about whether the WCSB can recover its production levels and re-establish its reputation as a very significant portion of North American supply. From greatly exaggerated viewpoints, such as "Canada will soon be a net importer of gas", to well-considered concerns like, "how much will Canadian demand growth affect long-term exports to the U.S.?" or "Is the WCSB in permanent decline?", the WCSB has been called into question.

Talk about great timing.

The entire North American industry is paying incredibly close attention to current and future gas supplies. There can't be a more opportune time to provide facts, comparisons, and answers about the WCSB — to perhaps the largest most attentive audience we've collectively experienced.

Industry participants directly involved in the WCSB are in the best position to tell the story. TransCanada is connected to most of the production in the WCSB, and has the contracts needed to build into B.C. in order to capture the prolific shale potential of the Horn River and Montney plays. We've accumulated a great deal of knowledge and intelligence on the supply potential in the WCSB. Producers are publicly and enthusiastically responding to the game changers that will be discussed more fully in this book.

"No doubt there is a sizeable amount of recoverable gas in the ground, maybe hundreds of trillions of cubic feet."

Rob Spitzer
Apache Canada
Horn River Gas Producers Group – *Platts Gas Daily*, January 7, 2009

Myths and Realities

"The Horn River is the next Barnett shale."

Michael Mazar
Oil & Gas Analyst, BMO Capital Markets
– *Daily Oil Bulletin*, October 7, 2009

EXECUTIVE SUMMARY

A competitive evolution is taking place in the Western Canadian Sedimentary Basin (WCSB). With future North American natural gas prices being dampened by growing shale production in the Lower 48, Canadian industry stakeholders are focussing on more cost-competitive means and ways to improve gas production. This report is intended to help describe the agents of change which signal the potential for a substantial improvement in the productive capability of the WCSB within a few short years. The following is an overview of these game changers.

1. **The ultimate potential of the Basin** has been vastly improved due to the advent of economic access to its unconventional resources — shale gas, tight gas, and coal bed methane (CBM). Over its history, the WCSB's ultimate potential has primarily reflected the economic productivity of the conventional resource base. The recent addition of the unconventional resources to the ultimate production potential of the WCSB has the effect of almost doubling the accessible resource base *(see chart below)*.

Ultimate Potential of the WCSB

	Cumulative Production TCF	Remaining Potential TCF	Ultimate Potential TCF
WCSB Conventional	168.0	109	277.0
WCSB CBM	0.7	55.6	56.3
Montney Shale Hybrid	0.1	30 – 50	30.1 – 50.1
Horn River Shale	negligible	40 – 100	40 – 100
WCSB Total	168.8	234.6 – 314.6	403 – 483.4

2. **Game changing events** are taking place which provide the cost improvements necessary to enable the growth in unconventional production given today's gas price forecast. As these events materialize, the momentum for drilling and production is increasing.

The Horn River and Montney Shale plays of B.C. are emerging, as the necessary enablers come into play, including fiscal reform, infrastructure development, new technology and fit-for-purpose rigs. An integral component is the economies of scale, where manufacturing-style approaches to development are creating the key cost efficiencies underlying these resource plays.

From a geologic perspective, these shale plays stack up very favourably with their U.S. counterparts.

Key Characteristics of Some Canadian and U.S. Shales

	Barnett	Haynesville	Marcellus	Horn River	Montney
Depth (ft.)	6,500 – 9,000	10,500 – 13,500	3,000 – 8,500	6,500 – 13,000	5,000 – 10,000
Thickness of Shale (ft.)	100 – 500	200 – 300	50 – 250	300 – 600	300 – 500
Total Organic Content (%)	3.0 – 7.0	3.0 – 5.0	3.0 – 12.0	3.0 – 10.0	2.5 – 6.0
Original Gas in Place (Bcf / Section)	50 – 200	150 – 250	50 – 150	130 – 320	60 – 150
Recovery Factor (%)	20 – 40	20 – 40	20 – 40	20 – 40	20 – 40
Est. Ultimate Recoverey (Bcf / Well)	1.0 – 4.0	4.5 – 8.5	2.2 – 4.1	3.0 – 9.0	2.0 – 6.0

There is every indication that the Canadian shale plays can grow and perform at least as well as their U.S. counterparts.

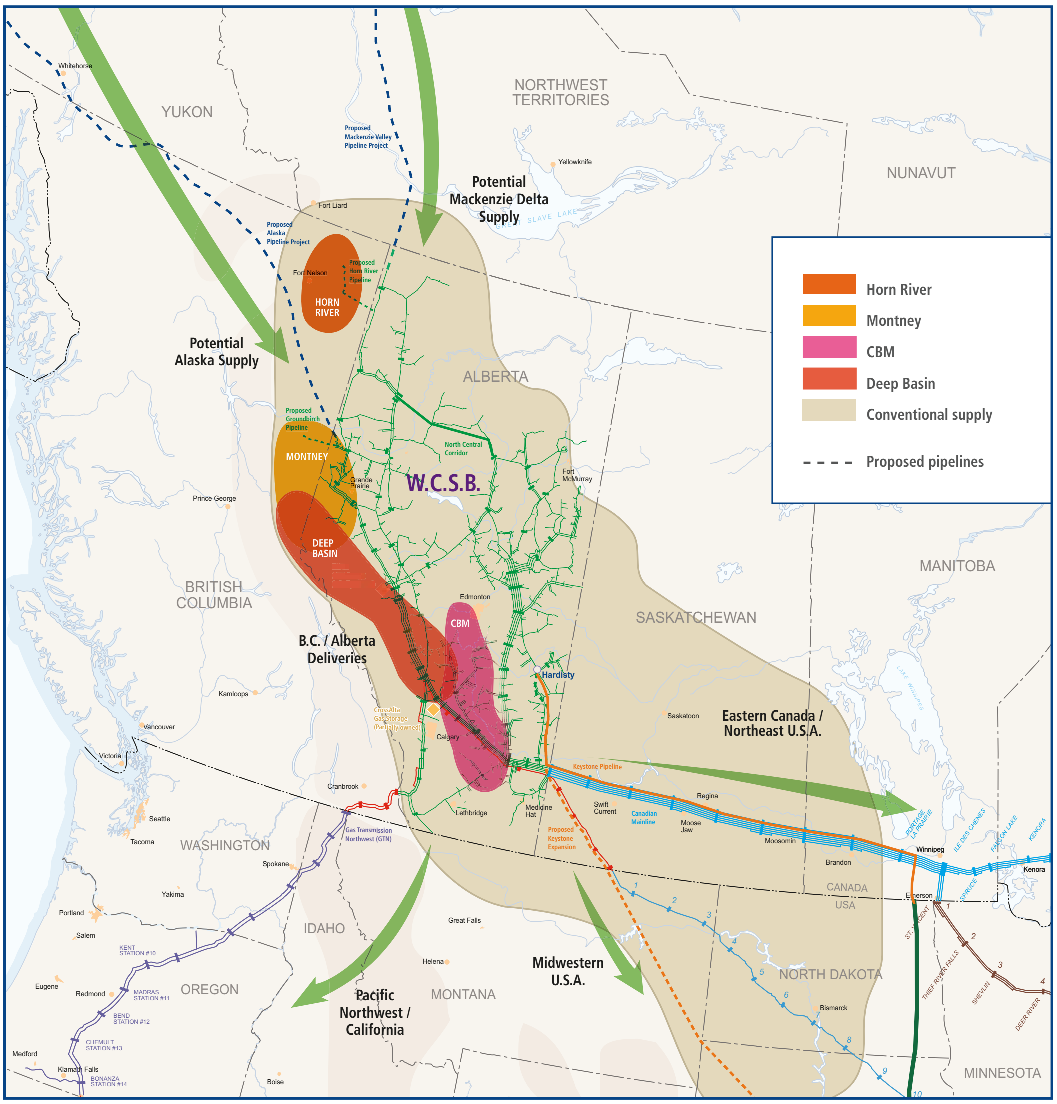
CBM reserves are actively being produced today, and have become a welcome part of the WCSB supply mix.

Vast conventional resources in Alberta, particularly in low permeability reservoirs within the Deep Basin *(see Figure 1)* will benefit from the technology developed for shale plays, and await imminent and necessary changes to the Alberta fiscal and royalty regime to become potentially economic resource plays in their own right.

3. **TransCanada's Alberta System footprint overlays the highest potential plays in the Basin.** Minor extensions of the Alberta system are bringing gas from the B.C. shale plays directly to the Alberta hub at NOVA Inventory Transfer (NIT). We expect by 2014 that the B.C. shales alone will likely contribute an incremental 1.6 Bcf/d to the TransCanada supply mix. This does not include incremental supplies that will be accessible simply as a result of the new pipelines into these areas, which leads to the possibility of even greater volumes *(see Figure 2)*.

Figure 1

TransCanada's WCSB Footprint



Myths and Realities

Figure 2

New Service Contract Developments: Horn River and Montney

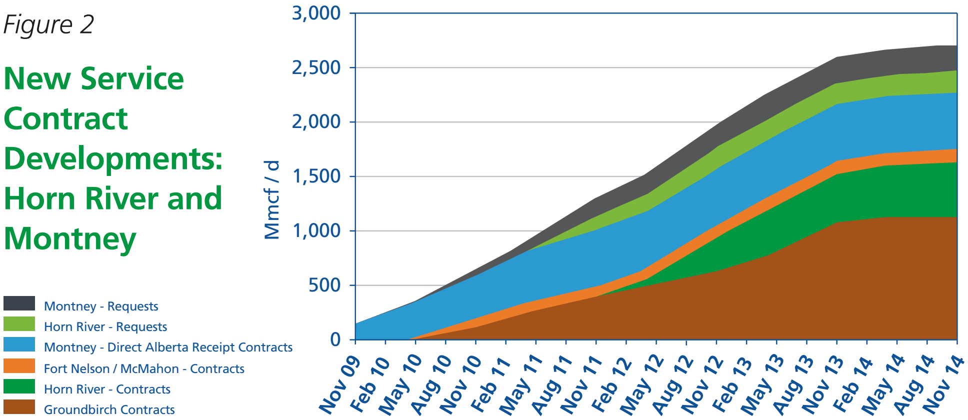


Figure 2 shows how rapidly the commercial interest in connecting the shale plays is growing. TransCanada has executed transportation contracts that will result in construction of new facilities required to secure these plays. And we are already evaluating requests for more.

4. **On the doorstep of NIT:** The B.C. shales, the Alberta Deep Basin, and the Horseshoe Canyon CBM plays all sit on the doorstep of NIT, and share the same economic access to this trading center as all other connected supplies. The Alberta Hub (NIT) is one of the most liquid and transparent trading points on the continent. Backed by 10 Bcf/d of physical gas, and with access to the growth potential of the major resource plays, NIT remains one of the most secure supply points on the continent *(see Figure 3)*.

Figure 3

Supply Flowing to NIT Flowing to Markets

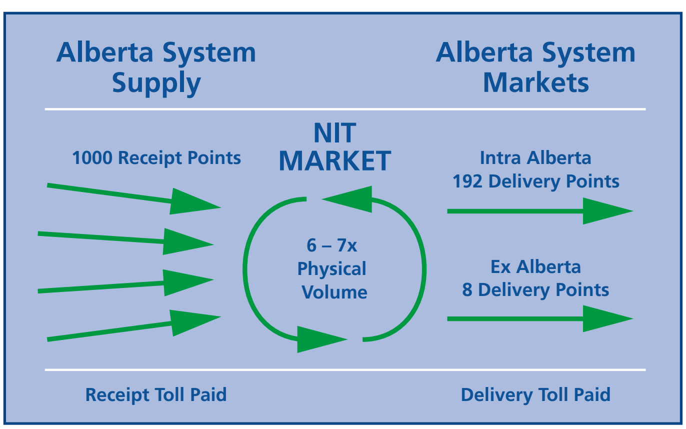
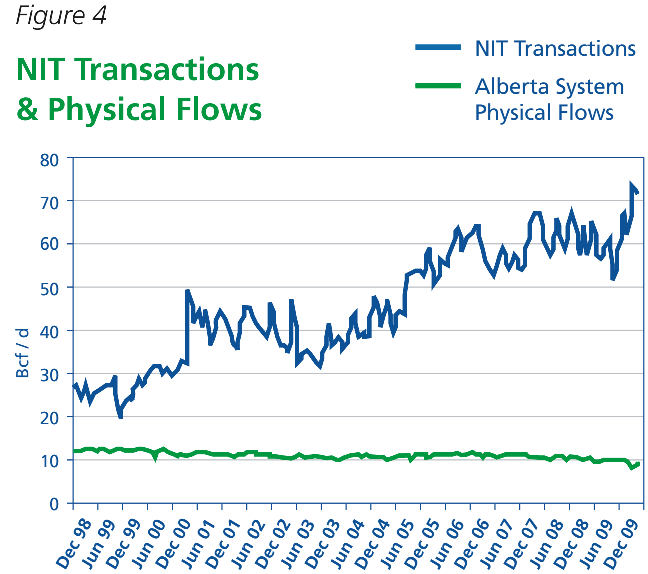


Figure 4

NIT Transactions & Physical Flows

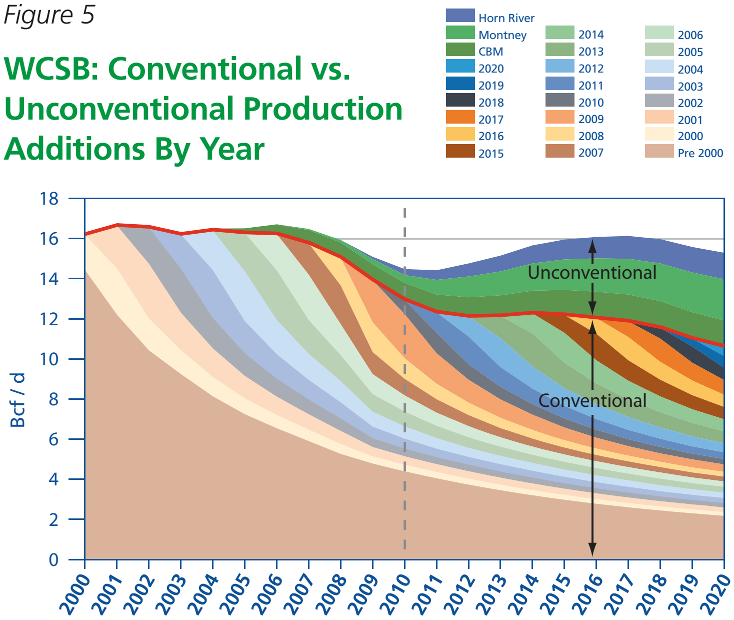


5. **The impacts to WCSB exports are optimistic.** Several sensitivity cases have been developed around these game changers to consider their impact, including the potential impacts of oil sands demand. We have provided a great deal of insightful information to help you evaluate for yourself the possibilities of the WCSB.

Have we changed our official forecast? No. TransCanada's forecast is based on probability assessments of known and measurable indicators covering both macroeconomic factors, local knowledge, as well as a *continuum* of improvements to technology and cost efficiencies.

Figure 5

WCSB: Conventional vs. Unconventional Production Additions By Year



Sept. 09 Base Case: Price Forecast as referenced on page 40.

Figure 5 highlights several points worth noting:

1) It shows that we are in the very early stages of shale development.
2) It chronicles the dip in production response due to recessionary factors in 2008.
3) The lag in supply recovery is primarily reflective of the time needed for the industry to re-tool (literally and figuratively) for resource play development.
4) Conventional production can be maintained at reasonably high levels for some time to come.

Conclusion

We hope we've conveyed, in the context of this book, the potential impact of all these game changers and the sense of momentum that puts new optimism on the productive capability of the WCSB for the long-term, albeit recognizing that throughout the history of the WCSB, North American markets have connected to this vast producing region to enhance their own security and diversity of supply. Those reasons are still valid today.

Our purpose in providing this information is to set the stage for ongoing dialogue and a common understanding of the key elements of what makes this such a virbrant supply basin.

DISPELLING THE MYTHS

Myth:

Canadian shales are not as prolific as U.S. shales, and even so are too far away from the market to be commercial.

Reality:

- **WCSB shales are prolific:** The ultimate potential of the WCSB is climbing as each play is developed.
- **WCSB shales are competitive:** By any geologic measure Canadian shales stack up on par with their U.S. counterparts. Shale production growth in Canada is now emerging due to the use of newly developed drilling technologies, and infrastructure development in more remote locations.
- **Nova Inventory Transfer (NIT) levels the playing field:** Canadian shales sit on the doorstep of the largest and most liquid natural gas trading hubs in North America — NIT. TransCanada's Alberta System has transportation contracts in place that will result in building new pipeline facilities into these new resource areas. A modest extension of our existing facilities provides direct access from the B.C. shale plays to the largest Canadian market — NIT. The Alberta System's NIT mechanism ensures that these shale plays will not be economically disadvantaged relative to any other connected supplies.
- **Pipeline access:** By 2014, we expect approximately 1.6 Bcf/d of incremental production into the Alberta System from the Horn River and Montney plays on facilities designed to capture further growth up to almost 3 Bcf/d.

Myth:

The WCSB is in steep decline and will not recover.

Reality:

- **Dramatic increase:** The remaining productive potential of the WCSB has more than doubled, and potentially tripled, as a result of the emergence of the shale plays.
- **Technology driving WCSB unconventional growth:** Unconventional resource plays such as the B.C. shales, Alberta Deep Basin, and coal bed methane (CBM) plays are already demonstrating increased production and the potential for growth, capitalizing on the same technologies driving U.S. shale growth.
- **WCSB conventional resources can continue at high levels for years:** While there is a substantial conventional resource remaining, and it will continue to support large volumes of production, it has become the higher cost development play. It is likely that the conventional reserve base of the WCSB has matured, and entering into a long period of gradual decline. However, production from conventional resources can be maintained at reasonably high levels for some time to come *(Figure 5)* with a favourable fiscal and regulatory environment as well as effective application of technology.
- **Step changes strengthen the WCSB conventional outlook:** Regardless of the massive shift towards resource play development in the WCSB, there is still a significant physical and human resource base dedicated to conventional gas. Fiscal incentives are now being sought from governments which, coupled with improvements in technology and more efficient regulations, signify a step change in conventional activities which could lead to a higher outlook for conventional production.

Myths and Realities

Myth:

Growing U.S. shale reserves mean U.S. markets don't need WCSB gas anymore.

Reality:

- **The WCSB is secure:** In decades past, markets in Canada and the U.S. sought WCSB supplies in order to ensure security of supply through diversifying their purchase portfolios. As detailed on page 36, gas purchased at NIT in Alberta is still the most secure purchase on the continent.
- **The WCSB is connected:** The pipelines needed to serve these markets from the WCSB are in place, are operationally excellent, and have a long standing record of reliable service and delivery.
- **The WCSB competitive evolution:** Game changers to technology, regulation, and fiscal incentives are all acting to ensure that WCSB supply can continue to be competitive.

Myth:

All WCSB supplies will be consumed in the oil sands. There will be nothing left to export.

Reality:

- **The recession and efficiencies in gas consumption are reducing forecasts for oil sands demand:** The global recession has had an impact on oil sands development. As a result, over the last 18 months TransCanada's forecast of oil sands demand growth to 2015 has been reduced by 700 Mmcf/d.
- **WCSB supply growth offsets demand:** Even in our base case scenarios, supply growth is sufficient to offset all forecast Western Canadian demand growth. There is no net decline in exports which can be attributable to the oil sands.
- **Game changers increase supply for export:** Furthermore, if the impact of game changers such as technology improves the total WCSB natural gas production levels toward our high case scenario, there will be net increases to future exports.

"There will be adjustments (to the Alberta royalty program). We've just got to get together with the industry, put everything on the table and say 'for the next X number of years these are the rules, these are the regulations' so that industry has certainty in terms of where we go."

Hon. Ed Stelmach
Premier of Alberta
– December 17, 2009

"Our goal is to be the most competitive jurisdiction in North America to invest your capital."

Hon. Blair Lekstrom
B.C. Minister of Energy, Mines and Petroleum Resources
– June 18, 2009

Game Changers

"Multi-stage fracturing is giving every (oil and gas) operator in Western Canada Sedimentary Basin an opportunity to do more with what they own."

John Dielwart

President and CEO, ARC Energy Trust
– *Daily Oil Bulletin*, September 21, 2009

"It's very promising that the land sale showed such a substantial increase on the conventional gas side."

Bob McManus

Alberta Energy, referring to strong results in Alberta government's year-end land sale
– *Daily Oil Bulletin*, December 17, 2009

"This is a remarkable jump for the last sale of the year. Having a second year of drilling incentives is a factor and the government has made encouraging remarks about getting the province's competitive situation back where it needs to be."

Gary Leach
SEPAC referring to the Alberta Government's year-end land sale
– quoted in *Daily Oil Bulletin*, December 17, 2009

"Multi-frac horizontals a game changer..."

– *Daily Oil Bulletin*, October 7, 2009

A RISING TIDE LIFTS ALL BOATS

There's a momentum evolving in the WCSB — a rising tide — which has the potential to significantly improve the production outlook of the WCSB.

Technology and regulatory changes are driving new economies for shale plays and also have the potential to be a game changer for conventional supplies.

Fiscal incentives — B.C. royalties and infrastructure credits — are all having the effect of "lifting" the shale forecast.

The anticipated Alberta royalty changes will be a critical driver in improving the conventional production levels.

SHALES ARE DRIVING THE BASIN

The WCSB is undergoing a dramatic and rapid shift toward the pursuit of unconventional gas accumulations also referred to as "resource plays".

With little or no natural permeability, these regionally distributed gas accumulations, involving organic shales, tight clastics and coalbeds can be technically challenging to drill, complete and produce, but the potential prize is enormous.

The untapped natural gas resource endowment is staggering. Two WCSB plays, the Montney and Horn River, have recently captured the spotlight.

Both plays have demonstrated exceptionally encouraging results to date, and the pace of their development can be expected to accelerate with ongoing improvements in the application of technology and development of regional infrastructure such as roads and services.

In Northeast B.C., major industry players have demonstrated their long term commitment to resource plays by spending approximately $4 billion at British Columbia land sales to lock up drilling rights over large areas of the Horn River and Montney plays.

While the B.C. shales are clearly seen as the growth vehicle for WCSB production, the technology that makes these plays possible can be applied economically to both conventional resources — particularly the tight gas in the Deep Basin — and CBM.

At the same time, it has become clear that the WCSB needs to remain competitive in the face of a massive step-change in the production outlook for U.S. shale gas production. The resulting market signal — an attenuated price — has forced all stakeholders in the WCSB to take action to seek out the cost savings, efficiencies and economies of scope and scale in order to maintain or grow all the resources of the WCSB, whether conventional or unconventional.

The following is a discussion of the game changers underway today which could "collectively" drive our shale production forecasts to the next level.

IMPROVEMENTS IN TECHNOLOGY

The widespread application of horizontal drilling in concert with massive multi-stage hydraulic fracturing has recharged the natural gas industry.

Horizontal drilling brings significantly more of the wellbore in direct contact with the reservoir than traditional vertical drilling. The ability to drill horizontally over long distances has increased over the last several years from about 1,000 meters to an upper limit that is rapidly closing in on 2,500 meters, although horizontal legs of 1,600 to 2,000 meters are more typical.

In addition, we are gradually seeing for-purpose drilling rigs and teams evolving that allow rigs to crawl in a self-propelled manner to each well location within a centrally located drilling pad without the need for traditional tear downs, transport and set ups. Large centralized drilling pads will be able to host up to 32 wellbores with all facilities on site such as proppant and water storage, which are the essential ingredients for hydraulic fracturing.

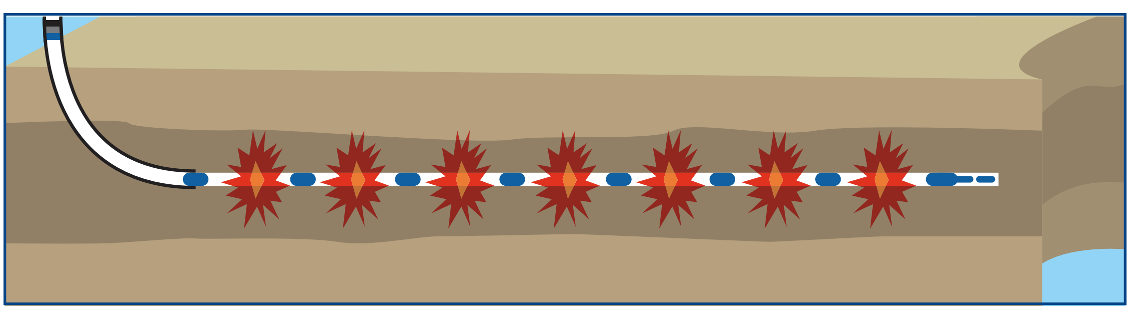
Proppant: essentially small rounded sand particles that are injected with the frac fluid into the reservoir to "prop" open the fractures.

In a sense, these drill pads will evolve to where drilling, completion and stimulation can continue on a year round basis, eliminating the seasonal limitation (winter) of the northern drilling window and driving down the traditional costs associated with seasonal activity.

Massive multi-stage hydraulic fracturing is the second big breakthrough. Multi-stage hydraulic fracturing has had a huge impact in economically unlocking vast amounts of natural gas that only a few years ago were considered unproducible.

In a few short years, the upper limit on frac stages has risen from four to 20 stages, with 10 – 12 stages being the standard in ultra low permeability plays such as the Horn River and the Montney. Not so long ago, one frac per day was the norm, which has now quickly risen to three to four per day.

In addition, traditional drilling tools are being improved and calibrated for ultra low permeability reservoirs that will ensure optimal positioning of hydraulic fracs in the most favourable locations along the horizontal section of the wellbore. These advances will inevitably result in higher initial production rates as well as increased ultimate recoveries.



Horizontal "leg" with seven stage frac zones — up to one mile in length.

Technology Impacts on Drilling Costs in the Montney

Figure 6 and *Figure 7* illustrate the reduction in costs (to drill and to complete) as exemplified by wells drilled by Advantage Oil & Gas Ltd. in the last couple of years.

Figure 6

Wells in Order of Drilling

Source: Advantage Oil & Gas Ltd.

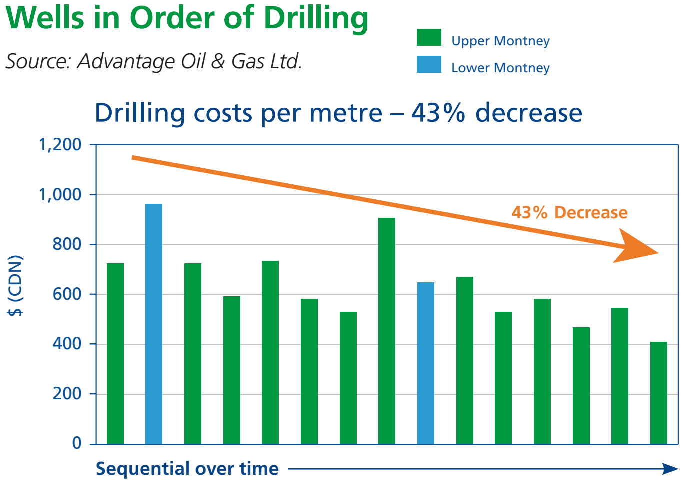
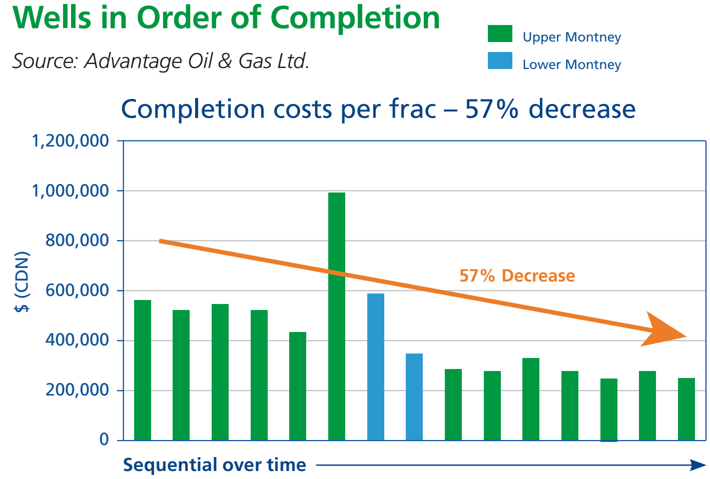


Figure 7

Wells in Order of Completion

Source: Advantage Oil & Gas Ltd.



As companies gain experience drilling horizontal wells and performing multi-stage frac jobs, the costs invariably come down as knowledge and experience is gained with each new well drilled.

New technologies currently being developed and deployed for shale and tight gas production can also be applied to conventional development and re-completions, helping to mitigate the longer term decline rates.

It's important to note that due to the use of better technology and better production practices, well productivity has already increased. Between 2006 and 2009, average initial production rates in the WCSB increased from 160 mcf/d to 220 mcf/d.

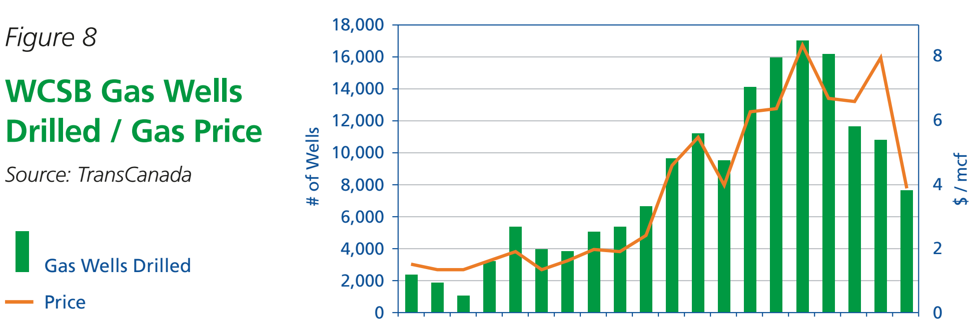
Therefore, drilling activity levels do not have to repeat historical peak levels in order to maintain current production or even increase production from current levels.

As shown in *Figure 8*, there is a very high historical correlation between drilling levels and gas price. This relationship continues to spur the drilling signal, where performance is expected to improve on a per-well basis.

Figure 8

WCSB Gas Wells Drilled / Gas Price

Source: TransCanada



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POSITIVE CHANGES IN REGULATION — Drilling, Completion and Production

Coal Bed Methane

To advance the economic development of coal bed methane (CBM) in Alberta, the Alberta Energy and Utilities Board (EUB), now called the Energy Resources Conservation Board (ERCB), established a system of "control wells" for the purpose of collecting pressure, productivity, and gas content (desorption) information to allow for an understanding of gas resources in coals.

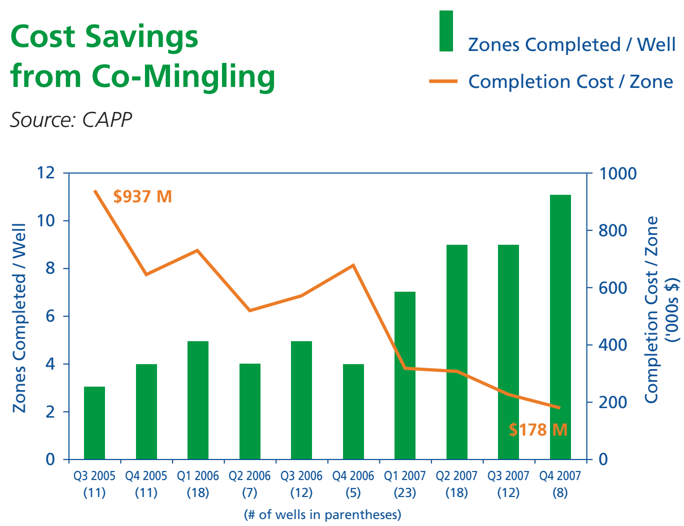
Prior to the establishment of control wells, the base data requirements for CBM wells were the same as the base data requirements for conventional gas wells. Producing CBM wells were required to have initial segregated pressure and deliverability data for each CBM pool producing from the well. Standard fluid analysis data and annual pressure surveys also were required for each CBM pool.

In 2006, the EUB established Production Entity No. 1, covering a large area between Edmonton and Calgary along the Horseshoe Canyon fairway, which allowed for the co-mingling of CBM production from individual coal seams from the Scollard zone down to the basal Belly River zone. The combination of a system of control wells and co-mingling has significantly enhanced the economics of CBM drilling and production in Alberta.

Figure 9

Cost Savings from Co-Mingling

Source: CAPP



Deep Basin

To improve the economics of "Deep Basin" tight gas exploitation, the ERCB established Development Entity No. 2 (DE2) in 2006, which includes the entire stratigraphic interval from the Cretaceous down to the Jurassic. Within the boundaries of DE2 all gas bearing zones that would be uneconomic to drill for and produce on an individual basis, can be produced in a co-mingled fashion without the requirement to perform separate flow and pressure testing or meter production from individual zones.

The boundaries of the original DE2 for the Deep Basin were significantly expanded recently *(see Figure 11 on page 23)*. It is estimated that these changes have resulted in savings of approximately $500,000 per well.

The regulatory process is also being streamlined within the DE2 area to facilitate the approval of drilling on a project basis as well as increased downspacing to increase ultimate recoveries.

POSITIVE CHANGES IN ROYALTY REGIMES

1. B.C. Government Stands Behind Resource Development

The B.C. government has been extremely proactive and aggressive in setting up a more favourable regime for oil and gas development, and this has already impacted the activity in the Horn River and Montney plays.

"Our goal is to be the most competitive jurisdiction in North America to invest your capital."

Hon. Blair Lekstrom
B.C. Minister of Energy, Mines and Petroleum Resources – June 18, 2009

It is developing the Oil and Gas Activities Act (OGAA) to provide a contemporary legislative framework to govern the energy industry's operations in B.C. OGAA will advance supporting regulations for all aspects of oil and gas development activities, including drilling and production, pipeline and facilities, oil and gas road developments, and environmental protection and management.

In August 2009, the Provincial Oil and Gas Stimulus Package was announced to enhance the competitive environment and attract investment. It includes:

- one year 2% royalty rate for all wells drilled in a 10 month window;
- enhancements to the deep royalty credit program;
- infrastructure royalty credit program (additional $50 million allotted); and
- amendments to improve drilling licence regulation.

Targeted royalty programs are available for key resource opportunities including unconventional resources (e.g. tight, shale and coal bed gas), marginal wells, infrastructure development, and deep well drilling. Targeted royalty programs increase the competitiveness of British Columbia's wells.

According to producers, the B.C. government is doing all the right things to stimulate development in their province:

"They have certainly made themselves one of the most competitive jurisdictions in North America. This [B.C. government stimulus package] reinforces that."

Carol Howes EnCana spokesperson – *Daily Oil Bulletin*, August 7, 2009

"The fiscal package says B.C. wants us there."

David Pryce Vice-President, Operations, CAPP – *Daily Oil Bulletin*, December 18, 2009

2. Alberta Government Incentives – In Place and on the Horizon

In January 2009, the Alberta Government introduced a new royalty structure for oil and gas which was intended to increase the compensation for Albertans. Instead, deflated prices and lower production have slashed the provincial gas revenues to roughly $1.9 billion, down from nearly $6 billion last year.

Alberta's Premier Ed Stelmach offered the following comments in a December 17, 2009 interview with the Calgary Herald:

"The prediction is that over the next four years we may see a substantial drop — about $4 billion worth of natural gas sales — if we don't look at repositioning Alberta given the game changer, being (U.S. and B.C.) shale gas."

"That doesn't mean that we won't be looking at the conventional gas side."

The Stelmach government has launched a competitiveness review, scheduled for completion by the end of January 2010, which will compare the competitiveness of Alberta's natural gas and conventional oil sectors with competing jurisdictions within Canada, with the U.S., and around the world. A key result, says the Premier, will be further changes to the province's royalty structure.

As a set of guiding principles for changing the regulatory and fiscal framework for natural gas, the government offers the following three key components:

- Facilitate the maximum production from the widest possible range of exploration and development opportunities, at the lowest possible costs, consistent with good conservation and environmental practices;
- Recognize that investors need to be rewarded;
- Recognize that Alberta deserves to receive a competitive level of compensation.

If the Alberta government comes through with fiscal changes as part of its competitive review, then the WCSB conventional supply potential will be higher. Since we don't know the outcome, this is not yet considered in TransCanada's current base case forecast.

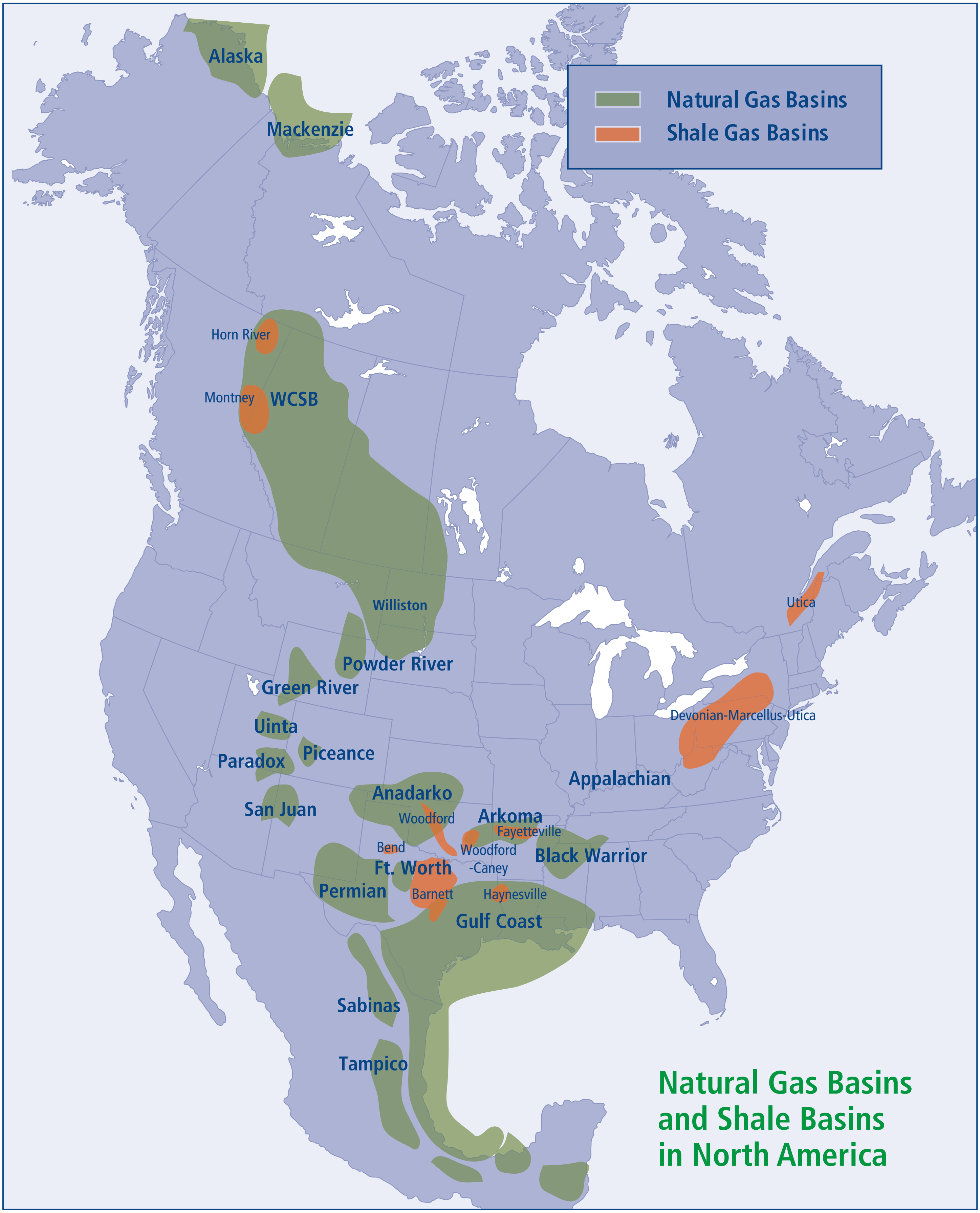
SUMMARY: GAME CHANGERS

A rising tide does lift all boats. In the case of the WCSB, it's a story of momentum — the need to fiscally compete with U.S. shales, the technology and scope required to do so, and applying the benefits of that technology to traditional supply development. These are the game changers coming about in the WCSB.

"The company [EnCana] is seeing significant opportunities arise in Western Canada."

citing **Randy Eresman**
President and CEO, EnCana
– *Daily Oil Bulletin*, July 24, 2009

Western Canadian Sedimentary Basin



Natural Gas Basins and Shale Basins in North America

THE WCSB'S POTENTIAL

The WCSB is a vast sedimentary basin underlying 1,400,000 sq. km. (540,000 sq. mi.) of Western Canada, extending from Manitoba to Northern B.C. and the Northwest Territories. It consists of a massive wedge of sedimentary rock reaching from the Rocky Mountains in the west to the Canadian Shield in the east, attaining depths of about 6 km (3.7 miles) under the mountains.

The WCSB contains one of the world's largest reserves of petroleum and natural gas.

Figure 10

Ultimate Potential of the WCSB

	Cumulative Production TCF	Remaining Potential TCF	Ultimate Potential TCF
WCSB Conventional	168.0	109	277.0
WCSB CBM	0.7	55.6	56.3
Montney Shale Hybrid	0.1	30 – 50	30.1 – 50.1
Horn River Shale	negligible	40 – 100	40 – 100
WCSB Total	168.8	234.6 – 314.6	403 – 483.4

The upside potential of the basin has operationally increased given the advent of resource plays and CBM.

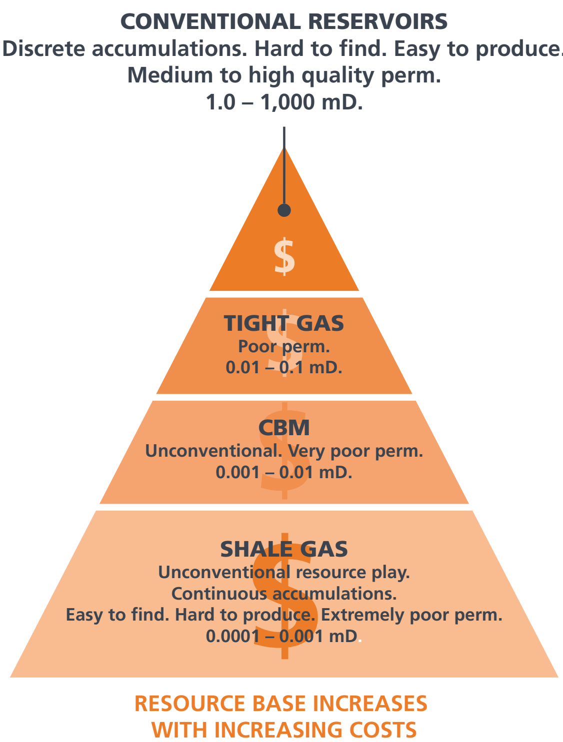
Conventional Resources and Unconventional Resources

The natural gas within the WCSB lies within numerous geologic formations and structures, but gas plays tend to be characterized by the relative simplicity — or difficulty — of development and extraction.

Conventional Resources – represents gas where the primary storage mechanism is that of "free gas" located in naturally occurring rock porosity within carbonates, sandstones and siltstones. Historically, conventional gas was more difficult to find, but relatively easy to drill and produce with vertical wells and a minimal amount of stimulation due to the high levels of naturally occurring permeability. Today, however, although still within the spectrum of conventional gas, industry is moving increasingly to low permeability conventional (tight) reservoirs that are often pervasively gas saturated, but can only be economically exploited through horizontal drilling and massive hydraulic fracturing to create permeability within the reservoir or by co-mingling the production of separate, thin gas bearing zones.

Unconventional Resources – represents gas where the primary storage mechanism is methane "adsorption" where the dense layers of gas molecules are literally attached to organic rock fragments. This accounts for the very high "gas in place" often associated with gas shales and CBM. Unconventional gas resources can be thought of as easy to find, but expensive and difficult to produce. It is only relatively recently that significant advances in horizontal drilling and fracturing techniques have been able to economically unlock the vast gas resources associated with organic shales. The term "resource play" generally refers to the application of horizontal drilling in combination with induced hydraulic fracturing for difficult to produce, low permeability gas reservoirs whether they are in the unconventional or in the lower end of the conventional realm.

Commercial success in shale gas is achieved through a "manufacturing" approach, utilizing economies of scale and the application of leading edge drilling and completion technology.



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UNCONVENTIONAL SUPPLY

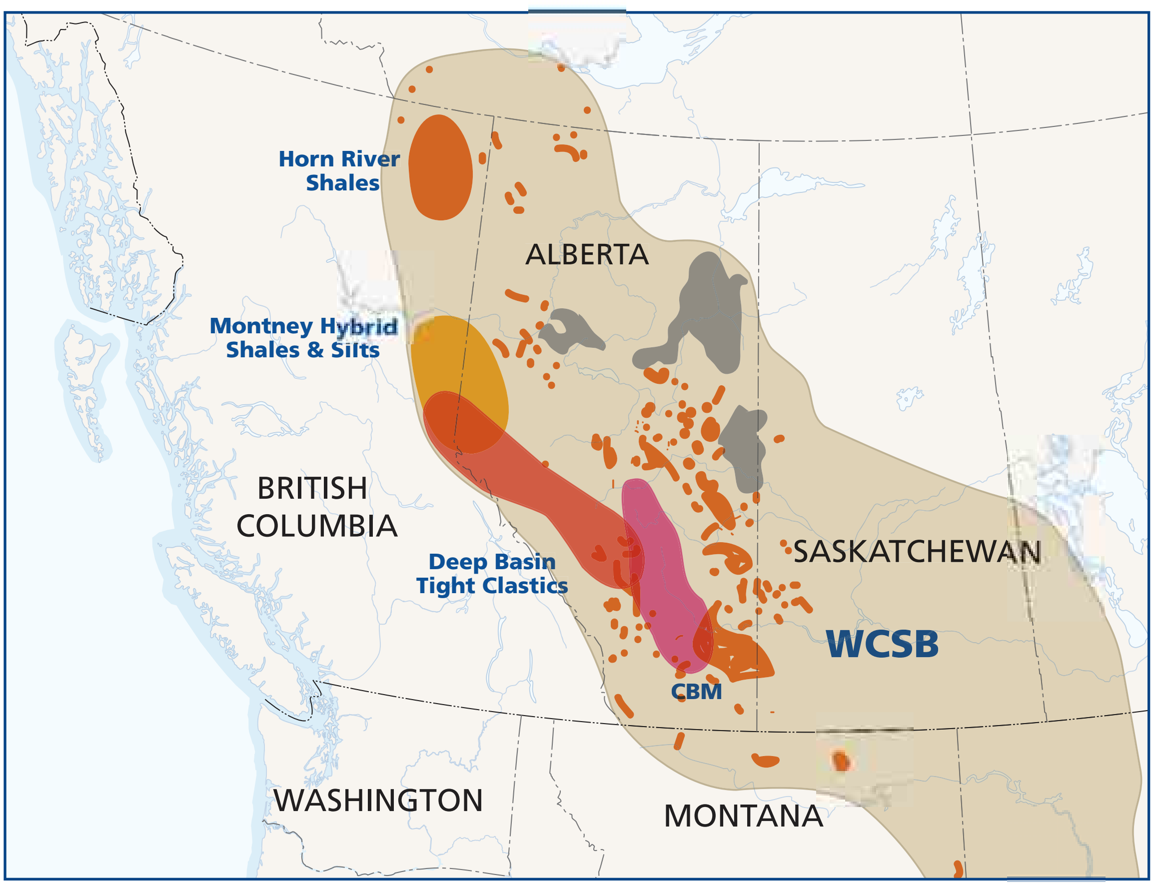
A dramatic and rapid shift is taking place in the WCSB. The emergence of unconventional, regionally distributed "resource plays" is complementing the traditional industry approach of risky exploration for high quality conventional gas traps.

The resource plays are technically challenging to drill, complete and produce because there is little or no natural permeability in the organic shales, tight sands and coal beds.

With resource plays the focus is not on exploration, but on exploitation where the application of new technology, economies of scale and the implementation of repeatable, assembly-line approaches to gas production are the keys to commercial success.

Figure 11

Resource Plays: Growth Regions in the WCSB



The Horn River and Montney Developments

Two WCSB plays that have recently captured the spotlight in Canada are the Montney and Horn River.

Horn River Play

The Horn River basin *(Figure 11)* covers approximately 1.2 million hectares, which is roughly twice the size of the Barnett shale play in Texas. Major operators have referred to the Horn River play as one of the most prolific shale gas plays on the continent.

The Horn River basin shales compare very favourably to the Barnett shales in Texas. It is in fact thicker and has more gas in place per square mile. A key factor influencing Horn River development is that it is situated in a sparsely populated region where development of the necessary supporting infrastructure (such as roads, services, etc.) is just beginning in a coordinated fashion. The B.C. Government is working diligently with key stakeholders to address these issues right now.

Once the infrastructure is in place, the Alberta System commercial mechanism (NIT) ensures that the Horn River is just as close to market as any other supply in the basin.

Operations in the Horn River began with two to three frac stages per well costing $1 million per stage. It has now evolved to an average of 12 to 14 stages per well, costing between $300,000 to $750,000 per stage, positioning the Horn River for world-class development, as this evolution has significantly improved the economics of each Horn River well.

The Horn River shale play has technically recoverable reserves estimated today at 40 to 100 Tcf, and this is expected to increase as more is understood about the play. Original Gas in Place is estimated at 500 Tcf or more, making today's recoverable reserves estimate a very conservative recovery factor of just 8 to 20%.

Operators in the area have collectively announced discovered gas resources of 50 to 60 Tcf with initial well production rates ranging from five to 13 Mmcf/d, which is well over 20 times the production from an average well in the WCSB. Drilling and completion costs, which were in the $15 to $20 million range fairly recently, have dropped significantly to around $9 to $12 million per well. Further cost reductions are likely as operators continue to climb the learning curve and develop efficiencies and economies of scale.

> *Unconventional gas industry leaders such as EnCana, Devon, Apache, EOG, Nexen and Quicksilver are expected to invest billions of dollars in developing the prolific gas resources of the Horn River basin.*

One such economy is in the development of very large drilling pads, with fit-for-purpose rigs that self-mobilize around the pad in order to stage for each directional hole. Not only will the rig set up and tear down time be eliminated for each new hole, but the pad enables year-round drilling — a significant improvement over traditional winter-only drilling practices that have been the rule in Northern Canada.

Although the Horn River basin has been the focus of industry interest, the same gas bearing shales can be found within the Cordova basin to the northeast and the Liard basin to the west. These have been largely untested.

Montney Play

The Montney gas play straddles the Alberta — Northeast B.C. border *(Figure 11)*. It is not a "pure" shale gas play like the Horn River, but rather a hybrid play with a rock structure comprised of both shale and tight sand components. The Montney has seen vertical drilling for a number of years with limited commercial success. It was only after the twin technologies of horizontal drilling and multi-stage hydraulic fracturing were implemented that production rates in the Montney really began to increase dramatically.

The Montney play today is estimated to have technically recoverable reserves of around 30 to 50 Tcf, which will most likely increase with time as the play moves westward into the deeper, "shalier" parts of the basin.

The key operators aggressively pursuing the Montney play at this time are EnCana, ARC Energy Trust, Shell, Murphy, Birchcliff, Advantage and Storm Energy.

In Northeast B.C., major industry players have demonstrated their long-term commitment to resource plays by spending approximately $4 billion at British Columbia landsales to lock up the Horn River and Montney.

Canadian Shales Stack Up Well Against U.S. Shales

These two resource developments stack up extremely well when compared to major U.S. shale plays. Both the Horn River and the Montney have generally thicker sequences of organic rich shales. In addition, their original gas in place per square mile compares favorably to their U.S. counterparts.

A key advantage of the WCSB shales may be the amount of available biogenic silica, which is crucial to the effective hydraulic fracturing of shales that leads to high ultimate recoveries. Subsequent to initial fracturing, U.S. shale operators have reported extremely high first year declines in the order of 80%, whereas Horn River and Montney operators are reporting significantly smaller first year declines in the order of 50% to 60%. This may be attributed to better proppant preservation in the WCSB plays.

Figure 12 **Key Characteristics of Some Canadian and U.S. Shales**

	Barnett	Haynesville	Marcellus	Horn River	Montney
Depth (ft.)	6,500 – 9,000	10,500 – 13,500	3,000 – 8,500	6,500 – 13,000	5,000 – 10,000
Thickness of Shale (ft.)	100 – 500	200 – 300	50 – 250	300 – 600	300 – 500
Total Organic Content (%)	3.0 – 7.0	3.0 – 5.0	3.0 – 12.0	3.0 – 10.0	2.5 – 6.0
Original Gas in Place (Bcf / Section)	50 – 200	150 – 250	50 – 150	130 – 320	60 – 150
Recovery Factor (%)	20 – 40	20 – 40	20 – 40	20 – 40	20 – 40
Est. Ultimate Recovery (Bcf / Well)	1.0 – 4.0	4.5 – 8.5	2.2 – 4.1	3.0 – 9.0	2.0 – 6.0

By any measure involving purely geological reservoir parameters, the Horn River and the Montney resource plays compare very favourably to their U.S. counterparts.

Relative pace of growth/development of B.C. shales vs. U.S. shales

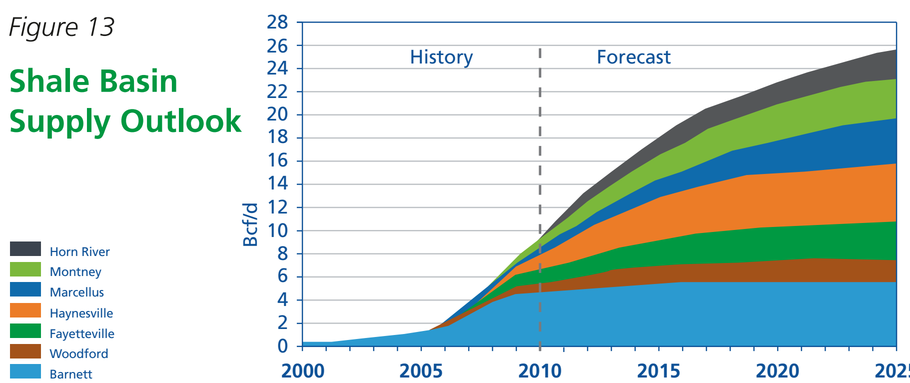
The Barnett play has a history that goes back more than 20 years. However, it's only been in the last 10 years that the Barnett has achieved commercial success due to the successful application of horizontal drilling and massive hydraulic fracturing. The growth curve for the Barnett has slowed down as the play becomes increasingly mature.

The technology and learnings from the Barnett play were quickly transferred for the exploitation of the Woodford and Fayetteville shales followed by the Haynesville — all of which have shown impressive production growth in a relatively short period of time without having to go through the trial and error approach that characterized the development of the Barnett shale in the early years. The Montney and Horn River are also seeing the benefit of the new technologies and production is quickly ramping up. The Horn River play has the potential to be one of North America's most prolific shale plays based upon resource endowment. However, activity is just emerging due to its remoteness, seasonality and general lack of infrastructure.

But the remoteness has a key advantage — it makes dense development of resource plays far easier than in regions of significant population or urban encroachment.

Figure 13

Shale Basin Supply Outlook



Coalbed Methane

CBM is predominantly located within the Alberta portion of the WCSB. CBM developments include the shallow Horseshoe Canyon coals located between Calgary and Edmonton and the deeper Mannville coals located northwest of Edmonton.

The Horseshoe Canyon CBM play is the most mature of the CBM plays, with thousands of wells drilled in the last several years that have demonstrated very solid, low risk, predictable results.

The Mannville play is not as far along on the technical learning curve as the Horseshoe Canyon play, which is deeper, more costly, and with water challenges. However, the Mannville represents significant future potential.

Regulatory Initiatives Benefit CBM Development

Control Wells and Co-Mingling

When the Alberta Regulator established Production Entity No.1 in 2006, it allowed for the co-mingling of CBM production from individual coal seams from the Scollard zone down to the basal Belly River zone. (Production Entity No. 1 covers a large area between Edmonton and Calgary along the Horseshoe Canyon fairway.)

This combination of a system of control wells – negating the need for individual well data for each producing formation – and co-mingling has significantly enhanced the economics of CBM drilling and production in Alberta.

CBM has become an important contributor to the WCSB mix of production; we can expect steady performance — and modest growth — from this sector.

Figure 14

WCSB Unconventional Gas Supply Outlook (Base Case)

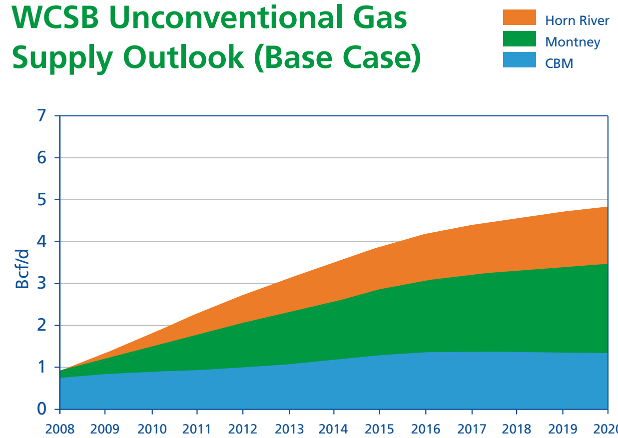
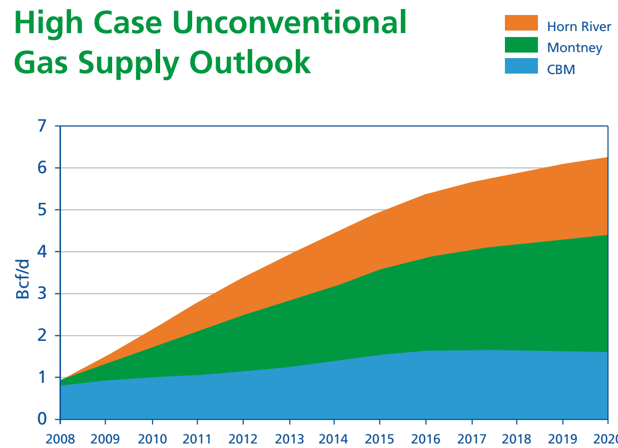


Figure 15

High Case Unconventional Gas Supply Outlook



CONVENTIONAL SUPPLY

About 90% of the current WCSB production is from conventional resources, traditionally the foundation of the WCSB basin supply. The WCSB enjoyed unprecedented growth in the conventional resource base from 1990 to 2000, growing in production from 10 Bcf/d to almost 17 Bcf/d. In the subsequent 10 years, the basin supply has been essentially flat, signifying that the conventional component of the supply mix has matured, and is entering a long period of decline.

Looking beyond the resource plays in the shales and tight sands, there is a vibrant engine of growth within the small producer community that will continue to exploit their niche strengths in conventional gas production. Not every producer has the appetite — or the capital — for the resource play investments in the B.C. and Alberta shales. There is a large economy based solely on exploring and producing conventional supply within the WCSB.

Smaller conventional pools, pool extensions, pool infills, co-mingling opportunities in new and existing wellbores, CBM and shallow gas are the domain of this key production engine. The changes to technology, regulation, royalties, availability of rigs and crews, and cost efficiencies are all features that the smaller producer will have access to.

Myth:

Conventional resources are depleted.

Reality:

They have simply become the higher cost production play. However, the aggregate effects of improved technology, regulatory encouragement and fiscal incentives may offset the cost disadvantage for many conventional plays. There is a large base of producers who are targeted to conventional production. Existing depreciated infrastructure and land positions help economies considerably.

"Low Permeability" Conventional Gas Reservoirs – Deep Basin Tight Plays

The WCSB has a very large untapped resource of very low permeability, pervasively gas-saturated sandstones and siltstones straddling the Alberta — B.C. border in the area known as the "Deep Basin".

The original play was discovered by Canadian Hunter back in the late 1970s. In the past, industry has only focused on the localized sweet spots where permeability and porosity were sufficient to support economic drilling and production. However, a large part of this resource has remained beyond economic reach.

The ERCB established Development Entity No. 2 (DE2) in 2006 to improve the economics of "Deep Basin" tight gas. It includes the entire strategraphic interval from the Cretaceous to the Jurassic Rock Creek Formation.

As a result, all gas bearing zones within the boundaries of DE2 that would normally be uneconomic to produce on an individual basis can be produced in a co-mingled manner from a single wellbore without the requirement to perform separate flow and pressure testing or meter production from individual zones.

Western Canadian Sedimentary Basin

In April 2009, the boundaries of DE2 were significantly expanded *(Figure 16)*.

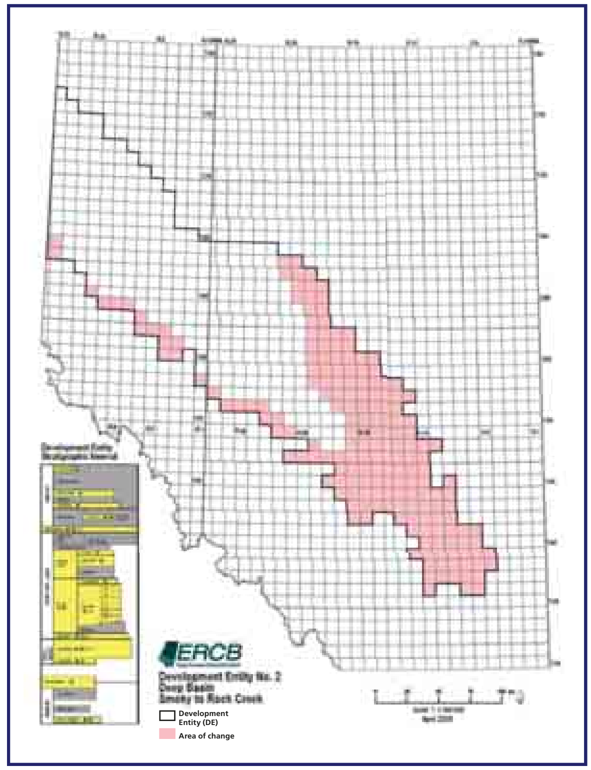
In addition, the Alberta regulatory process is also being streamlined within the DE2 so that drilling projects can be approved on an individual basis and increased down-spacing will also help increase recoveries.

The establishment and expansion of the Deep Basin DE2 is signalling a dramatic increase in the number of gas zones producing per wellbore, along with significant cost savings per completion. It is estimated that the ability to co-mingle production from multiple zones has resulted in savings of approximately $500,000 per well.

Figure 16

Recent Expansion of DE2

Development Entity (DE)
Area of change



Alberta's Biggest Land Sale in 2009 – $384 Million on December 16

There has been considerable speculation as of late that the land postings for the last Alberta land sale of the year — and the biggest in 2009 — are for a Duvernay shale play because they involved large contiguous tracts adjacent to the Leduc reef trends. However, it's just as likely that these postings were targeted to Deep Basin "tight gas" plays, particularly where horizontal drilling and multi-stage fracturing are expected to vastly improve economics. Either way, the indications of a significant new resource play are evident.

"It's very promising that the land sale showed such a substantial increase on the conventional gas side."

Bob McManus
Alberta Energy, referring to strong results in Alberta government's year-end land sale – *Daily Oil Bulletin*, December 17, 2009

Northern Gas Potential

Northern gas resources have the potential to be connected to TransCanada's infrastructure and supplement WCSB supplies. About 4.5 to 6 Bcf/d of Alaskan gas and 1.2 Bcf/d of Mackenzie Delta gas could be connected to TransCanada's Alberta System by 2020.

Alaskan gas is already discovered (with over 100 Tcf of natural gas resources, 35 Tcf of proven reserves) and is currently producing and injecting up to 8 Bcf/d into oil reservoirs to enhance oil recovery.

There is about 30 Tcf of potential resource in the Mackenzie Delta, about 9 Tcf of which has been discovered and can be an important component of the supply mix before the end of the decade.

There are several considerations that taken together suggest that these Northern frontier supplies will be a welcome part of the North American supply mix before the end of the decade.

- The aggregate annual decline of North American gas production is on the order of 14 to 15 Bcf/d.
- Even with the continued increase in shale production in both Canada and the U.S., higher cost gas will be required to offset the aggregate decline. This will naturally include conventional gas, tight gas, CBM and potential Northern gas.
- The cost of Northern gas compares favourably with the cost of incremental non-shale play production, and Nothern gas offers a significant contribution to the continental supply mix beyond the 2018 period.
- Any substantial initiatives to reduce GHG emissions through the increased use of natural gas in the power generation and/or transportation sectors means that even more non-shale gas will be required, making a contribution of Northern gas even more important.

The Northern gas supply potential and the expected WCSB production, in combination, could result in volume levels well in excess of 20 Bcf/d by 2020 *(see Figure 24 on page 42)*.

TransCanada is both a proponent and a partner in these key initiatives, and the TransCanada assets are well positioned to accommodate these production sources through its involvement in the Alaska and Mackenzie Valley pipeline projects.

In addition, TransCanada's Alberta System represents an attractive transportation option for these supplies, where low cost, rolled-in facilities construction will provide access to NIT, and from there to all North American markets currently served by the WCSB.

Northern Gas Update

Dateline – Calgary, January 7, 2010

The Mackenzie Project – On December 30, 2009, the Joint Review Panel (JRP) for the Mackenzie Gas Project (MGP) released its report. The report is the culmination of four years of work assessing the socio-economic and environmental impact of the MGP.

In a nutshell – "The Joint Review Panel of the MGP has concluded that, subject to the full implementation of the Panel's recommendations, the adverse impacts of the MGP, and the associated Northwest Alberta Facilities, would not likely be significant and that the Project and those facilities would likely make a positive contribution towards sustainability. In the Panel's view, the MGP could provide the foundation for a sustainable northern future."

So where do we go from here? The National Energy Board (NEB) will assess the JRP recommendations and associated comments from stakeholders and reconvene its hearing for Final Argument. This will occur in April 2010. The NEB has indicated that it will render its Decision in September 2010.

Subject to a positive decision from the NEB, the MGP proponents that include: Imperial Oil, Shell Canada, ConocoPhillips Canada, ExxonMobil Canada, and the Aboriginal Pipeline Group, will determine whether they are prepared to proceed with the project. Once the MGP proponents decide they wish to proceed, it is expected that it will take approximately six years to place the MGP into service.

The base design capacity of the MGP is 1.2 Bcf/d, with expansion capability of 1.8 Bcf/d. The MGP will interconnect with the Alberta System at the Alberta / Northwest Territories border.

Alaska – On August 1, 2008, the Alaska State Senate voted to approve the award of a licence under the Alaska Gasline Inducement Act to TransCanada. This step set the stage for TransCanada to advance its Alaska Pipeline Project (APP).

On June 11, 2009, TransCanada and ExxonMobil reached agreement to jointly pursue the APP.

The APP team is completing the work necessary to prepare the relevant applications and is developing the commercial material that will allow an Open Season process to be completed in July 2010. Following the Open Season process, regulatory filings and construction of the APP is expected to require 10 years with a forecast in-service date of 2020.

The APP will have an initial capacity of 4.5 Bcf/d with expansion capability to 5.9 Bcf/d.

The APP will interconnect with the Alberta System at either Fort Nelson in northeast British Columbia, or Boundary Lake which is located on the border between northeast B.C. and Alberta.

Another pipeline project (Denali) is competing with the APP to transport Alaska natural gas to North American markets. It is expected that the Denali project will likely interconnect with the Alberta System; however the location of the interconnection is unknown at this time.

WCSB Supply Overview

Shales are the growth story. With reservoir characteristics that parallel other North American shales, the Horn River and Montney plays can be expected to develop quickly as the necessary infrastructure evolves. As highlighted in the next section of this report, TransCanada is already developing the initial pipeline facilities to help enable that growth. These shales sit on the doorstep of the NIT hub and can expect the benefits of world class market access.

Provincial governments have embraced the need to provide incentives for drilling, infrastructure, as well as make regulatory improvements to promote production efficiencies that weren't possible in the past.

The long-term commitment to these resource plays is confirmed by approximately $4 billion spent at British Columbia land sales by major industry players in an effort to lock up Horn River and Montney drilling rights.

Untested shales in the Liard and Cordova remain high on the radar screen.

Conventional supplies are the cornerstone and remain the mainstay and producing foundation for the WCSB. While conventional development has likely matured, the conventional decline rate is expected to moderate as the investment climate improves.

We are relying on the resource plays of the WCSB to help restore overall production levels to the higher levels seen in the last decade, and even set the stage for production growth.

While there is a substantial conventional resource remaining, which will continue to support large volumes of production, it has become the higher cost development play. New step-changes in physical and fiscal efficiencies can improve the conventional forecast to the benefit of all.

CBM has become an important contributor to the WCSB mix of production, and we can expect steady performance and modest growth from this sector for the foreseeable future.

The Western Canadian Sedimentary Basin has the potential, and the momentum, to maintain its status as one of the most prolific, continental natural gas sources for decades to come.

"We think Horn River is going to be a very large gas play."

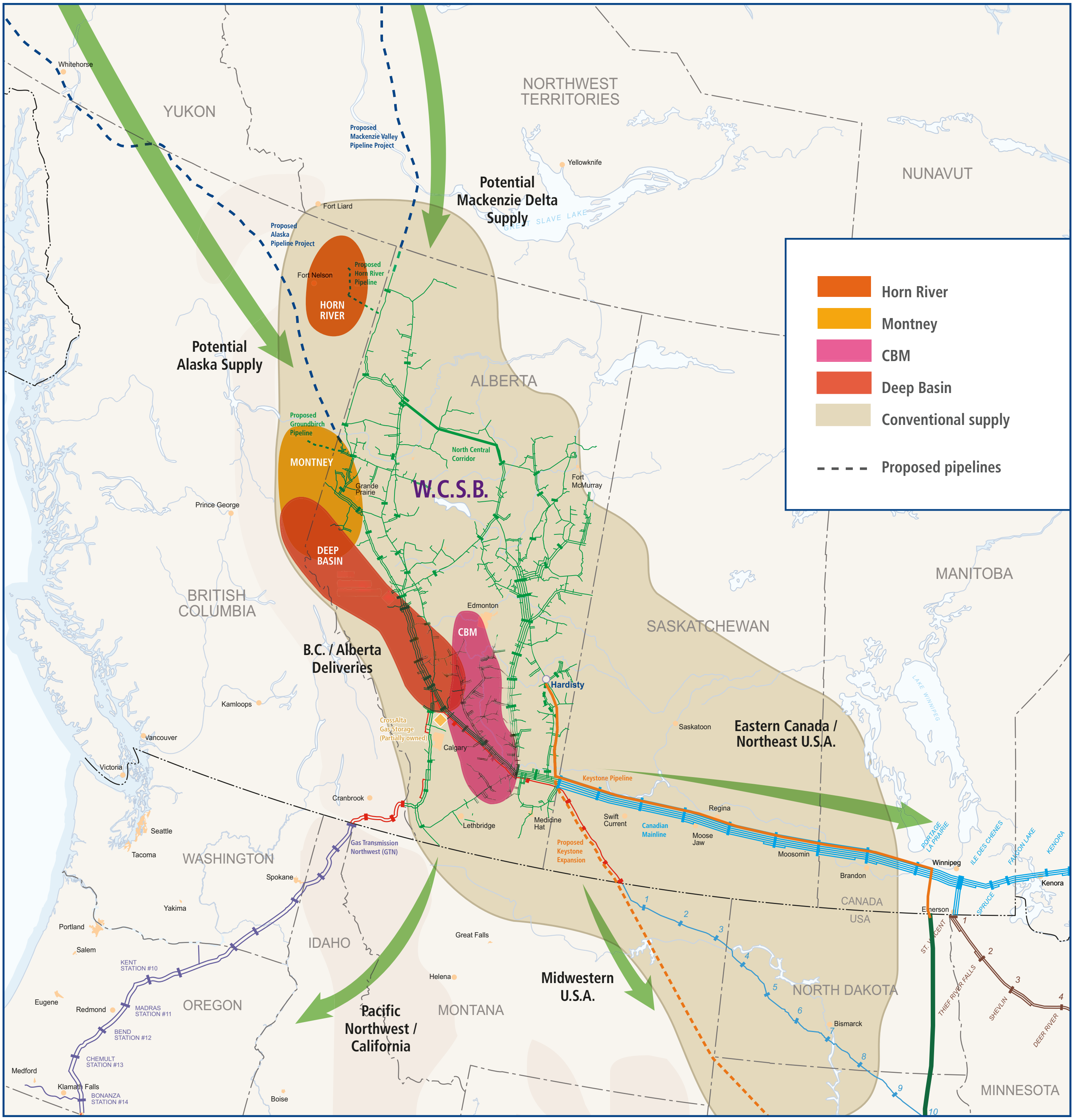
Glenn Darden
President and CEO, Quicksilver Resources Inc.
– *Daily Oil Bulletin*, February 26, 2009

TransCanada's Alberta System:
Where Supply and Markets Meet

"Going forward, natural gas will become a larger part of the world's energy equation."

George Kirkland
Executive VP, Upstream & Gas, Chevron
– *Daily Oil Bulletin*, October 13, 2009

TransCanada's Alberta System



PHYSICAL STATISTICS OF ALBERTA SYSTEM

- Approx. 24,000 km (15,000 miles) of pipeline of various pipe diameter ranging from 60.3 mm (NPS2) to 1,219 mm (NPS 48)
- 50 compressor stations (900 MW of total compression power)
- Average throughput of approximately 10 Bcf/day
- Approx. 1,000 receipt points
- Approx. 200 Intra and Ex-Alberta delivery points (into Pacific Northwest, California, U.S. Northeast and Midwest markets)
- Directly connected to over 320 Bcf of storage capacity at seven locations

SUPPLY CONNECTIONS TO THE WCSB

Having the capability to move well over 11 Bcf/d, with connections to virtually all WCSB supplies at approximately 1,000 receipt points, TransCanada's Alberta system is one of the largest individual pipeline systems on the continent. With access to over 320 Bcf of storage, and enjoying free access to one of North America's largest trading hubs, NIT, all supplies connected to the Alberta system are effectively aggregated and pooled at one transaction point for send-out to most of the major markets in North America. The net effect is unparalleled flexibility for a producer, and unrivalled purchasing efficiency and security for a gas buyer.

Because the Alberta System's pipeline infrastructure has such supply depth, and such reach throughout the entire basin, it's uniquely positioned as the most capital efficient provider of new facilities and services to growing supplies in both Alberta and B.C. With the switch to Federal jurisdiction, TransCanada's Alberta System can now extend its infrastructure across provincial borders and provide direct, integrated gas transmission service directly to NIT. This means that the Alberta System can be extended to the doorstep of new WCSB production sources such as the Horn River and Montney areas with commercial service being provided on a rolled-in basis thus reducing the economic hurdles faced by emerging B.C. shale plays.

EnCana

"Horn River also looks to be twice as productive on a per-well basis as other, more well-known shale plays in North America."

Mike Graham
President of EnCana's
Canadian Foothills Division
– Platts Gas Daily, Sept 11, 2009

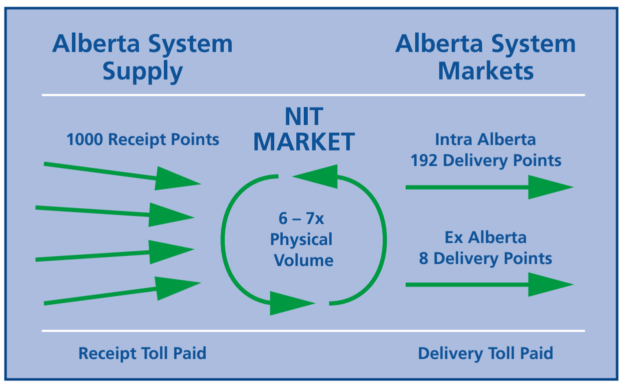
The value of the integrated Alberta System is most readily apparent in current projects underway, such as the Horn River, Montney, and North Central Corridor (NCC) projects. Here the Alberta System is advantaged by the capital, transactional, and jurisdictional efficiencies that have attracted and optimized the new shale plays in B.C.

NIT – The Market for Gas

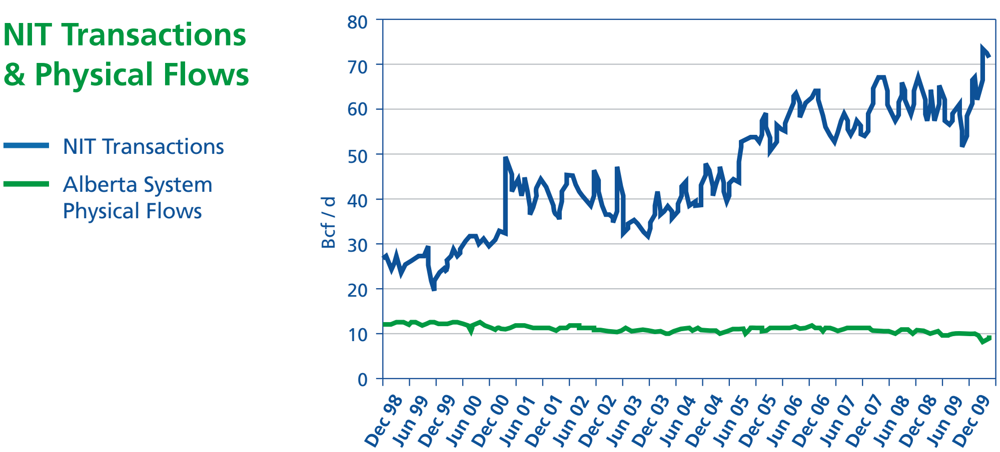
NIT is the engine behind one of the largest trading points on the continent. Customers access NIT by either (a) paying a receipt toll to get onto the Alberta System, (b) paying a delivery toll to leave the Alberta System, or (c) creating a NIT account for trading purposes. Once gas is on the system, it can transact as many times as needed. NIT transactions are free.

It doesn't matter if receipt points are in Southeast Alberta or up in the Horn River Basin of B.C., as soon as a customer's gas crosses the flange at the meter station it can trade at NIT.

Supply Flowing to NIT Flowing to Markets



NIT Transactions & Physical Flows



NIT – Alberta's Natural Gas Hub

The terms AECO, NIT and increasingly Alberta Hub are used interchangeably to refer to the Alberta gas price and the Alberta pricing point. Many in industry, including major industry publications such as Gas Daily, still refer to the WCSB market price as AECO (or the AECO-C Alberta Hub). The name AECO-C comes from the Alberta Energy Company storage facility at Suffield in southeast Alberta and the name lives on today. While the Suffield facility still exists, the term AECO no longer reflects the point at which Alberta gas pricing is determined. Alberta gas pricing is determined at NIT, which is a notional location on the Alberta System. Since NIT is the engine that drives the huge number of transactions in the market and provides the flexibility required by the Alberta System customers, NIT truly is Alberta's natural gas hub.

Liquidity. Transparency. Hundreds of buyers and sellers. Strong underlying physicals, including vast amounts of flowing gas, access to storage and effectively to line pack. Buying at NIT is arguably the most secure supply arrangement there is.

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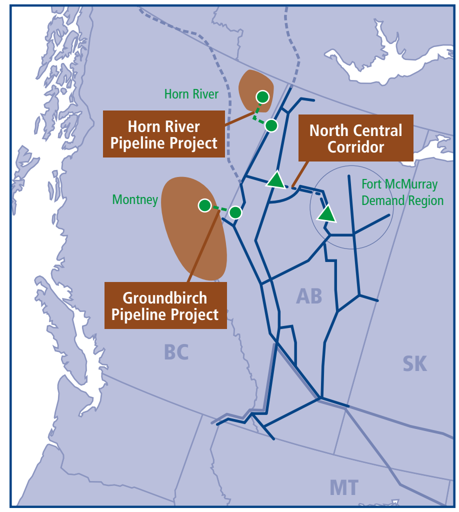
NEW SUPPLY ACCESS AND SYSTEM OPTIMIZATION



In the face of a significant shift from traditional conventional supplies towards tight sands and resource plays, TransCanada is developing a number of projects to access the growing shale supplies in B.C., and optimize the efficient deliveries of gas across the Alberta System. These projects are low capital extensions into these plays and provide access to the existing capacity and market liquidity of the Alberta System.

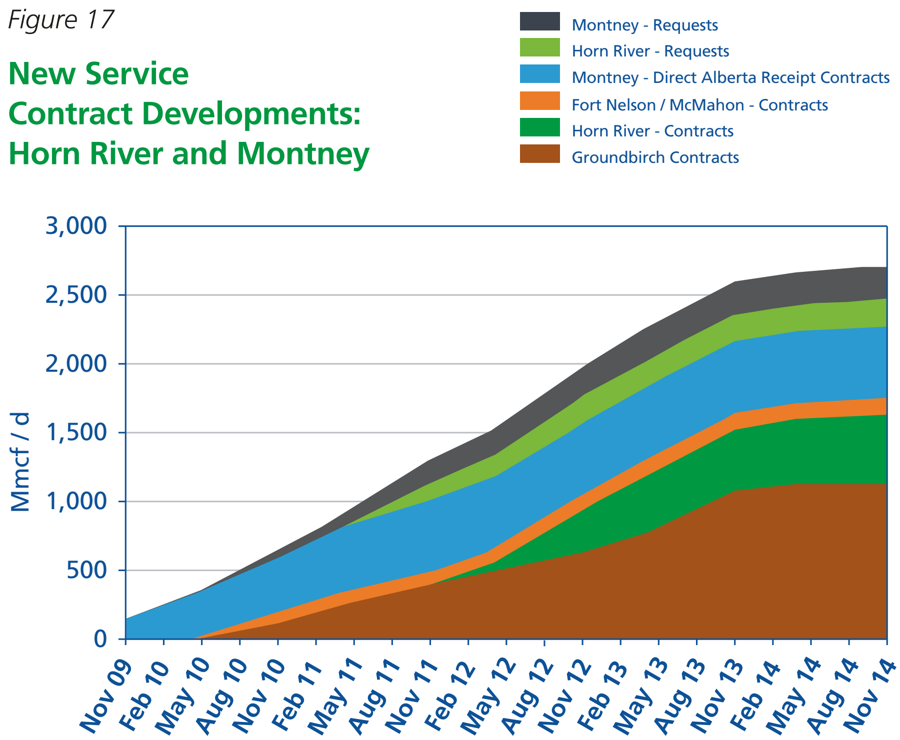
The Horn River Project is a 155 km (96.3 miles), 36/24" pipeline extension from our Northwest mainline into Northeast B.C. With initial contracts signed for 503 Mmcf/d and an in-service date of 2012. We expect future potential of up to 1.6 Bcf/d on this line.

The Groundbirch Mainline project is a 77 km (47.8 miles), 36" pipeline which will connect the Montney reserves directly to the Alberta System by November 2010. With initial contracts in place for 1.1 Bcf/d, we project growth up to 1.6 Bcf/d on these facilities.

Figure 17 shows the recent developments from the rapidly developing supply in B.C. that will connect with the Alberta System. TransCanada has executed contracts for service on its proposed Groundbirch and Horn River pipeline projects, for service at the outlet of the Fort Nelson and McMahon gas plants, and with other producers that have directly connected to the existing Alberta System. Additionally, TransCanada is examining additional requests for service from the Horn River and Montney plays.

Figure 17

New Service Contract Developments: Horn River and Montney



The North Central Corridor (NCC), to be placed in service in April 2010, is designed to meet and help balance out the system changes due to large scale shifts in supply and demand across the Province. This 42" pipeline will provide the necessary capacity to:

a) accommodate new supply growth in Northwest Alberta
b) integrate the shale plays of B.C.
c) utilize facilities in Northeast Alberta made spare by declining local supplies
d) service the oil sands and other Intra-Alberta growth
e) bolster delivery capacity at the Alberta/Saskatchewan border, and
f) optimize the facilities for the onset of frontier gas.

The NCC will also have the net effect of reducing the overall distance of haul on the Alberta System, resulting in a reduction in fuel consumption on the entire system by roughly 50%.

Myth:

All new B.C. shale gas production will go to the new Kitimat LNG project, which is proposed to export more gas away from traditional WCSB markets.

Reality:

TransCanada has transportation contracts in place that will result in the building of pipeline infrastructure for B.C. shales, and this creates a natural capital efficiency to build on. Individual producers may or may not commit to Kitimat, but the initial pipeline projects are being constructed to the Alberta System and NIT.

Positioning for Frontier Gas

TransCanada is both a proponent and an equity partner in the Alaska Pipeline Project and the Mackenzie Valley Pipeline project, which, in aggregate will provide roughly 5.5 to 6 Bcf/d of new supply to the Alberta System. As a key criteria, TransCanada's facilities planning process in Alberta will continue to incorporate the most efficient Frontier integration plan.

We expect that when Northern shippers come to scrub down their "South of 60" delivery options, the TransCanada Alberta System will continue to be first in capital efficiency, toll competitiveness, and greatest market diversity — including NIT.

The Alberta System and NIT: connected, efficient, great value, and positioned for growth.
The Alberta System is executing its plan to ensure that the WCSB becomes even more attractive.

"It's very promising that the land sale showed such a substantial increase on the conventional gas side."

Bob McManus
Alberta Energy, referring to strong results in Alberta government's year-end land sale
– *Daily Oil Bulletin*, December 17, 2009

Implications for Exports:
The Effect of Game Changers on TransCanada's Forecasts

"The industry has invested almost $30 billion dollars in British Columbia over the last eight years."

David Collyer
President, CAPP
from CAPP website – May 7, 2009

IMPLICATIONS FOR WESTERN CANADIAN EXPORTS

Throughout the previous sections the focus has been on the recent developments in Alberta and B.C., creating cost and efficiency gains that suggest a potential for a more robust supply outlook than contemplated in even our most recent base case.

This section deals with what it all means for exports.

1. FORECASTING SCENARIOS

The game changers discussed in this report have the potential of improving the outlook for the WCSB.

To illustrate the impacts of such uplift, we have provided some sensitivities around our existing base case forecast. As a baseline, it's important to understand TransCanada's key assumptions.

TransCanada's Base Case Forecast Assumption

1. Slow recovery from the current economic recession, and modest economic growth for the rest of the decade.
2. Average NYMEX price of $3.81 for 2009, $4.76 in 2010, and $5.38 US$/MMbtu in 2011.
3. Strong continental gas production and modest economic growth is expected to result in NYMEX prices averaging $5.75 (constant dollars) through 2015.
4. A continuing growth in unconventional gas supplies is expected, allowing for increases in domestic supply at modest prices.
5. Growth in domestic supply means relatively low levels of LNG imports.
6. Northern Frontier supplies (Mackenzie Delta and Alaska) are not included in the base case;
7. Gas demand growth will be very modest over the next decade:
   a) Growth in electricity demand is less than in prior forecasts
   b) Industrial demand is flat or declining in most regions
   c) Growth in gas demand for the Alberta oil sands remains strong
8. Pipeline infrastructure development and changes to pipeline flows will be driven more by the development of new, largely unconventional supplies than by growing gas demand.

2. TRANSCANADA'S BASE CASE SUPPLY FORECAST

In TransCanada's current base case scenario, WCSB production is expected to remain essentially flat at about 15 Bcf/d to 2020.

The National Energy Board projects that total WCSB supply to be essentially flat although slightly lower than TransCanada's at roughly 14 Bcf/d.

Although not included in the base case, *Figure 19* highlights how Northern Frontier supplies mix in with the current base forecast of WCSB production.

Industry Comparisons

Figure 20 compares TransCanada's forecast with comparable estimates from other major organizations.

Taken together, the expectation is a rather wide range of production possibilities by 2020 from those surveyed — from 14 Bcf/d to a high of 20 Bcf/d. A key determinant of each of these forecasts is the varying outlook of the growth and performance of unconventional plays in Western Canada.

Figure 18

WCSB Supply: Base Case Forecast

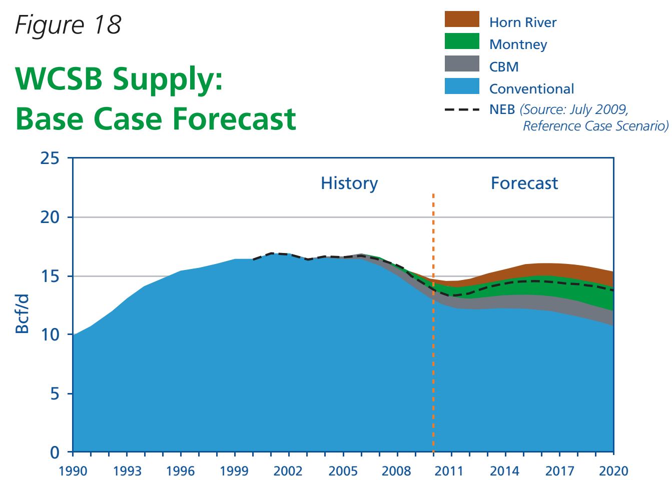


Figure 19

Total WCSB Supply and Northern Potential

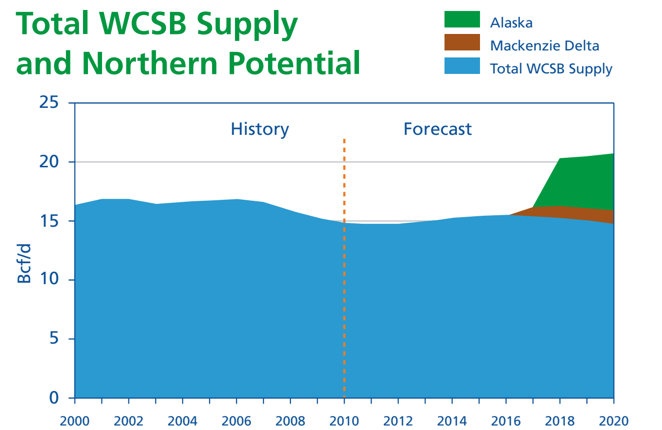


Figure 20

WCSB Supply Comparisons

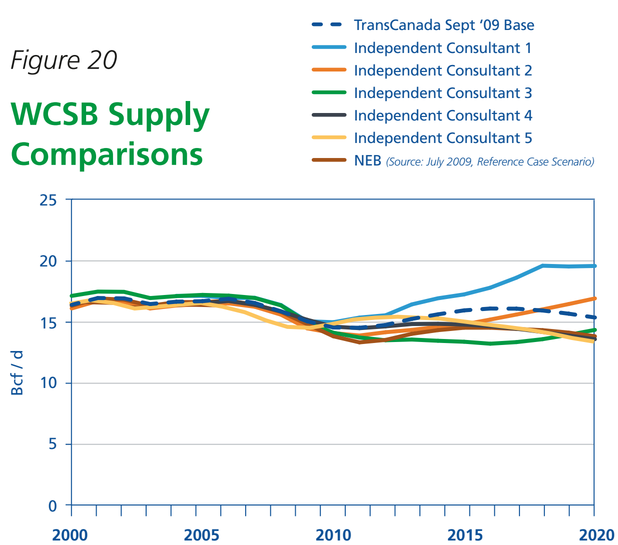
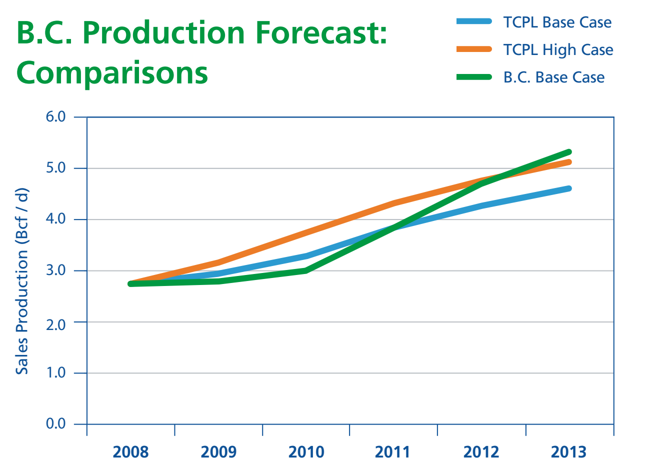


Figure 21

B.C. Production Forecast: Comparisons



Source: B.C. Ministry of Energy, Mines, and Petroleum Resources.

Implications for Exports

Aggregate Base Case Outlook for Conventional and Unconventional

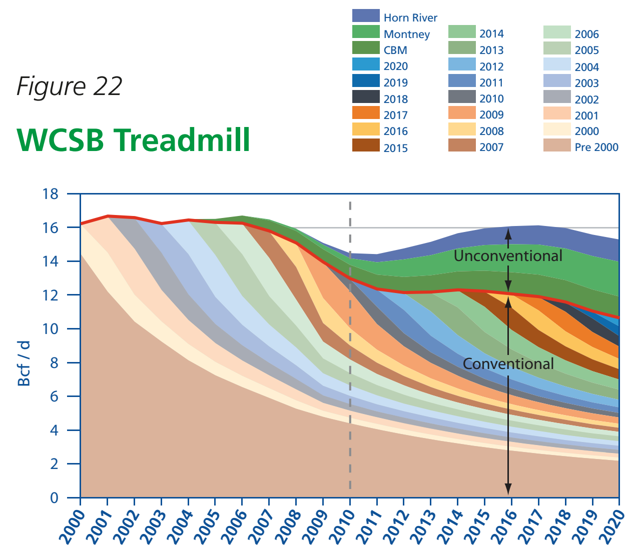
Figure 22 illustrates supply contributions by year with TransCanada's base case WCSB forecast.

- If drilling was to stop in any given year, the supply profile would follow the decline as shown.
- By 2020, conventional supply is still expected to provide 70% of new gas needed by 2020.

Note that unconventional supply shown will replenish in the same annual fashion as the conventional production.

Figure 22

WCSB Treadmill



Sept. 09 Base Case: Price Forecast as referenced on page 40.

3. TRANSCANADA'S HIGH SHALE CASE FORECAST — SENSITIVITY STUDY

The TransCanada high shale case referenced in this section *(see Figure 23)* considers the same basic assumptions as the TransCanada base case, but considers a stronger outlook for WCSB supply, driven by strong supply growth from the Montney and Horn River plays in British Columbia. Conventional and CBM supply is unchanged from the base case. This case also reflects the same outlook for Western Canadian demand as the base case, and does not include supply from either the Mackenzie Delta or Alaska.

Figure 23

WCSB High Shales Case Production Forecast

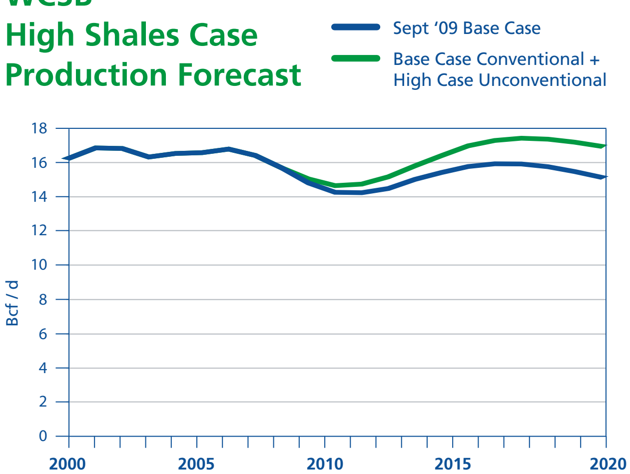
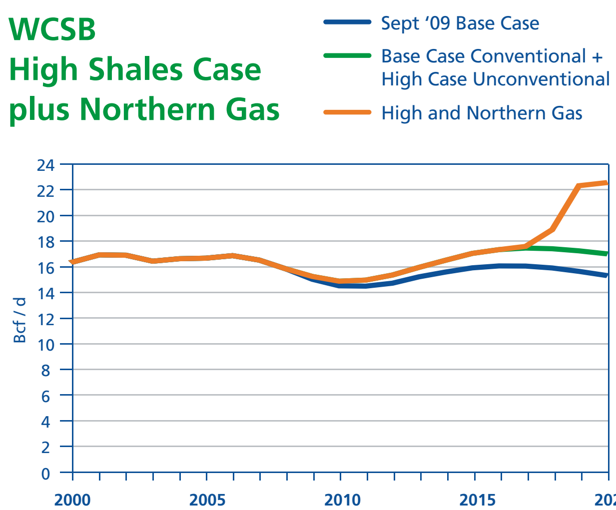


Figure 24

WCSB High Shales Case plus Northern Gas



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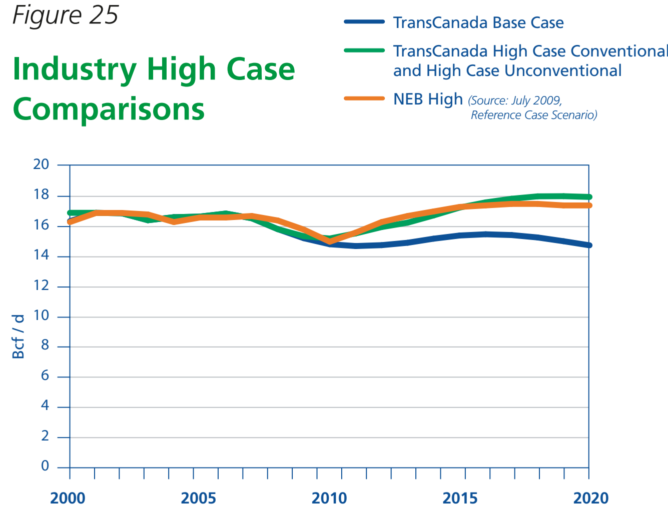
4. TRANSCANADA'S HIGH CONVENTIONAL AND HIGH SHALE FORECAST – SENSITIVITY STUDY

This case adds the conventional high case assumptions, which among other things relies on positive outcomes of the Alberta royalty review.

Figure 25

Industry High Case Comparisons

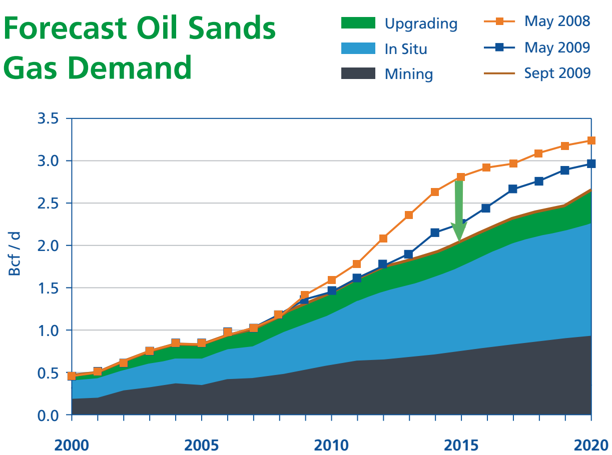


5. BASE CASE WESTERN CANADIAN DEMAND

The main engine for natural gas demand growth in Western Canada is the Alberta oil sands, which accounts for the majority of industrial demand growth. Western Canadian demand in 2008 consisted of 57% industrial demand, which will grow to 63% by 2020.

Figure 26

Forecast Oil Sands Gas Demand



The 2008/2009 recession, coupled with the rapid decline in crude oil prices, put many oil sands projects on hold and TransCanada, along with other forecasters, made significant changes to its oil sands production forecasts between 2008 and 2009. These changes are illustrated in *Figure 26*.

Most oil sands projects use natural gas to generate steam for the extraction process and for the production of hydrogen, which is used to upgrade bitumen into lighter synthetic crude. The quantity of natural gas varies between processes and projects but, on average approximately 1 Mcf of gas per barrel of production is currently being used in the oil sands. This is expected to decline as newer, more efficient processes are employed. However, natural gas is still the preferred fuel in the majority of new projects.

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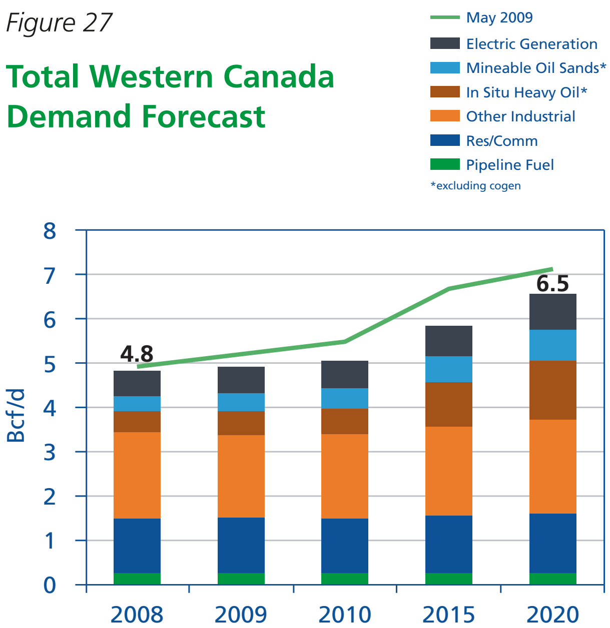
Implications for Exports

Figure 27

Total Western Canada Demand Forecast



The forecast consumption of natural gas in oil sands is shown in *Figure 26*. Demand is forecast to grow from 1.2 Bcf/d in 2008 to 2.7 Bcf/d in 2020, an increase of 1.5 Bcf/d. This is considerably lower than the growth in the 2008 forecast.

Other sectors that are growing, at a more modest pace, are the residential and commercial sectors and electric generation segment — much of which is associated with oil sands development. The resulting total Western Canadian demand growth is on the order of 1.7 Bcf/d from 2008 to 2020.

This growth is lower than the May 2009 forecast, as illustrated in *Figure 27*, due to the slower pace of oil sands development, a decline in the petrochemicals sector and the impact of the recession on the fertilizer market.

Low Case Western Canadian Demand Scenario

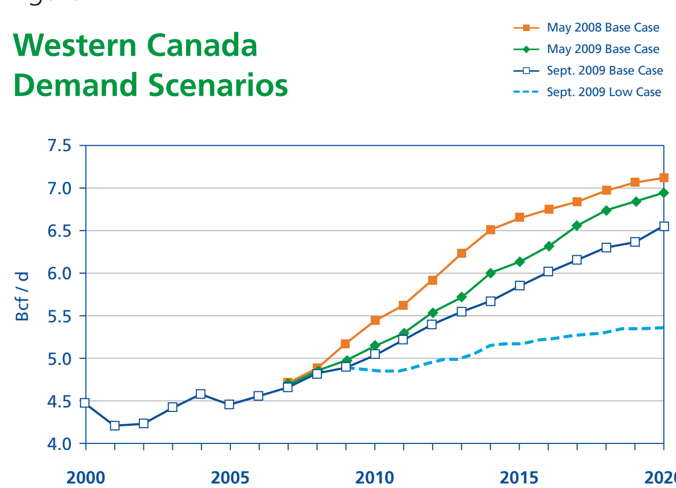
The prospects for oil sands project development have improved during 2009 as crude oil prices have recovered. The TransCanada low case demand scenario assumes that project developments are put on hold either due to a slower than expected recovery in world oil demand, leading to lower oil prices, or environmental legislation and taxes that could slow oil sands development.

Should these negative outcomes occur, development may be slowed to approximately 2 million barrels per day of production. Under these circumstances Western Canada demand growth could be slower, as illustrated in *Figure 28*. In this scenario demand grows to 5.3 Bcf/d by 2020, 1.2 Bcf/d less than the base case forecast of 6.5 Bcf/d, and presumes no more oil sands projects come on line.

While we don't use this low case in our scenarios, it does illustrate that there is potential upside for exports.

Figure 28

Western Canada Demand Scenarios



6. WESTERN CANADIAN EXPORTS

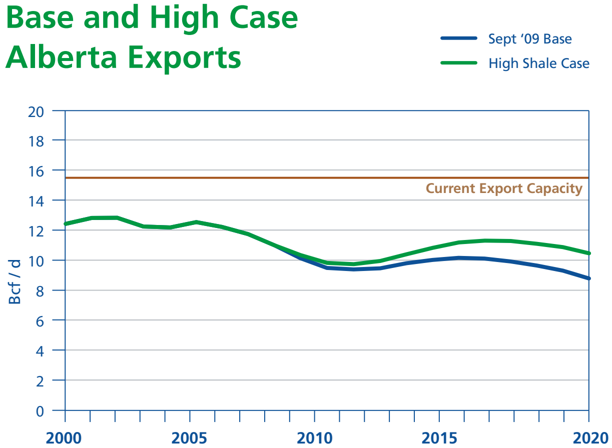
The difference between WCSB production and Western Canadian demand is the volume of gas available for export from the basin.

In our base case, supply growth approximately offsets demand growth leaving exports from the WCSB essentially flat over the next decade at 9 to 10 Bcf/d.

As shown in *Figure 29*, our high case forecast produces a higher export result, where total flows leaving Alberta would climb to about 11.5 Bcf/d.

Figure 29

Base and High Case Alberta Exports



The construction of new ex-basin pipeline appears unlikely in the current environment of significant excess capacity. The most probable drivers of new ex-basin capacity are:

a) the potential connection of significant volumes of northern gas,
b) an exceptionally strong performance by WCSB shale plays, or
c) a more modest aggregate decline rate from conventional resources.

Each of these drivers would also increase utilization of existing ex-WCSB pipelines.

Key Sensitivities to Export Flows:

Two factors that would contribute to further increases in export volumes include:
a) increased conventional production which could be driven by Alberta royalty changes, and
b) a reduction in Western Canadian demand growth forecast.

Conclusion: Impacts for Exports

Our current base case forecast shows Alberta exports flattening out at around 9 Bcf/d for the balance of the decade. In the high case, exports climb to about 11.5 Bcf/d.

It remains to be seen whether the game changing events discussed in this report can bring about the high case reality. However, we see the basis for optimism and the need to carefully assess and monitor the effects of the game changers.

Industry Input

COMMENTS FROM THE CANADIAN SOCIETY FOR UNCONVENTIONAL GAS (CSUG)

Natural Gas in the Western Canada Sedimentary Basin

Mike Dawson
President, Canadian Society for Unconventional Gas

While many investors who follow the natural gas industry have "written off" the Western Canada Sedimentary Basin (WCSB) as being mature and uneconomic in comparison to the emerging shale basins in United States, companies that are still producing from this region are just now beginning to recognize the potential of the "unconventional natural gas resources" that lie within this large geographic region. Recent exploration efforts in the Horn River Basin and the Montney trend have identified hundreds of trillions of cubic feet (TCF) of natural gas that has the potential to provide a stable assured supply for many years to come.

The resurgence of the WCSB as an attractive region to explore for oil and gas can be attributed primarily to the application of new drilling and completion technologies. Horizontal drilling and multi-stage fracturing is being used widely to access the hydrocarbons that are locked into the traditionally "tight" reservoirs throughout British Columbia, Alberta, Saskatchewan and even the southwest corner of Manitoba. New reservoirs are being developed and improved recoveries are being achieved from existing pools as a result of the new "horizontal" paradigm.

Governments also are recognizing the importance of the unconventional resources that the WCSB has to offer. Drilling and royalty incentives have been implemented by the provinces to create a competitive foundation upon which the new unconventional resource industry can grow.

There is no question that the WCSB has faced some significant challenges in recent years relative to cost competitiveness and declining conventional production. Many companies have responded to these challenges by embracing new and emerging technologies that have improved productivity while at the same time deriving cost efficiencies and savings. New and revised business models recognize the importance of efficiency, cost effectiveness and a synergistic approach to development. The application of these business elements along with new technologies will ensure that emerging unconventional natural gas resource plays from Western Canada will provide a sustainable supply of natural gas to the North American market for many years.

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