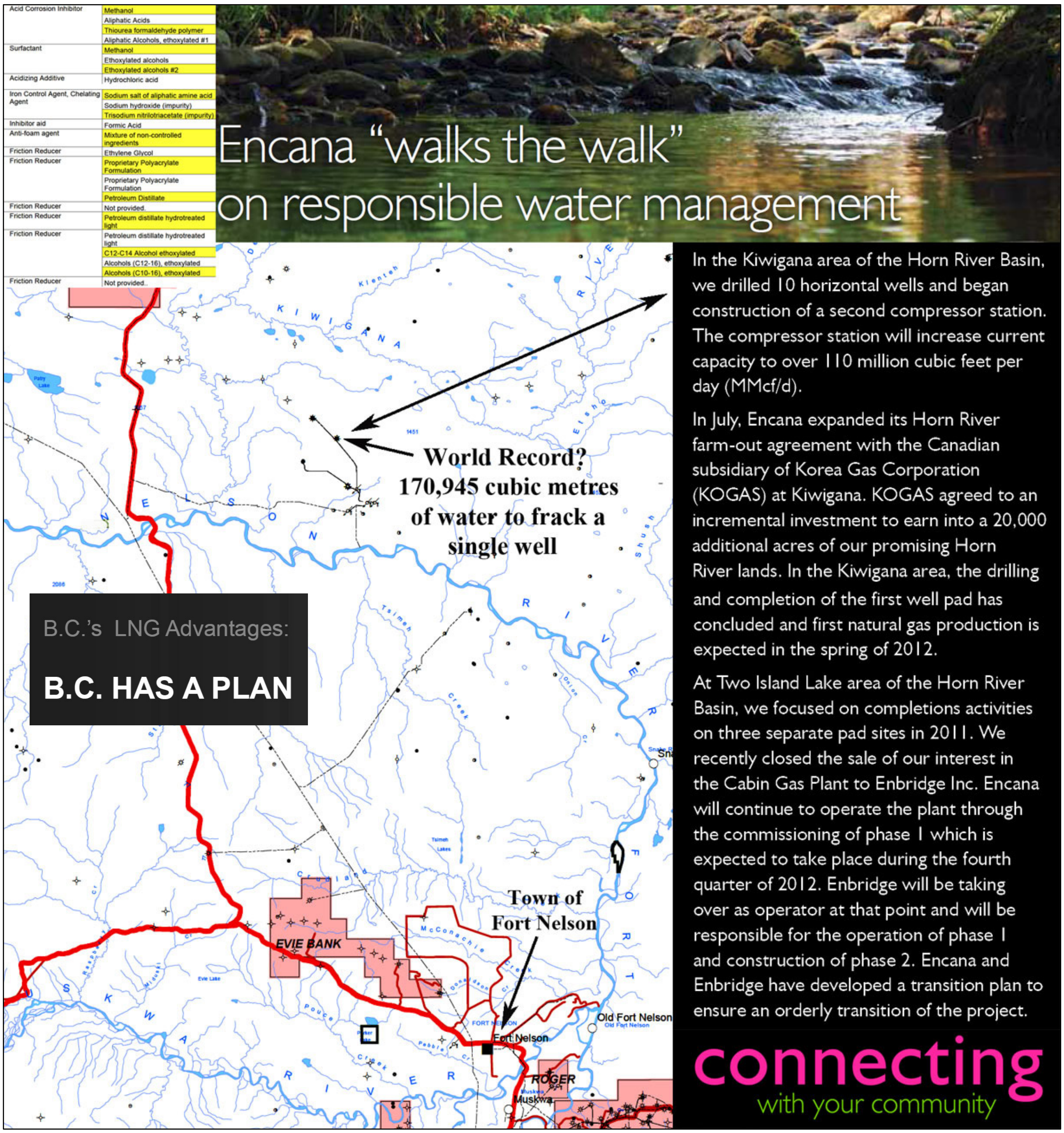
FRACK-MATH CONFIDENTIAL:

Cracking Open the Big Mystery on Water Volume Use in British Columbia's Multi Fracking Operations

By Will Koop
December 11, 2013
http://www.bctwa.org/FrackingBC.html



Cut-outs to right and top right from EnCana Corporation's Spring 2012 Newsletter, *Connecting with Your Community*.

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Conversion Table

1 Cubic Meter of water = 1,000 litres
1 Cubic Meter of water = 264.172 U.S. gallons
1 Cubic Meter of water = 219.969 Imperial (Canadian) gallons
1 Cubic Meter of water = 0.9586 Metric Tonnes
1 Metric ton = 2,204.623 pounds

EnCana's World Fracking Record / Single Well = 170,945 cubic metres of water
= 37,602,600.7 Imperial Gallons
= 45,158,882.54 U.S. Gallons
= 170,945,000 litres
= 163,867.88 Metric Tonnes

1. Introduction

As a connected outcome of a report recently published by the author on November 27, 2013, The Tip of BC's Fracking Iceberg: Frac-Focus Chemical Data, Water Volumes, Fracking Locations, and Operators in the Altares Gas Field, *North of Hudson's Hope, BC, Near and Within the Farrell Creek Watershed Area*, [1] which investigated the use of chemical additives and water usage in fracking operations in a small area north of Hudson's Hope, an investigation quickly followed to determine water usage for all of British Columbia's controversial fracking fields or "plays."

Experts have so far identified at least four extensive, unconventional hydrocarbon plays in northeast BC, the Montney, Cordova Embayment, Horn River, and Liard, geological formations within a small upper northwest segment of a massive continental formation known as the **Western Sedimentary Basin**, within which energy operators and the service industry have fracked, and continue to frack, thousands of unconventional oil and gas wells in western Canada and the northwest United States.

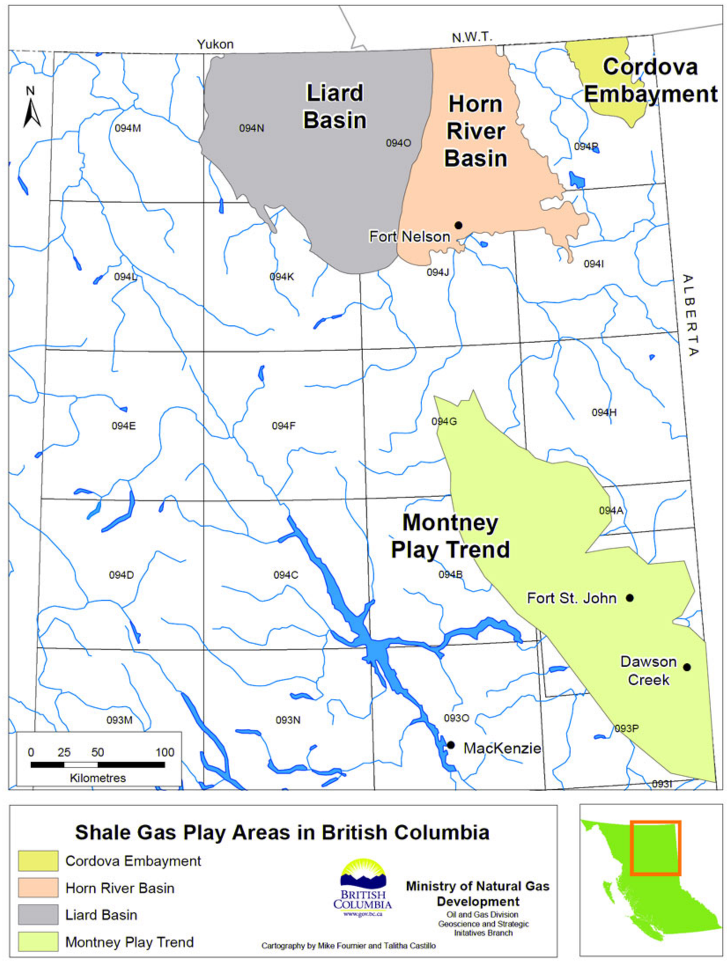


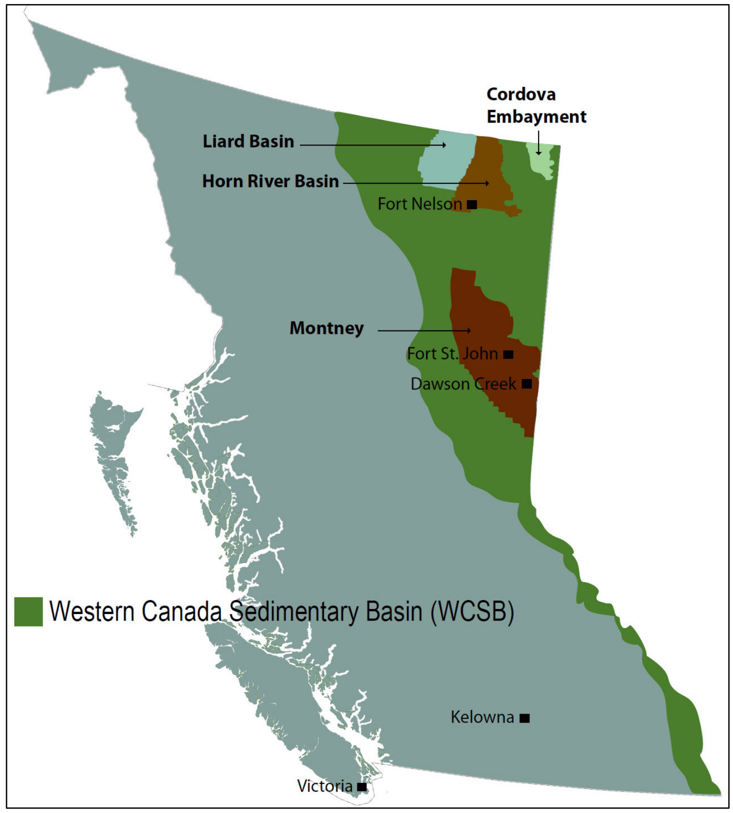
Figure 1. Key shale gas regions of Northeast British Columbia.

The map here copied from the new BC Ministry of Natural Gas Development's Oil and Gas Reports 2013-1, *Summary of Shale Gas Activity in Northeast British Columbia 2012*, shows the four "plays," a vast area in northeast BC, a triangular zone stretching about 650 kilometres in distance from the bottom right hand corner of the map to the top left or western boundary of the Liard Basin. What is not revealed on this map are the connected zones and intense petro activities in Alberta, directly to the right of the map, as BC's political border is separate from the petro political borders of oil and gas realms. As residents always note, there are often more Alberta license plates than BC plates seen in northeast BC.

Prior to January 1, 2012, the public was not provided with the incremental individual data, or numbers, of water volumes used in either single, or multi-stage, fracking ops for unconventional gas and oil wells by the oil and gas industry in northeast (or early ops in southeast) British Columbia. After January 1, 2012, this water volume data became transparent following the BC government's mandate for industry to publish its water use and chemical additive fluid data on the Frac-Focus website.

[1] Since the release of the report, minor revisions were made to correct a few spelling and factual errors, a modified version was updated on December 5, 2013.

Due to the loaded controversies of industry's use and abuse of water for fracking ops, no rigorous tests have been applied to verify or provide public confidence, through independent and accountable peer-reviewed scrutiny, of the water volume numbers that industry provides to Frac-Focus, as that data is both voluntary and based on 'trust' of a given operator's well activity records.



As was the case with the author's November 27, 2013 Alteras Gas Field report for a small representative area of northeast BC (some 1,200 square kilometres), all of the Frac-Focus oil and gas well data registry for all of northeast BC was retrieved from each of BC's **41** oil and gas energy operators by way of completed fracking operation entry dates of late November 2011 to December 2, 2013 (despite inherent nagging questions about water volume data confidence). Afterwards, it took six days to sort and enter data from the **718** entries onto a master spreadsheet table. The data was then multi-analyzed under various themes and categories for the production of numerous themed spreadsheet tables for all of northeast BC.

The two years of collected Frac-Focus data on reported water volumes used to frack individual wells is adequate to build a sound temporary understanding and projections on water volume numbers and good working guesses on water usage in the Montney and Greater Horn River Basins formation plays.

However, care must be taken in jumping to conclusions about fracking ops from the two year Frac-Focus data collection. In 2012 following, there has been a significant downward trend or decline in fracking ops in the Greater Horn River Basins where the largest fracking operations on the planet have apparently occurred. The downward trend is primarily due to the combined low monetary value of natural gas, greater costs from developing infrastructure in remote and isolated wilderness areas and increased service contracts and transportation costs, waiting for the air to clear on industry's intense political lobbying efforts for the government's push on controversial LNG (Liquified Natural Gas) and proposals to increase the electric grid capacity to service the fracking industry through added hydroelectric developments, i.e., Site C on the Peace River. The primary reason for the BC Liberals' proroguing (cancellation) of the Legislature in the Fall of 2013 is due to an integrated agenda to push and sell LNG as hard and fast as able and possible.

The information in this report on water usage will be undeniably critical as the concerned public wrestles with the threat of single and/or multiple LNG development proposals, with LNG's dependent need on aggressive fracking ops in northeast BC and in other BC unconventional plays yet to be tapped and harnessed, and the staggering cumulative environmental and social impacts associated with life-cycle fracking operations.

Why the BC government, through its energy Ministries, has itself yet not chosen to reveal comprehensive and accurate water volume usage from oil and gas well data - which it has amassed as hard copy and digital records, and can be easily and speedily compiled for the public's review - is an utter and disturbing mystery! The public has an inherent and constitutional right to this secret and obstructed data, even as, or more than the extensive and inclusive controversial rights granted by the government to the energy industry for water withdrawals and usages.

Another mystery is the fact that an unknown pool of this critical data, which is otherwise routinely hidden in what industry and government have conveniently classified as "confidential wells," where, oddly, total water volume data used to frack individual wells are not to be disclosed to the public!

No one has, until now, published summaries of the Frac-Focus public data on water volume usages in northeast British Columbia, which the present report purports to constructively accomplish. Prior to this report, all of the information by government and industry on water usage has been generalized or subjective. NGOs, public advocacy groups and concerned citizenry have been merely guessing about these numbers for the past three years, and wanting to get better information.

For the first time since multi-stage fracking operations seriously began about 2003 following, this civilian report aims to crack open the big mystery, not only to act as a catalyst for public discussion, but ultimately for the government and industry to fully disclose of all the data on water use for fracking ops since that time, including the early advent of horizontal drilling since the early 1990s.

Though the exorbitant use of water and its untreatable pollution and removal from the hydrologic cycle is a common and critical public concern, the life-cycle of fracking has many other detrimental environmental and social effects components and layers, each one of which may be as important on their own intrinsic merits as water use and water waste is.

As disturbing and grotesque as water corruption usage for fracking is for British Columbians, it is equally disturbing for its usage in Alberta, Saskatchewan and Manitoba, and for proposals throughout Canada. It is disturbing by the seemingly endless occurrences throughout the United States, and in many regions of the world. That's not to say that other experimental practices associated with nitrogen and carbon dioxide fracking by the service industry are by any means safer or better, as they have their own unique problems.

What is also disturbing is where the contaminated fracking and flow-back fluid waste is ultimately destined, much of it removed under intense artificial pressure as untreatable garbage into deep underground "injection" sites. What are the total numbers of these injection sites for British Columbia, for Alberta, for all of Canada, for the United States, for the world, and what are the combined volume totals for all those discarded fluids into these underground sites? What are the cumulative results of this bizarre methodology from injected pressures regarding upward, evolutionary, and inevitable mobile communication leakages to aquifers and to the earth's surfaces?

As an illustrative glimpse or hint of the world's sordid injection fate, here are some quotes from a September 24, 2013 *Amicus Curiae Brief* submitted to the Texas Supreme Court by the Texas Oil and Gas Association lobby group, and a following quote from a Texas law review journal, concerning an ongoing, unresolved court action in Texas that began in 1996:

This brief is tendered on behalf of the Texas Oil and Gas Association (TXOGA), which is paying the fee for its preparation. TXOGA is the largest and oldest petroleum organization in Texas, representing more than 5,000 members. The membership of TXOGA produces in excess of 90 percent of Texas' crude oil and natural gas, operates 100 percent of the state's refining capacity, and is responsible for the vast majority of the state's pipelines.

TXOGA member companies produce a quarter of the nation's oil, a third of its natural gas and account for one-fourth of the U.S. refining capacity.

As detailed in TXOGA's earlier brief, Class II injection wells are critical to the production of oil and gas. See Jan. 7, 2013 Br. at 12-15. The Railroad Commission has permitted more than 50,000 Class II injection wells. TXOGA members throughout the state depend upon injection wells to dispose of produced water, which is a necessary byproduct of oil and gas extraction. After this produced water is injected into nonproductive formations, horizontal migration miles below ground is inevitable, but it is impossible for an injection well operator to predict or control the precise path of migration within a formation that could span dozens of square miles. If anyone who owned an interest in property above a conceivable migration path could prevent an injection well from operating (either by suing for an injunction or holding out for excessive compensation), the ability to dispose of produced water, and in turn the ability to produce oil and gas, would be significantly compromised.

Because the ability to produce oil and gas is inextricably tied to the availability of injection wells, a new common law cause of action that threatens operation of injection wells likewise threatens oil and gas production.

As TXOGA's earlier brief and the parties' briefs detail, Texas jurisprudence demonstrates that subsurface property rights in the context of oil and gas production are not absolute. Under settled oil and gas law precedent, property owner A has no reasonable expectation that he can preclude adjacent property owner B from undertaking authorized activities incident to oil and gas production on B's property merely because they affect the movement of fluids miles below the surface of A's property. These decisions appropriately reflect the fact that there are no "property lines" in the deep subsurface. Contrary to FPL's argument, there also is no "tradition" of liability for operating a permitted well that causes no actual, recoverable damages.

> No. 12-095, Texas Supreme Court, Supplemental Brief of Amicus Curiae, filed September 24, 2013, Environmental Processing Systems, L.C. (Petitioner), vs. FPL Farming Ltd. (Respondent).

While the type of well at issue in FPL Farming is a TCEQ permitted Class I well, the most common type of injection well in Texas is an RRC permitted Class II injection well. There are approximately 50,000 of these wells in Texas and they are used for oilfield-related functions. A sizeable portion of these wells, about twenty percent, is used to dispose of saltwater produced from horizontal drilling.

The implications of the decision loom large. Although the case is nominally about a Class I waste injection well, the Beaumont court's analysis may also be applied to other subsurface trespass claims, including claims resulting from migration of saltwater from Class II injection wells commonly used by the oil and gas industry, or even claims from fracking. As such, many are watching the court to find out if this application of trespass will be affirmed, and if it is affirmed, whether limits are applied to available remedies.

> Continuing Saga of FPL Farming V. Environmental Processing Systems: *Will the Texas Supreme Court Set New Rules of Liability for Underground Trespass?* Charles Nixon, in Texas Journal of Oil, Gas, and Energy Law, 8 Tex. J., 428, June 27, 2013.

2. The Data

2.1. Summary Data

All **718** British Columbia gas and oil well data entries were retrieved from the [Frac-Focus website] at the end of November 2013. The entries had end-of-fracking dates ranging from late November 2011 to late November 2013. Selective data was then transferred from the data sheets onto a multi-category master table or spreadsheet, from which all the data was interpretively rendered, dissected, and analyzed.

Out of the **718** gas and oil well data entries, **628**, or **83 percent**, of which were chosen as candidates for **Table 1**, as the remaining **90** wells were those mostly of a separate category, those primarily associated with nitrogen and carbon dioxide based fracking operations, where water usage amounts varied from **0.1 to upwards of 1,000 cubic metres** per well. A separate accounting of this category of **90 wells** is provided, a grouping with a combined total of **37,047 cubic metres**, or, for perspective, a figure **four and a half times less** the volume of the largest single well fracked by EnCana in 2012 in the Horn River Basin, or **16,000 m3 less** than the Montney single well record.

The wells in **Table 1** demonstrate water use characteristics by operators in three fracking zones in northeast BC over a two year period: the Greater Horn River Basins, the Upper and Lower Montney Basin.

Table 1. Summary - BC Frac-Focus Reported Water Volumes and Wells Fracked - 2012-2013

Fracking Play	Total Wells Fracked November 2011 - November 2013	Average Volume of Water / Well (cubic metres)	Total Water Volumes (cubic metres)
Greater Horn Basins	74	70,164.05	5,192,139.89
North Montney	222	11,070.82	2,457,721.95
South Montney	332	7,680.11	2,549,797.38
Totals	**628**	**16,241.50**	**10,199,659.22**

Of a total **554** wells fracked in the Montney Basin over a two year period, where a total volume of **5,007,519.33** cubic metres of water was recorded, that figure is just under the **5,192,139.89** cubic metres of water recorded in the Greater Horn Basin for **74** wells, a difference factor of about **seven and a half (7.5) times**!

As summarized below, **24** wells, or one third of the **74** wells in the Horn, were fracked from one multi-well pad or location site in late 2011 to 2012, EnCana's **Kiwigana** wells, the combined water volumes of which total **2,510,508.44** cubic metres, or one half the total volume of water used in the two year period by all the other operators in the Greater Horn Basins.

This commonly understood, yet disturbing, relationship between greater water usages in the Greater Horn Basins in the north and lesser water usages the Montney Basin in the south should not in anyway be meant to condone water usages in the Montney. A sober and conscientious perspective should be applied whenever comparing an already absurd level of water use for the Montney by yet more absurd or revolting amounts in the Greater Horn Basins. In turn, the limited two-year data nevertheless demonstrates that much more water is required for multi-stage fracking in the North Montney than in the South Montney, a factor of about **one and a half (1.5) times greater**.

2.2. The Energy Operators and Frac-Focus Registry Well Data Entry Totals and Statistics

The **718** Frac-Focus data entries (including **10** for late 2011) were made by **forty-one (41)** registered energy operators in northeast BC. All of the energy operators currently registered with Frac-Focus are as follows, which includes the numbers of total wells fracked (in parentheses) for each energy operator from late November 2011 to 2013:

1. ARC Resources Ltd. - **50**
2. Apache Canada Ltd. - **8**
3. Artek Exploration Ltd. - **16**
4. Baytex Energy Ltd. - **1**
5. Black Swan Energy Ltd. - **9**
6. Bonavista Energy Corporation - **3**
7. Canadian Natural Resources Limited - **44**
8. Canbriam Energy Inc. - **14**
9. Carmel Bay Exploration Ltd. - **1**
10. Carnaby Energy Ltd. - **1**
11. ConocoPhillips Canada Operations Ltd. - **2**
12. ConocoPhillips Canada Resources Corp. - **4**
13. Crew Energy Inc. - **20**
14. Crocotta Energy Inc. - **6**
15. Dejour Energy (Alberta) Ltd. - **1**
16. Devon Canada Corporation - **5**
17. Devon NEC Corporation - **5**
18. EnCana Corporation - **117**
19. Enerplus Corporation - **2**
20. Imperial Oil Resources Limited - **8**
21. Murphy Oil Company Ltd. - **23**
22. Nexen Energy ULC - **18**
23. Painted Pony Petroleum Ltd. - **14**
24. Paramount Resources Ltd. - **2**
25. Pengrowth - **2**
26. PennWest - **17**
27. Procyon Energy Corp. - **1**
28. Progress Energy Canada Ltd. - **68**
29. Quicksilver Resources Canada Inc. - **8**
30. Ramshorn Canada Investments Ltd. - **1**
31. Secure Energy Services Inc. - **1**
32. Shell Canada Limited - **101**
33. Sinopec Daylight Energy Ltd. - **4**
34. Storm Resources Ltd. - **20**
35. Suncor Energy Inc. - **3**
36. TAQA North Ltd. - **1**
37. Talisman Energy Inc. - **73**
38. Tervita Corporation - **1**
39. Tourmaline Oil Corp. - **22**
40. UGR Blair Creek Ltd. - **6**
41. Yoho Resources Inc. - **2**

Table 2 focuses on a list of the top **23** water use energy operators registered with Frac-Focus, with **668** wells fracked over a two-year period, a combined, astounding **10,153,836.68 cubic metres** of water usage. [2] The highest recorded instance of water use per well is also featured in Table 2 for each operator during this period, with EnCana taking the big prize: setting perhaps the world record, of **170,945.2 cubic metres fracked for a single well**!

As summarized below, the activities of the above listed operators, and other operators not on this list because their fracking operations preceded the Frac-Focus mandate, were in decline or in hibernation from 2012 following. Other operators not on the Frac-Focus registry may have postponed operations for various reasons, or operators' land tenure holding interests may have been sold to other parties. It is very complicated to root out accurate operator activity data and to provide accurate assessments: only generalized assessments about the operators are made in this report.

[2] The remaining **18** operators were not chosen due to lower water usages, and/or where nitrogen and carbon dioxide fracking operations were conducted.

Table 2. BC Frac-Focus Data, 11/2011 - 11/2013: Top 23 Fracking Operators, Northeast BC

Operator	Wells Fracked 2011 / 2012	Water Volumes 2011/2012 / Operator Average cubic metres	Wells Fracked 2013	Water Volumes 2013 / Operator Average cubic metres	Total Wells Fracked 2011-2013	Water Volumes 2011-2013 / Operator Average cubic metres	Highest Water Volume / Single Well & Region cubic metres
EnCana	86	2,439,390.75 **28,365.01**	31	857,764.94 **27,669.84**	117	**3,297,155.69** **28,180.82**	**170,945.2** (Kiwigana)
Talisman	49	715,832.58 **14,608.83**	24	277,999.01 **11,583.30**	73	**993,831.59** **13,614.13**	**19,681.30** (Altares)
Nexen	18	869,913.05 **48,328.50**	0	0	18	**869,913.05** **48,328.50**	**60,331.61** (Komie)
Shell Canada	66	558,629.66 **8464.10**	35	260,378.72 **7,439.40**	101	**819,008.38** **8,108.99**	**27,884.40** (GrndBirch)
Progress	39	412,128.71 **10,567.40**	29	335,917.26 **11,583.35**	68	**748,045.97** **11,000.68**	**20,814.40** (Green)
Quicksilver	8	676,971.90 **84,621.50**	0	0	8	**676,971.90** **84,621.50**	**119,716.50** (Tattoo)
Imperial Oil	8	561,679.00 **70,209.90**	0	0	8	**561,679.00** **70,209.90**	**71,816.70** (Komie)
PennWest	17	551,148.10 **32,420.50**	0	0	17	**551,148.10** **32,420.50**	**57,725.80** (Helmet)
ARC	16	132,778.73 **8,298.70**	34	214,304.96 **6,303.09**	50	**347,083.69** **6,941.67**	**53,313.00** (Tower)
CNRL	10	38,221.29 **3,822.10**	34	280,203.9 **8,241.29**	44	**318,425.19** **7,236.94**	**12,255.00** (Septimus)
Tourmaline	24	123,425.73 **5,142.74**	11	87,384.55 **7,944.05**	35	**210,810.28** **6,203.15**	**14,305.75** (Doe)
Canbriam	6	50,191.66 **8,365.28**	8	120,907.16 **15,113.40**	14	**171,098.82** **12,221.34**	**19,687.54** (Altares)
Crew	7	24,869.07 **3,552.72**	13	108,955.20 **8,381.17**	20	**133,824.27** **6,691.21**	**11,081.59** (Septimus)
Painted Pony	6	54,681.51 **9,113.59**	8	78,189.35 **9,773.67**	14	**132,870.86** **9,490.78**	**15,038.25** (Town)
Conoco Res Cp	0	0	4	76,943.00 **19,235.75**	4	**76,943.00** **19,235.75**	**59,498.00** (Blueberry)
Black Swan	5	38,131.32 **7,626.26**	4	29,399.10 **7,349.78**	9	**67,530.42** **7,503.38**	**11,416.90** (N Aitken)
Apache	2	150.40 **75.20**	6	52,731.20 **8,788.53**	8	**52,881.60** **6,610.2**	**12,086.20** (Sundown)
Crocotta	1	587	5	41,225.29 **8,245.01**	6	**41,812.29** **6,968.72**	**11,061.21** (Doe)
Storm Res	8	6,032.50 **754.10**	12	20,334.00 **1,694.50**	20	**26,366.50** **1,318.33**	**2,854.50** (Umbach)
Bonavista	2	17,174.80 **8,587.40**	1	6,005.20 **6,005.20**	3	**23,180.00** **7,726.67**	**9,378.90** (W Blueberry)
Murphy Oil	21	20,320.58 **967.65**	2	1,529.00 **764.50**	23	**21,849.58** **949.98**	**1,394.84** (Sundown)
UGR Blair	6	6,390.60 **1,065.10**	0	0	6	**6,390.60** **1,065.10**	**1,195.60** (Jedney)
Yoho	2	5,015.90 **2,507.95**	0	0	2	**5,015.9** **2,507.95**	**4,861.30** (Nig)
Totals	**407**	**7,303,664.84** **17,945.12**	**261**	**2,850,171.84** **10,920.20**	**668**	**10,153,836.68** **15,200.35**	

The oil and gas well fracking activities of some of the larger and integrated energy company / corporate operators have investment portfolios and land holdings distributed in several, or many, oil and gas regions throughout northeast BC. For instance, with EnCana's activities over a two year period for its total **117** wells, those activities were dispersed through **9** oil and gas Regions, and in two different Basins: Brassey (**2**), Dawson (**5**), Kelly (**8**), Noel (**2**), Sunrise (**49**), Swan (**25**), and the Tower (**1**) Regions in the South Montney; and the Kiwigana (**24**) Region in the southwest border of the Horn River Basin northwest of the Town of Fort Nelson.

Other energy operators, such as Talisman, has all of its Frac-Focus registered data of **73** wells for this period confined to a minute quarter, the Alteras Gas Field in the North Montney, just north of the Town of Hudson's Hope, as featured and narrated in the *Tip of BC's Fracking Iceberg* report.

Operator and U.S.-based Apache, otherwise active in former years, particularly in the Horn River Basin area, has almost no activities registered with Frac-Focus. As stated elsewhere, Apache broke a world record in mid-2010 for the largest fracking operation in the Horn River Basin at Two Island Lake, only to have its partner energy operator, and former first LNG proposal partner, EnCana, break that world frack and field record a few months later on multi-well pad **63-K**, since apparently outdone by other records set by EnCana in the Kiwigana Region to the southwest in 2012.

Shell Canada proved it is a strong 'new gas age' devotee of the South Montney, with aggressive activities in the Sunset (**33**), Groundbirch (**46**), Saturn (**9**), and Monias (**6**) Regions, while flirting with three regions in the North Montney, Blueberry (**3**), Gundy (**3**), and Blair Creek (**1**).

Murphy Oil, another active operator in the Sundown and Swan Regions in the South Montney, is apparently hooked on nitrogen and carbon dioxide fracking, using only **21,850** cubic metres of water to frack **23** wells, **21** of which were fracked in 2013.

2.3. Watch Out for all that "Average" Business

The trick or catch about reading public government and private energy industry reports concerning water usage in fracking operations in northeast BC, is how authors and presenters always relate or describe the "average" use of water in multi-well fracking operations. Though important for some to 'calculate' trends, **Table 2**, under the **Highest Water Volume / Single Well & Region** column, distances itself entirely from these "average" notions, giving the public a strong sober dose of the big or 'peak' records for oil and gas wells, that is, as reported only over the last two years.

2.3.1. The South Montney

The geographical divide between the North and South Montney is defined by the east to west latitude flow of the Peace River, a name no longer representative or appropriate for the recent and current environmental and political petro agendas in the region: a Peace destroying much and many.

For the oil and gas Regions of the South Montney, the Frac-Focus data includes highest water volume use in **16** Regions: Brassey, Dawson, Doe, Grounbirch, Kelly, Monias, Noel, Parkland, Saturn, Septimus, Sundown, Sunrise, Sunset, Sunset Prairie, Swan and Tower. These recordings are presented in **Table 3** for each Region and for individual energy operator. From these highest water volumes, the **average highest use** figure for a single well is **17,560.19** cubic metres. ARC Resources has the big prize for the South Montney, at **53,313.00** cubic metres to multi-frack a single well.

Table 3. South Montney: Highest Water Volumes per Region / Operator, 2012 - 2013.

Region	Operator	Well Location	Well Number	Fracking Date	Highest Water Volume Cubic Metres
Brassey	EnCana	041-D/093-P-10	28275	11/24/2012	**18,020.50**
Dawson	EnCana	35-077-15	26921	03/18/2012	**10,870.10**
Doe	Tourmaline	28-080-15	28463	02/15/2013	**14,305.75**
Groundbirch	Shell Canada	10-080-21	28034	11/06/2012	**27,884.40**
Kelly	EnCana	068-H/093-P-01	27884	06/27/2012	**20,978.10**
Monias	Shell Canada	11-081-21	27378	06/18/2012	**6,757.90**
Noel	EnCana	074-L/093-P-01	28305	11/02/2012	**24,149.30**
Parkland	ARC Resources	32-080-16	28793	05/27/2013	**9,535.80**
Saturn	Shell Canada	09-080-19	28267	08/09/2013	**14,606.90**
Septimus	CNRL	36-081-20	27995	05/29/2013	**13,848.00**
Sundown	Apache	026-L/093-P-08	27139	01/17/2013	**12,086.20**
Sunrise	Tourmaline	13-080-16	28921	05/23/2013	**10,787.61**
Sunset	Shell Canada	20-080-18	27637	10/20/2012	**21,063.10**
Sunset Prairie	Tourmaline	04-079-18	26149	08/18/2012	**8,714.60**
Swan	EnCana	068-B/093-P-09	27277	05/12/2013	**14,223.70**
Tower	ARC Resources	10-082-17	27964	04/12/2012	**53,313.00**
				Highest 'Average'	**17,560.19**

2.3.2. The North Montney

For the oil and gas Regions of the North Montney, the Frac-Focus data includes highest water volume use in **32** Regions: N Aitken, Altares, Attachie, Beg, Birch, Blair Creek, Blueberry, W. Blueberry, Bubbles, W Buick, Cameron, Caribou, Daiber, Fireweed, Graham, Green, Gundy, W. Gundy, Inga, Jedney, Julienne, Kobes, Laprise, Lily, Nig, W. Nig, W. Peejay, Pocketknife, W. Stoddart, Town, Townsend, and Umbach.

These recordings are presented in **Table 4** for each Region and for individual energy operators. From these highest water volumes, the **average highest use** figure for a single well is **10,954.55** cubic metres. Shell Canada has the big prize for the North Montney, at **47,067.90** cubic metres to multi-frack a single well.

The 'average highest use' figures difference between the North and South Montney zones is the reverse of the summary well and water use data from **Table 1**, which shows that more water is being used to frack wells in the North Montney. This is perhaps related to the fact that fracking activities in the North Montney are not yet as developed and aggressive as they are in the South Montney, as energy operators are much closer to energy operating infrastructures and developments.

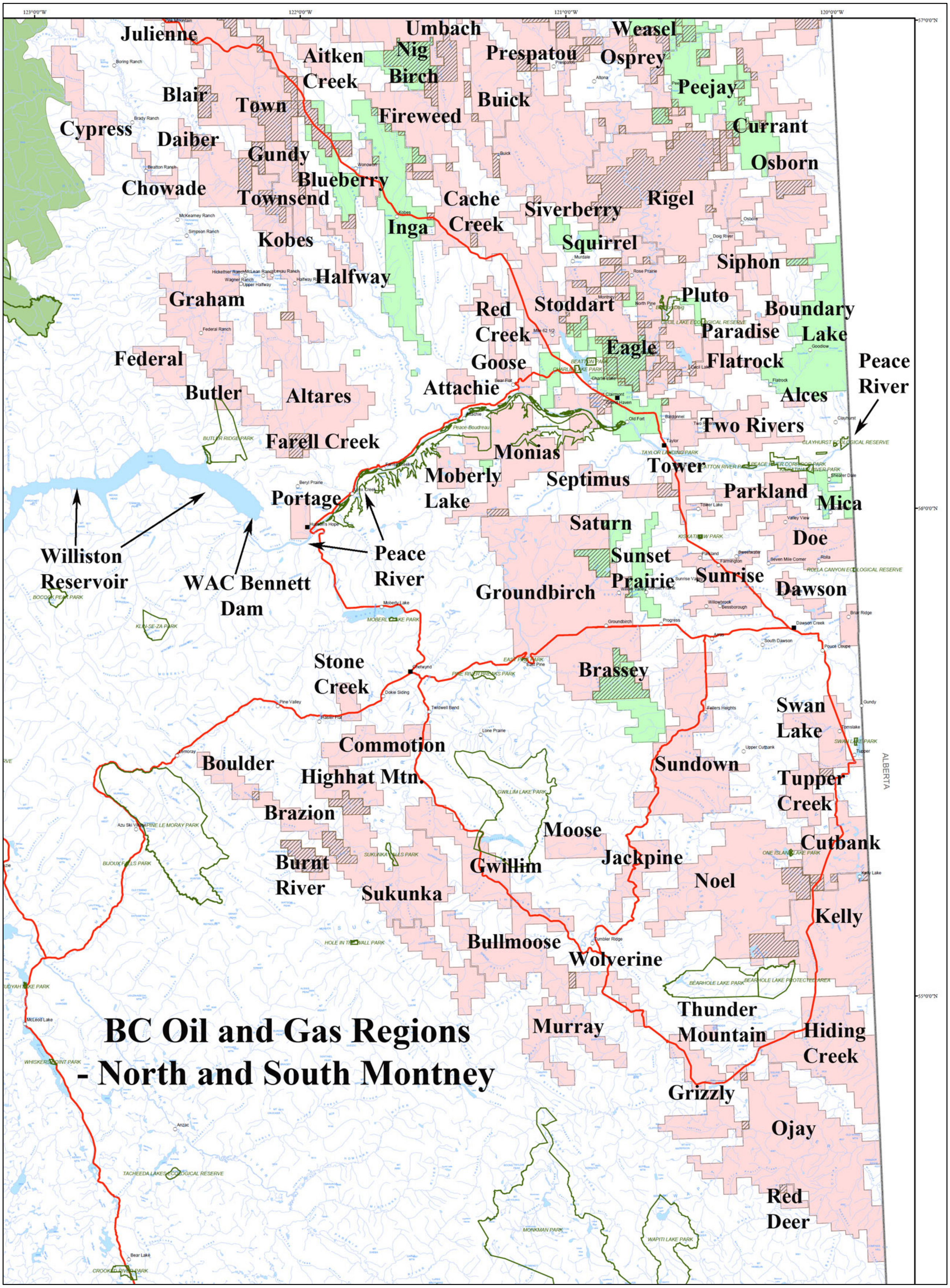
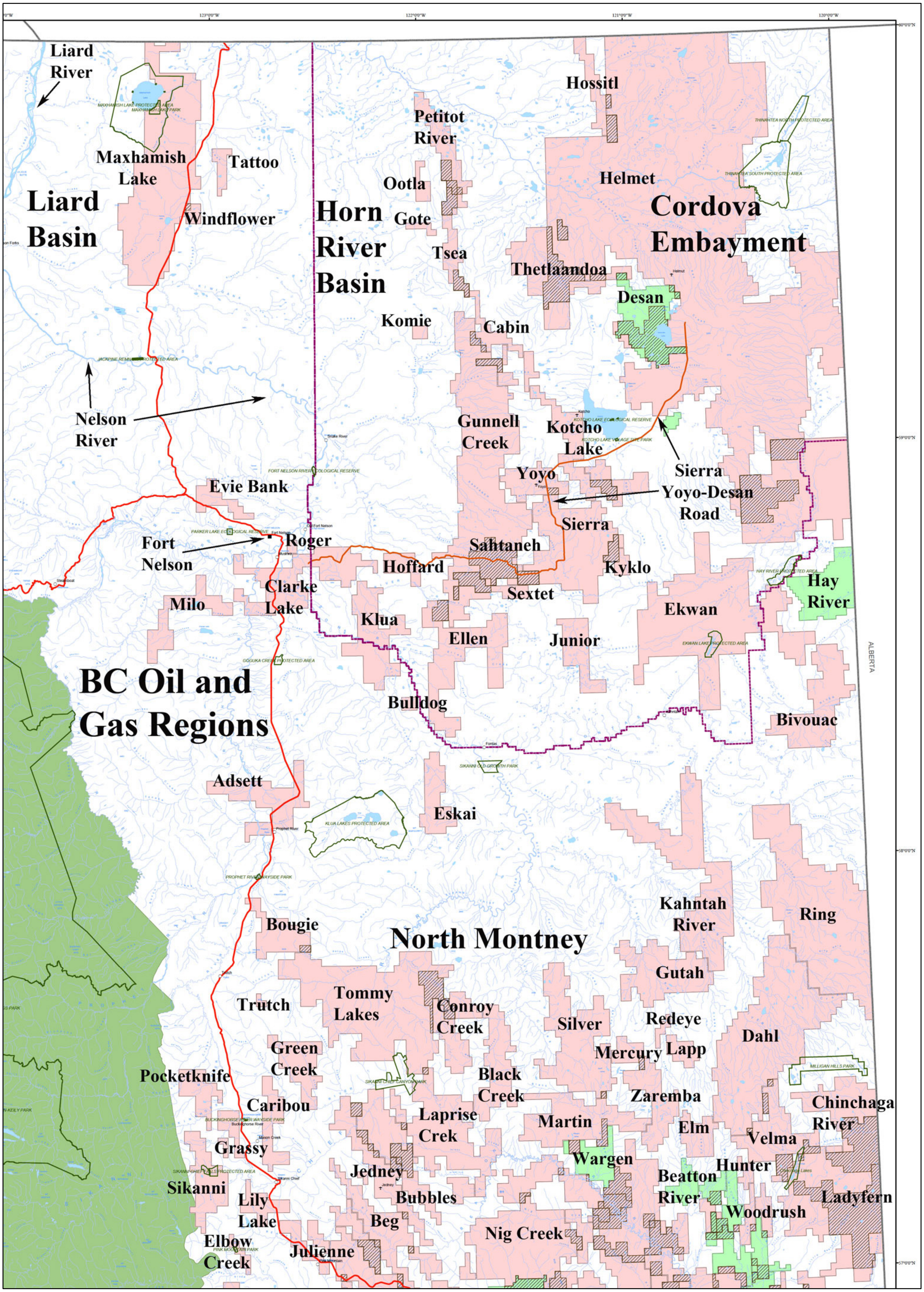

BC Oil and Gas Regions
- North and South Montney
Julienne
Umbach
Weasel
Aitken
Creek
Nig
Birch
Prespatou
Osprey
Peejay
Blair
Town
Cypress
Daiber
Gundy
Fireweed
Buick
Currant
Osborn
Chowade
Blueberry
Townsend
Cache
Creek
Inga
Siverberry
Rigel
Squirrel
Kobes
Halfway
Siphon
Graham
Red
Creek
Stoddart
Pluto
Boundary
Lake
Paradise
Federal
Goose
Eagle
Flatrock
Peace
River
Butler
Altares
Attachie
Alces
Two Rivers
Farell Creek
Monias
Tower
Moberly
Lake
Septimus
Parkland
Mica
Portage
Saturn
Doe
Williston
Reservoir
WAC Bennett
Dam
Peace
River
Sunset
Prairie
Sunrise
Groundbirch
Dawson
Stone
Creek
Brassey
Swan
Lake
Commotion
Boulder
Highhat Mtn.
Sundown
Tupper
Creek
Brazion
Moose
Cutbank
Burnt
River
Sukunka
Gwillim
Jackpine
Noel
Kelly
Bullmoose
Wolverine
Thunder
Mountain
Hiding
Creek
Murray
Grizzly
Ojay
Red
Deer
ALBERTA

Table 4. North Montney: Highest Water Volumes per Region / Operator, 11/2011 - 2013.

Region	Operator	Well Location	Well Number	Fracking Date	Highest Water Volume Cubic Metres
N Aitken	Black Swan	011-A/094-G-01	28546	02/07/2013	**11,416.90**
Altares	Canbriam	027-H/094-B-08	27956	07/25/2013	**19,687.54**
Attachie	ARC Resources	09-084-22	28198	09/22/2012	**6,190.70**
Beg	Black Swan	079-G/094-G-01	28071	08/09/2012	**10,326.90**
Birch	CNRL	043-K/094-A-13	28723	07/11/2013	**9,156.70**
Blair Creek	Shell Canada	078-G/094-B-16	27042	02/13/2012	**6,938.20**
Blueberry	Conoco Phillips Res Corp.	030-E/094-A-13	28239	11/02/2013	**11,369.00**
W. Blueberry	Bonavista	046-L/094-A-12	27930	03/09/2012	**9,378.90**
Bubbles	Black Swan	068-E/094-H-04	28741	02/20/2013	**8,779.60**
W Buick	Storm Res.	008-D/094-H-03	28868	07/11/2013	**2,820.5**
Cameron	Progress	009-A/094-G-02	28593	08/09/2013	**2,047.50**
Caribou	Progress	005-C/094-G-10	28613	07/22/2013	**14,534.70**
Daiber	Painted Pony	080-E/094-B-16	27958	12/03/2012	**13,148.14**
Fireweed	CNRL	052-H/094-A-13	27191	05/29/2012	**1,855.80**
Graham	Progress	079-G/094-B-08	28247	01/21/2013	**17,738.60**
Green	Progress	051-C/094-G-10	28525	09/09/2013	**20,814.40**
Gundy	Shell Canada	020-H/094-B-16	27022	10/29/2012	**47,067.90**
W. Gundy	Progress	044-B/094-B-16	26565	09/08/2012	**12,569.00**
Inga	Artek	013-A/094-A-13	27816	02/27/2012	**8,045.50**
Jedney	Black Swan	051-G/094-G-01	28176	12/15/2012	**10,621.49**
Julienne	Progress	009-G/094-G-02	28543	07/11/2013	**12,730.30**
Kobes	Progress	075-J/094-B-09	27587	08/29/2012	**10,551.50**
Laprise	Black Swan	049-D/094-H-05	15088	03/14/2013	**2,467.40**
Lily	Progress	048-K/094-G-02	28416	03/14/2013	**18,395.80**
Nig	Carmel Bay	022-C/094-H-04	29123	10/22/2013	**11,225.40**
W. Nig	CNRL	097-K/094-A-13	28203	09/12/2012	**9,030.71**
W. Peejay	CNRL	021-G/094-A-15	28845	09/13/2013	**1,233.00**
Pocketknife	Progress	095-L/094-G-07	28477	02/10/2013	**9,203.70**
W. Stoddart	Tervita	30-087-20	28116	08/30/2012	**1,241.80**
Town	Painted Pony	014-F/094-B-16	28210	08/29/2013	**15,038.25**
Townsend	Painted Pony	011-J/094-B-09	28015	03/11/2013	**12,065.20**
Umbach	Storm Res.	071-D/094-H-03	27826	01/25/2013	**2,854.50**
				Highest 'Average'	**10,954.55**



Liard River
Maxhamish Lake
Tattoo
Liard Basin
Windflower
Horn River Basin
Petitot River
Ootla
Gote
Tsea
Komie
Hossitl
Helmet
Cordova Embayment
Thetlaandoa
Desan
Cabin
Nelson River
Gunnell Creek
Kotcho Lake
Yoyo
Sierra Yoyo-Desan Road
Sierra
Evie Bank
Fort Nelson
Roger
Sahtaneh
Hoffard
Kyklo
Sextet
Clarke Lake
Milo
Klua
Ellen
Junior
Ekwan
Hay River
BC Oil and Gas Regions
Bulldog
Bivouac
Adsett
Eskai
Kahntah River
Ring
Bougie
North Montney
Gutah
Tommy Lakes
Trutch
Conroy Creek
Silver
Redeye
Dahl
Mercury
Lapp
Green Creek
Pocketknife
Black Creek
Zaremba
Caribou
Laprise Crek
Martin
Chinchaga River
Elm
Velma
Grassy
Wargen
Hunter
Jedney
Beatton River
Sikanni
Bubbles
Ladyfern
Lily Lake
Woodrush
Beg
Elbow Creek
Nig Creek
Julienne
ALBERTA

2.3.3. The Greater Horn Basins

For the oil and gas Regions of the Greater Horn Basins, the Frac-Focus data includes highest water volume use in only **5** Regions: Fortune, Helmet, Kiwigana, Komie, and Tattoo.

These recordings are presented in **Table 5** for each Region and for individual energy operators. From these highest water volumes, the **average highest use** figure for a single well is **95,706.68** cubic metres. EnCana Corp. has the big prize for the Horn River Basin, for all of British Columbia, and perhaps the planet, at **170,945.20** cubic metres to multi-frack a single well.

Table 5. Greater Horn Basins: Highest Water Volumes per Region / Operator, 11/2011 - 2013

Region	Operator	Well Location	Well Number	Fracking Date	Highest Water Volume Cubic Metres
Fortune - Horn River Basin	Quicksilver	050-A/094-O-15	26073	05/26/2012	**58,329.19**
Helmet - East Cordova Basin	PennWest	064-G/094-P-10	27438	08/21/2012	**57,725.80**
Kiwigana - Horn River Basin	EnCana	067-D/094-O-07	27251	06/29/2012	**170,945.20**
Komie - Horn River Basin	Imperial Oil	009-K/094-O-01	26453	09/05/2012	**71,816.70**
Tattoo - Horn River Basin	Quicksilver	050-A/094-O-15	27482	05/17/2012	**119,716.50**
				Highest 'Average'	**95,706.68**

When making predictions about future fracking water volume usage in northeast BC, it is important to keep these 'upper' or highest water volume figures in mind, because energy operators may be heading more and more in those directions! As already witnessed since the arrival of multi-stage-well fracking in BC since about 2003, an absurd and greedy fracking benchmark for water volumes, frack sand, etc., etc., only leads to another! (Boys with Toys)

2.4. Examining the Greater Horn Basins

Due to the greater or more significant volumes of water required by energy operators to multi-frack unconventional wells in the Cordova, Horn, and Liard Basins than in the Montney (**Table 1**), and the fact that only few data entries have been filed with Frac-Focus about water volumes in only two of these upper three Basins, whereby statistical trends on water volume usage are not as easily understood over the last two years as they may be in the Montney, it is critical to conduct a closer examination of the Frac-Focus data submitted to date, and to analyze data on all of the active wells fracked in these upper fracking Basins prior to the BC Frac-Focus mandate of January 1, 2012.

More details from Frac-Focus data on energy operators in **Table 5** are therefore provided in the following five **Tables, 6 through 10**, in the Horn River and Cordova Embayment Basins, for five energy operators.

Table 6. EnCana's Kiwigana Creek area fracking operations, December 2011 to June 2013, northwest of Fort Nelson (partnership with Korea Gas)

Region	Well Number	Well Name	Well Location	Fracture Date	Fracked By	Volume of Water / Well Cubic Metres
Kiwigana	26754	A	067-D/094-O-07	06/11/2012	Schlumberger	159,057.50
Kiwigana	27248	A-A	067-D/094-O-07	06/13/2012	Schlumberger	116,932.47
Kiwigana	27249	A-B	067-D/094-O-07	05/18/2012	Schlumberger	**170,038.44**
Kiwigana	27250	A-C	067-D/094-O-07	06/30/2012	Schlumberger	101,366.10
Kiwigana	27251	A-D	067-D/094-O-07	06/29/2012	Schlumberger	**170,945.20**
Kiwigana	27252	A-E	067-D/094-O-07	06/29/2012	Schlumberger	159,815.00
Kiwigana	27253	A-F	067-D/094-O-07	06/22/2012	Schlumberger	98,502.50
		6			**Total**	**976,657.21**
Kiwigana	26597	B	015-D/094-O-07	12/05/2011	Schlumberger	104,307.20
Kiwigana	26598	B-A	015-D/094-O-07	01/26/2012	Schlumberger	71,245.20
Kiwigana	26599	B-B	015-D/094-O-07	01/23/2012	Schlumberger	65,586.00
Kiwigana	26600	B-C	015-D/094-O-07	01/26/2012	Schlumberger	65,176.40
Kiwigana	26601	B-D	015-D/094-O-07	01/13/2012	Schlumberger	56,593.40
Kiwigana	26593	C-A	015-D/094-O-07	01/23/2012	Schlumberger	112,059.10
Kiwigana	26594	C-B	015-D/094-O-07	01/26/2012	Schlumberger	115,855.30
Kiwigana	26595	C-C	015-D/094-O-07	01/15/2012	Schlumberger	83,141.80
Kiwigana	26596	C-D	015-D/094-O-07	01/10/2012	Schlumberger	107,742.50
		9			**Total**	**781,706.90**
Kiwigana	28029	A	090-D/094-O-07	06/19/2013	Schlumberger	93,133.44
Kiwigana	28208	A-A	090-D/094-O-07	06/20/2013	Schlumberger	111,414.14
Kiwigana	28213	A-B	090-D/094-O-07	06/20/2013	Schlumberger	116,846.82
Kiwigana	28215	A-D	090-D/094-O-07	05/23/2013	Schlumberger	83,945.28
Kiwigana	28216	A-E	090-D/094-O-07	05/31/2013	Schlumberger	96,188.80
Kiwigana	28217	A-F	090-D/094-O-07	05/31/2013	Schlumberger	84,446.75
Kiwigana	28218	A-G	090-D/094-O-07	05/26/2013	Schlumberger	82,648.00
		7			**Total**	**668,623.23**
Totals		**22**	(11 wells pending)			**2,426,987.34**

Table 7. Imperial Oil's Komie area fracking operations in the Horn River Basin, August to September 2012

Region	Well Number	Well Name	Well Location	Fracture Date	Fracked By	Volume of Water / Well Cubic Metres
Komie	26446	B	008-K/094-O-01	08/21/2012	Schlumberger	70,007.80
Komie	26447	B-A	008-K/094-O-01	08/05/2012	Schlumberger	69,522.00
Komie	26448	B-B	008-K/094-O-01	09/05/2012	Schlumberger	70,474.20
Komie	26449	B-C	008-K/094-O-01	08/25/2012	Schlumberger	69,917.20
Komie	26450	A-A	009-K/094-O-01	08/21/2012	Schlumberger	70,019.00
Komie	26451	A-B	009-K/094-O-01	08/05/2012	Schlumberger	69,932.30
Komie	26452	A-C	009-K/094-O-01	09/04/2012	Schlumberger	69,989.80
Komie	26453	A-D	009-K/094-O-01	09/05/2012	Schlumberger	**71,816.70**
Totals	**8**					**561,679.00**

Table 8. PennWest's Helmet area fracking operations in the East Cordova Basin, June to August, 2012

Region	Well Number	Well Name	Well Location	Fracture Date	Fracked By	Volume of Water / Well Cubic Metres
Helmet	27427	D-A	064-G/094-P-10	08/21/2012	Baker Hughes	53,671.00
Helmet	27429	D-C	064-G/094-P-10	08/21/2012	Baker Hughes	33,452.20
Helmet	27437	D	051-G/094-P-10	07/14/2012	Baker Hughes	23,999.20
Helmet	27438	D-D	064-G/094-P-10	08/21/2012	Baker Hughes	**57,725.80**
Helmet	27439	D-E	064-G/094-P-10	08/21/2012	Baker Hughes	34,353.10
Helmet	27678	D-A	051-G/094-P-10	06/25/2012	Baker Hughes	26,171.00
Helmet	27679	D-B	051-G/094-P-10	07/11/2012	Baker Hughes	46,740.90
Helmet	27756	D-C	051-G/094-P-10	06/18/2012	Baker Hughes	55,699.80
Helmet	27757	D-D	051-G/094-P-10	06/19/2012	Baker Hughes	56,714.80
Helmet	27758	D-E	051-G/094-P-10	06/19/2012	Baker Hughes	35,752.30
Helmet	27759	D-F	051-G/094-P-10	06/19/2012	Baker Hughes	41,712.80
Helmet	27760	D-G	051-G/094-P-10	07/07/2012	Baker Hughes	39,119.90
Helmet	27761	D-H	051-G/094-P-10	07/03/2012	Baker Hughes	43,790.70
Totals	**13**					**548,903.50**

Table 9. Quicksilver's Tattoo area fracking operations in the Horn River Basin, May to June, 2012

Region	Well Number	Well Name	Well Location	Fracture Date	Fracked By	Volume of Water / Well Cubic Metres
Tattoo	27480	D-C	050-A/094-O-15	05/17/2012	Calfrac	84,169.46
Tattoo	27481	D-D	050-A/094-O-15	06/08/2012	Calfrac	75,502.05
Tattoo	27482	D-E	050-A/094-O-15	05/17/2012	Calfrac	**119,716.50**
Tattoo	27483	D-F	050-A/094-O-15	06/08/2012	Calfrac	84,450.60
Tattoo	27484	D-G	050-A/094-O-15	05/13/2012	Calfrac	75,578.50
Tattoo	27485	D-H	050-A/094-O-15	06/09/2012	Calfrac	91,762.90
Tattoo	27486	D-I	050-A/094-O-15	05/15/2012	Calfrac	87,462.70
Totals	**7**					**618,642.71**

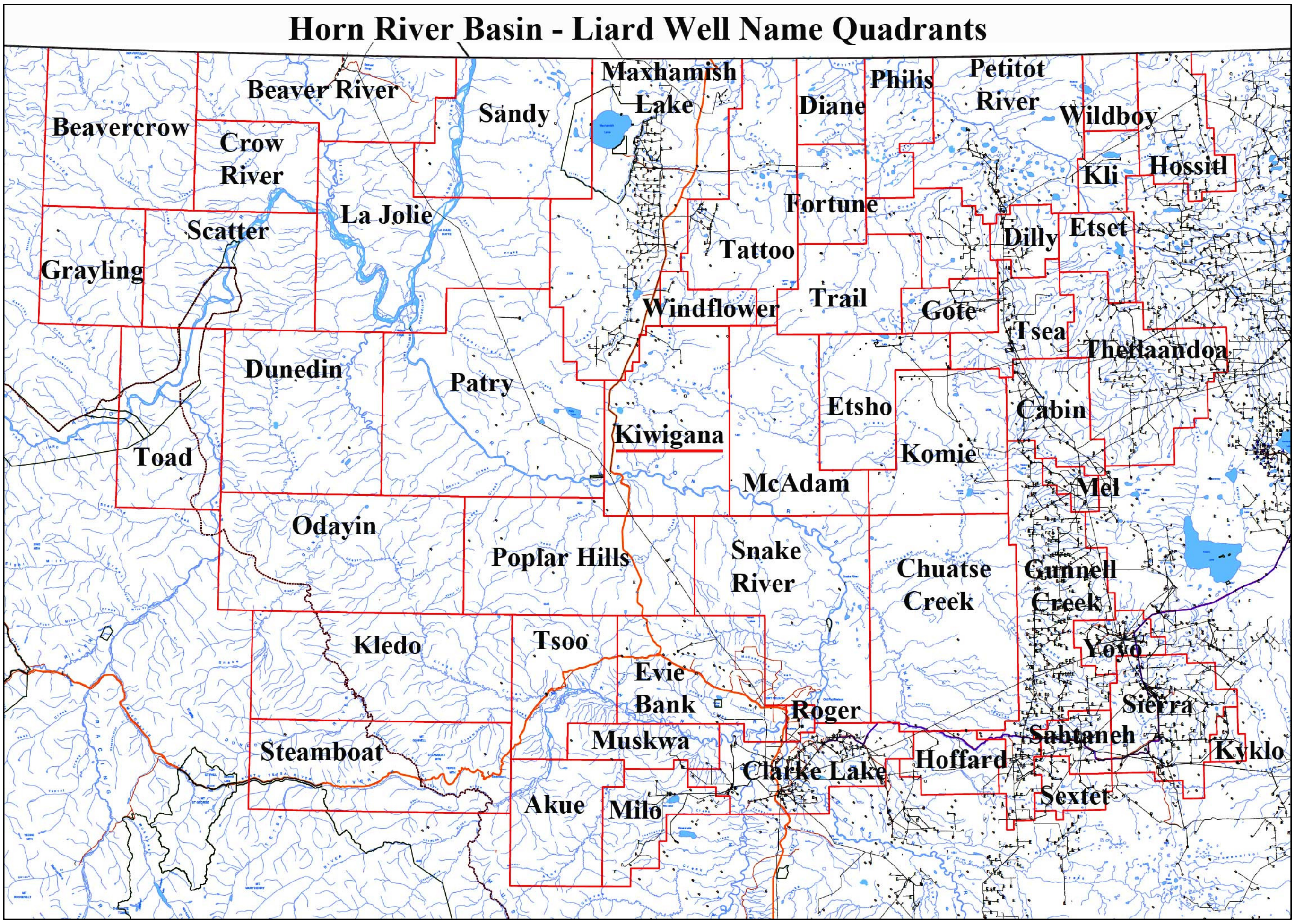
Table 10. Nexen's Komie area fracking operations in the Horn River Basin, July to August, 2012

Region	Well Number	Well Name	Well Location	Fracture Date	Fracked By	Volume of Water / Well Cubic Metres
Komie	26175	B	077-H/094-O-08	07/24/2012	Trican	51,700.00
Komie	26925	B-A	077-H/094-O-08	07/23/2012	Trican	**60,331.61**
Komie	26926	B-B	077-H/094-O-08	07/23/2012	Trican	29,944.64
Komie	26927	B-C	077-H/094-O-08	07/23/2012	Trican	51,514.48
Komie	26928	B-D	077-H/094-O-08	07/30/2012	Trican	57,764.99
Komie	26929	B-E	077-H/094-O-08	07/30/2012	Trican	52,205.70
Komie	26930	B-F	077-H/094-O-08	08/04/2012	Trican	48,385.64
Komie	26931	B-G	077-H/094-O-08	08/06/2012	Trican	49,372.64
Komie	26932	B-H	077-H/094-O-08	08/05/2012	Trican	56,409.74
Komie	26933	B-I	077-H/094-O-08	08/22/2012	Trican	49,339.16
Komie	26934	B-J	077-H/094-O-08	08/22/2012	Trican	43,120.11
Komie	26935	B-K	077-H/094-O-08	08/22/2012	Trican	40,802.61
Komie	26936	B-L	077-H/094-O-08	08/21/2012	Trican	45,008.71
Komie	26937	B-M	077-H/094-O-08	08/19/2012	Trican	49,171.34
Komie	26938	B-N	077-H/094-O-08	08/23/2012	Trican	45,979.25
Komie	26939	B-O	077-H/094-O-08	08/22/2012	Trican	42,960.29
Komie	26940	B-P	077-H/094-O-08	08/18/2012	Trican	50,877.95
Komie	26941	B-Q	077-H/094-O-08	08/24/2012	Trican	45,024.19
Totals	**18**					**869,913.05**

According to the OGC's updated December 2, 2013 Surface Hole data spreadsheet, Nexen has **20** active wells registered for the year 2012 (it is possible that **2** of the fracking dates preceded the January 1, 2012 Frac-Focus mandate date), and **10** for the year 2013, in the Komie area. However, Nexen has only filed **18** data sheets with Frac-Focus for the year 2012, and none for 2013 (which may still be pending). **Table 11** shows the names and locations of the missing, active gas wells.

Table 11. Nexen's Non-Registered Frac-Focus Data Sheets for its Komie area fracking operations in the Horn River Basin, 2012, and 2013

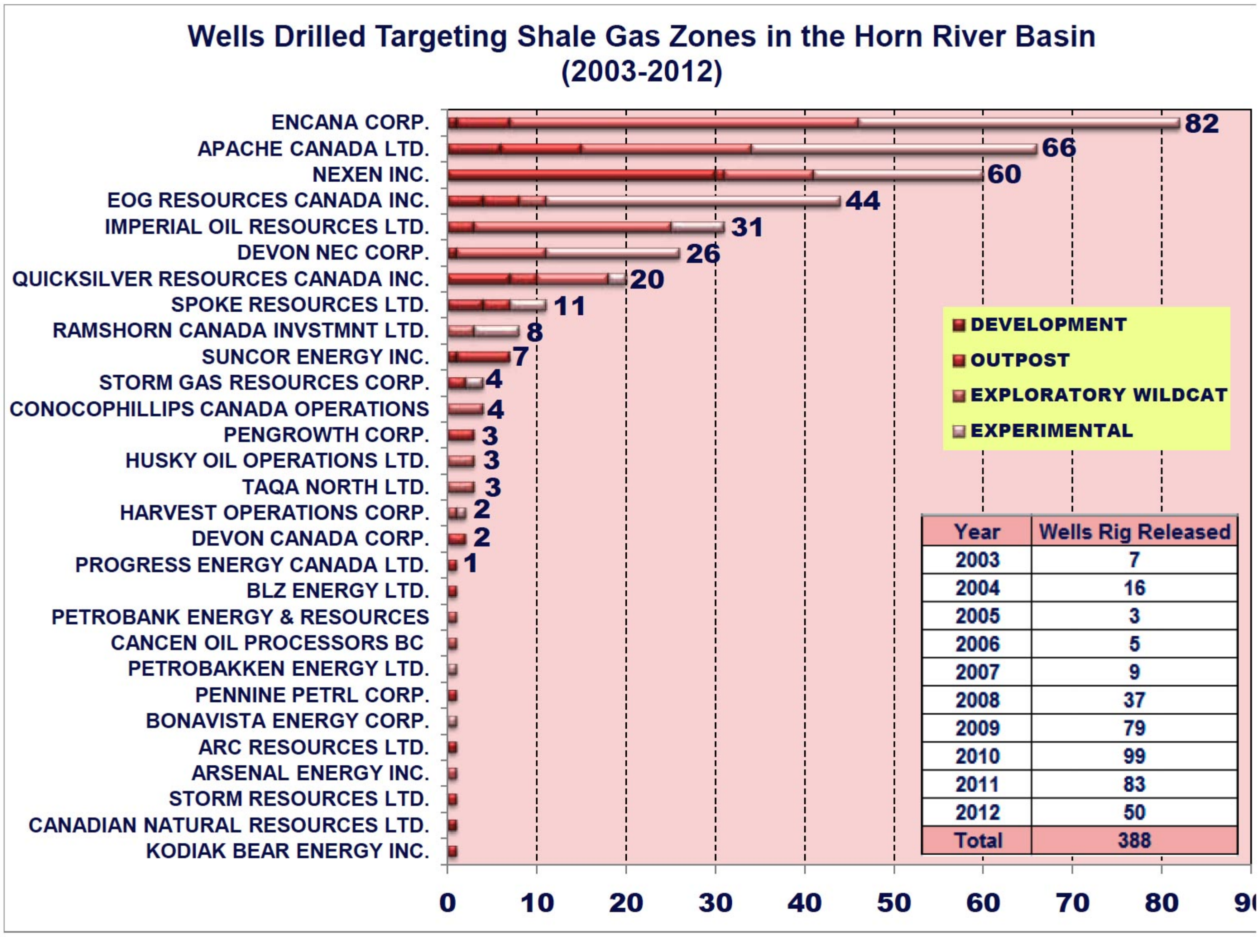
Region	Well Number	Well Name	Well Location	Fracture Date	Fracked By	Volume of Water / Well Cubic Metres
Komie	26764	D	001-J/094-O-08	2012?	?	?
Komie	26765	D-A	001-J/094-O-08	2012?	?	?
Komie	27595	D	037-H/094-O-08	2013?	?	?
Komie	28134	D-A	037-H/094-O-08	2013?	?	?
Komie	28135	D-B	037-H/094-O-08	2013?	?	?
Komie	28136	D-C	037-H/094-O-08	2013?	?	?
Komie	28137	D-D	037-H/094-O-08	2013?	?	?
Komie	28138	D-E	037-H/094-O-08	2013?	?	?
Komie	28139	D-F	037-H/094-O-08	2013?	?	?
Komie	28140	D-G	037-H/094-O-08	2013?	?	?
Komie	28141	D-H	037-H/094-O-08	2013?	?	?
Komie	28142	D-I	037-H/094-O-08	2013?	?	?



Above: Map area showing the Petroleum Region quadrants of the Liard (left) and Horn River (right) Basins. The Town of Fort Nelson is in the lower right hand corner of the Evie Bank quadrant. The East Cordova Basin is east or right of the map.

Assuming that BC energy operators are faithfully submitting fracking well data sheets to Frac-Focus, and on time (i.e., questions raised about Nexen in **Table 11**), the Frac-Focus registry assumes that only **7** wells were fracked in the Greater Horn Basins by EnCana in 2013. With another Frac-Focus well not tabled above for 2013 - a well fracked on October 2, 2013 by Ramshorn in the Tattoo Region, which used **21,988** cubic metres of water - this brings the total wells to **8** for the year. That sets a record in recent memory for the fewest wells fracked for a given year in the upper north.

According to Frac-Focus, in 2012 a total **64** wells were fracked by only five energy operators. Another well fracked in late 2011 was reported by EnCana (see **Table 6**). Though estimates on water volume usage can possibly be extracted for the future from water volume figures released by energy operators for 2012, whereby trends can be analyzed for operator preferences and characteristics for vertical depth and lateral (horizontal) well projects for a given geologic area, it may fail to some degree unless comprehensive data can be compiled from fracking operations over the previous years when operations came into full swing, from 2009 to 2011. However, that information is still more or less secret.



Year	Wells Rig Released
2003	7
2004	16
2005	3
2006	5
2007	9
2008	37
2009	79
2010	99
2011	83
2012	50
Total	388

Figure 5. Since 2003, operators in the Horn River Basin have drilled 388 shale gas–directed wells under various Lahee classifications. Drilling peaked in 2010 with 99 wells rig released. That number has fallen to 50 in 2012.

Above: Information from page 6 of a government report, *Oil and Gas - Summary of Shale Gas Activity in Northeast British Columbia 2012*, registering activities only in the Horn River Basin.

2.4.1. Water Volume Data from OGC's Induced Seismicity Report

The few tangible bits of information that have surfaced from the OGC's secret vault for water usage in the Horn River Basin prior to 2012 are contained in the OGC's (BC Oil and Gas Commission's) August 2012 report, *Investigation of Observed Seismicity in the Horn River Basin*, wherein government researchers acquired confidential and non-confidential data on water and frack sand volumes from about **6** energy operators to provide detailed information on how and why energy operator fracking operations caused a series and large numbers of earthquakes, or "seismic events." The following quote from page 6 of that report:

> *The Commission began a formal investigation in July 2011 into the anomalous events recorded by NRCan in the Etsho area. The investigation was extended to the Tattoo area when similar anomalous events were detected there in December 2011.*
>
> *The Commission began the investigation with a review of hydraulic fracturing and well completion information on wells situated near the area of observed seismicity in the Etsho*

area. The dates and times of hydraulic fracturing operations were compared to the dates and times of recorded seismicity events.

To obtain additional information to assist in the investigation, the Commission issued formal Information Requests (IRs) to six operators within the study area. The IRs provided the Commission access to data not currently required to be submitted by the operators to the Commission. Much of this operator information obtained is proprietary and includes detailed completion statistics, microseismic reports, groundwater analyses and seismic mapping. In some cases, confidential data is used to support findings or analyses but not reproduced within the report.

Under British Columbia legislation and regulation, specified oil and gas information is required to be collected and submitted to the Commission. This includes geophysical logs, sample reports and drilling and completion information. Data is held confidential for a time period as defined in the regulation, dependent on well classification.

Water volume data contained within Table 3 of the induced seismicity report, *Pad Hydraulic Fracturing Statistics for Etsho (non-confidential pads)* shown below, provides water volume "averages" for each well from seven separate well pads, with similar data from many other pads not reported on. To gain perspective on the OGC report's data, specific data related to each of the seven well pads are provided in this report through **Tables 12 to 18**, where a computation is made on the bottom row of each table on the total volumes of water usage per multi-well pad, without specific water usage volumes for each well, specific data withheld in the OGC's report.

Table 3: Pad Hydraulic Fracturing Statistics for Etsho (non-confidential pads). Minimum, maximum and average numbers are calculated from all pad data reviewed. Only non-confidential pads are listed in the table.

Well Pad	Wells/Pad	Stages/ Well	HZ Completed (m)	Fluid/Well (m^3)	Sand/Well (Tonnes)	Avg Pump Rate (m^3/ minute)	Fracs/Pad	# of Seismic Events
b-100-G	5	5	1,176	11,505	710	12	26	0
c-1-J	9	16	1,837	52,429	3,072	14	147	0
b-76-K	13	15	1,752	58,386	2,454	15	180	1
d-70-J	7	14	1,391	53,800	2,692	15	74	3
d-1-D	7	27	2,727	138,005	5,484	15	176	6
c-34-L	9	18	2,200	63,000	3,200	15	162	7
b-63-K	14	23	2,452	107,738	4,505	14	347	13
Average	**8**	**17**	**1,846**	**61,612**	**3,107**	**13**	**149**	**3**
Min.	**4**	**5**	**1,176**	**11,505**	**710**	**8**	**26**	**0**
Max.	**16**	**27**	**2,727**	**138,005**	**5,484**	**15**	**347**	**13**

Above: Table 3 from the OGC report on induced seismicity.

OGC's earthquake report states on page 11 that **90** wells were drilled and fracked in the Etsho area alone from February 2007 to July 2011 on *"**14** different drilling pads," "with more that **1,600** hydraulic fracturing stage completion operations."*

Table 12. EnCana's pad, 001-D/094-O-09, Fracked 2010-2011

Region	Well Number	Well Name	Well Location	Volume of 'Fluid' / Well Cubic Metres
Trail	25872	D	001-D/094-O-09	?
Trail	26171	D-A	001-D/094-O-09	?
Trail	26174	D-B	001-D/094-O-09	?
Trail	26238	D-C	001-D/094-O-09	?
Trail	26241	D-D	001-D/094-O-09	?
Trail	26242	D-E	001-D/094-O-09	?
Trail	26264	D-F	001-D/094-O-09	?
Trail	26265	D-G	001-D/094-O-09	?
Trail	26266	D-H	001-D/094-O-09	?
Trail	26267	D-I	001-D/094-O-09	?
Trail	26268	D-J	001-D/094-O-09	?
Trail	26269	D-K	001-D/094-O-09	?
Trail	26277	D-L	001-D/094-O-09	?
Trail	26278	D-M	001-D/094-O-09	?
Trail	26279	D-N	001-D/094-O-09	?
Trail	26280	D-O	001-D/094-O-09	?
	16 Wells		**Average 'fluid' volume for each well 138,005.00 cu. m.**	**Total Volume 2,208,080.00 Cubic Metres**

Table 13. EnCana's pad, 063-K/094-O-08, Fracked 2010

Region	Well Number	Well Name	Well Location	Volume of 'Fluid' / Well Cubic Metres
Etsho	25175	B	063-K/094-O-08	?
Etsho	25615	B-A	063-K/094-O-08	?
Etsho	25616	B-B	063-K/094-O-08	?
Etsho	25617	B-C	063-K/094-O-08	?
Etsho	25618	B-D	063-K/094-O-08	?
Etsho	25619	B-E	063-K/094-O-08	?
Etsho	25620	B-F	063-K/094-O-08	?
Etsho	25621	B-G	063-K/094-O-08	?
Etsho	25726	C	063-K/094-O-08	?
Etsho	25727	C-A	063-K/094-O-08	?
Etsho	25728	C-B	063-K/094-O-08	?
Etsho	25729	C-C	063-K/094-O-08	?
Etsho	25730	C-D	063-K/094-O-08	?
Etsho	25731	C-E	063-K/094-O-08	?
	14 Wells		**Average 'fluid' volume for each well 107,738.00 cu. m.**	**Total Volume 1,508,332.00 Cubic Metres**

Table 14. Apache's pad, 034-L/094-O-08, Fracked 2011

Region	Well Number	Well Name	Well Location	Volume of 'Fluid' / Well Cubic Metres
Etsho	26076	C-A	034-L/094-O-08	?
Etsho	26077	C-B	034-L/094-O-08	?
Etsho	26078	C-C	034-L/094-O-08	?
Etsho	26079	C-D	034-L/094-O-08	?
Etsho	26080	C-E	034-L/094-O-08	?
Etsho	26081	C-F	034-L/094-O-08	?
Etsho	26082	C-G	034-L/094-O-08	?
Etsho	26083	C-H	034-L/094-O-08	?
Etsho	26084	C-I	034-L/094-O-08	?
	9 Wells		**Average 'fluid' volume for each well 63,000 cu. m.**	**Total Volume 567,000.00 Cubic Metres**

Table 15. Encana's pad, 076-K/094-O-08, Fracked 2011 [3]

Region	Well Number	Well Name	Well Location	Volume of 'Fluid' / Well Cubic Metres
Etsho	23612	B	076-K/094-O-08	?
Etsho	23791	B-A	076-K/094-O-08	?
Etsho	23793	B-B	076-K/094-O-08	?
Etsho	23881	B-E	076-K/094-O-08	?
Etsho	24960	B-G	076-K/094-O-08	?
Etsho	24961	B-H	076-K/094-O-08	?
Etsho	24965	B-I	076-K/094-O-08	?
	7 Wells		**Average 'fluid' volume for each well 58,386.00 cu. m.**	**Total Volume 408,702.00 Cubic Metres**

Table 16. Encana's pad, 070-J/094-O-08, Fracked 2008 - 2009 [4]

Region	Well Number	Well Name	Well Location	Volume of 'Fluid' / Well Cubic Metres
Etsho	23601	D	070-J/094-O-08	?
Etsho	23792	D-A	070-J/094-O-08	?
Etsho	24551	D-D	070-J/094-O-08	?
Etsho	24552	D-E	070-J/094-O-08	?
Etsho	24553	D-F	070-J/094-O-08	?
Etsho	24661	D-J	070-J/094-O-08	?
	6 Wells		**Average 'fluid' volume for each well 53,800.00 cu. m.**	**Total Volume 322,000.00 Cubic Metres**

[3] EnCana's two well names, B-C and B-D, were fracked earlier on the same pad in 2008, with B-F cancelled in 2010.
[4] EnCana's two well name, D-C, is a water disposal well, drilled in 2010. Wells D-B, D-G, D-H and D-I were cancelled in 2010.

Table 17. Nexen's pad, 001-J/094-O-08, Fracked 2010 - 2011 [5]

Region	Well Number	Well Name	Well Location	Volume of 'Fluid' / Well Cubic Metres
Komie	26026	C	001-J/094-O-08	?
Komie	26758	C-A	001-J/094-O-08	?
Komie	26759	C-B	001-J/094-O-08	?
Komie	26760	C-C	001-J/094-O-08	?
Komie	26761	C-D	001-J/094-O-08	?
Komie	26762	C-E	001-J/094-O-08	?
Komie	26764	D	001-J/094-O-08	?
Komie	26765	D-A	001-J/094-O-08	?
Komie	26766	D-B	001-J/094-O-08	?
	9 Wells		**Average 'fluid' volume for each well 52,429.00 cu. m.**	**Total Volume 471,861.00 Cubic Metres**

Table 18. Devon NEC's pad, 100-G/094-O-08, Fracked 2009

Region	Well Number	Well Name	Well Location	Volume of 'Fluid' / Well Cubic Metres
Komie	24362	B	100-G/094-O-08	?
Komie	24615	B-A		?
Komie	24616	B-B		?
	3 Wells		**Average 'fluid' volume for each well 11,505.00 cu. m.**	**Total Volume 34,515.00 Cubic Metres**

Water volumes and other related data from a number of well pad locations in the Horn River Basin were not reported on in the OGC report, but were referenced on page 19. They are as follows:

- **Apache**: 052-L/094-O-08 (**15** wells in Etsho Region, fracked 2009 - 2010, category CASE)
- **Nexen**: 018-I/094-O-08 (**8** active gas wells in the Tsea Region, fracked in 2011, **one** well for water)
- **Devon NEC**: 087-G/094-O-08 (**4** active gas wells in the Komie Region, fracked in 2010)
- **EOG**: 055-B/094-O-09 (**5** active gas wells in the Gote Region, fracked 2010-2011, **one** well under category CASE, fracked in 2010)
- **Spark Resources (SPK)**: 068-B/094-O-15 (**2** gas wells fracked in 2009, and **2** in 2010 in the Tattoo Region).

OGC's data, shown in **Tables 12** through **18**, reveals that with a total **64** wells fracked between the years 2009 to 2001, by four separate energy operators on **seven** multi-well pads in the Horn River Basin, a total volume of **5,520,490** cubic metres of "fluids" was used. The data also shows that

[5] Nexen has fracked additional 4 wells on this pad in 2013, under OGC's experimental well category, and another 7 under CASE category for 2013.

EnCana got first prize for the highest use of "fluids" for a single well, which was averaged out at **138,005** cubic metres per well. However, the data does not show the highest volume of "fluids" used by EnCana for a single well on pad **001-D/094-O-09**, which, as the data in **Table 6** clearly demonstrates, was somewhere much higher than the average figure.

OGC's data for **64** wells also shows that the average "fluids" use per well between the years 2009 to 2011 stands at **86,257.66** cubic metres.

2.5. The BC Government's 2012 Presentation Data: Understating Highest Water Volumes and Usages in the Greater Horn and Montney Basins

On April 3, 2012, Elizabeth Johnson, formerly with the Ministry of Energy and Mines' Geoscience and Strategic Initiatives Branch, now with the Upstream Development Division with the new Ministry of Natural Gas Development, was one of about a dozen presenters at the 2012 Unconventional Gas Technical Forum, held from April 2 - 3 at the Victoria City Conference Centre. Water usage in northeast BC had become a significant / hot issue with the public, and Johnson, who had many assignments under this portfolio, gave a 25-page slide presentation at the Forum, *Water Issues Associated with Hydraulic Fracturing in Northeast British Columbia*.

One of Johnson's slides states that she had access to *"a database of wells with multiple fracture stages"* from 2005 to 2011 in the Montney and Horn River Basins, wherein were catalogued **528** wells - 133 in the Horn, and 395 in the Montney area - the *"majority"* of which were *"horizontal"* wells. She slide-stated that since 2007, *"slicwater volumes per frac"* had increased from **1,500** cubic meters to **5,000** cubic metres in 2010, an increase of **3.3** times over a space of three years. From 2007 to 2011, the underworld horizontal drilling lengths had increased from **1,000** metres to **3,100** metres, an increase of about the same ratio with frac volumes.

Johnson also stated that there had been a notable increase of *"frac stages per well,"* jumping from **four** in 2005 to **thirty-eight** in 2011, and that there were closer spacings between fracks, ranging from **400** metre spacings in 2007 to **100** metre spacings in 2010. She also summarized that energy operators were getting more operationally efficient and creative, doubling and tripling their operational strategies using *"vertical and horizontal placement staggering"* with *"dual and triple laterals."*

According to the internal document date of Johnson's latest pdf report on water use, *Hydraulic Fracture Water Usage in Northeast British Columbia: Locations, Volumes and Trends*, it was finalized on April 4, 2012, the day after her presentation at the Gas Forum on April 3. In her report are the working details behind her conference summary presentation.

In her report, Johnson explains the details behind the database mentioned in her slide presentation. As of September 2011, out of a total **30,997** wells in northeast BC, about **7,000** wells were "fracture completion" wells, and out of those, **509** wells were identified as those with "multiple completions." All the analyses in her report are a breakdown of fracking attributes concerning these **509** wells (Johnson figure was **528** in her slide presentation), as data now more than two years ancient.

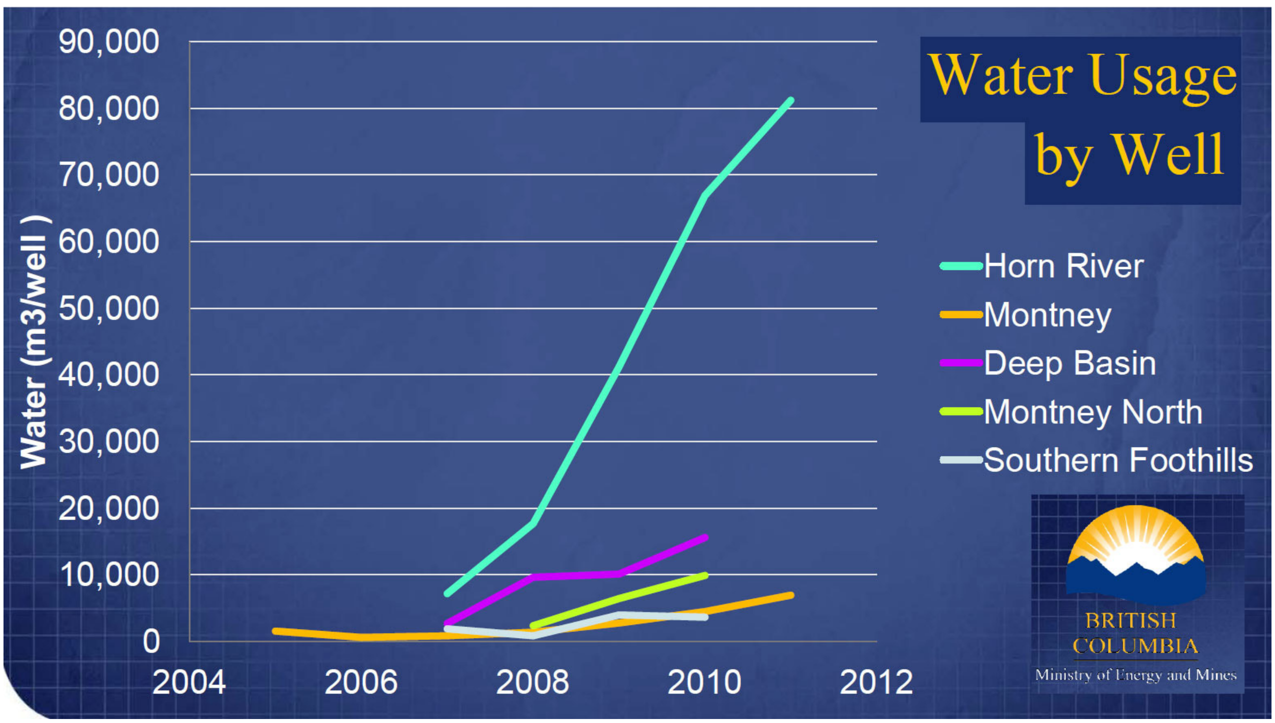
Johnson's report states the following on pdf-pages 1 and 3:

> *The volume of water used by the oil and gas industry in northeast British Columbia varies widely from less than **1,000** m^3 to more than **70,000** m^3 per well (Kennedy, 2011). It is*

important to establish the extent to which estimates for water use in one play are a meaningful proxy for industry-related water use in other areas.

To date, most of the assumptions made on industry-required volumes and the rate of usage in British Columbia has been based on general knowledge of the province's two major plays: the Montney Basin and the HRB (Horn River Basin). *This range represents a significant difference in the amount of water required by industry for multistage hydraulic fracturing. In the Montney Trend, water demand can be from **200** m^3 to **4,600** m^3 water per fracture stage with wells needing **800** to **13,000** m^3 water per well (Dunk, 2010; Burke et al., 2011). In the Horn River Basin, water demand ranges from 2,500 to 5,000 m^3 per fracture stage with values ranging from **10,000** to 70,000 m^3 per well (Horn River Producers Group, 2011).* [6]

A more thorough assessment of water demand in northeast British Columbia is required. Meaningful analysis will establish whether specific conditions exist for the rates of water usage, and whether a combined analysis of water use in the Montney Basin and the HRB is a meaningful proxy for industry-related water-use requirements in other areas.



Elizabeth Johnson's April 3, 2011 presentation slide, page 15, showing *Water Usage by Well*.

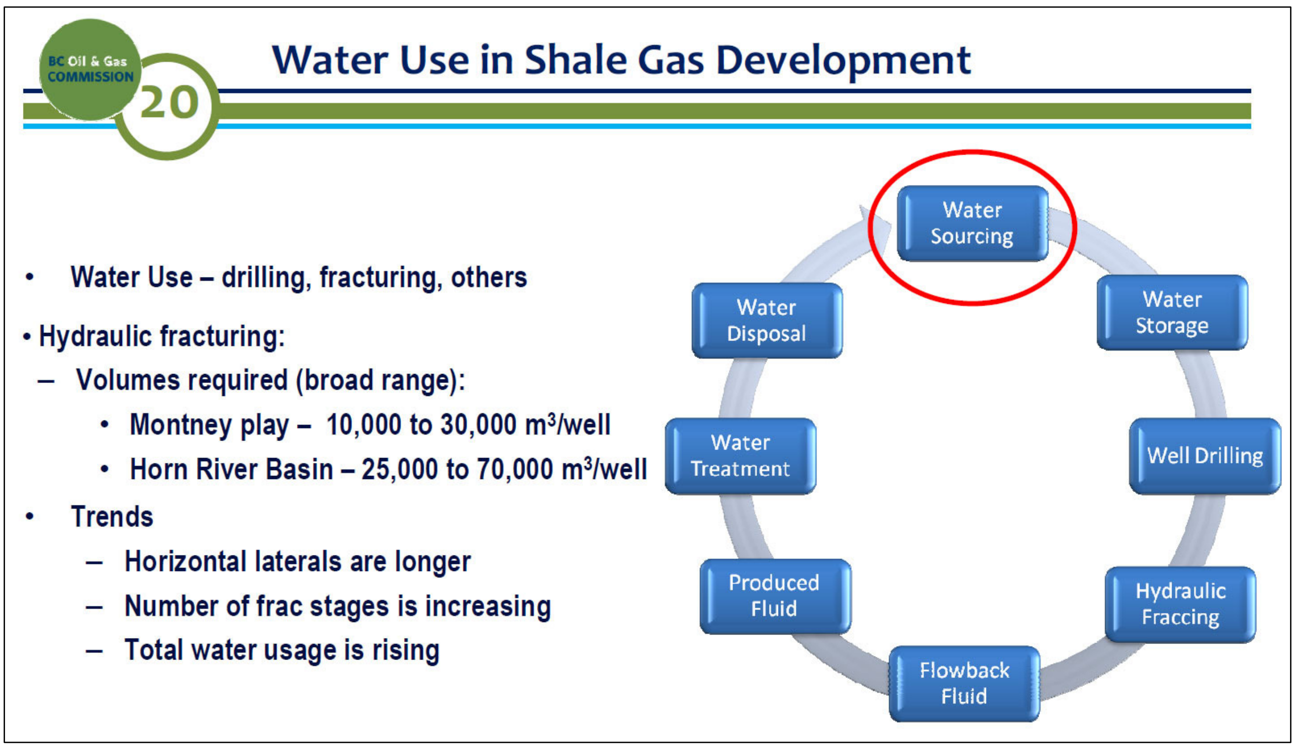
As clearly shown in the numerous Tables of the *FrackMath Confidential* report from Frac-Focus data on the Montney and Greater Horn Basins, and from government data preceding 2012 for the Horn Basin, Johnson's slide, above, on the highest water volume fracking usage for a single well, is inaccurate: it's off by more than **60,000** cubic metres for the Horn River alone!

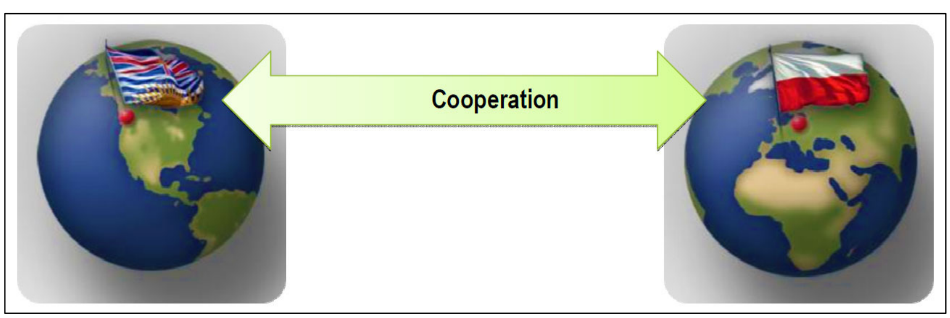
[6] The Horn River Producers Group four-page public relations report states 60,000, not 70,000, cubic metres. Johnson has mistaken this reference for BC OGC's Chief Engineer Mayka Kennedy's figure of 70,000, in Kennedy's May 12, 2011 slide presentation which she gave at a conference in Warsaw, Poland.

What accounts for Johnson's unfortunate miscalculation, particularly in a matter that deeply concerns the public? It may be that Johnson did not have open access to the OGC's and/or industry's digital database on water volume usage per single well. And, if Johnson did have access to this in-house data, then why was it not revealed?

As Johnson states in the quote above from the introduction of her report, the primary reference for the highest water volumes per single well for the Horn River Basins is from the OGC's Chief Engineer, Mayka Kennedy, cited in Kennedy's 34-page slide report of May 12, 2011, *BC Oil and Gas Commission - Experiences in Hydraulic Fracturing*, which Kennedy presented at a conference in Warsaw, Poland. In turn, where did Kennedy get her information from? Did she, or did she not, do her homework? Was she allowed to do her homework? Did she know or want to know the facts?

Prior to OGC Chief Engineer Kennedy's Warsaw presentation, EnCana and Apache had twice broken the world record on fracking operations at Two Island Lake in 2010, and from 2010 - 2011 EnCana's **average** water use per well in the Horn Basin was anywhere between **107,000** to **138,000** cubic metres for two multi-well pad operations (**Tables 12** and **13**, above), with individual well totals well beyond the averages.





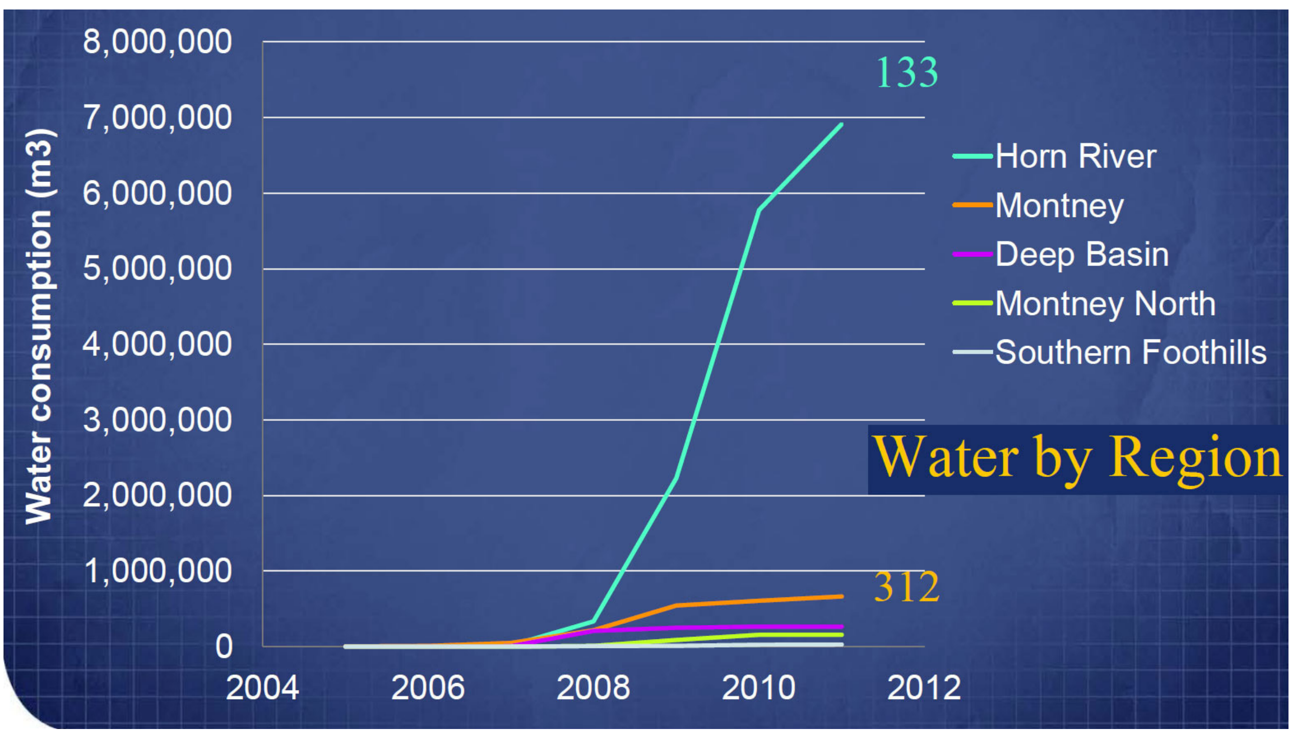
Images from Myrka Kennedy's slide presentation for Warsaw, Poland. For a narrative about the Poland fracking agenda and front, see the author's January 2012 report Frack EU: Unconventional Intrigue in Poland, particularly chapters 10 (*Harper's Men in Poland*), and 11 (*The Poland Portal Party*).

When compared to other consumptive users in the province, review of the water approval information indicates that oil and gas operations use only a fraction of the total water licensed in B.C. Of this amount, a preliminary look at actual volumes drawn vs. maximum approved shows use rates of less than five per cent, based on analysis of 2009 water use in the Horn River Basin. Going forward, information technology systems such as the water portal for surface water data collection and compliance and enforcement assurance measures will give a clear picture of how much of the water approved to be used by oil and gas industry is actually consumed.

Above and Below: Excerpts from the August 2010 report, *BC Oil and Gas Commission: Oil and Gas Water Use in British Columbia*.

The Commission's information systems department is working on a long-term strategic plan with several objectives focusing on the collection, tracking and forecasting of water use data.

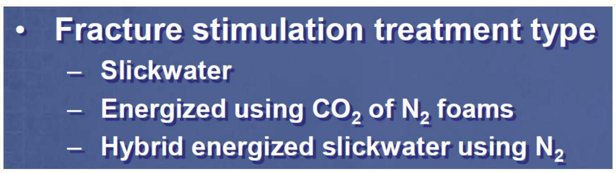
The author recently spoke with Johnson on December 5th. A casual question was asked if Johnson could cite, from her recollection, what the highest water volume usage figure for a single well was in northeast BC, what, in fact, the current northeast record was. Johnson did know, but couldn't divulge the information, as it was, at this point, still confidential. When the author cited the highest figure, the one stated in this report - EnCana's record of **170,945** cubic metres - Johnson was clearly unaware of this data from 2012, and asked what operational area this record occurred in. Johnson then stated that her confidential data (without divulging it) of the highest volume was far lower.

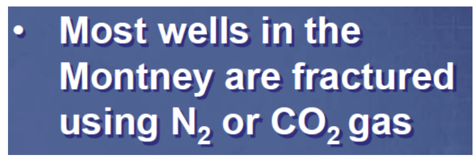


In another of Johnson's April 3, 2012 presentation slides, the one shown above, called *Water by Region*, shows the water volume usage in Horn Basin fracking operations. From the Frac-Focus data shown in Tables above, and from information from OGC's 2012 induced seismicity report, it appears the graph is wanting and inaccurate. **Table 1** volumes for 2012-2013, alone, total **5,007,519.33** cubic metres for the entire Montney, and for **74** wells in the Horn Basin for the two years, alone, the totals amount to **5,192,139.89** cubic metres. Projecting the **74** wells figure in **Table 1**, for **133** wells in the Horn Basin as shown in Johnson's graph, that would amount to **9,330,275.38** cubic metres, or **2.3** million cubic metres shy of the figure shown in the graph. When added to Johnson's graph, the total figure for water use in the Greater Horn Basins rises to over **16** million cubic metres. The Montney water use volume figures are off by about **4** million cubic metres.

It is apparent, therefore, from this analysis of three selected government reports and presentations, that even professionals working on oil and gas development water usage issues in government are somehow not being made aware of, or being informed of, the data that the OGC has, or should have, in its possession, some water volume usage data of which has recently been made public through the Frack-Focus registry, data that, nevertheless, still requires independent scrutiny for accuracy reporting.

2.6. Nitrogen and Carbon Dioxide Fracking-based Water Volumes





Cut-outs from Johnson's April 3, 2012 presentation slides.

Stated in section 2.1. of this report, a category of **90** wells out of a total **718** registered with Frac-Focus for the period of 2012 to 2013 were those with water volume usages of less than **1,000** cubic metres per fracked well.

Out the **90** candidate wells, **9** are from the Greater Horn Basins, with water volume totals of **2,843.80** cubic metres:

- one for TAQA North (Chinchaga), at **750.0** m3;
- seven for Devon Canada (Helmet - 6, and Desan -1), totalling **2,078.8** m3;
- one for PennWest (Helmet), at **15.0** m3.

The remaining **81** wells, with less than a total **1,000** cubic metres of water volumes used per single well, out of a total **554** wells reported to Frac-Focus over a two year period, or **14.6 percent**, are from the Montney. From **26** separate energy operators, the water volumes from these **81** wells total **34,277.10** cubic metres, as follows:

- **2** for **Apache** (Noel), totalling **150.4** m3;
- **1** for **ARC** (Attachie), totalling **468.6** m3;
- **15** for **Artek** (Inga), totalling **1.5** m3;
- **1** for **Baytex** (Cache), totalling **0.1** m3;
- **1** for **Black Swan** (Bubbles), totalling **700.7** m3;
- **1** for **Carnaby** (Paradise), totalling **93.1** m3;
- **5** for **CNRL** (3 in Septimus, 1 in N. Bubbles, and 1 in Alces), totalling **2,713.4** m3;
- **2** for **Conoco Phillips Op** (Kelly), totalling **720.0** m3;
- **3** for **Crew** (Septimus), totalling **302.0** m3;
- **2** for **Crocotta** (Doe, W. Stoddart), totalling **1,424.82** m3;
- **1** for **Dejour** (Woodrush), totalling **38.03** m3;
- **3** for **Devon Can.** (Eagle, Peggo-Pesh, and Buick Creek), totalling **823.88** m3;

- **2** for **Enerplus** (Julienne), totalling **1,951.3** m3;
- **17** for **Murphy Oil** (11 in Sundown, and 6 in Swan), totalling **13,484.12** m3;
- **2** for **Pengrowth** (Weasel), totalling **2.0** m3;
- **1** for **PennWest** (Fireweed), totalling **53.6** m3;
- **1** for **Procyon** (Rigel), totalling **46.6** m3;
- **1** for **Secure Energy** (Dawson), totalling **87.0** m3;
- **2** for **Shell Canada** (Sunset, Saturn), totalling **1,039.0** m3;
- **1** for **Sinopec D.** (Kelly), totalling **881.55** m3;
- **10** for **Storm Res.** (1 in Nig, 1 in W. Buick, and 8 in Umbach), totalling **5,644.6** m3;
- **1** for **Suncor** (Fireweed), totalling **90.0** m3;
- **1** for **Talisman** (Altares), totalling **924.0** m3;
- **3** for **Tourmaline** (2 in Goose, 1 in Sundown), totalling **1,495.9** m3;
- **1** for **UGR Blair** (Jedney), totalling **986.3** m3;
- **1** for **Yoho** (Inga), totalling **154.6** m3.

From this list of **26** operators, the reader can make computations for the average volume use of water for each operator.

2.7. The Service Industry Frackers: Who, For Whom and How Many, 11/2011 - 11/2013

The **718** Frac-Focus well data sheet entries provide dates when wells were reportedly fracked, predominantly "stimulated" for multi-stage horizontal (HZ) fracking operations by specialized service industry companies. **664** of these data entries provide the names of the following **eight** service industry companies, with numbers showing total well-fracking operations per service industry company from November 2011 to November 2013:

- Sanjel - **60**
- Halliburton - **82**
- Calfrac - **224**
- Trican - **103**
- Baker Hughes - **38**
- Canyon Technical Services Ltd. - **53**
- Schlumberger - **103**
- Nabors Well Service - **1**

Table 19 provides data on seven of these eight service companies, and the number of wells fracked for each energy operator over the two-year time period. The table indicates the preferred Service contractor for a particular fracking formation for individual energy operators. The contract Basins - the where behind the who and for whom - areas are not provided in this table.

Table 19. Energy Operator Clients and Service Industry Companies, 11/2011 to 11/2013, Number of Fracking Contracts per Individual Well.

Operator	Baker Hughes	Calfrac	Canyon Tech.	Halliburton	Sanjel	Schlumberger	Trican
Apache		6		2			
ARC				1	49		
Artek							1
Black Swan		9					
Bonavista					3		
Canbriam			14				
Carmel Bay			1				
Carnaby	1						
CNRL	1		12	31			
Conoco Can Op						2	
Conoco Res Cp		3		1			
Crew			5		3		12
Crocotta							6
Dejour							1
Devon Canada	5						
Devon NEC	5						
EnCana		5		47		60	5
Enerplus		2					
Imperial Oil						8	
Murphy Oil					4		19
Nexen							18
Painted Pony			14				
Paramount	2						
Pengrowth							2
PennWest	15				1		1
Procyon	1						
Progress		65	2				
Quicksilver		8					
Secure Energy							1
Shell Can.		99				2	
Sinopec D.			4				
Storm Res.		20					
Suncor							3
Talisman						31	42
TAQA North	1						
Tervita	1						
Tourmaline	6						29
UGR Blair		6					
Yoho		1	1				

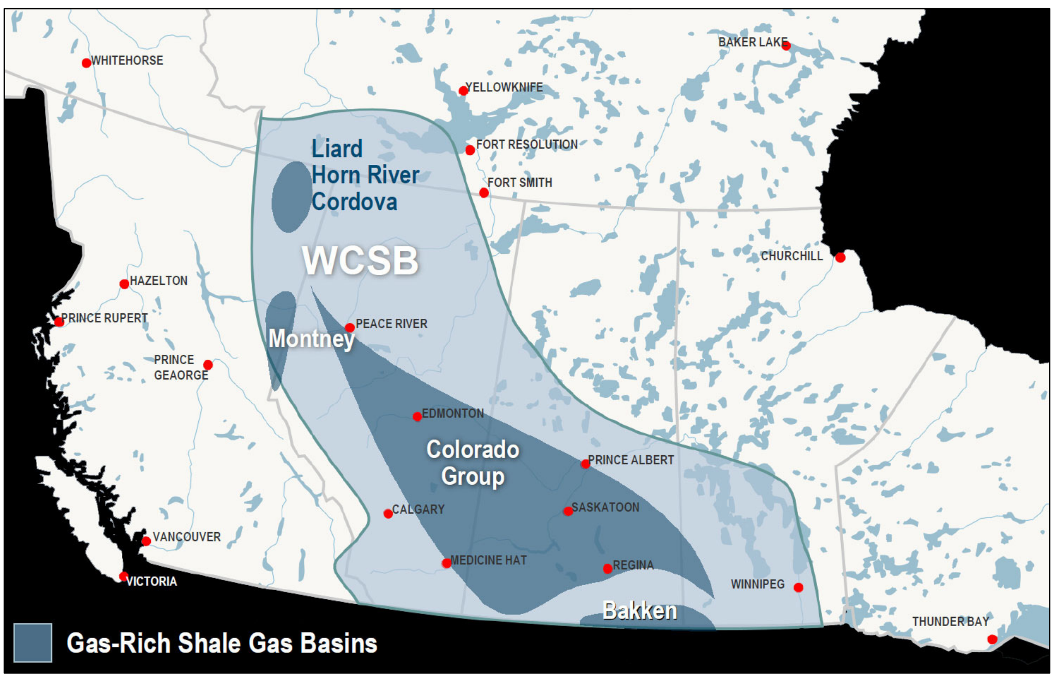
3. The LNG Dilemma: Legal Binding Gas Supply Contracts, Fracking Developments, and the Even Uglier Fate of Western Canada's Environment

For the first time since new unconventional multi-fracking technologies came into being some ten or less years ago in British Columbia and Western Canada, this report provides the BC public with some good working evidence and data, the nuts and bolts, on one component of the life cycle of fracking operations as it pertains to the staggering and unbelievable amounts of water usage and its toxic ruination and removal. The energy operators' numbers speak for themselves.

For further scrutiny of this evidence, **Appendix A, Oil and Gas Regions: Single Well Fracking Water Volumes Greater than 1,000 Cubic Metres**, provides a more detailed layout of the data for BC's named oil and gas regions.

This report does not provide future predictions on fracking operations for British Columbia's northeast petroleum energy operations in the Western Sedimentary Basin. What it does, is provide a hard look from registered industry data, in numerous tables, on what has, and what may occur, if LNG prospects should, heaven forbid, result. As such, it provides a sober basis for understanding such considerations, but most certainly does not promote it. Making predictions is tough business, for a particularly disturbing and ugly topic, and is perhaps the task of a second report by some other more competent and engaging authors.

Slide from Nexen's April 2012 presentation, *Shale Gas Water Management Responsible Development*.



LNG brings an inevitable and legally binding environmental threat to the provinces of Western Canada. Beyond lesser and local domestic and industry needs for natural gas (excluding the vast needs for gas energy to run the tar sands!), and Canada's obligations under the 1987 Free Trade Agreement to supply the United States with Canadian gas, the energy industry, i.e. the Canadian Association of Petroleum Producers (CAPP), has been lobbying western Provincial and Canadian governments for a number of years to commit its non-renewable, unconventional petroleum resources to international markets. If such contracts come into being, they therefore become legally binding upon the development and consistency of supply, a supply which is based on unprecedented amounts of fracking operations for unconventional gas, and all the endless nonsense and cumulative environmental and social costs and disasters that should accompany them. That goes for the Yukon and Northwest Territories as well, where such lobbying is also occurring.

The first whiff of this legal binding dilemma arose with information presented to the National Energy Board (NEB) from late 2010 to mid-2011 from three energy operators, Houston, Texas-headquartered Apache and EOG Resources, and Alberta-headquartered EnCana. In a triangle partnership for Canada's first LNG export terminal in Kitimat, the three corporations had to file **"Corporate Supply Pool"** data to prove to the NEB's review board auditors that the corporations had sufficient, verifiable potential to provide a **twenty (20)** year supply of gas to overseas markets. Such a supply was not isolated to current and future gas fracking production operations over time from locations within BC, but from within both Alberta and Saskatchewan (and perhaps Manitoba), as they are all interconnected in a vast pipeline grid, with more gridding proposed.

The following are quotes and data tables that each of the three energy operators filed with the NEB, showing the summary information and annual incremental rates of added fracked gas wells to be developed over a **20**-year period as a long-term condition of LNG contracts. [7]

3.1. EnCana's Corporate Supply Pool [8]

The following from EnCana's April 21, 2011 filing:

Encana's Corporate Supply Pool in Western Canada consists of reserves and economic contingent resources as set out in the tables and described in the text below. Encana's Western Canada Corporate Supply Pool will evolve over the term of the gas export licence.

Table 1

Encana AB and BC Marketable Gas Volumes as of 2011-12-31	10^9m^3	Bcf
Reserves		
2P Developed	120	4,252
2P Undeveloped	132	4,678
Total Reserves	**253**	**8,930**
Economic Contingent resources		
2C Best Estimate	**550**	**19,413**
Total	**803**	**28,343**

*Reserves and Contingent resources as evaluated as at December 31, 2010 by GLJ Petroleum Consultants Ltd. ("GLJPC") and McDaniel & Associates Consultants Ltd. ("McDaniel")

Table 2

Encana Aggregate Supply Demand Balance					
Source of Supply	**Remaining Marketable Gas** 10^9m^3		**Remaining Marketable Gas** Bcf		**Type of Estimate**
2P Reserves	253		8,930		GLJPC, McDaniel
2C Economic Contingent Resources	550		19,413		GLJPC, McDaniel
Total Supply	803		28,343		
Demand	**Daily Max** $10^6m^3/d$	**Daily Max** MMcf/d	**Total Demand** 10^9m^3	**Total Demand** Bcf	
Long Term Gas Commitments	11.9	420	86.9	3,066	

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[7] Some of this data was revealed in the author's revised May 16, 2011 report, Follow the GA$: Kitimat LNG Export Terminal and Pacific Trails Pipeline Chronology. The author was an Intervenor in NEB's Kitimat LNG 2011 review.

[8] Note: as this NEB filing information from the three energy operators is almost three years old, some of the information about each of three corporations may have changed, as is certainly the case with EnCana, which has recently divested itself of some of its holdings and assets.

1. Reserves and Contingent Resources

Encana is required to provide reserves data prepared in accordance with Canadian securities regulatory requirements, specifically National Instrument 51-101 ("NI51-101"). Since inception, Encana has retained independent qualified reserves evaluators ("IQREs") to evaluate and report on 100% of Encana's natural gas and liquid reserves annually. In 2010, Encana's Canadian reserves and contingent resources were evaluated by GLJPC and McDaniel. Professional signoffs executed by the IQREs are attached to this as Exhibit A.

For Encana's 2P reserves, the working interest remaining marketable gas as at December 31, 2011 is 253 $10^9 m^3$ (8,929 Bcf). For Encana's 2C (best estimate) economic contingent resources, the working interest remaining marketable gas as at December 31, 2010 is 550 $10^9 m^3$ (19,413 Bcf).

2. Assets and Land

Portfolio Description

Encana has built one of the largest, low-cost, contiguous land positions in many of North America's best resource plays. Within Western Canada these include Bighorn in the Deep Basin where the tight gas, multi-zone stacked Cretaceous play produces primarily sweet, liquids-rich natural gas. Encana's CBM play integrates the Horseshow Canyon Coals with shallow sands. In Cutbank Ridge, Encana's focus is on long-term growth using the latest extraction technology to produce gas from the Montney, Doig and Cadomin formations. Lastly the Greater Sierra area is focused on the development of the Jean Marie formation and the Horn River Basin.

Land Position

Encana holds varying interests in a significant land position in Western Canada. Encana's land position is shown highlighted in yellow in Figure 1. Encana's net mineral land position in Western Canada is approximately 14,200 sections (9.0 million acres or 3.7 million hectares).

3. Reserves Determination

The evaluations by the IQREs are conducted from the fundamental petrophysical, geological, engineering, financial and accounting data. Processes and procedures are in place to ensure that the IQREs are in receipt of all relevant information. Reserves and contingent resources are estimated on material balance analysis, decline analysis, volumetric calculations or a combination of these methods, in all cases having regard to economic considerations. In the case of producing reserves, the emphasis is on decline analysis where volumetric analysis is considered to limit forecasts to reasonable levels for non-producing reserves and contingent resources.

The Canadian Oil and Gas Evaluation Handbook ("COGEH") is utilized by Encana and the IQREs as the industry standard to provide a clear and concise definitional framework for the assessment and reporting of petroleum resources, as described in Appendix 1, of the KM LNG Additional Evidence dated March 15th.

4. Productive Capacity

Drilling Schedule

Along with production from its existing wells, Encana has forecasted a drilling schedule (Table 3) which, in combination with the existing 12,227 producing wells, yields the production forecast presented in Figure 5. These forecasts are a consolidation of the drilling and production forecasts from the reserves and contingent resources reports prepared by GLJPC and McDaniel.

The production profiles are generated from the reserves and contingent resources reports including the production from the above wells and the existing wells as prepared by GLJPC and McDaniel.

Table 3

Year	Wells per Year	Cumulative Well Count
2011	782	782
2012	1,312	2,093
2013	2,193	4,286
2014	1,541	5,827
2015	1,643	7,470
2016	1,539	9,009
2017	1,100	10,109
2018	1,074	11,182
2019	1,250	12,433
2020	1,266	13,699
2021	1,287	14,986
2022	1,248	16,234
2023	1,109	17,343
2024	1,145	18,488
2025	852	19,339
2026	709	20,048
2027	95	20,143
2028	0	20,143
2029	0	20,143
2030	0	20,143
2031	0	20,143
2032	0	20,143
2033	0	20,143
2034	0	20,143
2035	0	20,143

5. Encana's Corporate Supply Forecast:

Encana's annual corporate supply forecast from 2011 through 2035 is presented in Table 4.

Table 4

Encana Gas Supply Forecast (Western Canada) Company Interest Marketable Production

Year	Total Proved plus Probable Reserves (10^3m^3/day)	Best Estimate Economic Contingent resources (10^3m^3/day)	Total (10^3m^3/day)	Total Proved plus Probable Reserves (MMcf/d)	Best Estimate Economic Contingent resources (MMcf/d)	Total (MMcf/d)
2011	45,843	387	46,230	1,618	14	1,632
2012	51,066	3,696	54,762	1,803	130	1,933
2013	55,371	11,189	66,560	1,955	395	2,350
2014	56,859	22,284	79,142	2,007	787	2,794
2015	52,014	35,026	87,040	1,836	1,236	3,073
2016	44,783	43,217	88,000	1,581	1,526	3,106
2017	38,082	49,642	87,724	1,344	1,752	3,097
2018	33,272	53,002	86,273	1,175	1,871	3,046
2019	29,515	55,153	84,668	1,042	1,947	2,989
2020	26,526	57,041	83,567	936	2,014	2,950
2021	24,045	59,151	83,195	849	2,088	2,937
2022	21,887	61,147	83,034	773	2,159	2,931
2023	20,008	63,233	83,241	706	2,232	2,938
2024	18,380	64,823	83,203	649	2,288	2,937
2025	16,904	64,806	81,710	597	2,288	2,884
2026	15,517	64,927	80,444	548	2,292	2,840
2027	14,294	63,348	77,642	505	2,236	2,741
2028	13,137	59,401	72,538	464	2,097	2,561
2029	12,071	56,514	68,585	426	1,995	2,421
2030	11,087	53,427	64,514	391	1,886	2,277
2031	10,185	50,056	60,241	360	1,767	2,127
2032	9,308	45,696	55,005	329	1,613	1,942
2033	8,373	41,627	49,999	296	1,469	1,765
2034	7,543	38,581	46,124	266	1,362	1,628
2035	6,828	35,831	42,659	241	1,265	1,506

6. Annual Supply/Demand Balance

Encana's forecast of annual corporate supply and demand forecast from 2011 to 2035 is presented in Table 5 and Figures 5.1 and 5.2:

Table 5

Year	Supply (10^3m^3/day)	Supply (MMcf/d)	Demand (10^3m^3/day)	Demand (MMcf/d)
2011	46,230	1,632	0	0
2012	54,762	1,933	0	0
2013	66,560	2,350	0	0
2014	79,142	2,794	0	0
2015	87,040	3,073	5,949	210
2016	88,000	3,106	5,949	210
2017	87,724	3,097	5,949	210
2018	86,273	3,046	11,898	420
2019	84,668	2,989	11,898	420
2020	83,567	2,950	11,898	420
2021	83,195	2,937	11,898	420
2022	83,034	2,931	11,898	420
2023	83,241	2,938	11,898	420
2024	83,203	2,937	11,898	420
2025	81,710	2,884	11,898	420
2026	80,444	2,840	11,898	420
2027	77,642	2,741	11,898	420
2028	72,538	2,561	11,898	420
2029	68,585	2,421	11,898	420
2030	64,514	2,277	11,898	420
2031	60,241	2,127	11,898	420
2032	55,005	1,942	11,898	420
2033	49,999	1,765	11,898	420
2034	46,124	1,628	11,898	420
2035	42,659	1,506	11,898	420

3.2. Apache's Corporate Supply Pool

The following from Apache's May 16, 2011 filing:

In the original Application, dated December 9, 2010, Apache's Corporate Supply Pool consisted of conventional gas in Western Canada and unconventional gas in British Columbia ("BC"), as set out in the tables and described in the text below. Apache's Corporate Supply Pool will evolve over the term of the gas export licence.

Table 1

Apache BC, AB, and SK Marketable Gas Volumes as of 2010-06-30		
***Conventional**	**10^9m^3**	**Bcf**
Proved Developed	37.5	1,332
Proved Undeveloped	12	426
Total Proved	49.5	1,758
Unconventional		
Resource (HRB)	251.3	8,920
Total	**300.8**	**10,678**

*Conventional reserves as per Ryder Scott audit.

Table 2

Apache Aggregate Supply Demand Balance					
Source of Supply	**Remaining Marketable Gas**				**Type of Estimate**
	10^9m^3		**Bcf**		
Conventional	49.5		1,758		Ryder Scott
Unconventional	251.3		8,920		Apache
Total	300.8		10,678		
Demand	**Daily max 10^3m^3/d**	**Daily max MMcf/d**	**Total Demand 10^9m^3**	**Total Demand Bcf**	
Long Term Gas Commitments	20,200	715.2	147.1	5,222.4	

As submitted in the Additional Evidence of March 15, 2011, Apache's forecast estimate of Canadian Marketable Gas Volume as shown in Table 1 was prepared as of June 30, 2010 and is based upon an internal evaluation of Apache's proved conventional gas reserves as audited by Ryder Scott, as well as Apache's internal forecast estimate of its Horn River Basin unconventional gas supply.

Apache completed an update to its Canadian Marketable Gas Volume as of December 31, 2010. This update takes into account an independent resource assessment of Apache's Horn River Basin Marketable Gas Volume that has been prepared by GLJ Petroleum Consultants ("GLJ") and that was submitted in the Additional Evidence of March 15, 2011. In addition, Apache has revised its internal forecast estimate of all remaining Canadian Marketable Gas Volume (i.e. all conventional and unconventional resources excluding Horn River). The revised forecast is presented in the following Revised Tables 1 and 2 below, which also assume possible Q2 2011 dispositions, as requested in NEB IR 1.19:

Revised Table 1
Post – Possible Q2 2011 Dispositions

Apache BC, AB and SK Marketable Gas Volumes as of 2010-12-31

	10^9m^3	**Bcf**
Conventional & Unconventional (Excluding Horn River)[1]		
Proved Developed	38.3	1361
Proved Undeveloped	16.7	592
Total Proved	55.0	1953
Horn River		
Proved	12.3	438
Proved + Probable	19.3	685
Best Estimate Economic Contingent Resource	265.0	9,412
Total Horn River Best Estimate	284.3	10,097
Total Canadian Corporate Supply Estimate	**339.3**	**12,050**

Note:
(1) "Corporate (Excluding Horn River)" refers to Apache's total proved Canadian conventional resources as well as its Canadian unconventional resources separate from the Horn River resources.

Revised Table 2
Post - Possible Q2 2011 Dispositions

Apache Aggregate Supply Demand Balance

	Remaining Marketable Gas		
Source of Supply	**10^9m^3**	**Bcf**	**Type of Estimate**
Conventional & Unconventional (excluding Horn River)	55.0	1,953	Apache
Horn River	284.3	10,097	GLJ
Total	339.3	12,050	

Demand	Daily max $10^6m^3/d$	Daily max MMcf/d	Total Demand 10^9m^3	Total Demand Bcf
Long Term Gas Commitments	16.2	573	120.3	4,250

1. Conventional

In the original Application, Apache's conventional reserves were reviewed by Ryder Scott Company, L.P. ("Ryder Scott"). Ryder Scott prepared a report summarizing their audit of the Apache corporate conventional reserves as submitted for SEC Reporting purposes, and is attached to this Appendix as Exhibit A. The conventional gas volumes reviewed by Ryder Scott included only proved reserves and should be considered a conservative estimate of resource and supply potential of those properties. For Apache's conventional reserves, the total proved working interest remaining marketable gas as at June 30, 2010 is 49.5 10^9m^3 (1,758 Bcf).

The Ryder Scott assessment does not include Western Canadian natural gas reserves associated with the recently announced Apache acquisition of the majority of BP's Canadian gas properties. Apache estimates the proved and probable gas reserves associated with the acquisition are in excess of 57.6 10^9m^3 (2,033 Bcf).

As submitted in the Additional Evidence of March 15, 2011, Apache's revised Total Canadian Marketable Gas Volume forecast is 12,050 Bcf as of December 31, 2010. This is an increase of 1,372 Bcf over its June 30, 2010 forecast estimate as presented in Table 1. This increase is attributed in part to resource acquisitions not accounted for in the June forecast as well as the results of the GLJ Horn River Basin assessment.

2. Unconventional

Apache's unconventional Horn River Basin ("HRB") shale gas play is located in Northeastern British Columbia. The shale play, by its very nature, differs from conventional plays because it has high geological certainty. The greatest factor in reducing early uncertainty in shale play outcomes lies in achieving technological advances to improve development economics through increasing well productivity while at the same time reducing capital and operating costs. The 2009 NEB Energy Brief A Primer for Understanding Canadian Shale Gas stated that, "This emerging resource can be considered a technology driven play as achieving gas production out of otherwise unproductive rock requires technology-intensive processes".

The economics of unconventional plays are strengthened by the British Columbia Net Profits royalty system which holds royalties at 2 per cent until capital recovery occurs (based on the royalty definition of capital recovery).

i. Apache Internal Forecast
In its original Application, Apache estimated its unconventional marketable gas supply at 252.6 10^9m^3 (8,920 Bcf) according to the methodology described below.

ii. GLJ Independent Forecast
As submitted in the Additional Evidence of March 15, 2011, during the first quarter of 2011, GLJ reviewed Apache's Horn River interests and conducted an assessment of reserves and contingent

resources in accordance with the Canadian Oil and Gas Evaluation Handbook ("COGEH") standards. GLJ's conclusions are summarized below:

Company Interest Sales Volumes					
Reserves			Economic Contingent Resources		
Total Proved Bcf	Total P+P Bcf	Total 3P Bcf	Low Estimate Bcf	Best Estimate Bcf	High Estimate Bcf
438	685	860	3,908	9,412	13,748

(a) Geological Description

The HRB shale was encountered in the late 1950's in the development of the Clarke Lake gas field by wells seeking deeper horizons. In 2006, both Encana and Apache hydraulically fractured the thick shale zone in existing vertical wells to determine if economic gas production was possible. Due to favourable results, the HRB shale gas project was initiated.

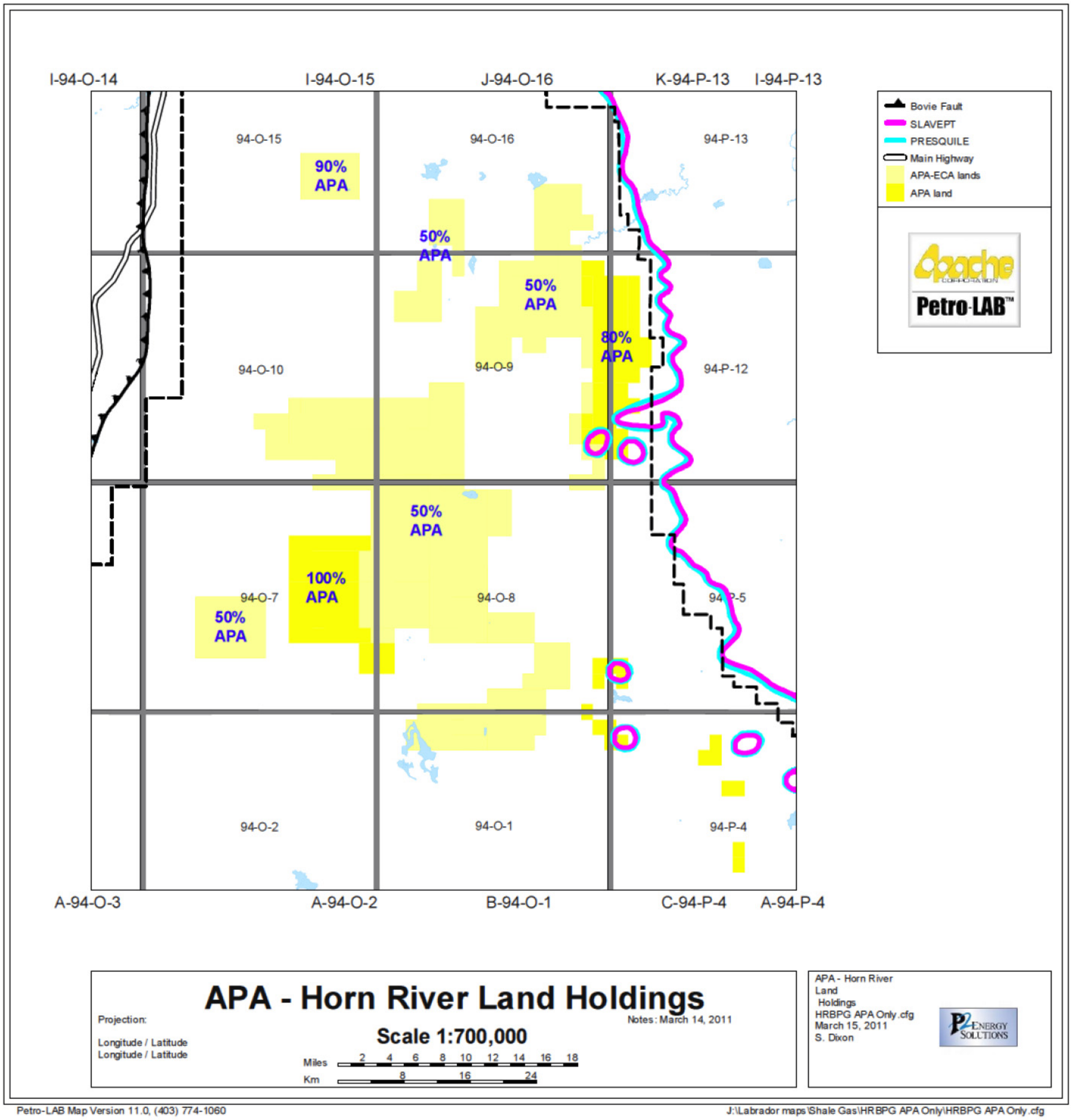
Referring to Figure 1, the Middle Devonian shales in the HRB are bounded to the north by the BC/Northwest Territories border, the Bouvie fault system to the west, and the Slave Point reef complex to the east. In the south, a poorer quality reservoir near the town of Fort Nelson was used as the boundary. The HRB covers an area of 10,880 km2, dips to the west and lies at depths greater than 2200 meters with reservoir temperature in excess of 120o C. This thick shale sequence can reach over 180 m in gross thickness. The shale zones of interest are referred to as the Muskwa, Otterpark and Evie formations. The reservoir produces methane and variable amounts of carbon dioxide with no liquid production to date.

The reservoir is a marine sequence of extremely fine grained sediments rich in quartz, calcite, clays and organic matter. The reservoir permeability is very low and measured in nano-Darcies. The exact permeability is a matter of debate due to technological measurement constraints. With such low permeability, wells will not flow without extensive stimulation treatments. The actual measured permeability of the native shales is not predictive of the productivity of the wells post-stimulation. The productivity of wells is highly influenced by the fracturing techniques, spacing of the fracture treatments, and total number of fracture stages ("fracs") per well.

(b) Land Position

In the original Application, it was noted that Apache holds a significant land position in the HRB with varying degrees of working interest. Apache's land position is shown highlighted in yellow in Figure 1. Apache's net land position in the HRB is 330 sections (85,487 ha).

As submitted in the Additional Evidence of March 15, 2011, GLJ's resource assessment took into account updates that have occurred to Apache's land position in the Horn River Basin. While Apache's net land position has not changed, the location of some of its specific land interests have and primarily result from land swap transactions. An update to Figure 1 is shown below:



Revised Figure 1 – Horn River Basin and Apache Lands

(e) OGIP Calculation

i. Apache Internal Forecast

In the original Application, Apache calculated a working interest raw gas ("WIRG") in place of 1.0 $10^{12}m^3$ (36.4 Tcf) based on its land position. This number was derived from OGIP mapping and multiplied by Apache's working interest in each section. The WIRG in place was divided by Apache's land position to determine an average 3.3 10^9m^3/section (110.3 Bcf/section). Apache believes that this number is conservative and is currently reassessing the OGIP estimates by reviewing and incorporating all available core data, isotherm data and petrophysical data.

ii. GLJ Independent Forecast

As submitted in the Additional Evidence of March 15, 2011, aggregation of the total proved plus probable reserves plus the best estimate of economic contingent resources reflects GLJ's current best estimate opinion of Apache's Horn River Basin marketable gas supply volume. Aggregation of the COGEH reserve categories of total proved plus probable reserves plus a best estimate of economic contingent resources in GLJ's opinion provides for an equivalent to the more historic standard term of established reserves.

Parameters used by GLJ to assess economic contingent resources differed from the parameters used by Apache in its internal assessment of the Horn River resource. These differences are summarized as follows:

GLJ Parameter Table

Parameter	GLJ	Apache
Average OGIP per section, Bcf	163.7	110.3
Total Apache OGIP, Bcf Raw	48,820	36,400
Best Estimate Type Curve IP30, Mcf/d per frac	530	600
Number of fracs, per well	20	15
Shrinkage, per cent	20	19
Best estimate recovery factor	25.9[1]	30.3
Proved plus Probable Reserves + Best Estimate Economic Contingent Resources, Bcf Sales	10,097	8,920

ii. GLJ Independent Forecast

As submitted in KM LNG's Response to NEB IR 1.12(a), the original well design was based on 15 frac stages per well and 1650m horizontal lateral lengths. Since the filing, horizontal well lengths have been drilled longer to accommodate more frac stages per well (ie. now 2400m horizontal length versus older vintage 1650m horizontal wells). Apache has tested wells with increased lateral lengths and additional frac stages per well (up to 28 fracs) and has seen no apparent deviation from per stage type curve parameters. To date, a linear relationship has been observed between total well production and number of frac stages per well, evidencing the theory that more frac stages per well provide a proportional increase in total well production. The proposed marketable production development forecast utilizing 20 fracs per well is now considered a conservative development approach to what has already been proved and tested in the Horn River Basin. The increased production resulting from longer wells with more frac stages per well, results in a lower total amount of wells required to achieve a comparable production and recovery performance across the Apache land base.

As submitted in KM LNG's Response to NEB IR 1.12(b), GLJ based type curve parameters on review of historic Barnett shale production, and further refined parameters to account for available production data on 48 Horn River wells. GLJ has used decline exponents of 1.3, 1.4 and 1.4, with terminal decline rates of 7.0, 6.0 and 5.0 percent in the low, best and high estimate categories. Initial production rates, terminal decline rates were considered in order to account for gas-in-place, completion spacing and potential for interference under the assumed approximate spacing of 120m fracture spacing and 20 fracture stages per well.

Expected ultimate recovery per well:

- *Average Best Estimate per well across all evaluated regions: 10.6 BCF raw per well*
- *Current Development Area, Muskwa-Otter Park: 14.4 BCF raw per well.*

Projected number of wells:

- *Total P+P plus Best Estimate Contingent Resources: 1,183.*

Projected horizontal length of wells:

- *Approximately 2,400 meters (120 meters per stage).*

4. Productive Capacity

(a) Conventional

The forecast of conventional productive capability was determined by Apache and audited by Ryder Scott.

As submitted in the Additional Evidence of March 15, 2011, Apache completed an update to its Canadian Marketable Gas Volume as of December 31, 2010. This update takes into account an independent resource assessment of Apache's Horn River Basin Marketable gas volume that has been prepared by GLJ. In addition, Apache has revised its internal forecast estimate of all remaining Canadian Marketable gas volume (i.e. all conventional and unconventional resources excluding Horn River).

(b) Unconventional

Drilling Schedule

Along with production from its existing wells, Apache forecasted a drilling schedule in the original Application (Table 3) which, in combination with the type curve profile, yields the production forecast illustrated in Figure 5.

This projection of wells drilled is the current estimate of a reasonable development plan.

Table 3

Year	Cumulative Well Count	Wells per Year
2010	36	36
2011	68	32
2012	118	50
2013	168	50
2014	218	50
2015	268	50
2016	318	50
2017	368	50
2018	418	50
2019	468	50
2020	518	50
2021	568	50
2022	618	50
2023	668	50
2024	718	50
2025	768	50
2026	818	50
2027	868	50
2028	918	50
2029	968	50
2030	1018	50
2031	1068	50
2032	1118	50
2033	1168	50
2034	1218	50

In the original Application, it was assumed that each drilled well would have 15 fracs. Therefore, the initial instantaneous production rate per well was 289 10^3m^3/day (10.2 MMcf/d). Due to the high decline rate, this results in a first month average production rate of 255 10^3m^3/day (9.0 MMcf/d).

As submitted in the Additional Evidence of March 15, 2011, GLJ's Best Estimate of Apache's Horn River Basin marketable gas supply volume also adopted an evaluation case that used an updated drilling schedule than the schedule presented in Table 3 above. The new drilling schedule is shown below:

Revised Table 3

Year	Cumulative Net Average Producing Well Count	Apache Net Wells Drilled per Year
2011	32	3
2012	46	9
2013	64	14
2014	118	50
2015	160	42
2016	204	44
2017	249	45
2018	294	45
2019	340	46
2020	385	45
2021	430	45
2022	480	50
2023	525	46
2024	609	84
2025	697	88
2026	783	86
2027	843	61
2028	902	59
2029	960	58
2030	1018	58
2031	1076	58
2032	1134	58
2033	1183	48
2034	1183	0
2035	1183	0

5. Apache's Corporate Supply Forecast:

Apache's current annual corporate supply forecast from 2011 through 2035, assuming possible Q2 2011 dispositions, was provided in KM LNG's submission of April 26, 2011 in the following Revised Table 4.

Revised Table 4
Post - Possible Q2 2011 Dispositions

Apache Corporate Gas Supply Forecast (Canada – BC, Alberta and Saskatchewan)

Apache WIRG Marketable Production

Year	Corporate* 103m3/day	Horn River 103m3/day	Total 103m3/day	Corporate* MMcf/d	Horn River MMcf/d	Total MMcf/d
2011	12,799	2,124	14,923	452	75	527
2012	12,941	3,171	16,112	457	112	569
2013	14,272	4,417	18,689	504	156	660
2014	11,780	8,467	20,247	416	299	716
2015	10,109	10,845	20,954	357	383	739
2016	9,033	12,601	21,634	319	445	764
2017	7,815	14,300	22,115	276	505	781
2018	6,853	15,744	22,597	242	556	798
2019	6,060	17,047	23,107	214	602	816
2020	5,437	18,038	23,475	192	637	829
2021	4,899	18,802	23,701	173	664	837
2022	4,446	19,963	24,409	157	705	862
2023	4,049	20,841	24,890	143	736	879
2024	3,710	24,947	28,657	131	881	1,012
2025	3,426	29,251	32,678	121	1,033	1,154
2026	3,115	32,083	35,198	110	1,133	1,243
2027	2,832	33,329	36,161	100	1,117	1,217
2028	2,577	30,299	32,876	91	1,070	1,160
2029	2,322	29,761	32,083	82	1,051	1,133
2030	2,095	29,648	31,743	74	1,047	1,121
2031	1,926	29,704	31,630	68	1,049	1,117
2032	1,727	29,846	31,573	61	1,054	1,115
2033	1,586	29,478	31,064	56	1,041	1,097
2034	1,444	25,655	27,099	51	906	958
2035	1,331	22,002	23,333	47	777	824

** Corporate forecast not including Horn River and proposed disposition properties.*

3.3. EOG's Corporate Supply Pool

The following from EOG's May 16, 2011 filing:

EOG's Corporate Supply Pool primarily consists of unconventional gas located in British Columbia ("BC") as set out in the tables and described in the text below. EOG's Corporate Supply Pool will evolve over the duration of the Export Licence: no specific reserves are dedicated to the License and no specific reserves will be used to support export sales contracts. At the present time, EOG is rationalizing its Alberta based reserves and the anticipated commercial transactions will impact such supply. As such, for the purposes of demonstrating that EOG has adequate supply to support the requested Licence, EOG has focused on its BC based reserves within the Horn River area. The formal reserve report prepared for EOG by the engineering firm of DeGolyer and MacNaughton ("D&M"), as of October 1, 2010, has also been restricted to this area as they are adequate to meet the term volume requested.

Table 1

EOG Horn River Marketable Gas Volumes as of 2010-10-01		
Horn River	**10^9m^3**	**Bcf**
Proved	43.6	1,540
Proved + Probable	104.7	3,695
Proved + Probable + Possible	112.9	3,987
Contingent Resource	161.6	5,705
Total 3P + Contingent	**274.6**	**9,692**

Table 2

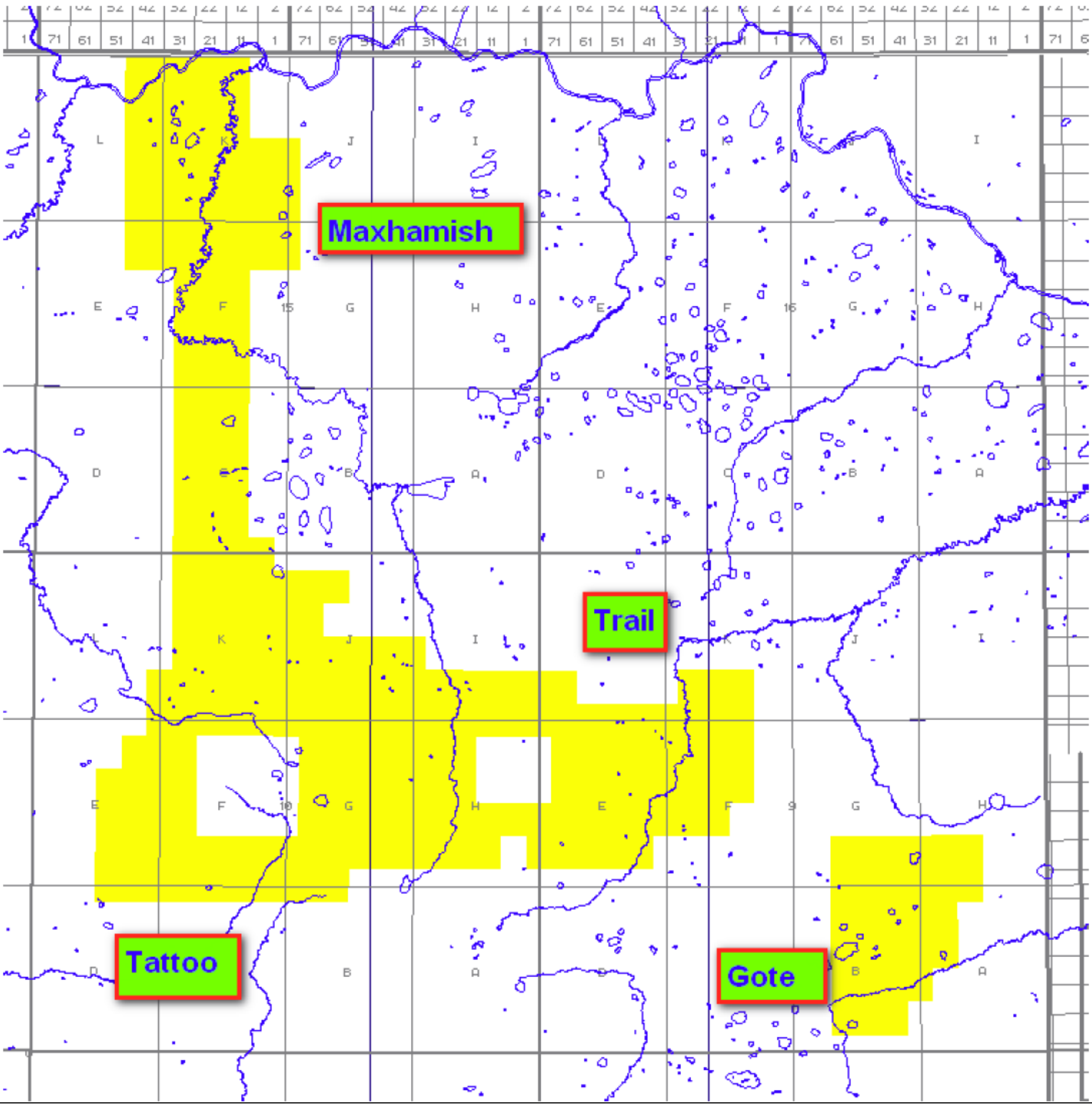
EOG Aggregate Supply Demand Balance					
Source of Supply	**Remaining Marketable Gas**				**Type of Estimate**
	10^9m^3		**Bcf**		
Total	274.6		9,692		D&M
Demand	**Daily max $10^3m^3/d$**	**Daily max MMcf/d**	**Total Demand 10^9m^3**	**Total Demand Bcf**	
Long Term Gas Commitments	19,430	686	141.8	5,007.8	

EOG's BC reserves centre around its unconventional gas field in the Horn River Basin ("HRB"). The Horn River formation is a Devonian-age siliceous shale gas reservoir in North Eastern BC, ("NEBC"), north of Fort Nelson, which includes the Muskwa/Otter Park and Klua/Evie members. EOG currently hold interests in 157,500 net acres that overlie the Horn River formation and believes to have approximately 1400 drill locations on this acreage.

EOG has been producing Horn River gas since 2008 from the Maxhamish area and has engaged D&M to provide a resource assessment of its Horn River acreage to National Instrument 51-101 ("NI 51-101") standard and the results of that assessment are herewith described as well as EOG's interpretation of the production profile.

EOG's land position is described in Figure 1 by the yellow highlighted blocks.

Figure 1 – EOG's Land Position (Yellow) With Area Names



Methodology for Resource Assessment

Original Gas In Place ("OGIP") Determination

Reservoir data collected from operated and industry wells for the respective formation members were utilized to estimate and map OGIP across EOG's acreage position. As EOG's acreage covers a wide area, the OGIP was found to range between 4.3 $10^6 m^3$ - 5.1 $10^6 m^3$/section. Generally, in the West (Maxhamish and Tattoo), where the Horn River formation is deeper, additional OGIP was calculated due to higher pressures versus the equivalent formation on the East (Trail and Gote). Figure 2 is D&M's estimate of OGIP across EOG's entire acreage.

Recoverable Gas In Place Determination

Detailed decline curve and rate transient analysis of producing wells was tempered by reasonable recovery factors of estimated OGIP to determine recoverable gas in place. These recovery factors were 31% for proven and 41% for probable and contingent recoveries. Type curves, scaled appropriately for future wells with 5,000-foot laterals and 15 stages of completion, were applied across the acreage position for a total of 1400 locations. Figure 3 is the D&M estimate of gross unshrunk Estimated Ultimate Recoverable ("EUR") volumes.

Figure 2 – D&M's Estimate of OGIP Across EOG's Acreage

Area	Zone	Average OGIP, $10^6 m^3$/section	Average OGIP, Bcf/section
WEST	Muskwa/Otter Park	2.4	83.8
WEST	Klua/Evie	2.6	92.7
	Total	5.0	176.5
EAST	Muskwa/Otter Park	2.1	73.7
EAST	Klua/Evie	2.3	81.5
	Total	4.4	155.2

Figure 3 – D&M's Estimate of Gross Unshrunk EUR across EOG's Acreage

Area	Zone	Average EUR, e3m3/well	Average EUR, Bcf/well
WEST	**Muskwa/Otter Park**	**195 – 275**	**6.9 - 9.7**
WEST	**Klua/Evie**	**215 – 303**	**7.6 - 10.7**
EAST	**Muskwa/Otter Park**	**173 – 241**	**6.1 - 8.5**
EAST	**Klua/Evie**	**187 – 266**	**6.6 - 9.4**

EOG's Horn River Development Plan

D&M classified the first five years of the development plan as proved undeveloped with the next three years of the development plan being classified as probable undeveloped. In addition, an incremental probable wedge of forecast production based on the difference in the probable and proved type curves for each respective proved undeveloped well was estimated and classified as probable undeveloped. An incremental possible wedge of forecast production based on the difference in the possible and respective type curves for each proved and probable undeveloped well was estimated and classified as possible undeveloped. The majority of locations for the first 8 years of EOG's development plan are on Net Profit Royalty acreage granted by the BC Government, which includes reduced fiscal terms. The remaining development plan locations have the statutory royalty rate and are classified as contingent resources.

Figure 5 – EOG's Proposed Development Schedule

	Year	Total # Net Wells DRILLED	Cum # Wells
5 Year Plan	2010	10	10
	2011	10	20
	2012	9	29
	2013	75	104
	2014	75	179
5-10 Year Plan	2015	100	279
	2016	100	379
	2017	100	479
	2018	50	529
	2019	50	579
10+ Year Plan	2020	50	629
	2021	50	679
	2022	50	729
	2023	50	779
	2024	50	829
	2025	50	879
	2026	50	929
	2027	50	979
	2028	50	1,029
	2029	50	1,079
	2030	50	1,129
	2031	50	1,179
	2032	50	1,229
	2033	50	1,279
	2034	50	1,329
	2035	50	1,379
	2036	21	1,400

Because of the shrinkages discussed previously, it is estimated that EOG will need 7.29 $10^6 m^3/d$ (257 Mmcf/d) field production (gross unshrunk) in 2015 to meet EOG's marketing commitments of 5.94 $10^6 m^3/d$ (210 Mmcf/d) and 14.6 $10^6 m^3/d$ (514 Mmcf/d) field production (gross unshrunk) in 2017 to achieve EOG's marketing requirements of 11.9 $10^6 m^3/d$ (420 Mmcf/d). Both EOG and D&M have forecast EOG's Horn River production growth until 2035. EOG is also providing its' more conservative view of the ramp up in production. The field ramp up as per Figure 5 well count profile over delivers volume versus the required targets. Depending on economic conditions and the viability of increased drilling to satisfy alternate markets, the volume profile shown can be maintained flat with much fewer wells (estimated at less than 50). The gross interest shrunk profile below exceeds the marketing volume requirements (20.5 $10^6 m^3/d$ average production versus 11.9 $10^6 m^3/d$ required).

Technically Recoverable Resource and Recoverable Reserves

D&M's resource assessment indicates that there is 347 $10^9 m^3$ (12.254 Tcf) of technically recoverable unshrunk volumes on EOG's working interest acreage. Of this total, it is estimated that, adjusted for shrinkage, there is 288 $10^9 m^3$ (10.2 Tcf) of technically recoverable shrunk volumes. [9]

Figure 11 – Total Gross Resource on EOG Land

Classification	Technical EUR (unshrunk), $10^9 m^3$	Technical EUR (unshrunk), Bcf
Proved Plus Probable	137	4838
Possible and Contingent	210	7416
Total	347	12254

Figure 12 – EOG's Technically Recoverable Volumes*

	Technical EUR (shrunk), $10^9 m^3$	Technical EUR (shrunk), Bcf
Total	288	10170

Figure 13 – Reserve Estimates in Each Category – Gross (includes crown gas)

	Gross EUR (shrunk), $10^9 m^3$	Gross EUR (shrunk), Bcf
Proved	43.6	1540
Proved + Probable	104.7	3695
Proved + Probable + Possible	112.9	3987
Contingent	161.6	5705
Total (Proved+Probable+ Possible+Contingent)	274.6	9692

Note

EOG Resources, Inc. (the parent of EOG Resources Canada Inc.) is subject to the rules and regulations of the United States Securities and Exchange Commission ("SEC") and, accordingly,prepares and publicly reports the estimated reserves of its consolidated group of companies (including EOG Resources Canada Inc.) in accordance with such rules and regulations. Conversely, the D&M Report was prepared using reserves and contingent resources definitions consistent with those of Canadian National Instrument 51-101. As a result, the reserve and resource estimates and related amounts reflected in this Appendix and in the D&M Report differ from the reserve estimates and related amounts publicly reported by EOG in its filings with the SEC.

[9] *Technically recoverable volumes includes both EOG's and the Crown's share of the volumes.*

3.4. KM LNG Operating Partnership Summary Information

The following are excerpts from the revised Kitimat LNG Licence Application, filed with the NEB on May 16, 2011:

The following table summarizes the gas supply requirements anticipated at the Terminal inlet, and the balance of this Section demonstrates Apache, EOG and Encana's abilities to meet their respective share of these gas supply requirements.

KITIMAT LNG TERMINAL		APACHE	EOG	ENCANA
Total Term Requirement at Inlet (assumes Phase 2 commences 2015)		20-year Term Requirement @ 40%	20-year Term Requirement @ 30%	20-year Term Requirement @ 30%
289,398,000 10^3m^3 (10,220 Bcf)		115,759,200 10^3m^3 (4,088 Bcf)	86,819,400 10^3m^3 (3,066 Bcf)	86,819,400 10^3m^3 (3,066 Bcf)
Total Daily Requirement at Inlet		Daily Requirement @ 40%	Daily Requirement @ 30%	Daily Requirement @ 30%
Phase 1 2015-2018	19,800 10^3m^3 (700 MMcf/d)	7,930 10^3m^3/d (280 MMcf/d)	5,950 10^3m^3/d (210 MMcf/d)	5,950 10^3m^3/d (210 MMcf/d)
Phase 2 2018-2035	39,600 10^3m^3 (1,400 MMcf/d)	15,870 10^3m^3/d (560 MMcf/d)	11,890 10^3m^3/d (420 MMcf/d)	11,890 10^3m^3/d (420 MMcf/d)

***1.2** The terms that KM LNG requests for the Licence include:*

***Term:** The term of the Licence shall be 20 years commencing on the first export of quantities under the Licence and continuing for a period of 20 years thereafter.*

***Annual Quantity:** During any year the quantity of LNG that may be exported shall not exceed 10 million tonnes (natural gas equivalent of approximately 13,300,000 10^3m^3 or 468 Bcf).*

***Term Quantity:** During the term of the Licence, the quantity of LNG that may be exported shall not exceed 200 million tonnes (natural gas equivalent of approximately 265,000,000 10^3m^3 or 9,360 Bcf).*

***Annual Tolerance:** As a tolerance, the amount of gas that may be exported in any 12-month period may exceed the annual volume by 10%.*

***Export Point:** The LNG will be exported at a point on the outlet side of the liquefaction terminal to be located at Bish Cove, near the Port of Kitimat, British Columbia, Canada.*

***2.2** This is the first time that an export of LNG has been applied-for under the present National Energy Board Part VI (Oil and Gas) Regulations, for the purpose of accessing offshore markets. A daily maximum is not requested in light of the particular nature of this application.*

- *Unlike continental North American natural gas markets served by onshore pipelines, Asia Pacific LNG buyers are seeking long-term secure gas supply arrangements with regulatory certainty before committing to long-term contractual commitments. Therefore a long-term*

- *The application is a response to a rapidly changing North American gas market that is driven by recent technological advances and a current and foreseen abundance of supply. The majority of the gas that is proposed to be exported under the Licence will likely be sourced from Northeast British Columbia. This region is widely considered to hold significant gas resources, although it is in a relatively early stage of development.*

2.4. Natural gas produced in Western Canada will be transported from a delivery point on the Spectra Energy BC pipeline ("Spectra"), near Summit Lake, B.C., to the Kitimat LNG Terminal by PTP Limited Partnership's ("PTP LP") proposed $1.1 billion Pacific Trail Pipeline ("PTP").

3.2 Apache Corporate Supply Pool:

Apache's share of LNG to be exported under this Application will be sourced from its ownership of natural gas reserves and production located in Canada, currently British Columbia, Alberta and Saskatchewan, as it may evolve over the duration of the Licence ("Apache Corporate Supply Pool"). All gas reserves quoted by Apache and included in this Application are owned by Apache.

3.5 EOG Corporate Supply Pool:

EOG's share of LNG to be exported under this Application will be sourced from its ownership of natural gas reserves and production located in Canada, currently British Columbia and Alberta, as it may evolve over the duration of the Licence ("EOG Corporate Supply Pool"). At the present time, EOG is rationalizing its Alberta based reserves and the anticipated commercial transactions will impact this source of supply. Therefore, for the purposes of demonstrating that EOG has adequate reserves and supply to support the requested licence, EOG has focused on its British Columbia reserves. All gas reserves quoted by EOG and included in this application are owned by EOG.

3.8 Encana Corporate Supply Pool, Reserves/Resource and Productive Capacity:

This application relies on the intervener supply evidence filed by Encana on April 21, 2011.

3.4. Frack-Math Projections

From the data provided by the three former partners in Canada's first LNG export license, is all the information needed to understand the future fracking impacts from just one such application to Western Canada. For all the other LNG applications, **Do The Frack-Math**!

4. Recommendations

1. **The BC government has an abysmal reputation for not divulging comprehensive data on water usage over time for fracking operations. There should be immediate steps taken to make such reporting mandatory and available to the public on a government website, in order to ensure accountability and transparency. This data should go back to the year 2000 following, for each and every well-fracking operation conducted. The data should include the dates of when the fracking occurred, the name of the operator, the volume of water used, the location, name and number of the well. The data must include all confidential well classifications to provide only the water usages therefrom and therein.**

2. **An independent and knowledgeable audit team should be assembled to review and verify the data that energy operators submit to the Frac-Focus registry, in order to double-check the numbers and information. That team should also check with the Regulators to ensure that all operators have filed when completing wells.**

3. **Provincial and Federal governments should implement conservation measures on the use and export of natural gas produced in Canada.**

The following is a quote from the end of the author's *Final Argument* presented to the National Energy Board Hearing in Kitimat on July 14, 2011 regarding the Kitimat LNG proposal:

> *There is one last matter we would like to address, and that relates to the document by the former chair of the NEB, Mr. Roland Priddle, Export Impact Assessment Report, regarding his therein repeated advice that "there will be no need for Canadian gas users to adjust their energy consumption patterns by conservation or by switching to alternative fuels" (on adobe pages 7, 13 and 20). Given the global concerns and circumstances today concerning the use and abuse of fossil fuels, and their impact on the environment and on the future status of energy reserves, we are disappointed in and perplexed by Mr. Priddle's statement.*
>
> *In this regard, we note that the May 2011 Hughes report [Will Natural Gas Fuel America in the 21st Century?], however, strongly advises the opposite. We would remind the Board, that both Mr. Hughes and Mr. Priddle were members of the same committee in Canada, the Potential Gas Committee. Here is what the Hughes report states:*
>
> > ***The Unavoidable Solution: Energy Conservation***
> >
> > *It is past time for policy makers to get serious about the most important strategy we can and must adopt in order to succeed in this new era—energy conservation. Reducing demand for energy and using energy more efficiently are the cheapest and most effective ways of cutting carbon emissions, enhancing energy security, and providing a stable basis for economic planning.*
> >
> > *Unfortunately, energy supply limits and demand reduction do not support robust economic growth. This is probably the main reason why policy makers and many energy analysts and environmentalists shy away from conveying the real dimensions of our predicament. However understandable this response may be from a political perspective, it is one that only compromises our prospects as a nation and a species.*

> *There is much we can do to ensure a secure social and natural environment in a lower-energy context, but we are unlikely to take the needed steps if we are laboring under fundamentally mistaken assumptions about the amounts of energy we can realistically access, and the costs of making that energy available.*
>
> *Reducing the consumption of energy through efficiency and conservation is paramount if we are to reduce emissions, enhance energy security, and promote a more sustainable energy future. The growth mindset that has served us so well for the past few centuries no longer suits the situation we find ourselves in. Fossil fuels are a finite, one-time resource. Neither natural gas nor oil nor coal can fuel the 21st century to its end in the manner to which we have become accustomed. Understanding the full-cycle environmental costs of future energy choices is crucial. Although there are no silver bullets, there are many options in planning a more sustainable way forward, and I have tried to outline some of them here. We'd best get on with them.*

In summary, Madame Chair, we have some serious concerns about the long-term viability of KM LNG's export license with the NEB. These concerns relate to the applicant's claims from its associated Hearing documents and Hearing Transcript statements, including KM LNG's final argument this morning, about the viability of this project based on the interpretation and forecast of data about the long-term supply of natural gas produced in Canada primarily from the exploration and production of deep shale gas in Canada's three western-most provinces, British Columbia, Alberta and Saskatchewan. We believe that the interpretation of this data by the applicant's primary natural gas supply consultants, Ziff Energy Group, and the supportive document filed by Mr. Roland Priddle, seem to have a number of problems and narrow interpretations about serving Canadians over the long term, in what they generally and narrowly define as serving the "public interest".

Appendix A. Oil and Gas Regions: Frac-Focus Data - Single Well Fracking Water Volumes Greater than 1,000 Cubic Metres

Region / Named Well Zone / Play	Wells Fracked 2011	Wells Fracked 2012	Total Water Volumes 2012	Operators & Wells Fracked 2012	Wells Fracked 2013	Total Water Volumes 2013	Operators & Wells Fracked 2013	Total Wells Fracked 2012-2013	Total Water Volumes 2012-2013	Highest Water Volume Single Well Fracked
Altares North Montney	8 (127,188 cub. met.) Talisman	50	687,588.14	Canbriam (6) Progress (4) Talisman (40)	34	420,564.87	Canbriam (8) Progress (2) Talisman (24)	84	1,108,153.01	**19,687.54** Canbriam (Well # 27956)
Attachie North Montney	0	1	0	0	0	6,190.70	ARC (1)	1	6,190.70	**6,190.70** ARC (Well # 28198)
Beg North Montney	0	3	26,809.13	Black Swan (3)	0	0		3	26,809.13	**10,326.9** Black Swan (Well # 28071)
Birch North Montney	0	2	13,558.1	Paramount (2)	1	9,156.7	CNRL (1)	3	22,714.80	**9,156.7** CNRL (Well # 28723)
Blair Creek North Montney	0	1	6,938.2	Shell (1)	0	0		1	6,938.20	**6,938.2** Shell Canada (Well # 27042)
Blueberry North Montney	0	3	24,451.8	Shell Can.	6	94,168.4	Bonavista (1) Conoco Res Cp (4) Progress (1)	9	118,620.20	**11,369** Conoco Res Cp (Well # 28239)
W Blueberry North Montney	0	2	17,174.8	Bonavista	0	0	0	2	17,174.80	**9,378.9** Bonavista (Well # 27930)
Brassey South Montney	0	2	34,121.1	EnCana	0	0	0	2	34,121.10	**18,020.5** EnCana (Well # 28275)
Bubbles North Montney	0	0	0	Black Swan	1	8779.6	Black Swan	1	8,779.60	**8779.6** Black Swan (Well # 28741)
Cameron North Montney	0	0	0	0	1	2,047.5	Progress	1	2,047.50	**2,047.5** Progress (Well # 28593)
Caribou North Montney	0	4	30,831.3	Progress	2	26,895.5	Progress	6	57,726.80	**14,534.7** Progress (Well # 28613)
Daiber North Montney	0	3	35,086.71	Painted Pony	0	0	0	3	35,086.71	**13,148.14** Painted Pony (Well # 27958)
Dawson South Montney	0	4	31,963.43	ARC (2) EnCana (2)	11	78,494.5	ARC (8) EnCana (3)	15	110,457.93	**10,870.1** EnCana (Well # 26921)

Region / Named Well Zone / Play	Wells Fracked 2011	Wells Fracked 2012	Total Water Volumes 2012	Operators & Wells Fracked 2012	Wells Fracked 2013	Total Water Volumes 2013	Operators & Wells Fracked 2013	Total Wells Fracked 2012-2013	Total Water Volumes 2012-2013	Highest Water Volume Single Well Fracked
Doe South Montney	0	2	11,300.61	Tourmaline	5	49,911.57	Crocotta (2) Tourmaline (3)	7	61,212.18	**14,305.75** Tourmaline (Well # 28463)
Fireweed North Montney	0	2	3,519	CNRL	0	0	0	2	3,519.00	**1,855.8** CNRL (Well # 27191)
Fortune Horn Basin	0	1	58,329.19	Quicksilver	0	0	0	1	58,329.19	**58,329.19** Quicksilver (Well # 26073)
Graham North Montney	0	2	30,398.31	Progress	2	28,118.4	Progress	4	58,516.71	**17,738.6** Progress (Well # 28247)
Green North Montney	0	7	63,621	Progress	6	76,152.3	Progress	13	139,773.30	**20,814.4** Progress (Well # 28525)
Groundbirch South Montney	0	21	174,461.3	Shell Can.	25	182,843.62	Shell Can.	46	357,304.92	**27,884.4** Shell Can. (Well # 28034)
Gundy North Montney	0	6	130,112.5	Progress (3) Shell Can (3)	0	0	0	6	130,112.50	**47,067.9** Shell Can. (Well # 27022)
W Gundy North Montney	0	2	24,631	Progress	0	0	0	2	24,631.00	**12,569** Progress (Well # 26565)
Helmet Cordova Basin	0	15	551,079.5	PennWest	0	0	0	15	551,079.50	**57,725.8** PennWest (Well # 27438)
Inga North Montney	0	2	11,963.2	ARC Yoho	1	6,999.8	ARC	3	18,963.00	**8,045.5** Artek (Well # 27816)
Jedney North Montney	0	3	12,774.99	Black Swan	0	0	0	3	12,774.99	**10,621.49** Black Swan (Well # 28176)
Julienne North Montney	0	0	0	0	4	34,688.36	Progress	4	34,688.36	**12,730.3** Progress (Well # 28543)
Kelly South Montney	0	9	82,917.08	EnCana (6) Sinopec (3)	2	10,952.5	EnCana	11	93,869.58	**20,798.1** EnCana (Well # 27884)
Kiwigana Horn Basin	1 104,307.2 EnCana	16	1,737,578.01	EnCana	7	668,623.23	EnCana	23	2,406,201.24	**170,945.2** **EnCana** **(Well # 27251)**

Region / Named Well Zone / Play	Wells Fracked 2011	Wells Fracked 2012	Total Water Volumes 2012	Operators & Wells Fracked 2012	Wells Fracked 2013	Total Water Volumes 2013	Operators & Wells Fracked 2013	Total Wells Fracked 2012-2013	Total Water Volumes 2012-2013	Highest Water Volume Single Well Fracked
Kobes North Montney	0	5	42,499.58	Progress (2) Suncor (2) CNRL (1)	0	0	0	5	42,499.58	**10,551.5** Progress (Well # 27587)
Komie Horn Basin	0	26	1,431,592.05	Imperial (8) Nexen (18)	0	0	0	26	1,431,592.05	**71,816.7** Imperial Oil (Well # 26453)
Laprise North Montney	0	0	0	0	1	2,467.4	Black Swan	1	2,467.40	**2,467.4** Black Swan (Well # 15088)
Lily North Montney	0	11	112,917.1	Progress	9	120,580.5	Progress	20	233,497.60	**18,395.8** Progress (Well # 28416)
Monias South Montney	0	6	37,901.9	Shell Can.	0	0	0	6	37,901.90	**6,757.9** Shell Can. (Well # 27378)
N Aitken North Montney	0	0	0	0	2	18,152.1	Black Swan	2	18,152.10	**11,416.9** Black Swan (Well # 28546)
Nig North Montney	0	2	7,653.4	Yoho (1) Storm R (1)	5	19,228	Carmel B (1) Storm R (4)	7	26,881.40	**11,225.4** Carmel Bay (Well # 29123)
W Nig North Montney	0	1	9,030.71	CNRL	0	0	0	1	9,030.71	**9,030.71** CNRL (Well # 28203)
Noel South Montney	0	2	45,706	Apache (2) EnCana (2)	2	13,448.1	Apache	4	59,154.10	**24,149.3** EnCana (Well # 28305)
Parkland South Montney	0	12	61,498.06	Tourmaline	6	36,718.5		18	98,216.56	**9,535.8** ARC (Well # 28793)
Pocketknife North Montney	0	0	0	0	2	16,290.7	Progress	2	16,290.70	**9,203.7** Progress (Well # 28477)
Saturn South Montney	0	0	0	0	8	72,413.3	Shell Can.	8	72,413.30	**14,606.9** Shell Can. (Well # 28267)
Septimus South Montney	0	8	51,976.37	ARC (2) CNRL (2) Crew (4)	52	419,249.86	ARC (8) CNRL (31) Crew (13)	60	471,226.23	**13,848** CNRL (Well # 27995)
Sundown South Montney	0	8	21,732.74	EnCana (1) Tourmaline (3)	4	39,283.1	Apache	12	61,015.84	**12,086.2** Apache (Well # 27139)

Region / Named Well Zone / Play	Wells Fracked 2011	Wells Fracked 2012	Total Water Volumes 2012	Operators & Wells Fracked 2012	Wells Fracked 2013	Total Water Volumes 2013	Operators & Wells Fracked 2013	Total Wells Fracked 2012-2013	Total Water Volumes 2012-2013	Highest Water Volume Single Well Fracked
Sunrise South Montney	0	46	331,821.05	EnCana (40) Tourmaline (6)	19	142,288.06	Crocotta (2) EnCana (9) Tourmaline (8)	65	474,109.11	**10,787.61** Tourmaline (Well # 28921)
Sunset South Montney	0	32	236,861.89	Shell Can (32) Tourmaline (1)	1	4,370.5	Shell Can.	33	241,232.39	**21,063.1** Shell Can. (Well # 27637)
Sunset Prairie South Montney	0	2	15,017	Tourmaline	0	0	0	2	15,017.00	**8,714.6** Tourmaline (Well # 26149)
Swan South Montney	0	17	119,741.04	EnCana	9	70,767.3	EnCana	26	190,508.34	**14,223.7** EnCana (Well # 27277)
Tattoo Horn Basin	0	7	618,642.71	Quicksilver	1	21,988	Ramshorn	8	640,630.71	**119,716.5** Quicksilver (Well # 27482)
Tower South Montney	0	5	77,959.1	ARC	12	94,077.8	ARC (11) EnCana (1)	17	172,036.90	**53,313** ARC (Well # 27964)
Town North Montney	0	9	55,099.2	Painted Pony (2) Progress (4)	6	55,221.15	Painted Pony	15	110,320.35	**15,038.25** Painted Pony (Well # 28210)
Townsend North Montney	0	1	2,803.6	Painted Pony	2	22,968.2	Painted Pony	3	25,771.80	**12,065.20** Painted Pony (Well # 28015)
Umbach	0	0	0	0	2	3,860	Storm Res.	2	3,860.00	**2,854.50** Storm Res. (Well # 27826)
W Buick	0	0	0	0	3	6,067.2	Storm Res.	3	6,067.20	**2,820.5** Storm Res. (Well # 28868
W Peejay North Montney	0	0	0	0	1	1,233	CNRL	1	1,233.00	**1,233** CNRL (Well # 28845)
W Stoddart North Montney	0	1	1,241.8	Tervita	0	0	0	1	1,241.80	**1,241.8** Tervita (Well # 28116)
	231,495.2									
Totals	**9**	**364**	**7,082,903.7**		**255**	**2,885,260.32**	**9,968,164**	**619**	**9,968,164.02**	