Assessment of the Availability Of Natural Gas in The Western Canadian Sedimentary Basin

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I. INTRODUCTION

Brown Williams Moorhead and Quinn, Inc. (BWMQ) has prepared this report on conventional and unconventional natural gas supplies of the Western Canadian Sedimentary Basin (WCSB). In this report, specific reviews were made of the history, gas production, estimates of proven reserves and estimates of undiscovered resources.

The principal purpose of this report is to present estimates of the availability or productive capability of natural gas in certain regions of the WCSB. An assessment of the unconventional resource, coalbed methane is also included in this report. Forecasts of the area-wide natural gas productive capability were based upon estimates of proven reserves, discovery process estimates of reserve additions, pipeline connection parameters and deliverability profiles.

Discovery process is the relationship between the efforts (drilling) and the potential for natural gas discoveries.

II. SUMMARY AND CONCLUSIONS

The gas supply regions of the WCSB are in both an intermediate and mature stage of development. The province of Alberta, with its conventional oil and gas deposits is the anchor to the WCSB. It is in its mature stage of development.

The assessment of gas supply herein is based on three ingredients: remaining reserves, reserves appreciation and undiscovered resources. Remaining reserves are the proved and economically producible gas discoveries. Reserves appreciation are resources believed to exist that are directly related to reserves already discovered. Undiscovered resources are estimated gas accumulations that are believed to exist, but have not yet been proven by drilling.

The productive capacities of proven gas reserves in the WCSB vary considerably. The Reserves-to-production ratios in the WCSB presently are at their lowest level, reflecting only very modest surplus pipeline gas. Estimates of future annual gas discoveries were made employing a discovery - process model as described below. Productive capacity decline rates were applied to determine the availability of gas from new supply sources.

The availability of supplies from future sources was added to the availability of current proven sources to arrive at the overall productive capability of natural gas supplies from the various areas.

The various supply areas of the WCSB are currently reliable, active and viable in providing adequate throughput for the network of pipelines connected to them. In the longer-term, however, the current grade of natural gas accumulations will be exhausted, giving way to the discovery of progressively smaller deposits. The result will be a continuing and gradual decline in the productive capability from existing and future connected supply sources.

III. BACKGROUND – WCSB

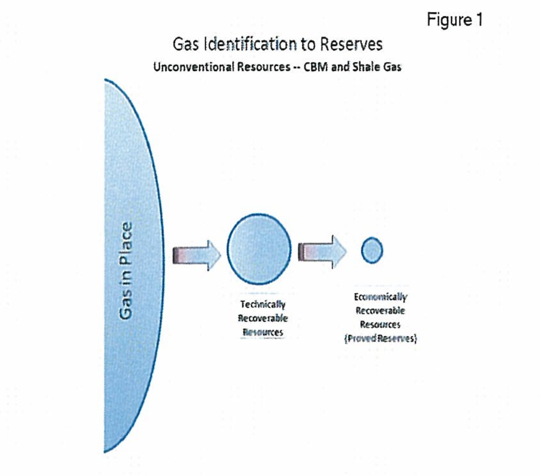
The WCSB is a vast oil and gas producing province underlying Western Canada. It includes southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia and the southwest corner of the Northwest Territories. The WCSB contains one of the world's largest accumulations of oil and gas deposits. It supplies a large amount of the North American market. The WCSB is a large, somewhat gas prone, geologically heterogeneous area that contains numerous gas productive areas. Numerous oil and gas prone formations and prospective reservoirs are present. Productive reservoirs include carbonates (limestone), sandstones and shales with all types of porosity and permeability as well as naturally fractured reservoirs and coalbed methane reservoirs.

Proven natural gas discoveries in the WCSB as of the end of 2006 are shown below:

Cumulative Prod to 12/31/2006	Tcf	156
Remaining Reserves at 12/31/2006	Tcf	57
Ultimate Reserves at 12/31/2006	Tcf	213

The Canadian Gas Potential Committee (CGPC) has estimated (2006) potential gas resources for the WCSB of 143 Tcf (conventional) and 11-45 (natural gas from coal).

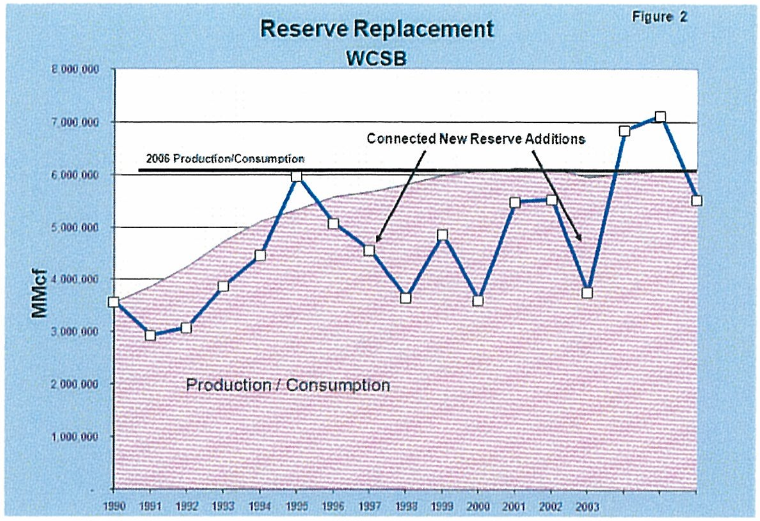
The majority of the large gas pools have been discovered and a significant portion of the discovered reserves have already been produced. According to the CGPC's study, 62 percent of the undiscovered potential will occur in 21,100 pools larger than 1 Bcf of original gas in place; and, the remaining 38 percent will occur in approximately 470,000 pools, each containing less than 1 Bcf of original gas in place. Original gas in place is the amount of hydrocarbon, in this case natural gas that is "in situ." Only a portion of the gas in place is recoverable. For conventional natural gas reservoirs the recovery factor is anywhere's from 50 to 80 percent. For unconventional gas reservoirs, such as coalbed methane, the recovery factor ranges between 5 and 12 percent, with an average of about 8 percent. For unconventional reservoirs, the relationship between gas in place and that recoverable is shown in Figure 1.



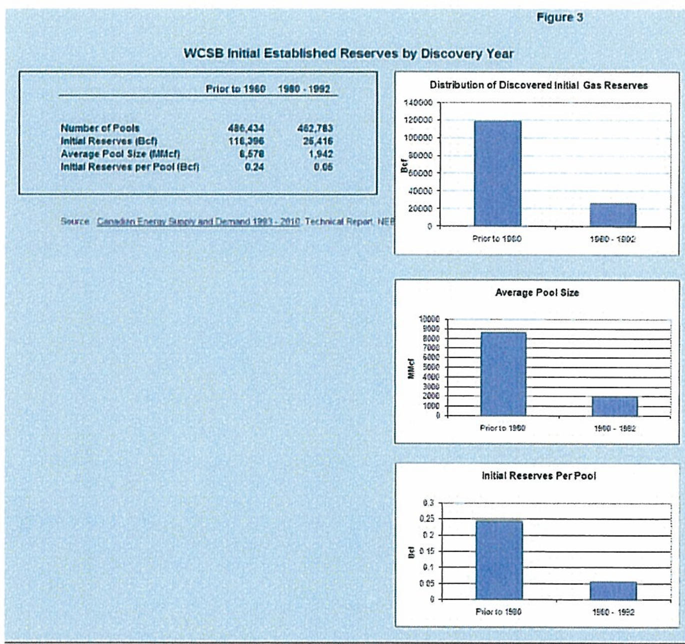
For the conventional resources in the WCSB, the CGPC estimates 464 Tcf as the original gas in place, while they estimate the recoverable portion to be 278 Tcf. The recovery factor is approximately 60 percent. Their most current estimate of the remaining recoverable amount, as of the end of 2005 is 143 Tcf.

To date, producers have discovered approximately one half of the entire endowment of natural gas resources in the WCSB. What appears to remain undiscovered is an amalgam of medium and small fields. Many of the small field discoveries will be marginal.

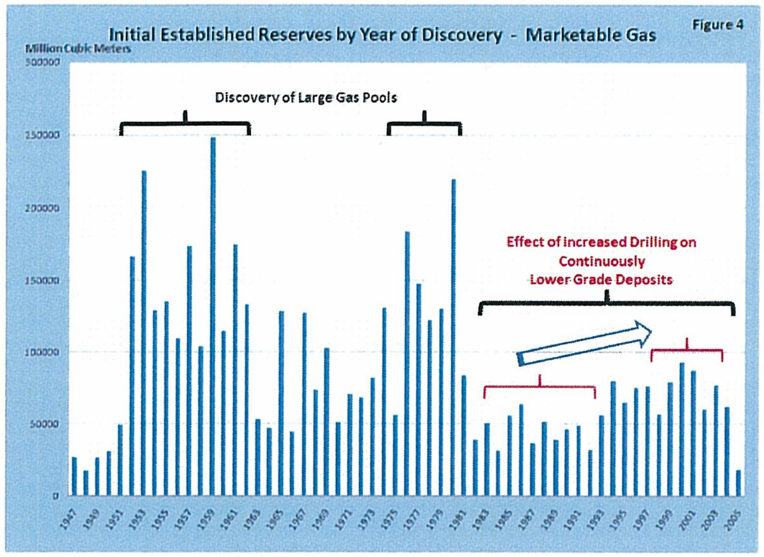
Presently, the WCSB, especially for conventional resources, has all the earmarks of a producing province that is in its mature stage. With the exception of 2004 and 2005, annually connected new reserve additions have not reached a level to replace the 2006 production level. In eight of the past ten years the new reserves were under the consumption level. This is demonstrated in Figure 2.



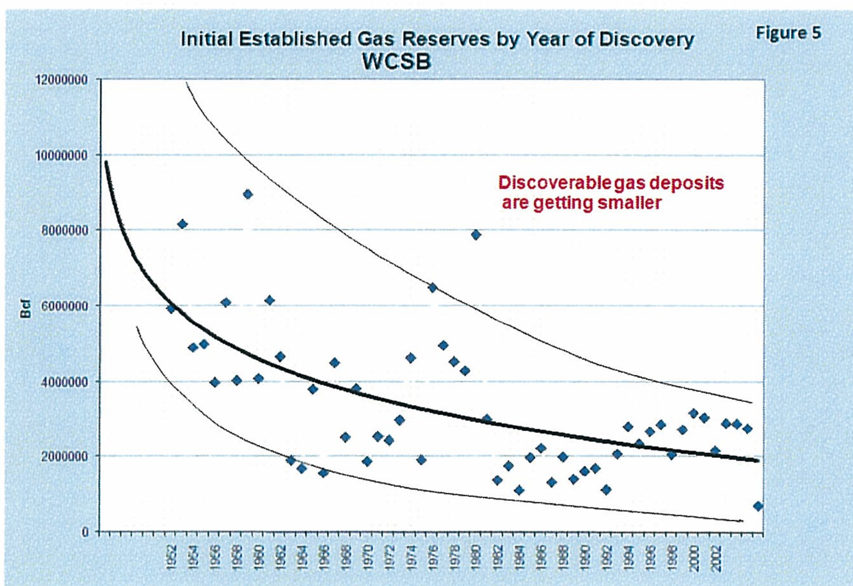
Reserve additions by year of discovery since the years of the large field discoveries are progressively smaller as shown below in Figure 3.



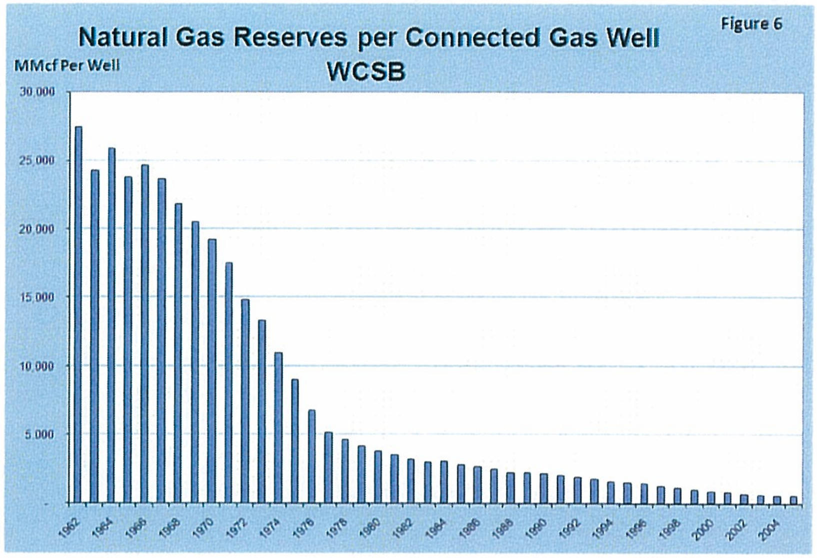
This progression is shown on an annual basis in Figure 4. **This figure shows the decline in new pool discoveries over time. This chart shows that all the large fields were discovered prior to 1980. The large fields are relatively easy to find and were found early in the life of the WCSB province.**



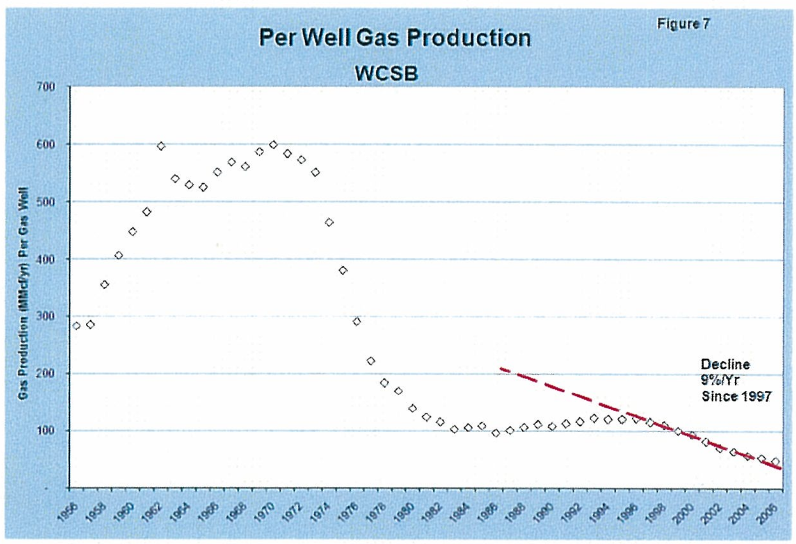
And, further, the new gas reserves on an annual trend basis, by year of discovery is shown in Figure 5. **This same data, in billion cubic feet, is shown in terms of upper and lower ranges, with the trend is clearly downward.**



The per well gas reserves are also decreasing each year. This is shown in Figure 6.



The average per well production by years throughout the WCSB is decreasing as shown in Figure 7.



The declining performance of each year's natural gas discoveries in terms of an average gas well connection is shown below in Figure 8.

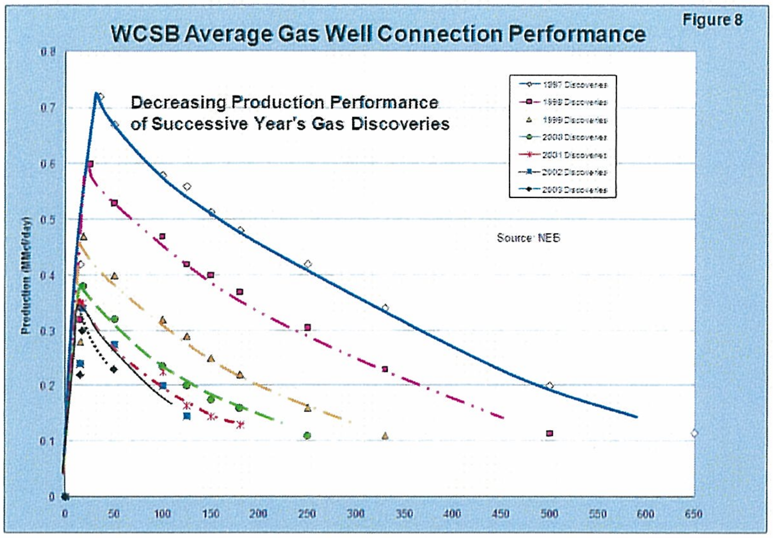
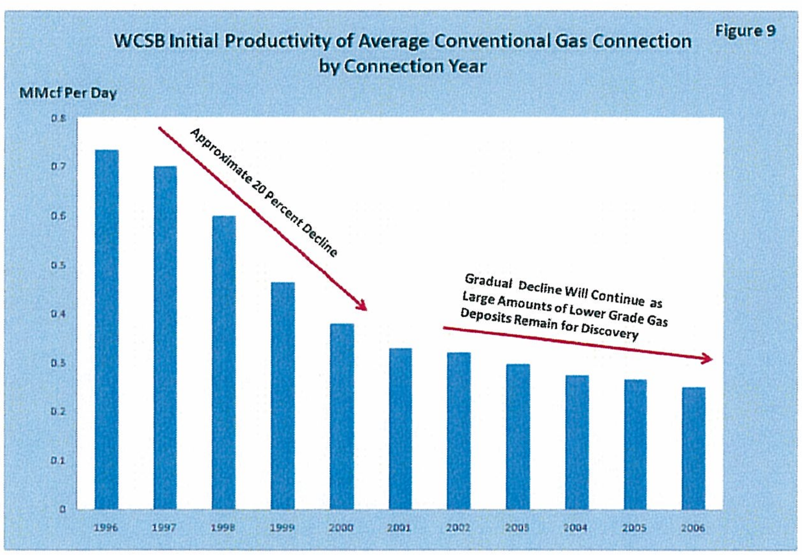
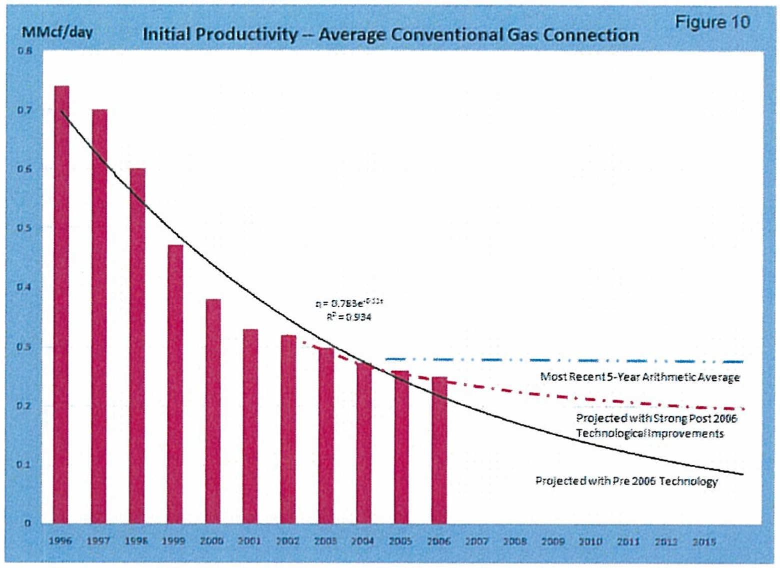


Figure 8 clearly shows a decrease in the initial production or productivity over each year's new discoveries. Notice how the decline rate in the initial years of production is increasing. This, among others, indicates that a much lower grade of natural gas deposit is available for discovery and exploitation.

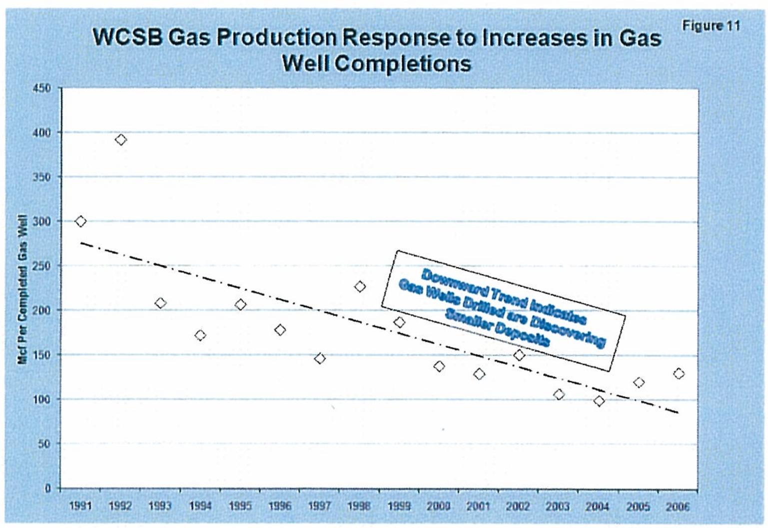
The decline in gas well productivity is as shown below in Figure 9.



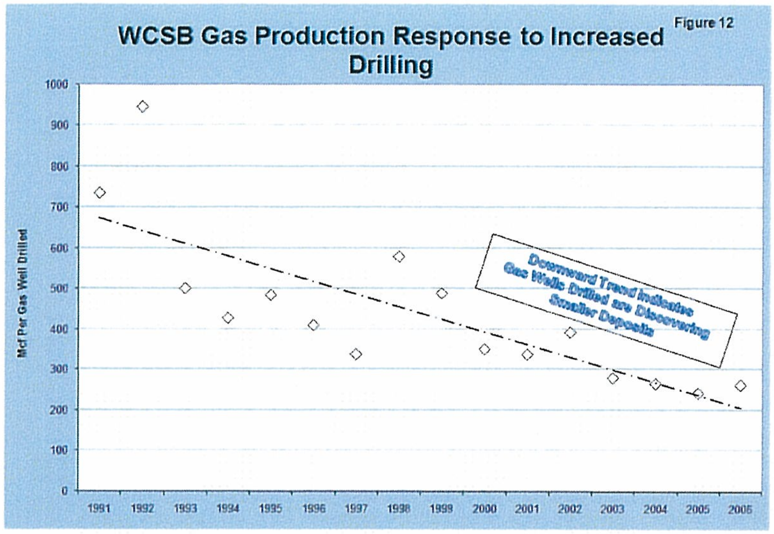
The various trends that could occur from the gas well initial productivity are shown in the graph in Figure 10.



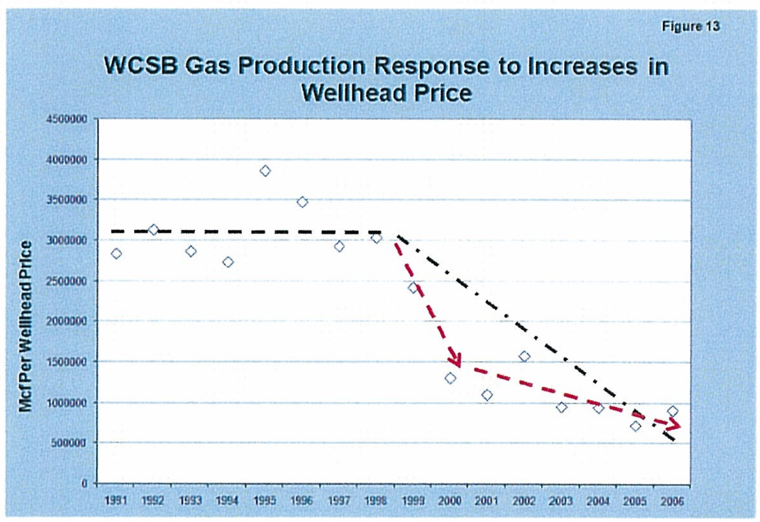
Gas production response to the increasing number of gas wells completed is in a clear decline as shown in Figure 11.



Gas production response to increased drilling is a clear decline as shown in Figure 12.



Gas production response to wellhead price increases is a clear decline as shown in Figure 13.



The above facts indicate that the WCSB is entering the mature stage. Canada's National Energy Board ("NEB") has recognized these facts and states: "recent drilling and production data suggests that the WCSB may be maturing; and changes in natural gas resource estimates may be warranted for some areas."

As of January 2008, the status of natural gas sourced in the WCSB is that the pipelines exporting gas out of Western Canada and those pipelines receiving the produced gas could face huge amounts of unused capacity.

My analysis so indicates and further, according to the Canadian Energy Research Institute (CERI), such unused capacity could amount to 42 percent by 2018. CERI said unused takeaway capacity out of Western Canada is currently 2.5 Bcf per day, representing 17% of the available capacity, and it is projected to further deteriorate, reaching 3.5 Bcf per day of un-utilized capacity, representing 24% of capacity, by 2012.

A challenge for certain gas resources in the region is to exploit technically available gas in locations where reserves are characterized by “tight” matrix porosity and permeability, naturally fractured ,reservoirs and coalbed methane and make them economically recoverable resources. There are, however, modest amounts of new fields that will be discovered in this region. Most new field discoveries will come from the deep portions of the basin. Reserve additions, especially in strata lying above 6,000 feet are due essentially to growth in existing reserves from field extensions. Existing production in this area is holding constant due to a large amount of drilling, however the area is expected to be in an overall downward trend.

An indication of such a mature stage is the average well productivity, which has decreased dramatically and the slope of the overall decline rates has steepened. The remaining undiscovered conventional resources are found in increasingly smaller average pool sizes.

In essence, the WCSB is in a treadmill status where the angle of the treadmill is increasingly steep. The current declining status of conventional Canadian natural gas resources will limit, to various degrees, the economic life of pipeline facilities dependent on carrying such volumes.

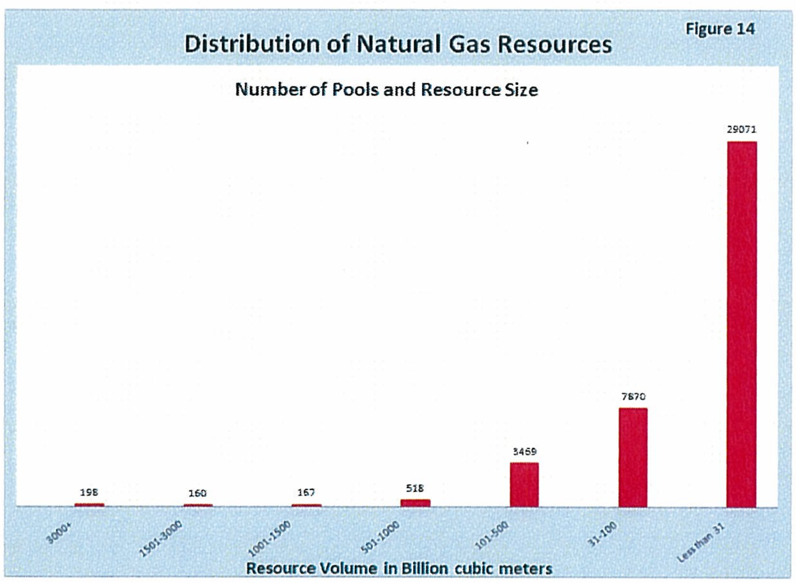
IV. METHODOLOGY

Proven Reserves

An analysis of the producibility of proven gas reserves was made using information obtained from the National Energy Board (NEB) and the CGPC. Calculations of the proven reserves are as of the end of 2006. The productive availability of those proven reserves was obtained from data assembled by the NEB and extrapolated employing constant percentage decline rates until the reserves are exhausted. The proven gas reserves were obtained from NEB, which in turn collected the data from producers. The NEB also provided the productive capacity rates of those reserves.

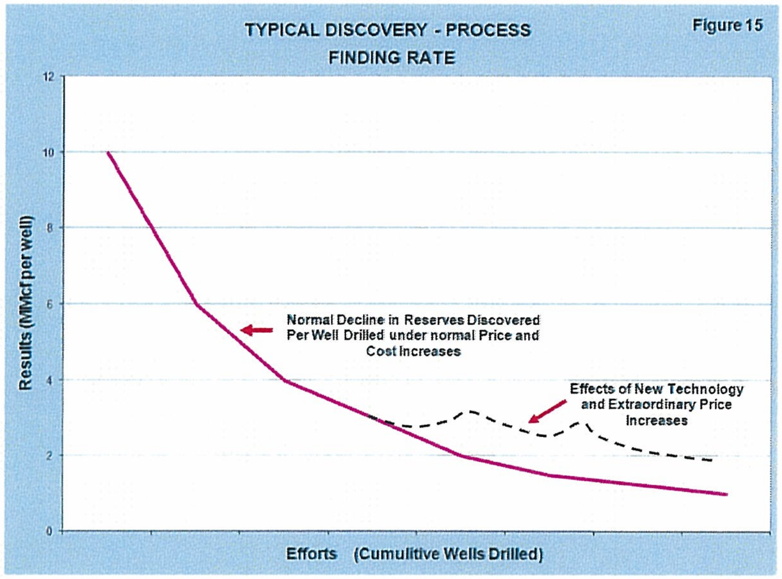
Future Reserve Additions

A characteristic observed in the petroleum producing areas of the North American gas supply areas is a rapid drop off in size from the largest known field to the smaller ones. Hydrocarbon accumulations are the result of complex geological processes. Furthermore, the actual quantities of producible reserves are further defined on the basis of technological and economic considerations. As a consequence of all these independent influences and the multiplicative nature of the factors affecting the size of a gas accumulation, field sizes in producing basins are typically log normally distributed (Figure 14).

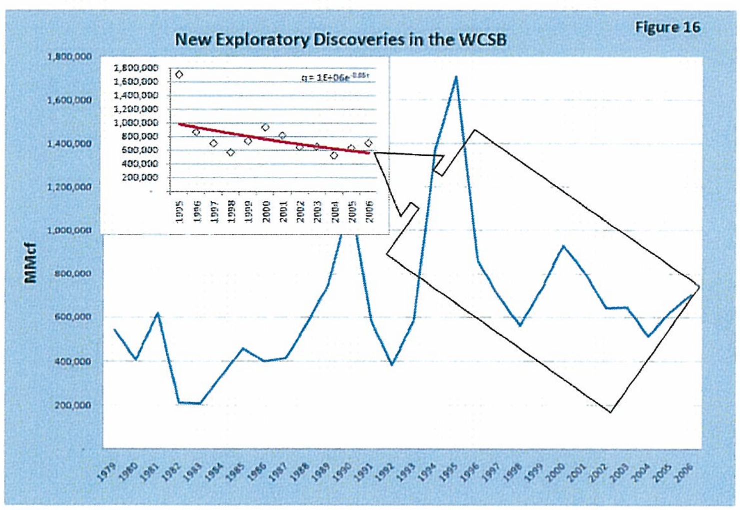


That is, a few very large fields contain the bulk of the reserves and many, many small fields contain, in aggregate, a smaller portion of the reserves. Also, another characteristic of gas supply basins is that large fields are discovered early in the exploration process, and subsequent discoveries

are smaller and the product of increasingly greater efforts. This is demonstrated in illustrative form in Figure 15, below.

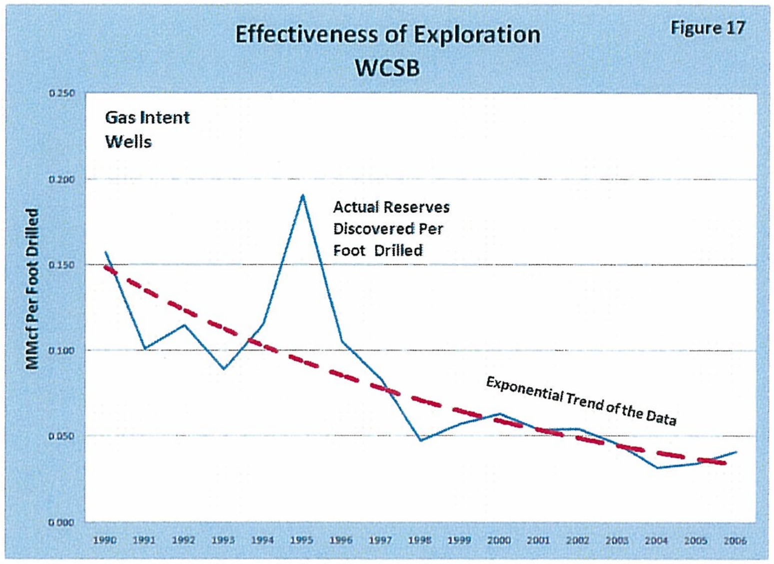


This concept is illustrated in Figure 16 with actual data concerning the size of discovered gas deposits found annually in the WCSB.



While the above graph illustrates the magnitude of the annual exploratory discoveries (similar relationships were constructed for development discoveries), when the number of wells or drilling footage is

factored with those discoveries, the level of just how effective the drilling effort is determined. This relationship of the efforts to results is shown in Figure 17 as the finding rate or effectiveness of exploration.



Analysis of the distribution of deposits (Figure 2) and the reserves by year of discovery (Figures 4 and 5) indicate that the remaining recoverable gas prospects will be small, some quite economically marginal, which will depend upon an adequate wellhead price as well as favorable technology. The favorable technology is one whose cost is not prohibitive.

<u>The Finding Rate Methodology</u>

One measure of the discoverability of resources is the rate at which resources are found. This method compares the drilling footage in a particular year with the related discoveries. This method depicts the normal stage of events that take place when a gas-bearing province graduates past its initial discovery stage and enters its more or less mature stage. The

degree of maturity of the producing life of the supply areas can be determined by comparing the amount of gas resources already discovered with an estimate of the ultimate resources.

The nature of oil and gas accumulations creates a distribution of fields and reservoirs made up of a small number of large fields, a larger number of medium size fields and a seemingly unending amount of small fields. The various areas of the WCSB are no exception. An example of the distribution of gas reserves in the WCSB is shown on Figure 14. This is typical of the exploratory events of an oil and gas province.

The basic concept of this Finding Rate Methodology is shown on Figure 15. At times, the declining rate of effectiveness is mitigated by: better technologies for discovery and resource recovery, greater understanding of the geophysics, and reservoir performance of the field in the province. This mitigation is also shown on Figure 15.

Advances in technology are, however, a double-edged sword with respect to extending the life of gas resources and ultimately the life of associated producing equipment and pipeline facilities. Exploration and production (E&P) technology varies throughout the industry, from increasing the success ratio in exploration to more efficient production techniques. While some advances in technology may allow the commercialization of heretofore unproduceable hydrocarbon deposits, most others relate to the profitability of technically discoverable oil and gas resources. For example, four causes for the accelerated production of a given gas resource in the U.S. Rocky Mountain area and the accelerating decline rates in the WCSB, relate to technology. They are:

- 3-D seismic
- Horizontal wells
- Efficient completion techniques
- General miscellaneous technology

An example of the effect of new geophysical technology (e.g. 3-D seismic) on E&P is basically an improvement in the exploration success ratio. With advances in geophysical technology, producers are better able to locate oil and gas deposits and also to determine whether they should be explored or bypassed as a viable project.

Technology advances do not come cheap. Its application must be in terms of the potential value of the resource. This assessment takes into account technology, in that the forecasts were based upon the employment of various trends, which included advances in technology.

An examination of the year to year changes in natural gas discoveries along with the expended efforts (wells drilled) determined that the supply areas of the WCSB paralleled the premise of this model (that large initial field discoveries give way to smaller ones). In addition to the field size facts cited earlier, further analysis confirmed that indeed most of the larger fields have been discovered as well as many of the medium size fields. This can be observed by inspecting the relationship between the new fields discovered and the exploratory efforts as shown on Figure 17.

This can also be seen by analysis of the finding rate methodology in terms of exploratory effort. Most of the significant gas discoveries are actually associated with fields previously discovered. See the historical data shown on Tables 1 and 2. The above derived most likely finding rate is a 5-year snapshot of a long trend from higher levels of how effective exploration and development was in prior years. I observed both exploratory wells and development wells. Development wells do not reflect the effort to find new discoveries. However, they contribute significantly to the reserve base. "Results" (in terms of annual gas discoveries) of the drilling effort are also shown on Tables 1 and 2.

Table 1

Wells Drilled and Discoveries Made in the WCSB

	Non Assoc, Assoc and Soln Discoveries		Non Associated and Associated Explaratory Drilling			Non Associated and Associated Development Drilling		
	Exploratory	Development	Wells	Gas Intent Meters	Footage	Wells	Gas Intent Meters	Footage
1979	543,585							
1980	405,315	3,111,307	2,209	3,448,570	11,311,311	3,125	2,612,133	8,567,795
1981	620,751	3,644,196	1,884	2,750,119	9,020,390	2,313	1,929,003	6,327,131
1982	212,118	2,074,052	1,122	1,551,175	5,087,854	2,044	1,499,947	4,919,827
1983	207,105	2,923,158	747	1,086,829	3,564,799	1,014	974,636	3,196,807
1984	337,645	7,577,957	1,057	1,424,179	4,671,308	1,384	1,082,363	3,550,152
1985	459,430	1,596,619	1,095	1,474,062	4,834,922	2,128	1,722,431	5,649,573
1986	399,525	671,512	802	1,125,062	3,690,204	1,008	974,675	3,196,935
1987	415,234	521,522	1,043	1,453,615	4,767,857	1,170	1,125,920	3,693,019
1988	575,037	1,918,273	1,610	2,068,620	6,785,073	1,646	1,561,981	5,123,296
1989	752,490	3,937,539	1,689	2,098,589	6,883,372	1,521	1,304,560	4,278,958
1990	1,144,320	2,433,088	1,796	2,217,591	7,273,697	1,335	1,224,151	4,015,216
1991	583,827	2,355,922	1,317	1,762,151	5,779,856	1,107	967,581	3,173,665
1992	379,475	2,710,052	806	1,011,321	3,317,133	634	575,710	1,888,328
1993	587,886	3,284,489	1,688	2,025,661	6,644,169	2,655	2,187,508	7,175,025
1994	1,369,993	3,632,985	2,859	3,635,023	11,922,876	4,239	3,733,698	12,246,528
1995	1,708,626	5,099,927	2,018	2,734,303	8,968,514	2,631	2,501,586	8,205,203
1996	862,344	4,202,500	1,865	2,497,401	8,191,476	3,304	3,216,335	10,549,579
1997	696,045	3,863,903	1,814	2,557,658	8,389,117	4,446	4,667,016	15,307,812
1998	562,400	3,035,094	2,609	3,634,189	11,920,139	3,980	3,832,875	12,571,831
1999	731,416	3,811,059	2,754	3,903,352	12,802,994	5,851	5,307,207	17,407,639
2000	929,802	3,746,354	3,218	4,529,593	14,857,064	7,263	6,406,864	21,014,512
2001	811,547	5,755,418	3,509	4,616,141	15,140,942	8,406	7,323,869	24,022,290
2002	641,966	4,881,672	2,785	3,631,990	11,912,929	7,307	6,377,844	20,919,328
2003	646,520	3,118,896	3,705	4,362,483	14,308,943	10,663	9,028,420	29,613,219
2004	515,380	6,340,480	4,001	4,971,957	16,308,020	12,404	11,483,960	37,667,390
2005	624,104	6,494,706	4,392	5,557,259	18,227,810	12,896	12,540,234	41,131,967
2006	700,952	4,823,180	3,582	5,219,947	17,121,425	11,226	11,490,297	37,688,173

Table 2

Determination of Finding Rate
Nonassociated Conventional Gas Discovered Per Foot Drilled

EXPLORATORY DRILLING FOOTAGE				
20 YEAR AVERAGE 1987-2006 =	10,576,170		15,575,825	Most Likely
5 YEAR AVERAGE 2002-2006	15,575,825			
AVERAGE OF HIGHEST 5	16,331,052		16,331,052	High
AVERAGE OF LOWEST 5 *Since 1990*	6,241,266		6,241,266	Low
EFFECTIVENESS				
High 5 Average =	0.136	MMcf/foot	0.136	High
Low 5 Average	0.040	MMcf/foot	0.040	Low
Last 5 Years	0.039	MMcf/foot	0.039	Most Likely

DEVELOPMENT DRILLING FOOTAGE				
20 YEAR AVERAGE 1987-2006 =	15,884,649		33,404,015	Most Likely
5 YEAR AVERAGE 2002-2006	33,404,015			
AVERAGE OF HIGHEST 5	33,404,015		33,404,015	High
AVERAGE OF LOWEST 5 *Since 1990*	4,891,488		4,891,488	Low
EFFECTIVENESS				
High 5 Average =	0.773	MMcf/foot	0.773	High
Low 5 Average	0.148	MMcf/foot	0.148	Low
Last 5 Years	0.156	MMcf/foot	0.156	Most Likely

When these "results" or annual gas discoveries are divided by the annual exploratory wells drilled, a more focused relationship develops as to the size of the discovery for the effort expended. This confirms that the large fields have already been discovered and that new discoveries are going to be generally confined to a considerably more moderate size. This concept of discoveries per well drilled is referred to by the EIA as the Finding Rate Methodology.

The Finding Rate Methodology began in the late 1950s and early 1960s and continues to be used today. The famous oil and gas forecaster, M. King Hubbert developed various aspects of it and used it in his presentations and forecasts. The renowned petroleum engineer and recipient of the C. C. Uren Award from the Society of Petroleum Engineers, J.J Arps also developed the Finding Rate Methodology in the early 1960s, referring to it as the Effectiveness of Exploration. The methodology was and still is employed widely by those forecasting oil and gas resources. This methodology was employed by the staff of the Commission as early as 1973. The EIA exclusively uses the Finding Rate Methodology to forecast long range oil and gas discoveries in its state-of-the art Annual Energy Outlook publication.

The model used the relationship between annual reserve additions and both exploratory and development well drilling over time in years and cumulative feet drilled from a base of 1990. For the most likely case, the exploratory finding rate is extrapolated at a constant level using the 5-year mean value developed in Tables 1 and 2 until a point is reached where 90 percent of the total endowment is reached. The total endowment is defined as all the gas that will eventually be discovered (past discoveries plus the CGPC's estimates of potential resources). CGPC's estimates of potential gas resources for the WCSB are shown on Table 3.

Table 3

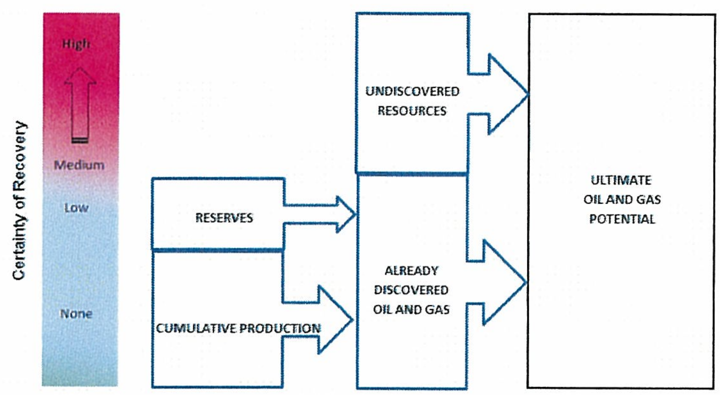
Gas Estimates of the Canadian Gas Potential Committee
Volumes in TCF

	WCSB Gas Endowment	
	Conventional	Coalbed Methane
Total Gas in Place	464	516
Initial Recoverable Resources	278	11-45
Remaining Initial Recoverable Resources	143	11-45

The Initial Recoverable Resources as estimated by the CGPC is considered the Ultimate Gas Potential. The following chart (Figure 18) puts the Ultimate Gas Potential into context with discovered and undiscovered reserves and resources and the certainty of recovery.

Figure 18

Ultimate Oil and Gas Potential Terminology



V. FORECAST OF FUTURE CONVENTIONAL DISCOVERIES AND GAS AVAILABILITY IN THE WCSB

The future gas availability from conventional sources is made up of the amount available from existing proven gas reserves and the estimate of the amount of gas available from future discoveries.

The Availability from Proven Reserves

The annual amount of gas available from proven sources in the WCSB is determined by applying decline curve rates to the remaining reserves of each vintage year of gas discoveries. The calculations are made for various areas of the WCSB, such as the Foothills Front, the Foothills and the Central Area of Alberta to the Fort St. John area of British Columbia and Southwest Saskatchewan area. The production decline rates are made up of the 2006 productivity in MMcf per day and the various decline rates from the first to the fourth along with the time period between each. The decline rates were developed from NEB analysis of actual well production data of GeoScout. For example, the availability of natural gas from existing proved reserves in the Alberta Foothills Area is shown in Figure 19.

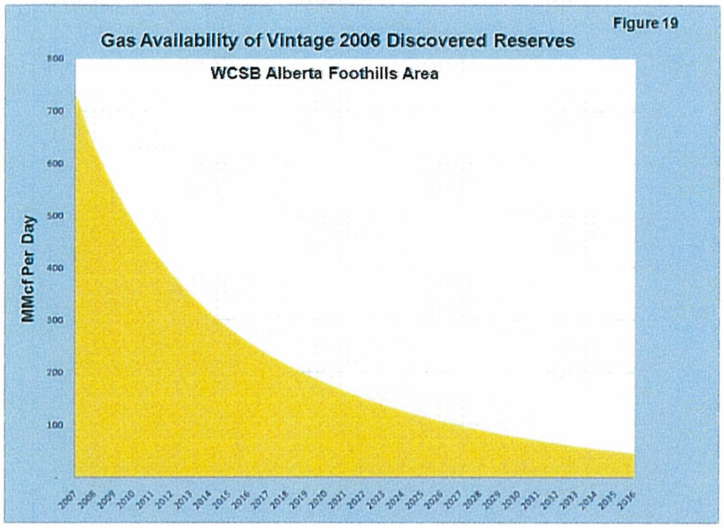


Figure 19

The above graph is made up of, and derived from the various vintages of gas discoveries in the Alberta Foothills Area as shown in Figure 20.

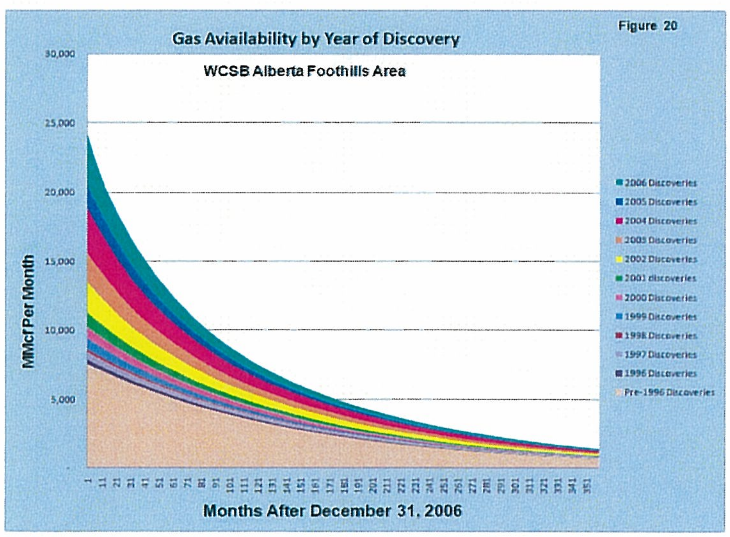


Figure 20

The availability from proven reserves from all vintages for the total WCSB is shown in Figure 21.

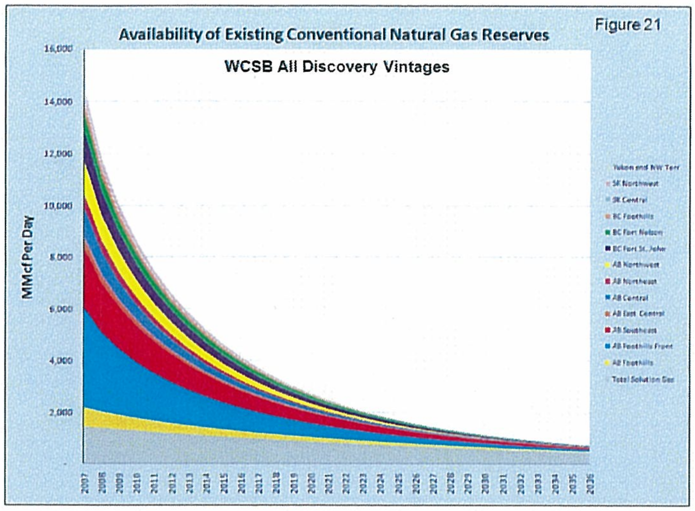


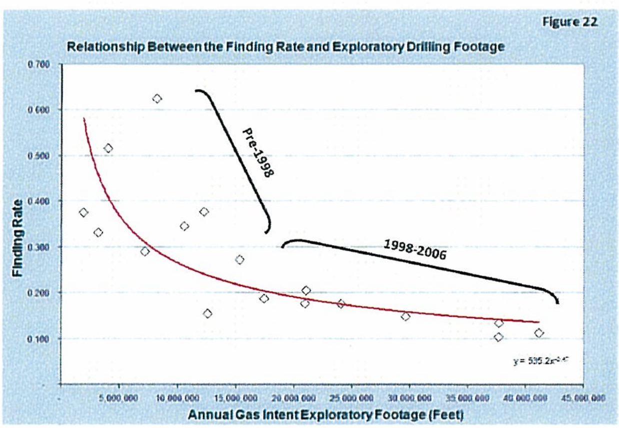
Figure 21

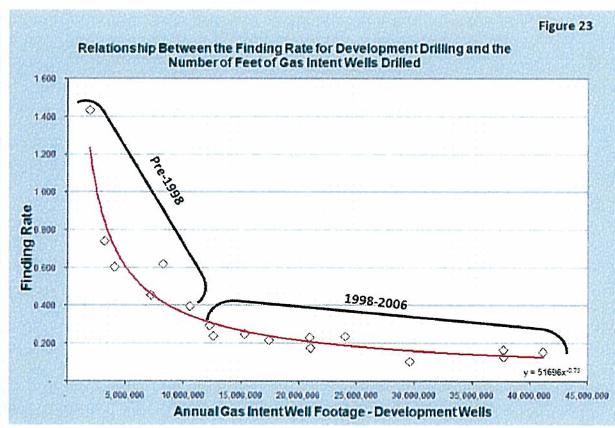
<u>The Availability from Undiscovered Gas Resources – Part 1</u>

The availability of gas from the forecast of future discoveries (results) is determined by multiplying the finding rate by the annual drilling footage (efforts). The annual drilling footage as well as the derivation of the applicable finding rate is in terms of gas intent drilling.

The most likely and initial level is represented by the mean value of the finding rate from 2002 through 2006. The same procedure is used in determining the finding rate for both exploratory and development drilling. I employed a constant level of finding rate until 90 percent of the ultimate resources are discovered as I expect some occasional increases in the finding rate due to forces not directly indicated in the data. As mentioned earlier, any decline in the finding rate curve will be mitigated by technological increases in the exploration and drilling techniques along with an increased awareness of the geophysics and reservoir mechanics. Technological increases are included in the 1990-2006 data. I am assuming that future

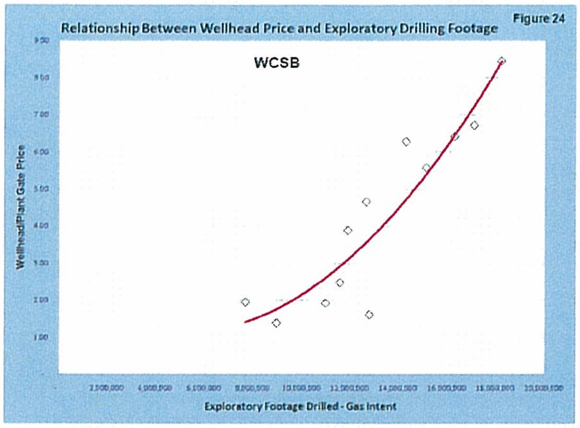
technological increases will occur at the same rate as in the historical statistics. I found, in some cases unsurprisingly, that as drilling exceeds certain levels, the finding rate declines. This is due most likely to the drilling of lower grade prospects in a particular year. See Figure 22 (Exploratory) and Figure 23 (Development), as shown below, for the historical relationship between footage and finding rate along with their respective years. These relationships are shown here to demonstrate the complexity of the drilling - discovery process. However, they were not used in the forecast of gas discoveries. This is conservative, as including such a potential relationship would lower the magnitude of future gas discoveries.

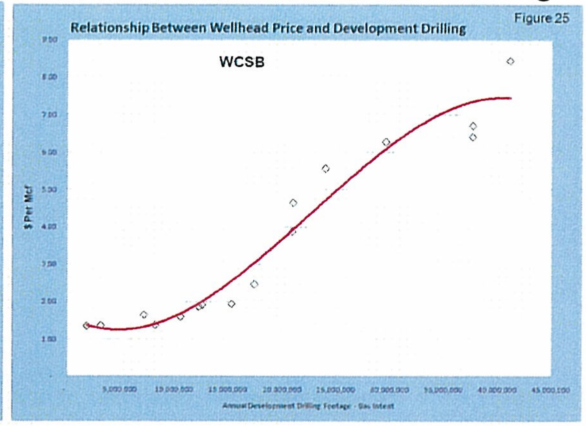




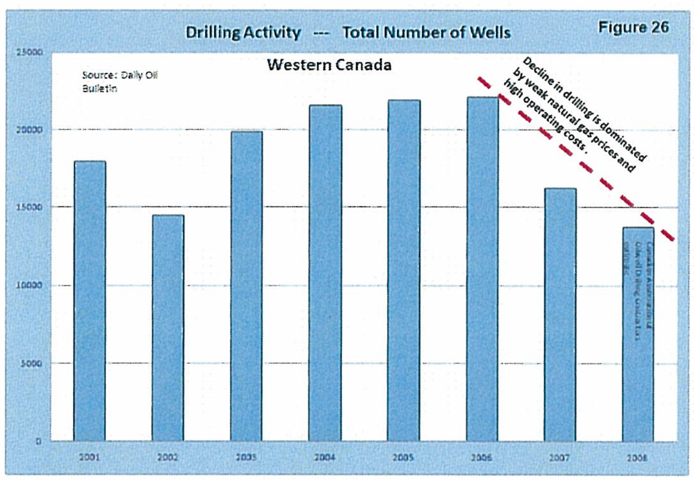
The determination of the future discoveries from exploratory drilling by applying a representative constant level of drilling activity to the corresponding finding rate is shown on Table 4. For the determination of the discoveries from development drilling, with its application of a constant level of annual drilling activity, based upon the most recent 5-year period, reflecting the development drilling activity response to increases in the

wellhead price of gas, available transportation and other positive factors contributing to healthy drilling programs is shown in Table 5. This period included very significant increases in the price of gas at the wellhead and only one modest decrease. I believe that in the future such similar increases and decreases will occur probably eventually leading to a further overall price increase. Some agencies predict price increases only slightly, others predict more modest increases, such as a wellhead price of $12 per Mcf by 2025. The choice of exploratory and development drilling levels herein, fully reflects an overall average price increase over the pertinent period, all the while daily, monthly and yearly prices will fluctuate both up and down. Specifically, I found a relationship to exist between the price of gas at the wellhead and exploratory development drilling effort in the WCSB. While an increase in wellhead gas prices is an inducement to increase exploratory drilling efforts, many factors come into play with respect to the exploratory drilling response, such as drilling risk, in-place transportation, financing, royalties and costs trends. The graphs shown on Figures 24 and 25, of wellhead gas price and drilling effort show just a general trend.





In order to demonstrate the difficulty in predicting specific mid-term to long-term annual exploratory drilling activity, Figure 26 shows the actual 2001 to 2007 and estimated 2008 number of wells drilled in the WCSB (Source: Daily Bulletin). This figure shows the decline in drilling from 2006 dominated by weak natural gas prices and high operating costs.



In 2007, fewer wells were drilled in Canada, equivalent to activity 5 to 6 years ago. Canadian operators face escalating field costs, softening natural gas prices, gas transportation differentials to the US and weakening of the US dollar. Escalating field costs are the result of the nature of Canadian petroleum supplies

Canadian gas drilling is down 40 percent in 2007, barely above levels 6 years ago while US drilling is higher. The above illustrates the level of uncertainty in forecasting specific amounts of exploratory and development drilling that would take place in the long-term.

The rationale for a Constant Annual Drilling Rate in the near-term and mid-term encompasses the unlikely ability to accurately predict the exact level of drilling in any particular year and, also to accommodate the potential for specific tight sand and shale gas targets. The historical drilling targets have always included tight gas and shale gas. Drillers were always aware that such targets might be, under certain circumstances, economically producible. In setting the future annual drilling as a constant level, It is assumed that any loss of interest in traditional carbonate and sandstone targets will be picked up by added interest in tight formation and shale prospects. The traditional carbonate and sandstone prospects are becoming smaller in aerial extent, thickness, porosity and permeability. As the porosity and permeability of drillable prospects become smaller, they simply enter the relm of "tight gas." They are becoming extremely marginal irrespective of technological gains. Oil and gas deposits in shale formations, while marginal and highly sensitive to price and technological advances, and also higher cost may become a viable main target.

Therefore, it is reasonable for purposes of this WCSB gas supply evaluation to include tight gas and shale gas as an integral part of the drilling and finding rate model.

The Future Discoveries resulting from the application of the drilling effort to the finding rates in the WCSB are shown on Table 4 for exploratory discoveries and Table 5 for development discoveries.

Table 4

Determination of Future Natural Gas Discoveries
Western Canada Sedimentary Basin
Most Likely Effectiveness of Exploration -- Most Likely Forcasted Footage

Year	Cumulative Exploratory Drilling Footage	Effectiveness of Exploration Gas Intent	Annual Exploratory Drilling Footage	Gas Intent Exploratory Drilling Footage	Actual and Forecasted Reserve Additions
	Feet	*MMcf/Foot*	*Feet*	*Feet*	*Bcf*
1980	199,237,086	0.036	17,168,271	11,311,311	405,315
1981	213,202,293	0.069	13,965,207	9,020,390	620,751
1982	223,570,465	0.042	10,368,172	5,087,854	212,118
1983	232,770,468	0.058	9,200,003	3,564,799	207,105
1984	245,815,598	0.072	13,045,131	4,671,308	337,645
1985	260,941,856	0.095	15,126,258	4,834,922	459,430
1986	270,246,501	0.108	9,304,645	3,690,204	399,525
1987	281,512,770	0.087	11,266,269	4,767,857	415,234
1988	294,717,092	0.085	13,204,322	6,785,073	575,037
1989	305,676,320	0.109	10,959,228	6,883,372	752,490
1990	317,278,874	0.157	11,602,554	7,273,697	1,144,320
1991	327,033,902	0.101	9,755,028	5,779,856	583,827
1992	334,040,245	0.114	7,006,342	3,317,133	379,475
1993	346,012,802	0.088	11,972,558	6,644,169	587,886
1994	363,509,021	0.115	17,496,219	11,922,876	1,369,993
1995	377,589,257	0.191	14,080,236	8,968,514	1,708,626
1996	393,799,204	0.105	16,209,947	12,802,996	862,344
1997	408,138,630	0.083	14,339,425	7,691,896	696,045
1998	423,607,713	0.047	15,469,084	10,996,194	562,400
1999	438,276,939	0.057	14,669,226	11,586,098	731,416
2000	454,371,728	0.063	16,094,789	12,673,255	933,332
2001	473,343,294	0.054	18,971,566	15,140,942	811,547
2002	488,472,485	0.054	15,129,190	11,912,929	641,966
2003	506,362,907	0.045	17,890,422	14,308,943	646,520
2004	525,894,431	0.032	19,531,524	16,308,020	515,380
2005	548,030,623	0.034	22,136,192	18,227,810	624,104
2006	571,788,676	0.041	23,758,054	17,121,425	700,952
2007	588,359,420	0.041	16,570,743	11,941,834	488,899
2008	606,170,830	0.041	17,811,410	12,835,930	525,504
2009	625,281,374	0.041	19,110,545	13,772,162	563,833
2010	644,391,919	0.041	19,110,545	13,772,162	563,833
2011	663,502,464	0.041	19,110,545	13,772,162	563,833
2012	682,613,008	0.041	19,110,545	13,772,162	563,833
2013	701,723,553	0.041	19,110,545	13,772,162	563,833
2014	720,834,098	0.041	19,110,545	13,772,162	563,833
2015	739,944,643	0.041	19,110,545	13,772,162	563,833
2016	759,055,187	0.041	19,110,545	13,772,162	563,833
2017	778,165,732	0.041	19,110,545	13,772,162	563,833
2018	797,276,277	0.041	19,110,545	13,772,162	563,833
2019	816,386,822	0.041	19,110,545	13,772,162	563,833
2020	835,497,366	0.041	19,110,545	13,772,162	563,833
2021	854,607,911	0.041	19,110,545	13,772,162	563,833
2022	873,718,456	0.041	19,110,545	13,772,162	563,833
2023	892,829,001	0.041	19,110,545	13,772,162	563,833
2024	911,939,545	0.041	19,110,545	13,772,162	563,833
2025	931,050,090	0.041	19,110,545	13,772,162	563,833
2026	950,160,635	0.041	19,110,545	13,772,162	563,833
2027	969,271,179	0.041	19,110,545	13,772,162	563,833
2028	988,381,724	0.041	19,110,545	13,772,162	563,833
2029	1,007,492,269	0.037	19,110,545	13,772,162	507,450
2030	1,026,602,814	0.033	19,110,545	13,772,162	456,705
2031	1,045,713,358	0.030	19,110,545	13,772,162	411,034
2032	1,064,823,903	0.027	19,110,545	13,772,162	369,931
2033	1,083,934,448	0.024	19,110,545	13,772,162	332,938
2034	1,103,044,993	0.022	19,110,545	13,772,162	299,644
2035	1,122,155,537	0.020	19,110,545	13,772,162	269,680
2036	1,141,266,082	0.018	19,110,545	13,772,162	242,712
					15,181,157

Table 5

Determination of Future Natural Gas Discoveries
Western Canada Sedimentary Basin
Most Likely Effectiveness of Development -- Most Likely Forcasted Footage

Year	Cumulative Exploratory Drilling Footage	Effectiveness of Exploration Gas Intent	Annual Exploratory Drilling Footage	Gas Intent Exploratory Drilling Footage	Actual and Forecasted Reserve Additions
	Feet	*MMcf/Foot*	*Feet*	*Feet*	*Bcf*
1980	260,997,347	0.363	16,631,010	8,567,795	3,111,307
1981	273,244,943	0.576	12,247,595	6,327,131	3,644,196
1982	285,943,637	0.422	12,698,694	4,919,827	2,074,052
1983	302,503,415	0.914	16,559,779	3,196,807	2,923,158
1984	322,934,922	2.135	20,431,507	3,550,152	7,577,957
1985	349,197,440	0.283	26,262,517	5,649,573	1,596,619
1986	362,935,523	0.210	13,738,083	3,196,935	671,512
1987	378,352,359	0.141	15,416,836	3,693,019	521,522
1988	396,273,266	0.374	17,920,906	5,123,296	1,918,273
1989	406,502,293	0.920	10,229,028	4,278,958	3,937,539
1990	417,235,618	0.606	10,733,324	4,015,216	2,433,088
1991	428,139,161	0.742	10,903,543	3,173,665	2,355,922
1992	439,246,228	1.435	11,107,067	1,888,328	2,710,052
1993	462,356,131	0.458	23,109,903	7,175,025	3,284,489
1994	490,600,916	0.297	28,244,785	12,246,528	3,632,985
1995	518,045,840	0.622	27,444,924	8,205,203	5,099,927
1996	545,670,473	0.398	27,624,632	10,549,579	4,202,500
1997	587,446,573	0.252	41,776,100	15,307,812	3,863,903
1998	609,219,338	0.241	21,772,765	12,571,831	3,035,094
1999	636,843,970	0.219	27,624,632	17,407,639	3,811,059
2000	671,108,972	0.178	34,265,002	21,014,512	3,746,354
2001	711,025,008	0.236	39,916,035	24,022,290	5,755,418
2002	744,433,015	0.230	33,408,007	20,919,328	4,881,672
2003	788,625,695	0.104	44,192,680	29,613,219	3,118,896
2004	840,352,718	0.166	51,727,024	37,667,390	6,340,480
2005	899,458,318	0.155	59,105,600	41,131,967	6,494,706
2006	955,307,403	0.127	55,849,085	37,688,173	4,823,180
2007	994,260,966	0.156	38,953,563	26,286,709	4,111,854
2008	1,036,131,018	0.156	41,870,052	28,254,819	4,419,712
2009	1,081,055,003	0.156	44,923,985	30,315,679	4,742,078
2010	1,130,555,511	0.156	49,500,508	33,404,015	5,225,166
2011	1,180,056,018	0.156	49,500,508	33,404,015	5,225,166
2012	1,229,556,526	0.156	49,500,508	33,404,015	5,225,166
2013	1,279,057,033	0.156	49,500,508	33,404,015	5,225,166
2014	1,328,557,541	0.156	49,500,508	33,404,015	5,225,166
2015	1,378,058,049	0.156	49,500,508	33,404,015	5,225,166
2016	1,427,558,556	0.156	49,500,508	33,404,015	5,225,166
2017	1,477,059,064	0.156	49,500,508	33,404,015	5,225,166
2018	1,526,559,571	0.156	49,500,508	33,404,015	5,225,166
2019	1,576,060,079	0.156	49,500,508	33,404,015	5,225,166
2020	1,625,560,586	0.156	49,500,508	33,404,015	5,225,166
2021	1,675,061,094	0.156	49,500,508	33,404,015	5,225,166
2022	1,724,561,602	0.156	49,500,508	33,404,015	5,225,166
2023	1,774,062,109	0.156	49,500,508	33,404,015	5,225,166
2024	1,823,562,617	0.156	49,500,508	33,404,015	5,225,166
2025	1,873,063,124	0.156	49,500,508	33,404,015	5,225,166
2026	1,922,563,632	0.156	49,500,508	33,404,015	5,225,166
2027	1,972,064,139	0.156	49,500,508	33,404,015	5,225,166
2028	2,021,564,647	0.156	49,500,508	33,404,015	5,225,166
2029	2,071,065,155	0.141	49,500,508	33,404,015	4,702,649
2030	2,120,565,662	0.127	49,500,508	33,404,015	4,232,385
2031	2,170,066,170	0.114	49,500,508	33,404,015	3,809,146
2032	2,219,566,677	0.103	49,500,508	33,404,015	3,428,231
2033	2,269,067,185	0.092	49,500,508	33,404,015	3,085,408
2034	2,318,567,692	0.083	49,500,508	33,404,015	2,776,867
2035	2,368,068,200	0.075	49,500,508	33,404,015	2,499,181
2036	2,417,568,708	0.067	49,500,508	33,404,015	2,249,263
					139,334,930

The finding rate is adjusted in Tables 5 and 6 through analysis of the depletion of entire WCSB's natural gas endowment. This is shown in Table 6, below.

Table 6

DETERMINATION OF PRODUCTION AND DECLINE IN ENDOWMENT
WCSB

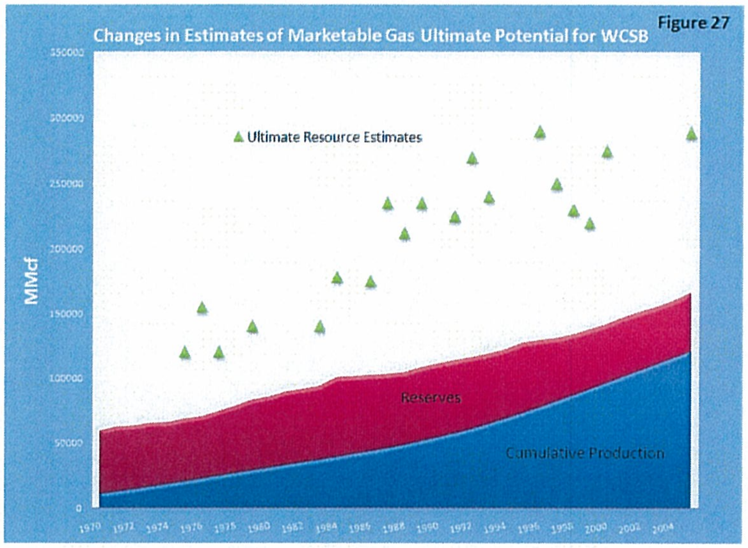
Year	New Expl Additions	New Development Additions	New Total Additions	Accumulated Ultimate Reserves	Percent of Ultimate Endowment
2001				183,716	
2002	641,966	4,881,672	5,523,638	189,239	54.03
2003	646,520	3,118,896	3,765,416	193,005	55.11
2004	515,380	6,340,480	6,855,860	199,861	57.06
2005	591,771	6,494,706	7,086,477	206,947	59.09
2006	638,802	4,823,180	5,461,982	212,409	60.65
2007	461,498	4,111,854	4,573,352	216,983	61.95
2008	496,051	4,419,712	4,915,763	221,898	63.36
2009	532,232	4,742,078	5,274,310	227,173	64.86
2010	532,232	5,225,166	5,757,398	232,930	66.50
2011	532,232	5,225,166	5,757,398	238,687	68.15
2012	532,232	5,225,166	5,757,398	244,445	69.79
2013	532,232	5,225,166	5,757,398	250,202	71.44
2014	532,232	5,225,166	5,757,398	255,960	73.08
2015	532,232	5,225,166	5,757,398	261,717	74.72
2016	532,232	5,225,166	5,757,398	267,474	76.37
2017	532,232	5,225,166	5,757,398	273,232	78.01
2018	532,232	5,225,166	5,757,398	278,989	79.66
2019	532,232	5,225,166	5,757,398	284,747	81.30
2020	532,232	5,225,166	5,757,398	290,504	82.94
2021	532,232	5,225,166	5,757,398	296,261	84.59
2022	532,232	5,225,166	5,757,398	302,019	86.23
2023	532,232	5,225,166	5,757,398	307,776	87.87
2024	532,232	5,225,166	5,757,398	313,534	89.52
2025	532,232	5,225,166	5,757,398	319,291	91.16
2026	479,009	4,702,649	5,181,658	324,473	92.64
2027	431,108	4,232,385	4,663,493	329,136	93.97
2028	387,997	3,809,146	4,197,143	333,333	95.17
2029	349,198	3,428,231	3,777,429	337,111	96.25
2030	314,278	3,085,408	3,399,686	340,510	97.22
2031	282,850	2,776,867	3,059,717	343,570	98.09
2032	254,565	2,499,181	2,753,746	346,324	98.88
2033	229,108	2,249,263	2,478,371	348,802	99.59
2034	206,198	2,024,336	2,230,534	351,033	100.22
2035	185,578	1,821,903	2,007,481	353,040	100.80
2036	167,020	1,639,712	1,806,733	354,847	101.31
	13,292,404	129,145,383	142,437,787		

Cumulative Prod to 12/31/2006	Tcf	156
Remaining Reserves at 12/31/2006	Tcf	57
Ultimate Reserves at 12/31/2006	Tcf	213
Undiscovered Resources - CGPC Less 2006 Discoveries	Tcf	137
Ultimate Res and Resources at 12/31/2006	Tcf	350
Percent of Endowment Discovered at 12/31/2006	Tcf	61%

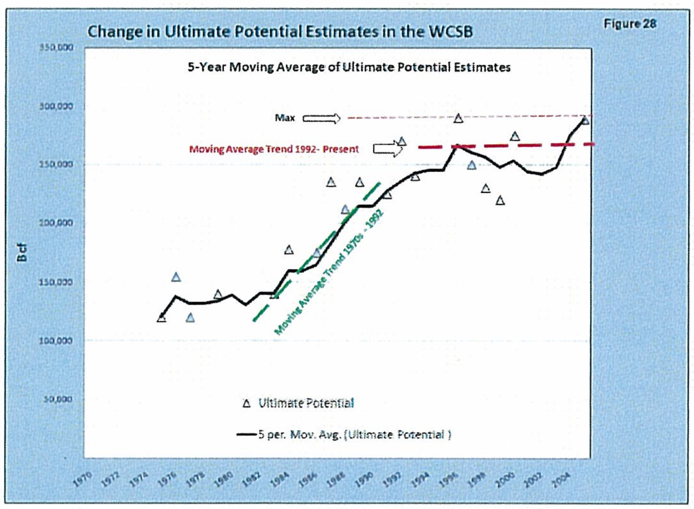
Ultimate Resources

Ultimate resources or endowment is the sum of discovered and undiscovered natural gas resources. Discovered resources are the sum of the cumulative production and the remaining reserves to date. Numerous estimates of the ultimate resources in the WCSB have been made over the years. Undiscovered resources are estimated through various models such as the discovery-process model described herein.

The various estimates of ultimate resources are shown in Figure 27.



The changes in the ultimate potential estimates showing moving average trend lines and maximum values are shown in Figure 28.



Since 1992 the rate of growth in the ultimate resource estimates has slowed and become constant. The relatively constant values are the product of 6 different Canadian agencies who estimate the ultimate potential conventional resources (See Figure 29).

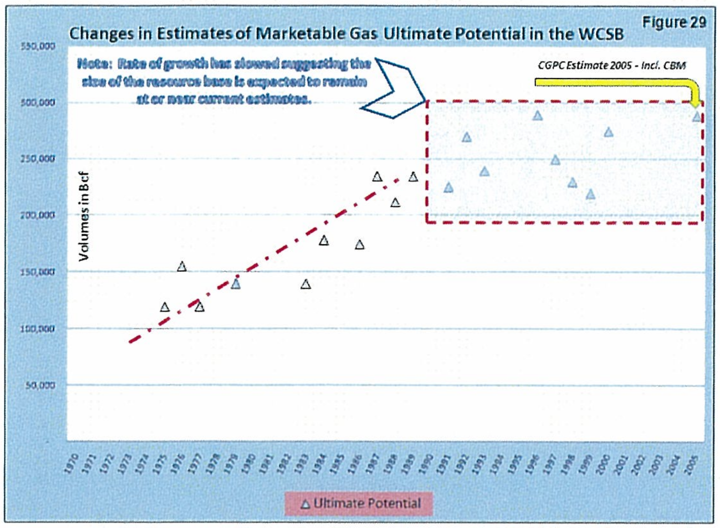
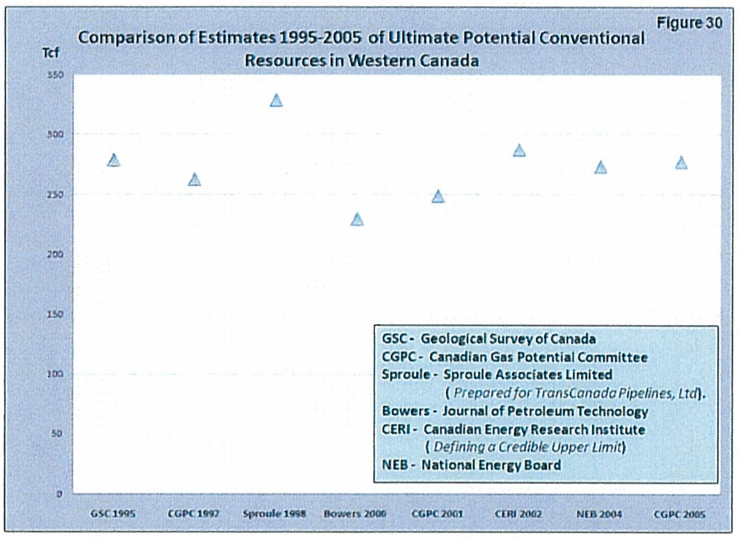


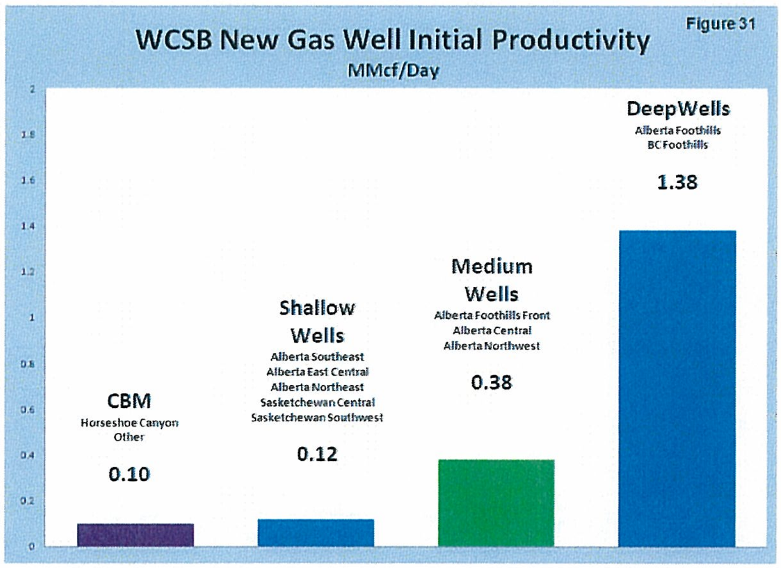
Figure 30 shows a more focused graph of the most recent estimates.



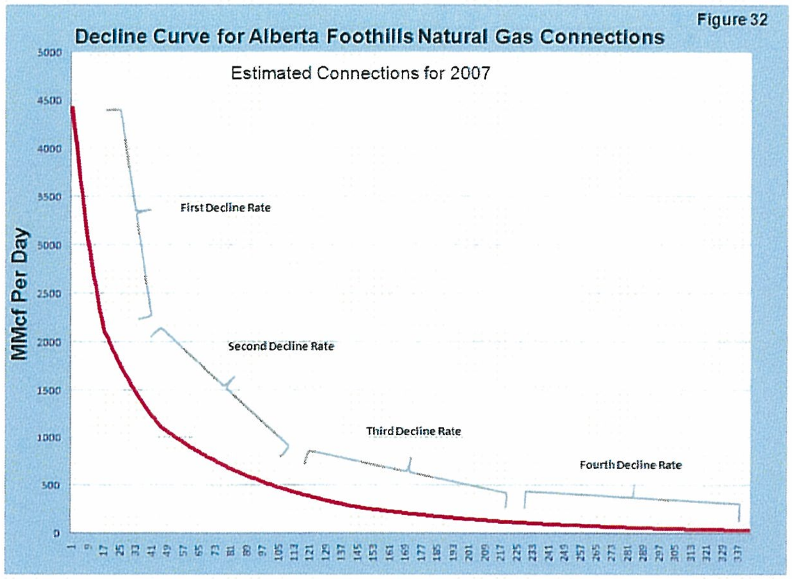
Thus there appears to be a consensus as to the approximate ultimate level of Canada's WCSB conventional natural gas endowment. The ultimate resource level of the CGPC is employed for this study. The importance of the estimate of the ultimate resource level is that it establishes a threshold for the discovery process in any dynamic oil and gas supply model. This study establishes a decline in the finding rate of 10 percent when the future gas discoveries reach the ultimate resource level of 90 percent (see Table 7).

The Availability of Undiscovered Gas Resources – Part 2

To determine the availability from the estimated future gas discoveries, I applied to each determined annual future reserve addition, by WCSB sub area (Foothills, Central, etc). Each area exhibits varying production characteristics. The initial productivity of gas completions varies as shown in Figure 31.



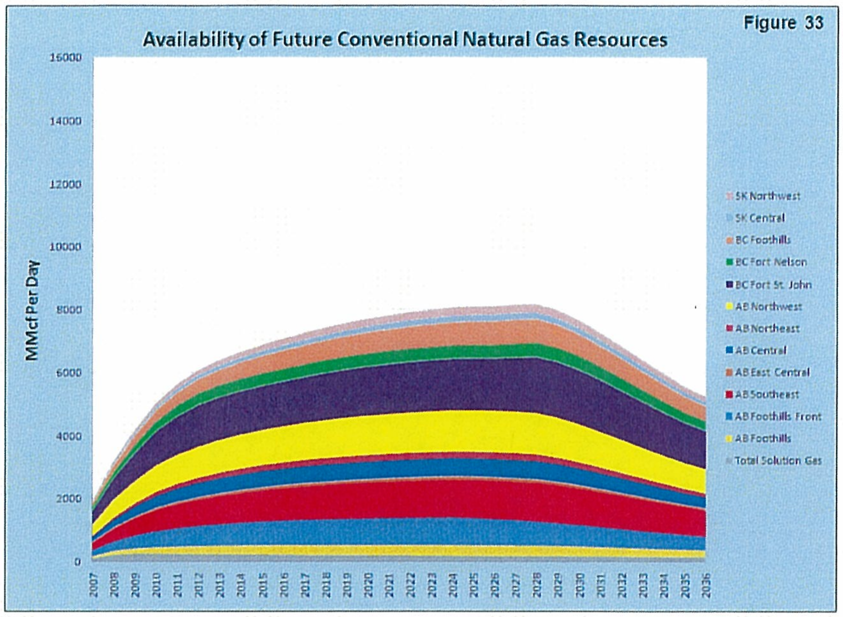
The production rates employed herein are derived by the NEB from their analysis of actual gas production data obtained from GEOScout. An example of the decline curve applicable to future gas well connections in the Foothills of Alberta is shown in Figure 32.



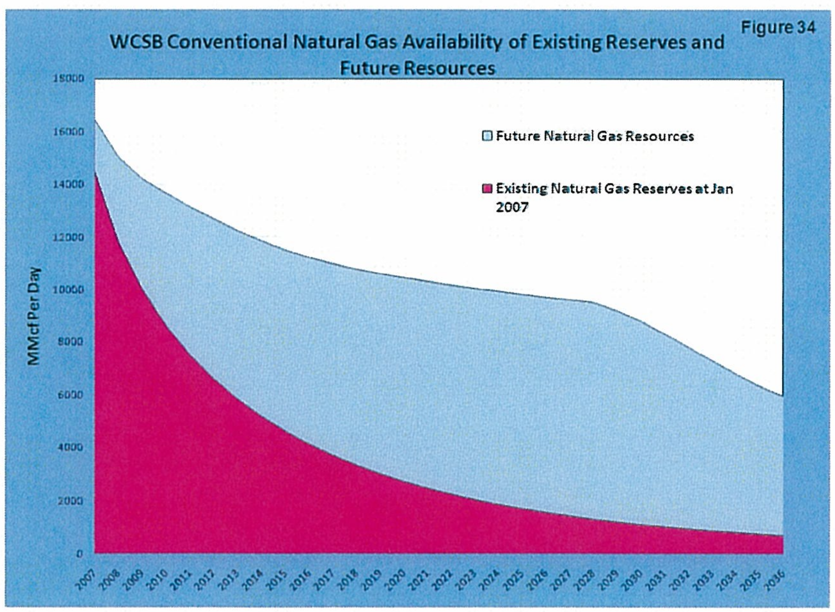
These production decline rates are considered long-term. Analysis of the key decline rate parameters of gas well completions in the WCSB indicates that since 1998 it is stable. Each sub area of the WCSB exhibits its own decline rate parameter, however over recent time it has stabilized. In a mature oil and gas province, such decline rate components remain constant.

With respect to the initial productivity of each completion, it is assumed, in the long term, that it also will also stabilize. Currently, it is in a slight decline, much flatter than previous years (this is demonstrated in Figures 9 and 10). While, in itself, it should continue to decrease due to the finite amount of prospects and the ability of producers to explore on a concerted selectivity basis, however, technological advances should boost up the declining initial productivity trend. This would net out to a constant initial productivity.

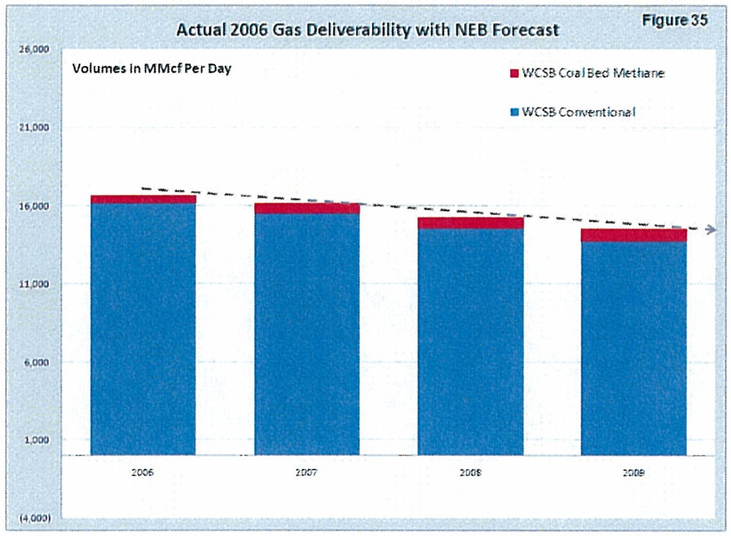
The availability from new reserves beginning in 2007 is determined to be as shown in Figure 33.



To the production profile of future reserves, I added the production profile for the beginning of year 2007 proven (already discovered) gas reserves. This is shown on Figure 34.



For comparison purposes, the NEB, in their Short-term Canadian Natural Gas Deliverability study, forecasts the deliverability from conventional resources in the WCSB to be as shown below in Figure 35.



A significant amount of WCSB conventional gas production is produced from low permeability reservoirs that are more properly categorized separately as "tight gas." Some estimates have tight gas comprising approximately 30 percent of total production in the WCSB in recent years, and should increase as the basin continues to mature. Presently, tight gas is not defined, nor is it distinguished from conventional gas. Thus, tight gas is included in the determination of the availability of conventional gas in the WCSB.

VI. FORECAST OF THE AVAILABILITY OF COALBED METHANE

Background

Coalbed methane or coal-bed gas or as it is referred to in Canada as natural gas from coal (NGC) is a natural gas associated with coal. It is

mainly composed of methane and, like natural gas from traditional sources, with various amounts ethane, nitrogen and carbon dioxide. The methane gas occurs in coal formations in three ways:

- As gas adsorbed onto coal surfaces
- As free gas in fractures, cleats or other porosity, and
- As gas dissolved in the water within the coal beds.

The amount of gas generated in a particular coal formation depends upon:

- Depth of the formation
- Pressure
- Temperature
- Coal bed thickness
- Coal composition

The CBM production process includes removal of water in the coal by pumping to the surface and disposal. This allows the pressure in the coal to drop sufficiently for the gas to flow. The water production varies in quantity and quality. For example, the Horseshoe Canyon Formation in Alberta contains very little water, which enhances the economics of exploiting that resource. On the other hand, the Mannville Formation, also in Alberta, contains large quantities of water, some with extremely poor quality, which makes disposal particularly costly.

CBM flow rates tend to be relatively low. For example, a typical Horseshoe Canyon CBM well exhibits an initial productivity before declining of about 77 Mcf per day. Conventional WCSB wells currently average 270 Mcf per day.

CBM is considered to be an unconventional gas because of how the gas is stored and the manner in which the gas is produced. With gas in conventional reservoirs contained in the pore space of the rock, the majority of gas in coal is adsorbed (bonded) to the surface of the coal. The production process of coal gas is different because of the low pressure and the presence of water. CBM is produced by reducing the pressure to very low values (de-watering) to initiate production. As the pressure reduced through a differential between the wellbore and the coal formation the water is produced and the gas residing in the natural fractures and any other pore space will move throughout the coal toward the wellbore. With further pressure reduction, the gas which is bonded to the coal surface will slowly enter the desorption process and flow through the micro-porosity to the same porous pathways of the natural cleat network of fractures.

<u>CBM in the WCSB</u>

In the WCSB, there are 4 coal formations that are targets for CBM exploitation:

- Ardley
- Horseshoe Canyon
- Mannville
- Kootenay

The Horseshoe Canyon Formation is the most prevalent CBM formation in the WCSB. Its main attribute is that it is mostly water free. On the downside is the fact that rates and pressures remain low and as a result compression is required to pressure up the gas to pipeline input.

The Ardley Formation is a very shallow coal seam with low pressure and fresh-water. To date there is little commercial development of the Ardley.

The Mannville Formation has the attribute of containing thick seams of coal, however, salt water pervades the seams. Sever environmental issues result due to the disposal of the produced water. Some commercial development of the Mannville Formation occurs.

The Kootenay Formation is the deepest CBM play in the WCSB. None of the Kootenay Formation projects is commercial to date.

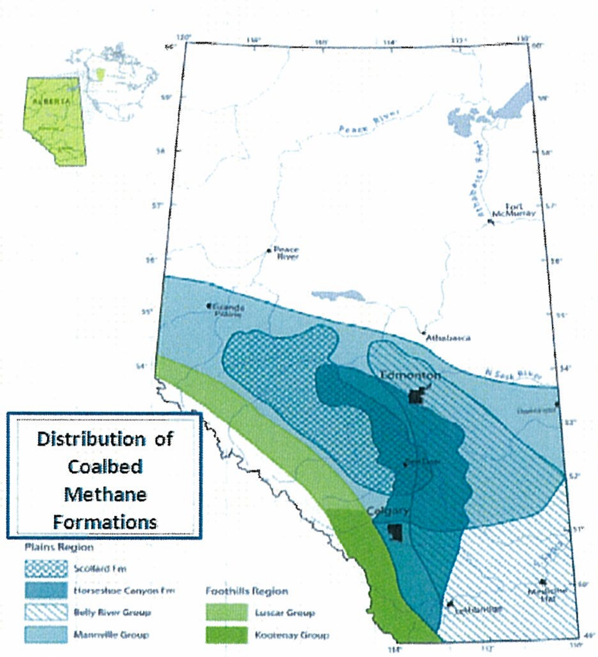
Wells drilled as CBM targets, wells producing and gas production by the above CBM plays is as follows:

	Wells Drilled	Wells Producing	Gas Production (MMcf per Day)
Horseshoe Canyon	9,762	4,347	373
Mannville	822	209	47
Ardley	100	unknown	unknown
Kootenay	39	unknown	unknown

As mentioned earlier, the CBM coals in the WCSB consist of individual coal seams usually less than 15 feet thick. The coals are interbedded with sand zones. The sands often contain conventional natural gas (Also sandstone target wells that penetrate coal zones will produce some CBM gas). Production of the conventional gas found in the interbedded sands, including the gas from the coal seams, results in the production rate for the CBM well. The amount of production that is actually coming from the sands is not precisely known, however various estimates have been made that indicate a range of 10 to 40 percent.

The extent of the coal seam formations is shown in Figure 36 with Alberta's main CBM fairway.

Figure 36



Map courtesy of ERCB

After 4 years of Canadian CBM experience in prospecting for natural gas from coal, the success of a given technique in US coal basins is not any guarantee of success in Canada is a valid assumption. A comparison of WCSB CBM formations with those in the Lower 48 is shown in Table 7. Differences are apparent, such as the gas content and permeability.

Table 7

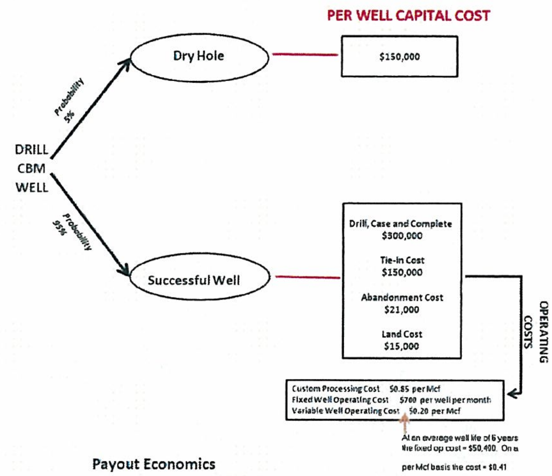
Comparison of North American Coal Bed Methane Plays

Basin	Coal Bearing Formation	Thickness of Coal Formation (Feet)	Gas Content (scf/ton)	Gas Content Bcf/Section	Permeability Average
Canada - WCSB					
Alberta Plains - Shallow	Horseshoe Canyon	15-35	25-75	1.5-3	1-10
	Scollard	10-50	50-120	3-9	1-10
Alberta Plains - Deep	Upper Mannville	10-35	150-350	3-10	0.1-10
Mountains and Foothills	Gates	50-150	50-350	10-40	varies greatly
U.S. - Lower 48					
San Juan Basin	Fruitland	70	225-350	15-20	20-50
Black Warrior Basin	Pottsville	25	300-400	10-15	<10
Uinta Basin	Ferron	25	350-450	13-18	10-30
Powder River Basin	Fort Union	Up to 100	25-50	2-5	100-1000
Raton Basin	Raton	30	350	10-14	1-20

CBM in the WCSB appears to be a commercial, yet marginal play. This is evidenced by analysis of the economics as shown below in Figure 37.

Figure 37

DEMONSTRATION OF MARGINAL NATURE OF AVERAGE CBM WELL - WCSB



Payout Economics

Wellhead Price = $6.50/Mcf

Net Revenue = $3.74/Mcf ($6.50/Mcf less royalty and Op. Costs - $2.76/Mcf)

Average Recoverable Reserves per Well = 120,634 Mcf
CBM Wells as of Dec. 2006 - 10,723
CBM Wells as of Sept. 2007 - 8,129
Original Recoverable Reserves - 27,780 Mm3

Net Revenue = $451,171

Capital Investment = -$486,000 Note: At a wellhead price of $7.50 the difference is $61,678

Difference = -$34,829

Source:
Reserves - EUB ST 98-2007
Total Wells - EUB Bulletin 2007-05
Note; of the total 10,723 CBM wells, 6905 have produced or were producing by Dec. 31, 2006. These wells may have produced from only coals or from a combination of coals and other gas zones (sand).

An important point is that CBM, tight gas and shale gas, while categorized as unconventional, are not new. They have, historically, in the WCSB, not been the main target of individual drilling programs. Such formations containing coal (CBM), sandstones and carbonates with very low porosity and permeability (tight gas) and shale (shale gas) have been penetrated by the well bore and in various cases produce gas comingled with the production of the main sandstone or limestone target.

Actually, when CBM and shale gas are the primary target, gas production from inter-layered sandstones are comingled with the production from coal and shale formations. The Horseshoe Canyon formation consists of a stratagraphic interval of 320 to 890 feet of which 3 to 70 feet of aggregate coal in up to 30 individual coal beds (zones), many of which are very thin and intermingled between sandstone and shales. In fact, for traditional WCSB gas wells where sandstone and carbonate formations are the primary target for gas production, many wells will also produce gas from coal (CBM) and shale (shale gas) formations.

For example, a recent survey by AJM Petroleum Consultants of CBM wells in the Horseshoe Canyon formation, the producing well count is as follows:

❖ Wells producing CBM only.	951
❖ Wells producing from coal and sandstone, i.e., no differentiation of production.	547
❖ Probable production from coal and sandstone, data not absolutely definitive.	183
❖ Confidential wells, most likely producing from coal.	384
❖	
Total	2,065

Of this total, the AEUB identified 1,470 as CBM target wells.

Availability of CBM in the WCSB

An assessment of the availability of CBM in the WCSB is made employing the current trend in drilling with wells drilled and wells connected along with the employment of production rates developed by the NEB based upon actual GeoScout data. The number of wells drilled and connected historically with the assumed wells drilled and connected in the future is shown in Figure 38 and Table 8.

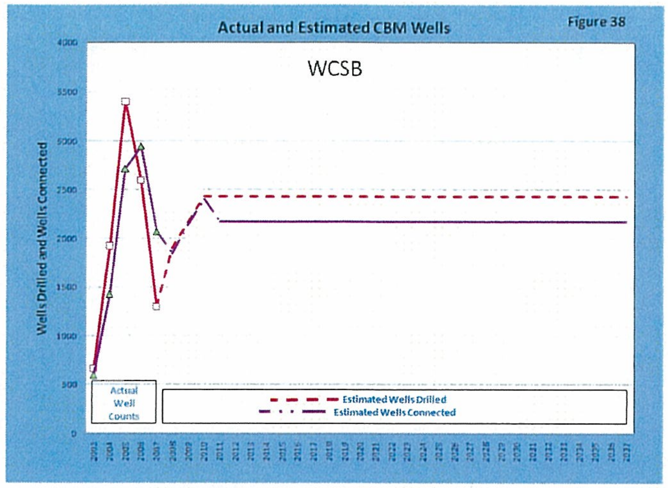


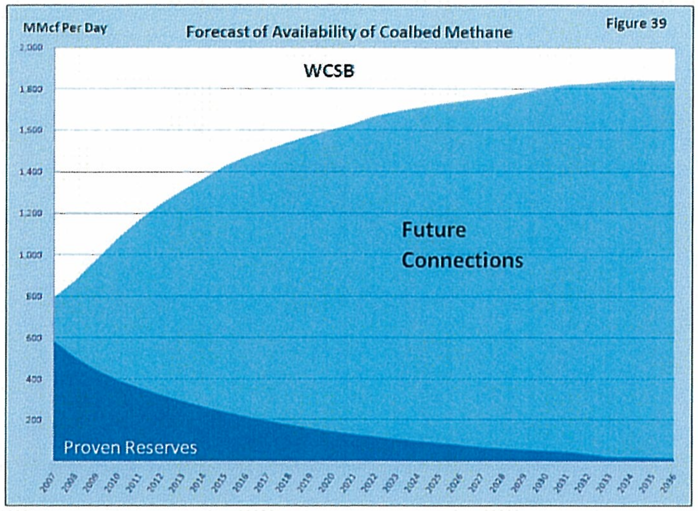
Table 8

CBM Wells Drilled

Total Wells Drilled	Year	Well Count	Wells Connected	Total Wells Conn
670	2003	670	601	601
2,597	2004	1,927	1,427	2,028
6,002	2005	3,405	2,721	4,749
8,608	2006	2,606	2,948	7,697
9,908	2007	1,300	2,073	9,770
11,814	2008	1,906	1,842	11,612
13,995	2009	2,181	2,152	13,764
16,432	2010	2,437	2,410	16,174
18,869	2011	2,437	2,179	18,353
21,306	2012	2,437	2,179	20,532
23,743	2013	2,437	2,179	22,711
26,180	2014	2,437	2,179	24,890
28,617	2015	2,437	2,179	27,070
31,054	2016	2,437	2,179	29,249
33,491	2017	2,437	2,179	31,428
35,928	2018	2,437	2,179	33,607
38,365	2019	2,437	2,179	35,786
40,802	2020	2,437	2,179	37,965
43,239	2021	2,437	2,179	40,144
45,676	2022	2,437	2,179	42,323
48,113	2023	2,437	2,179	44,502
50,550	2024	2,437	2,179	46,681
52,987	2025	2,437	2,179	48,860
55,424	2026	2,437	2,179	51,039
57,861	2027	2,437	2,179	53,219
60,298	2028	2,437	2,179	55,398
62,735	2029	2,437	2,179	57,577
65,172	2030	2,437	2,179	59,756
67,609	2031	2,437	2,179	61,935
70,046	2032	2,437	2,179	64,114
72,483	2033	2,437	2,179	66,293
74,920	2034	2,437	2,179	68,472
77,357	2035	2,437	2,179	70,651
79,794	2036	2,437	2,179	72,830
82,231	2037	2,437	2,179	75,009

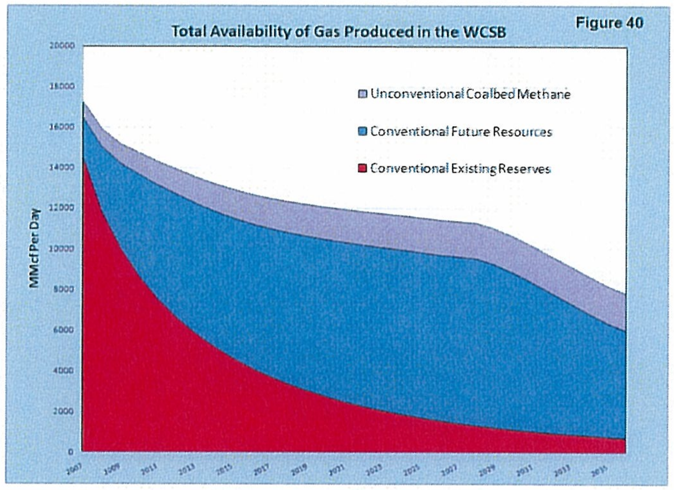
	Well Count
Average 2004-2006	2646
Average 2005-2007	2437

Figure 39 shows the results of the forecast of the availability of CBM in the WCSB with the availability from existing reserves and undiscovered resources.


MMcf Per Day
Forecast of Availability of Coalbed Methane
Figure 39
WCSB
Future Connections
Proven Reserves

VII. TOTAL ASSESSED NATURAL GAS AVAILABILITY FROM THE WCSB

The assessed availability from conventional sources and the unconventional CBM in the WCSB is shown in Figure 40.



VIII. CONCLUSIONS AND IMPLICATIONS

The purpose of this report is to perform a realistic assessment of the amount of natural gas available from the WCSB for market throughout Canada and export to the U.S. To that end, the assessment must be reasonable and realistic to be employed as an indicator of the useful lives of pipeline facilities that in whole or in part transport such upstream gas. Useful lives of pipeline facilities translate to investment recovery. As such, gas supplies of a highly uncertain recovery and of somewhat conceptual nature were not considered as part of this assessment.

Natural gas production from Western Canada will continue to be the anchor of Canada's gas supply. Future natural gas supplies will cost more to discover and exploit as the quality and size of the deposits shrink. Currently, in WCSB both conventional gas and CBM are characterized by low-rate wells, with the result that much drilling will be required. CBM will be important, but at best may only partially stem the decline in WCSB gas production.