Applying Economics to the Assessment – CERI's Gas Supply Model

Paul Mortensen, Director Natural Gas Supply
Canadian Energy Research Institute
Calgary, AB

ABSTRACT
At a time when concerns are increasingly focused on the availability of future gas supplies to sustain growing domestic and export markets, the amount of gas remaining to be produced at reasonable prices is of vital interest to the natural gas industry, regulators and policy-makers. Resource assessments by the Canadian Potential Gas Committee and the Geological Survey of Canada provide geological/statistical estimates of the total volume of recoverable gas by play throughout Canada. Although truly a major undertaking, the value of the geologic assessments is limited by the absence of information on how much of the potential is economic to produce. Until an estimate is made of the costs to produce the gas, the total volume of remaining potential is of limited relevance.

Other organizations have previously attached economics to resource assessments. One of the major previous undertaking in this field was the Alberta Energy Resources Conservation Board (now the Alberta Energy and Utilities Board) 1992 study of the Ultimate Potential and Supply of Natural Gas in Alberta. A similar effort was initiated by Natural Resources Canada to attach economics to the 1990 natural gas resource assessment by the Geological Survey of Canada. This effort fell victim to cutbacks within the department after completing three of the five strata groups for the Western Canada Sedimentary Basin.[1] The United States Geological Survey typically provides an economic component to its resource assessments.[2] Several organizations provide estimates of finding and development costs, but these refer only to established reserves and not to the remaining resource potential.

Taking up the challenge, the Canadian Energy Research Institute (CERI) began work in 1996 on the development of a modeling framework to assign development profiles and costs to pool size distributions for Alberta and British Columbia. CERI's Gas Supply Model is also used to project the rates at which development might occur and thereby provide a means of estimating future

[1] Devonian Gas Resources of the Western Canada Sedimentary Basin, GSC Bulletin 452, 1993., Triassic Gas Resources of the Western Canada Sedimentary Basin, Interior Plains, GSC Bulletin 483, 1994., Carboniferous and Permian Gas Resources of the Western Canada Sedimentary Basin, GSC Bulletin 515, 1997.
[2] Attanasi, Emil D., Economics and the 1995 National Assessment of United States Oil and Gas Resources, USGS Circular 1145, 1998.

deliverability, production and prices. This work was extended in 2000 to include the tracking and recovery of natural gas liquids.[3]

CERI examined 110 mature plays in Alberta and British Columbia. In accordance with the assessment developed by the Geological Survey of Canada, these plays incorporate an estimated 73,000 pools with over 17,000 pools already discovered. Reservoir parameters are assigned to the undiscovered pools on the basis of discovered pools of similar size within the same play. Economic analysis is performed on each of the pools in two distinct stages.

The first stage of the economic analysis reviews each pool using a standard tank model approach. Based on initial gas in place, recovery factors, production history where available, and reservoir temperature and pressure conditions, the tank model is used to identify the number of wells and compression power that will be required to exploit the pool. The tank model also predicts annual production from each pool. These factors, together with related capital and operating costs, are used to generate a profitability index for each pool.

This initial stage of the economic analysis ranks pools in order of profitability alone. For existing, producing pools, this analysis is limited to determining whether to add incremental wells, or incremental compression power. For existing pools not yet on production, the analysis is based on the presence of a discovery well, collecting all costs for development. Undiscovered pools are ranked on the same basis as unconnected pools, with the exploration process and related costs performed in a separate analysis as part of stage two.

Stage two of the economic analysis is used to determine the discovery and development timing of each pool. Natural gas directed expenditures are first estimated based on production and price data for both crude oil and natural gas. The available natural gas spending is then divided between exploration and development. Exploration funds are assigned to regions of the province based on an assumed risk profile. Within each supply region, success rates and exploration costs are combined to determine the number of successful new pool discoveries each year in each region.

Development expenditures are divided into two categories. The first priority in allocating development funds is to implement any development plans related to producing pools for which development has not yet been completed. The second category is funds available to develop pools that have not yet come on production. Within this second category, funds are allocated to pools based on the ranking established in stage one of the economic analysis.

With both stages of analysis completed for a given year, productive capability, or deliverability, can be estimated for each producing pool in the province.

---

[3] To be released in the forthcoming CERI study “Canadian Natural Gas Liquids: Market Outlook 2000 – 2010”.

Comparison of deliverability to projected demand provides a measure of market balance. If deliverability exceeds demand within a range typical of stable pricing, prices are assumed to remain constant. However, if deliverability is not sufficiently above projected demand, as in today's tight market, prices are adjusted upward. Similarly, if deliverability is significantly in excess of demand, such as in the "gas bubble" years of the early to mid 1990's, prices are adjusted downward.

Production is moved through a representation of the processing and pipeline infrastructure in Alberta and British Columbia. The provinces are divided into 70 regions to better reflect capacity constraints, infrastructure requirements and demand/export locations. The composition of the raw gas streams and recovery factor assumptions are used to determine the volume of natural gas liquids recovered at field plants. The composition of the field-processed gas is tracked through the pipeline system to the straddle plant locations.

Natural gas production, by-products production, and related prices are used to generate pre-tax revenues and pool-level capital and operating costs. Industry-level tax and royalty estimates are then applied to determine the net revenues available for reinvestment in exploration and development in the following year.

The presentation will include CERI's projection of natural gas production from Alberta and British Columbia over the 2000 to 2015 period. Production is provided on a regional basis consistent with the eight Petroleum Services Association of Canada (PSAC) regions in the two provinces.

As supply concerns take center stage and interest in frontier sources continues to rise, estimates of the size of the economically recoverable natural gas resource take on even greater relevance. Expectations regarding drilling requirements, expenditures and reinvestment, tax and royalty revenues, deliverability, production and, of course, prices are of vital importance to participants as they attempt to navigate the unsettled waters of today's North American natural gas market. A framework like the CERI Gas Supply Model is well suited to address these issues and serve as a valuable supplement to any resource assessment.