Parabolic Projection of Four Assessments of Canadian Conventional Natural Gas Resources

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Abstract

The parabolic projection technique employed in previous papers was applied to four recent published assessments of Canadian conventional natural gas resources—those of the Canadian Gas Potential Committee, the Canadian Energy Research Institute, and the two scenarios formulated in the 2003 supply/demand study of the National Energy Board. This technique was modified by applying constraints at two assumed upper limits of conventional output of seven and eight Tcf per year to in effect establish a plateau peak that was extended in time by the quantity of gas whose production had been delayed.

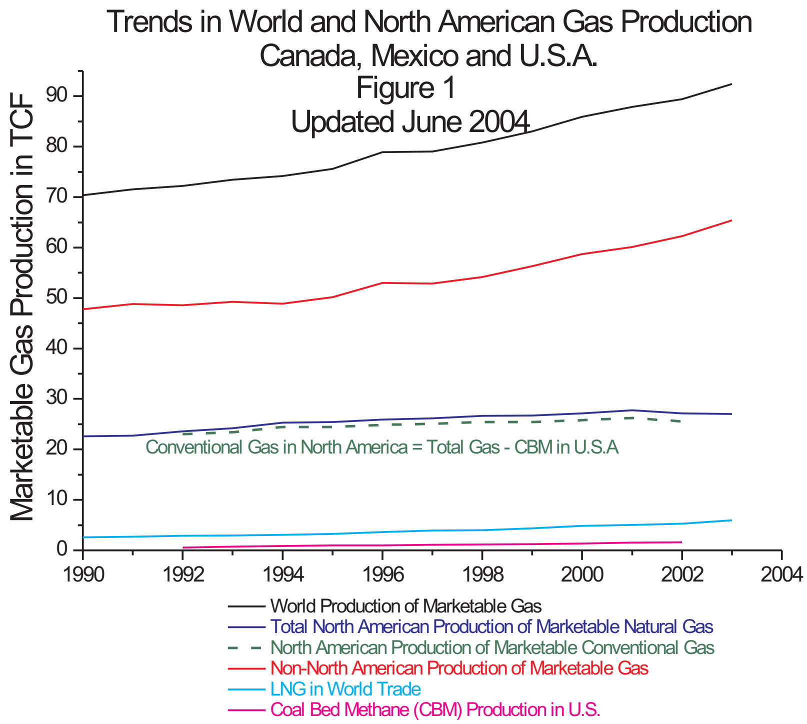
On a common basis of comparison, the assessments of undiscovered remaining conventional natural gas in Canada covered a range from 207 for the Canadian Gas Potential Committee case to 422 Tcf used in a recent Canadian Energy Research Institute study, if the latter value is interpreted correctly in this paper. The two National Energy Board scenario cases were in between these assessments at 299 and 327 Tcf respectively. Applying a constraint on production leads to an extension of the plateau peak. For a peak production of 7 Tcf per year, the plateau peak is reached essentially now in all four cases, and the decline resumes in Case 1 in 2028, Case 2 in 2059, Case 3 in 2041, and Case 4 in 2045. The corresponding dates for reaching a plateau peak at 8 Tcf/year are 2010, 2006, 2007, and 2007 respectively. The decline resumes in 2018, 2048, 2031, and 2035 respectively.

It is unlikely that the rapid rise in supply of natural gas from Canadian conventional sources to the U.S. characteristic of the past decade can continue although it is possible the development of non-conventional sources of Coalbed Methane might allow about another one Tcf/year to be exported. In conditions of low demand growth, the price of gas is unlikely to fall much below $4/1000 cubic feet on U.S. trading markets for any extended period of time given that the floor price is effectively set by the two next lowest cost sources of supply—non-conventional gas from Coalbed Methane and imported Liquefied Natural Gas. In periods of high demand, the prices may be much higher. Two conceptually different classes of economic rent in the natural gas system were identified in the paper.

Introduction

In a previous paper[1], a scenario was formulated in which North American (including Mexican) conventional natural gas production peaked no later than 2010 which is well before the peak in world conventional natural gas production will be reached in the 2050-60 time frame. The peak in the world production of conventional oil is expected in the intermediate period of 2017-2020. The peak in world conventional natural gas production is also expected to coincide approximately with the peak in world population at around eight billion about 2050.

Given that the North American peak occurs well before the world peak in conventional production, gas will tend to move from world surplus areas to North America. This gas will be supplied either directly in the form of Liquefied Natural Gas (LNG), or indirectly by conversion to other liquid fuels shippable by tanker, such as methanol or liquid hydrocarbons. It may also be imbedded in energy-intensive products shipped to North America, such as aluminum and Directly Reduced Iron produced as a feed for the steel industry. The trends in both world and North American gas production for the past decade are illustrated in Figure 1. World production, particularly that outside North America, is increasing steadily in contrast to the situation in North America where the peak for the three nations



taken together may have already passed. Production trends for two non-conventional sources of natural gas, LNG delivered to markets by cryogenic tanker (LNG) and Coalbed Methane (CBM), are also shown as steadily increasing though both account for only a small fraction of the market at present.

The shape of the production curve for the three North American countries is also noteworthy: it is stretched out and flat, the opposite of a well-defined peak. In this situation, the actual date of the peak may only be known with certainty in retrospect. The decline from such a peak would be expected to be slow.

World production of natural gas (excluding that flared or re-injected) is given as 89.2 trillion cubic feet (Tcf) in 2002 and world reserves at the end of that year are reported as 5502 Tcf in the *BP Statistical Reviewof World Energy.*[2] Canadian production was 6.5 Tcf in 2002 or 7.3% of the world total.

Canadian reserves at 60.1 Tcf accounted for 1.1% of the world's total at the end of that year. Canada is thus producing much more gas in proportion to its reserves as compared to the world average.

This paper examines the possible pattern of future conventional gas production in Canada based upon four recent assessments of the remaining undiscovered resources published by the Canadian Gas Potential Committee[3], the Canadian Energy Research Institute[4], and the two scenarios formulated by the National Energy Board in *Canada's Energy Future: Scenarios for Supply and Demand to 2025*[5], one of a regular series of studies on this subject prepared every few years by this agency.

Recent National Energy Board Statements on the Canadian Natural Gas Position

The National Energy Board published another in its series of energy market assessment reports entitled *Short-term Natural Gas Deliverability from the Western Canada Sedimentary Basin* in December of 2002. In its conclusions, the Board states that `despite drilling a record number of gas wells in 2001 and the start-up of the highly productive Ladyfill project, increases in natural gas deliverability have been lower than projected in previous reports.' The Board believes that gas deliverability from the WCSB by the end of 2004 will fall some four per cent below the year-end 2001 production rate. Presently, to offset declines from existing wells, production from one year's new connections must amount to about twenty per cent of current production.

In its Annual Report for 2002, (released 14 March 2003), the NEB stated there is a good correlation between natural gas prices at the three pipeline `hubs' in North America (the main Henry Hub in Louisiana where the New York trading price is based, the AECO-C Hub in Alberta, and the emerging Dawn Hub in Ontario). This indicates there is now adequate transportation capacity between the Western Canada Sedimentary Basin (WCSB) and eastern markets so that the North American market is approaching a single unit.

The natural gas section of *Canada's Energy Future: Scenarios for Supply and Demand to 2025*[5] (released 3 July 2003) was of special interest in view of the higher prices and the disappointments in exploration activities in the eastern off-shore region that were experienced in early 2003. The Board acknowledged there is a major uncertainty in the future supply of natural gas. In price terms, the Board believes natural gas will rise to 90 percent of the crude oil price in its Supply Push scenario by 2025 and reach parity with crude oil by 2010 in its Techno-Vert scenario. In the Supply Push Scenario, natural gas production peaks about 6.57 trillion cubic feet per year (Tcf) and higher at 6.94 Tcf/year in the Techno-Vert Scenario due to the more successful application of new technology in the latter case. The earliest peak is in 2010 but these production forecasts include a growing component of non-conventional gas production from Coal Bed Methane operations.

In the course of a hearing related to toll and tariff matters, the NEB supported a submission by TransCanada PipeLines Limited in *Reasons for Decision* (RH-1-2002; ISBN 0-662-34489-8; p.32) reported in July 2003 in which the company showed that for six scenarios covering a wide range of outcomes, utilization of the company's main line to the east might be 50% of its current capacity as early as 2009 and as late as 2027, with the base cases at either 2018 or 2023, depending on whether or not new gas supply from northern regions was included.

Non-Conventional Gas Production

The two next costly supplies of gas to augment conventional production are from Liquefied Natural Gas (LNG) delivered by cryogenic tanker derived from `stranded' gas in surplus regions and from Coal Bed Methane (CBM) operations. At present there are four LNG receiving ports in the U.S. and these are likely to be augmented by additional facilities built in Mexico (in Baja California) to serve the California market, and one in Canada (near St. John in New Brunswick) with possibly another such facility along the St. Lawrence in Quebec to serve the eastern U.S. The LNG supply curve is thought to be a gently rising line increasing from about $ 4 per thousand cubic feet on the New York trading market. Because reserves of stranded gas are very large around the globe, particularly in the Middle East, large quantities of gas could eventually be involved. Most studies of LNG transport indicate that the costs of transport by tanker on the sea as compared to pipeline costs over the same distance over land cross at about 3,000 km with LNG transport costs (including the cost of the liquefaction and re-gasification facilities) lower at greater distances. The crossover point occurs sooner when the pipeline must be laid in deep water.

The Coalbed Methane supply curve probably starts out a little lower that the LNG curve but has a somewhat greater slope. Less gas in total is involved. What is remarkable is that these two options are very close in supply cost terms though their locations are very different—the LNG is supplied along the seacoast and the CBM at essentially mid-continental locations.

It may be that long pipelines from the Arctic region, such as the proposed Mackenzie Valley line, scheduled to enter service in 2009/2010, and the Alaska Pipeline, whose schedule depends upon the actions of the U.S. Congress, deliver gas for about the same supply price to major markets. Though there is one coal-to-gas synthetic facility (SNG) operating in the U.S. in North Dakota, the trading price would have to be consistently in the $US 6.00 range to encourage this option.

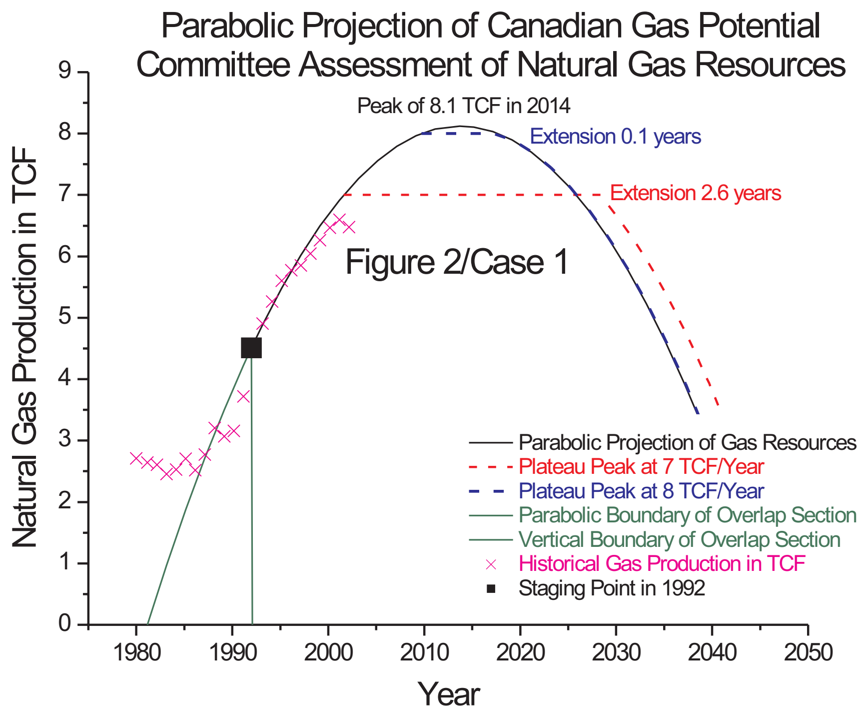
Given no substantial declines in demand in the immediate future, the floor price for natural gas on trading markets should be set by the cheapest alternative which is a mix of LNG and CBM at about $US 4.00 per thousand cubic feet.

Two different forms of economic rent may be identified in the North American natural gas system that are conceptually very different from each other once the peak in conventional production is past. In what might be termed the quasi-equilibrium case, economic rent arises from the difference between the $US 4.00/1000 supply price of the next least costly important alternatives and the supply price of the remaining conventional production. This difference per thousand cubic feet will fall with time because the slope of the conventional supply curve will increase faster than those of the two non-conventional alternatives.

In the non-equilibrium case, the price on trading markets may depend more upon the rate at which the two alternatives may be supplied. If demand is higher than the two non-conventional supply sources can be deployed, the price may be expected to be higher than the supply price of the alternatives as it was in the first half of 2003. There is thus a non-equilibrium dynamic difference between the actual price and the supply price of the non-conventional supply. In the first near-equilibrium case, the steadily declining rent will be captured by the conventional natural gas producers in North America. In the second non-equilibrium dynamic case, part of the rent may be captured by suppliers of LNG outside of North America. The sums of money involved in these economic rents may be very high and it is important that the distinction between these two cases be made clear.

Relation to the Price of Oil

In the `Techno-Vert' Scenario developed in the NEB supply/demand report, parity is expected between oil and gas prices sometime before 2025. But if North American conventional gas production peaks at or before 2010 and world conventional oil does not peak until as late as 2020, the possibility exists that the price of oil will be lower than that of gas at periodic intervals, given the normal fluctuations to be expected over time. If so, there will be periods when oil products will tend to substitute for gas before 2020. This question is important in the context of the generation of electricity in combined-cycle turbine facilities designed to burn natural gas, the favoured source of new generation at margin in North America at present. If so, liquid turbine fuel would be consumed in large quantities provided NOX emission standards could be met with the distillate fuel. In a deregulated electrical market, the independent generators of electrical energy can outbid others for fuel supply because the most expensive electricity is that which one does not have. This tendency gives rise to the `spiking' of prices of electricity that has been frequently noted in stressed deregulated electrical markets. At the very least, such a competion for distillate fuels would present another difficult problem for the aviation industry.



Parabolic Projection Methodology

Data Sources:

The cumulative production of conventional natural gas production in Canada to the end of 2002 was taken as 134 Tcf. Reserves at that time were 60.1 Tcf (BP Statistics). The Staging Year for the parabolic projection calculation was selected at 1992 to provide a ten-year period that included the immediately past era of rapidly increasing growth. Productionduring the ten years from 1992 to 2002 was 59.2 Tcf.

Equation for calculation of ultimate marketable conventional gas resource potential (here termed Qu = the term EUR employed in some other authors):

Qu = cumulative production + reserves + undiscovered marketable gas resources.

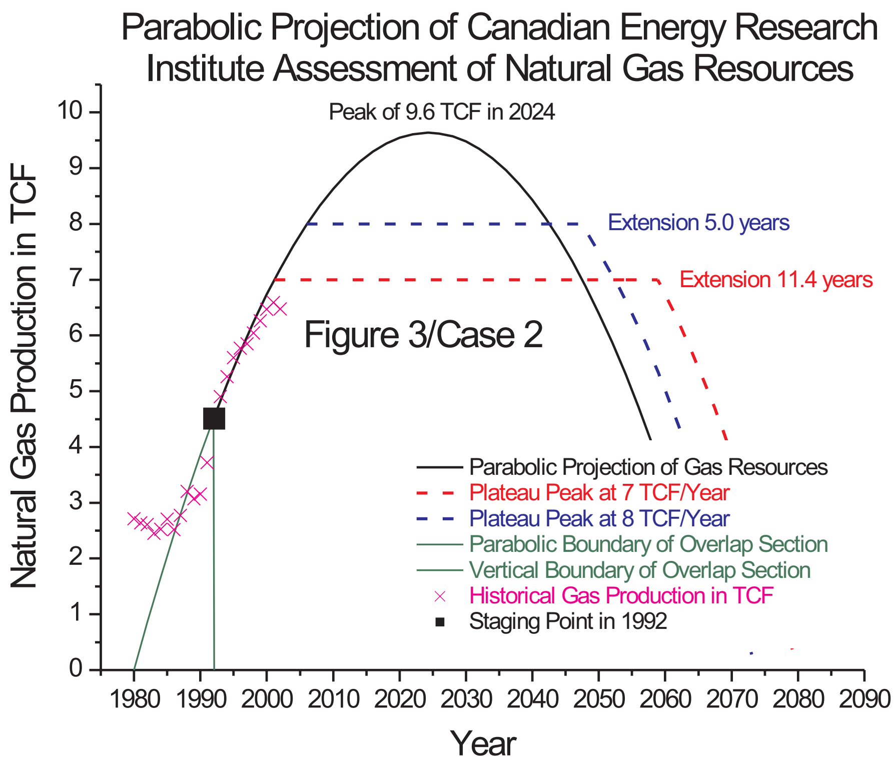
Case 1 - Canadian Gas Potential Committee Assessment Case:

The Committee uses the term `Nominal marketable gas' that it defines as `the gas in place in undiscovered prospects converted to *marketable* volumes by applying average recovery and surface loss factors of the discovered pools in the play.' This volume, given as 233 Tcf at the end of 1998, is corrected for the 25.7 Tcf produced between 1998 and 2002 to allow the calculation of Qu.

$$Qu = 134 + 60.1 + (233 - 25.7) = 401.4 \text{ Tcf}$$

Case 2 - Canadian Energy Research Institute Assessment (CERI):

CERI in its proprietary study[4] employed two undiscovered resource options–the Canadian Gas Potential Committee value as in Case 1 above and a second much higher value from an assessment espe-



cially commissioned for the purpose. This latter study is termed Case 2 here.

The cumulative production and reserves are the same as in Case 1 but the undiscovered conventional resources in place are a high 527 Tcf. As this is an assessment at the high end of the expected range, a similarly high 80% overall recovery factor is used here to convert to marketable gas to provide an upper range. It is not clear from the information available to this author whether this assessment includes some non-conventional sources of gas.

$$Qu = 134 + 60.1 + 0.8 \times 527 (= 421.6) = 615.7 \text{ Tcf}$$

Case 3 - National Energy Board `Supply Push' Scenario Case:

The National Energy Board explored two scenarios in its recent supply/demand study[5]: The `Supply Push' Scenario was presented here as Case 3 and the `Techno-Vert' Scenario as Case 4 below. The data was taken from Appendix 6 of this report but with the non-conventional gas resources (CBM) deducted. There were small differences in the cumulative gas production and the reserves at the end of 2002 as compared to the values employed in Cases 1 and 2 above but these were not considered significant.

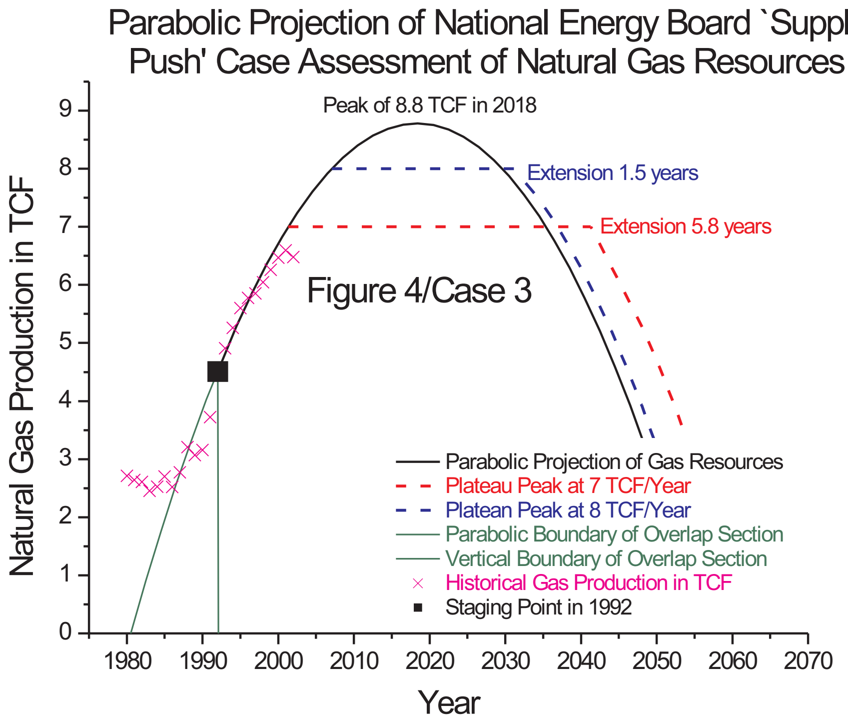
$$Qu = 133.5 + 57.1 + 299.4 = 490 \text{ Tcf}$$

Case 4: National Energy Board `Techno-Vert' Scenario Case

Data was taken from Appendix 6 and corrected for non-conventional resources as in Case 3.

$$Qu = 133.5 + 57.1 + 327.4 = 518 \text{ Tcf}$$

In the four cases, the Ultimate Resource Potential (Qu) varies from a low of 401.4 Tcf in Case 1 to a high of 615.7 Tcf in Case 2. The two National Energy Board Cases 3 and 4 were in between these values and quite close to each other at 490 and 518 Tcf respectively.



For comparison with the world as a whole, a recent comprehensive study reported by Gerling and Hempel in Germany placed world resources of conventional natural gas of the order 17,000 Tcf.[6]

Parabolic Projection Technique:

The Parabolic Projection technique was the same as that employed in previous papers.[7] Consistent with the previous natural gas papers, the selection of the parabola was based upon the cumulative production between the Staging Year 1992 and 2002 which was 59.2 Tcf. The plot is based upon the solution of the following equation:

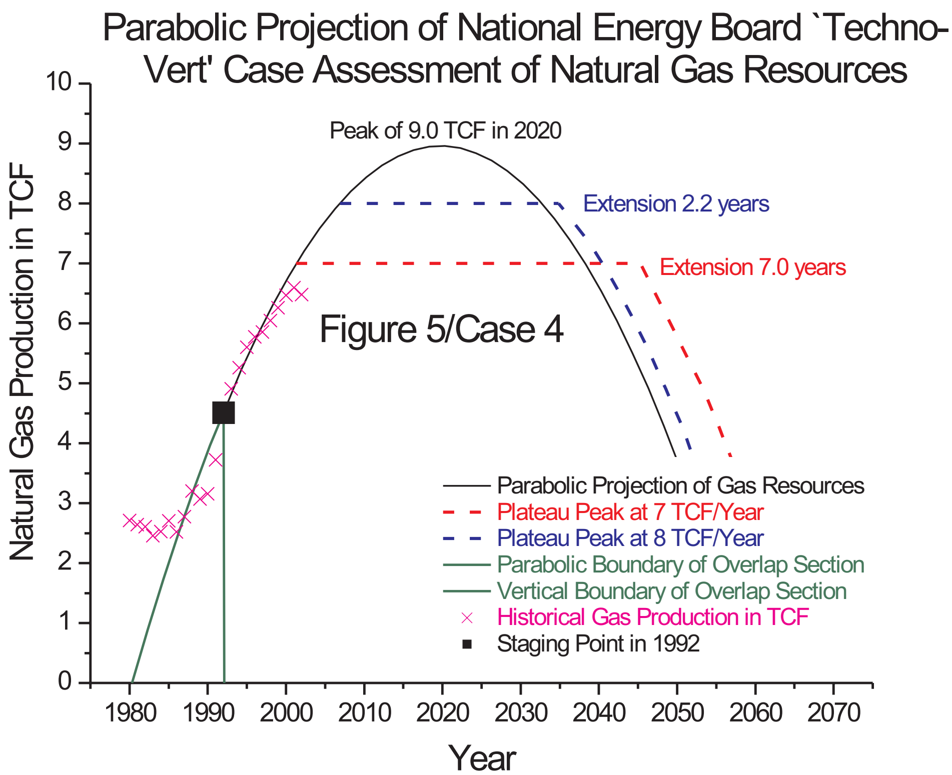
Cumulative Production to 1992 + area of Staged Parabola – area of Overlap Section = Qu.

The forward-looking Staged Parabolic method, unlike most other parabolic techniques, does not depend in any way on the production by year trend before 1992 but only on the cumulative production to that year and the production in the decade since to the present.

Given that the cumulative production to 1992 and Qu are known for a specific case, in the absence of an analytical solution the equation is solved by reiterating values of the ratio of the Overlap Section to the area of the Staged Parabola that must lie between 0 and 1. Any one value of this ratio will solve this equation and permit the drawing of the Staged Parabola and its Overlap Section that encompasses the desired quantity of gas. The particular Staged Parabola selected is the one whose area between 1992 and 2002 is the same as the production actually experienced over this decade. Usually six or seven trial iterations will be sufficient to choose the correct parabola. As in any iterative calculation of this type, it is important to approach the final value from both sides. A computer mathematics program is useful in solving one of the equations encountered in this calculation.

Horizontal Production Constraint Lines:

In all four cases, the maximum production is constrained to two levels: seven and eight Tcf per year respectively which are termed Plateau Peaks here.



The parabolic projection technique assumes that all the undiscovered resources are equally available which is far from the actual case though it is true the bulk of the remaining undiscovered resources are still in the Western Canada Sedimentary Basin. Resources in the Arctic, off the Newfoundland and Labrador Coasts, or at other remote locations, will prove difficult to connect to the pipeline system if they are ever connected at all. The delay in or even impossibility of making these connections will lead to a lower production than is predicted by the parabolic projection. The actual historical production record plotted in Figures 2 - 5 to 2002 already indicates a flattening tendency. The bottom-up time profiles employed in the National Energy Board supply/demand study for its two cases also show a flattening particularly when the non-conventional Coal Bed Methane is deducted from the plots.

The seven and eight Tcf per year production constraints were chosen taking regard of the trend of historical production and the NEB projections. These may be readily calculated using the parabolic technique employed here. For the case of a limit of seven Tcf per year, the intercepts with the parabolic curve may be determined by solving the quadratic equation of the parabola. The unproduced area above the seven Tcf line may be determined from the area formula for parabolas: $A = 2/3 (P - 7) \times t$, where P is the peak production predicted and t the difference in time between the two intercepts on each side of the parabola calculated from the solution of the quadratic calculation. This quantity is divided by seven in this example to calculate the length of time production is extended or prolonged at this level before the same decline curve as before sets in. The rectangle defined by the extension at 7 Tcf per year thus equals A. This calculation is repeated for production constrained at 8 Tcf per year in each of the four cases.

Figure 2/Case 1 - Canadian Gas Potential Committee Assessment:

With undiscovered remaining conventional resources of 207 Tcf at the end of 2002, the peak in unconstrained production of 8.1 Tcf occurs in 2014. With production constrained to 7 Tcf per year, the plateau peak is extended beyond the parabola boundary 2.6 years or to 2028.4. With production constrained to 8 Tcf per year, the plateau peak is extended 0.1 years to 2017.8.

Figure 3/Case 2 - Canadian Energy Research Institute Assessment:

With undiscovered remaining conventional resources of 421.6 Tcf at the end of 2002, the peak in unconstrained production of 9.6 Tcf occurs in 2024. With production constrained to 7 Tcf per year, the plateau peak is extended beyond the parabola boundary 11.4 years or to 2058.9. With production constrained to 8 Tcf per year, the plateau peak is extended 5.0 years to 2047.6.

Figure 4/Case 3 - National Energy Board `Supply Push' Scenario:

With undiscovered remaining conventional resources of 299.4 Tcf at the end of 2002, the peak in unconstrained production of 8.8 Tcf occurs in 2018. With production constrained to 7 Tcf per year, the plateau peak is extended beyond the parabola boundary 5.8 years or to 2041.2. With production constrained to 8 Tcf per year, the plateau peak is extended 1.5 years to 2031.1.

Figure 5/Case 4 - National Energy Board `Techno-Vert' Scenario:

With undiscovered remaining conventional resources of 327.4 Tcf at the end of 2002, the peak in unconstrained production of 9.0 Tcf occurs in 2020. With production constrained to 7 Tcf per year, the plateau peak is extended beyond the parabola boundary 7.0 years or to 2045.3. With production constrained to 8 Tcf per year, the plateau peak is extended 2.2 years to 2034.9.

Conclusion

On a common basis of comparison, the undiscovered assessments of remaining conventional natural gas in Canada covered a range from 207 for the Canadian Gas Potential Committee case to 422 Tcf used in a recent Canadian Energy Research Institute study, if the latter value is interpreted correctly in this paper. The two National Energy Board scenario cases are in between these assessments at 299 and 327 Tcf respectively.

Production was constrained to a maximum production of two Plateau Peaks at seven and eight Tcf/year respectively because of the low likelihood of the development of some of the identified natural gas resources in remote or difficult regions in the near future. These values used in the constraint scenarios are also supported by the `bottom-up' supply studies published by the NEB. Historical production trends over the past decade also suggest such a limit in this range is probable.

Applying a constraint on production leads to an extension of the Plateau Peak. For a peak production of 7 Tcf per year, the plateau peak is reached essentially now in all four cases, and the decline resumes in Case 1 in 2028, Case 2 in 2059, Case 3 in 2041, and Case 4 in 2045. The corresponding dates for reaching a plateau peak at 8 Tcf/year are 2010, 2006, 2007, and 2007 respectively. The decline resumes in 2018, 2048, 2031, and 2035 respectively.

It is unlikely that the rapid rise in supply of natural gas from Canadian conventional sources to the U.S. characteristic of the past decade can continue although it is possible the development of non-conventional sources of Coalbed Methane might allow about another one Tcf/year to be exported. Domestic demand is uncertain because of the possible needs for natural gas in the extraction and upgrading of the oil sands in Alberta and the degree to which new electrical generation will depend upon gas. High domestic demand from these two emerging consumption sectors could conceivable lead to a drop in exportable surplus of gas.

In conditions of low demand growth, the price of gas is unlikely to fall much below $4/1000 cubic feet on U.S. trading markets for any extended period of time with this floor price effectively set by the two next lowest cost sources of supply—non-conventional gas from Coalbed Methane and imported Liquefied Natural Gas. In periods of high demand, the prices may be much higher. Two conceptually different types of economic rent were identified in the paper.

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