HOW CHANGING GAS SUPPLY COSTS LEADS TO SURGING PRODUCTION:

a Ziff Energy White Paper

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ABSTRACT

Increased Shale Gas production has potential to dampen gas prices in North America. This paper presents a predictive gas production model using assessments of new gas well initial productivity, decline rates, and forecasts of connected wells through an assessment of the basin's maturity and cost. Methodology of full cycle gas cost assessment includes the analysis of operational expenditure, finding and development (F&D) costs, royalties, taxes, overhead, and producer's return for different basins. The gas fundamentals of supply and demand are related through gas prices, which are forecast based on analysis of supply and demand in a pendulum, non-equilibrium model.

The research paper includes analysis of full cycle gas cost in 2009 for two dozen different North America gas basins. Since well's expected ultimate recovery is growing, F&D cost in Shale and Tight Gas basins is reducing thereby helping the overall production economics. The analysis demonstrates that reduction of cost and increasing productivity enable producers to explore and develop even further. To showcase the overall results, a case study analysis of a U.S. Rockies basin full cycle gas cost and supply is presented. The analysis demonstrates that new production coming from Tight and Shale Gas basins would have a significant impact on overall gas supply. Particularly the Western Region would continue playing a significant role in North American gas supply.

INTRODUCTION

Purpose

Enhancements in drilling and completion technology, together with rising gas prices (to 2008) have made Shale Gas wells commercial leading to surging gas production growth, a surplus of supply over demand, and 'low' gas prices. This paper presents natural production and cost models, which are used to analyze the contribution one U.S. Rockies basin will make to North American gas supply, and, hence gas long-term natural gas prices.

Objectives and Scope

This paper's objectives are to:

- describe the production and cost models used
- identify factors affecting the model inputs in the near term and the limitations of knowledge in the long run
- show how the models interrelate and how they may be applied to assess the impact of gas supply on gas prices
- present comparative analysis of full cycle gas costs in 2009 and the impact of technology advances
- highlight how results differ from previous results and the limitations of knowledge.

METHOD

Two main spreadsheet models, with analyses of controlling factors, are used together to forecast gas production at the Basin or Play level:

- Production Analysis Model
- Cost Analysis Model.

Production Analysis

Production history is extracted from commercial and public databases to populate the predictive gas production model. Analyses of initial gas well productivity, decline rates of new and existing wells, and annual wells connected, and forecasts of these parameters are used to generate the gas production outlook for a specific gas basin or play. Figure 1 illustrates the parameters used to determine the gas production outlook and calculate the Expected Ultimate Recovery (EUR) per well for each natural gas basin or play:

- number of gas wells connected each year
- new well productivity (IP)
- gas well decline rates.

Figure 1
Gas Production Analysis and Forecast
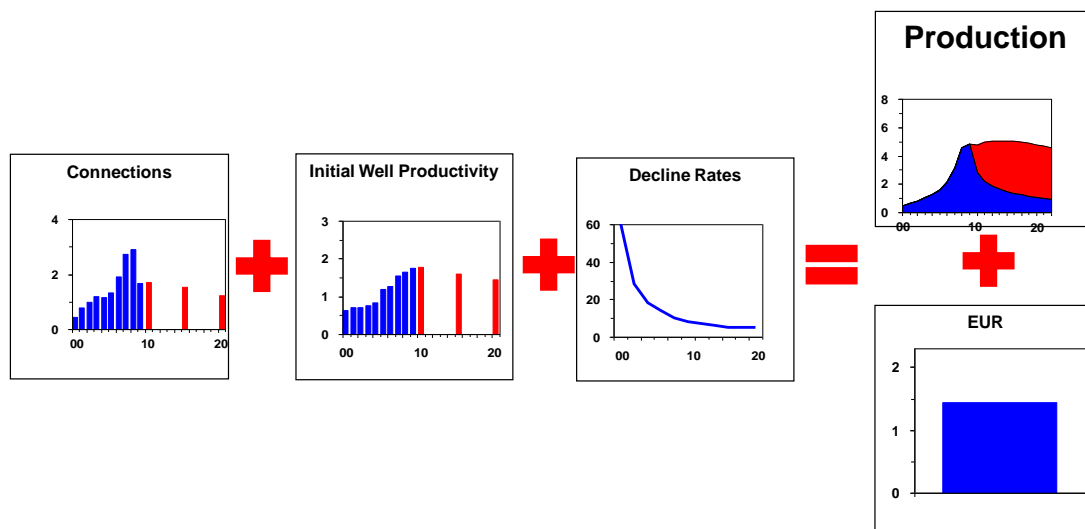
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Fundamental factors influencing model parameters include:

- gas prices – assumed to increase so that the average producer is able to recover full-cycle costs, including cost of capital. Those producers do not recover their full

cycle costs will reduce drilling or exit high cost basins and plays, decreasing gas supply. Higher prices translate to greater cash flow and increased development

- lower costs relative to gas prices increase producer cash flow leading to more drilling, and higher supply, as does revenue from Natural Gas Liquids

- game changing technology advancements in drilling and completions led to rapidly increasing Unconventional Gas production

- learning, knowledge transfer, and best operating practices have also helped reduce full cycle costs

- basin/play maturity impacts production: in immature plays, initial gas well productivity (IP) and Expected Ultimate Recovery (EUR) tend to increase as the play develops, resulting in lower costs. Mature plays have increasing gas well densities, leaving fewer opportunities for new drilling; the new wells have falling IPs and EURs and rising costs as most of the better locations have been drilled

- limited infrastructure and services (for example, pipeline access, frac equipment, water, or people restrictions) lead to lower production. This is modelled by delaying drilling and completions until this can be corrected

- Government policies tend to reduce gas supply by restricting access[1] and increase regulation. Environmental concerns over fraccing, and pollution have prompted regulatory reviews and investigations, which delay or restrict oil and gas development.

Thus, the number of gas wells connected each year is based on the economic attractiveness of the basin or play, maturity (gas well density, remaining Drill Spacing Units (DSUs), reserves and remaining resource potential), and infrastructure restrictions. Since the EUR of wells is growing, Finding and Development costs in Shale and Tight Gas basins are falling, thereby boosting production economics.

New gas well IPs and EURs are projected from recent trends, considering basin or play maturity, number of wells drilled rates (more wells leads to less high-grading), and potential for technology enhancements.

Gas well decline rates are estimated from recent trends, or calculated for a type well model using IP, EUR, and an appropriate decline model. The decline rates are applied to new wells and to existing wells with consideration to the age of the well. Gas well decline rates are expected to increase as plays and basins mature. Shale Gas and Tight Gas decline rates are higher than conventional gas and CBM plays.

The production model generates a raw gas production forecast (in most cases, the public production databases record raw gas production), which is converted to sales gas using shrinkage factors calculated from public sources and previous analyzes.

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[1] for the most part, these policies favour upward gas price movements and could include carbon emissions legislation, drilling moratoriums, and higher costs

Short-term factors driving high rig counts – the fundamental factors listed above fail to fully explain the high drilling rig counts in a low gas price environment. Figure 2 illustrates the short-term gas drilling influences that enable the producers to continue drilling even in low gas prices environment:

- HBP - "Hold By Production" is the need for leases to be validated by oil or gas production before the primary term expires

- NGLs - Natural Gas Liquids prices more closely reflect the price of oil than dry gas, thus NGLs provide a significant economic advantage

- Reserves – executives are creating 'once-in-a-lifetime' Energy Companies by assembling acreage and adding trillions of cubic feet of reserves and resource

- Capital Access – early Shale Gas field development requires capital expenditures in excess of normal cash flow from operations. Access to equity, debt, buyers of non-core assets, and government incentive programs are important to fund drilling

- Hedging – some producers have locked in future natural gas prices that allow adequate cash flow for drilling and providing additional rig deployment

- Joint Ventures – investments from partners assist operators in developing shale fields in the short term by lowering the operators full cycle costs

- natural gas prices and full cycle gas costs will continue to play a major role in the number of drilling rigs deployed long term as there are tens of thousands of available drilling locations in Shale and Tight Gas basins.

Figure 2
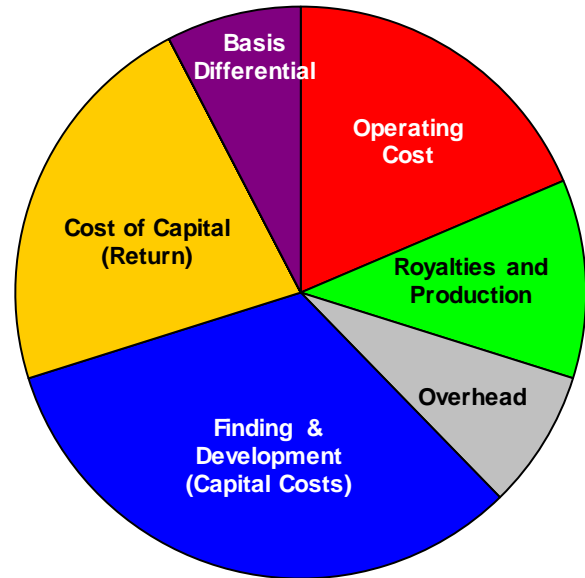**Short to Long Term Gas Production Drivers**
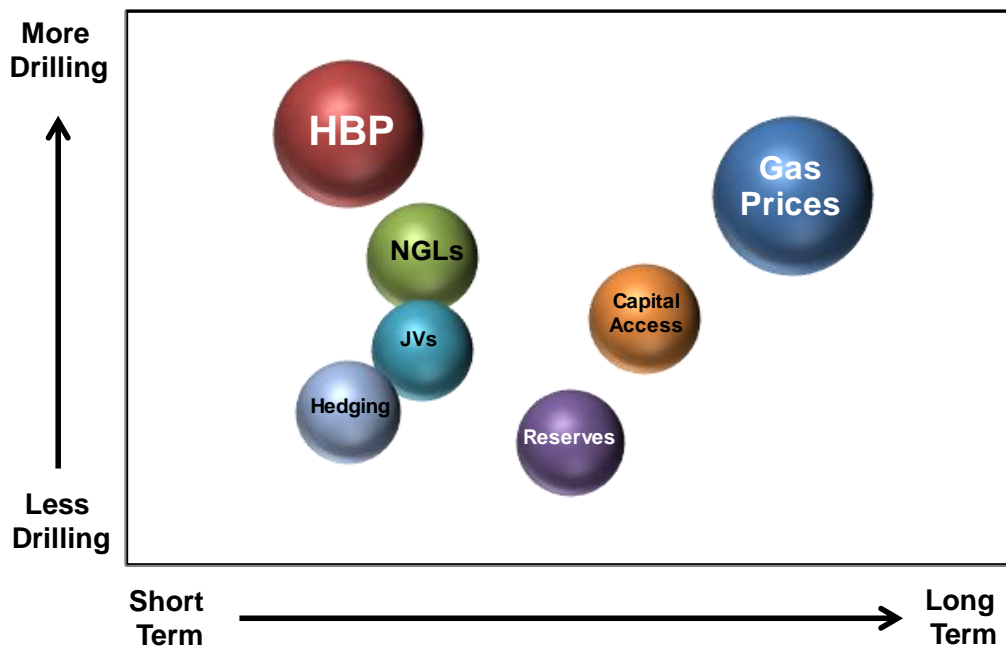
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Cost Analysis

The cost assessment model uses standardized definitions of costs, calculated on a unit (Mcf) basis, for each basin and gas type analysed to create an 'apples to apples' comparison of natural gas supply costs throughout North America. Figure 3 presents the gas cost categories used in this analysis:

- ***Basis Differential[2]*** – to compare gas supply costs of different basins, the gas basis differential must be added to the costs to provide a common reference point

- ***Operating Cost*** (lifting cost) includes Lease Operating Expense, Gathering & Transportation cost, and field processing fees

- ***Royalties and Production Taxes*** there are a variety of royalty regimes collected for freehold, State, Provincial, and Federal lands. Severance taxes are imposed by each U.S. State on production; no severance taxes are imposed on Federal leases. Ad Valorem taxes (a property tax) are imposed by each county on the value of the asset. Production taxes typically range from 4% to 15%. Consequently, the total royalty and production tax varies greatly within and between basins. Overall, most plays attract a combined royalty and tax rate of 20-25%

**Figure 3
Full Cycle Gas Cost Components**

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- ***Overhead*** includes all general and administrative expenditures (head office) expenditures relating to the upstream oil and gas industry, regardless of whether expensed or capitalized

- ***Finding & Development*** (F&D) costs (capital costs) are calculated by dividing all capital costs by the EUR found by incurring those costs. The EURs are not based on Securities and Exchange Commission standards, rather they are companies' estimates of ultimate recoverable resource, including royalty volumes. For gas plays, costs were increased by 2-8% for dry and abandoned holes and 8-15% for economic dry holes (wells abandoned with less than one year of production)

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[2] the gas basis differential is the gas price at Henry Hub minus the gas basin price

- *Cost of Capital* – capital (F&D) costs make no allowance for the time value of future production; investment is recovered from production revenue over the life of the well. Cost of Capital is calculated using a 15% return on investment (capital costs) before income tax[3] to account for the opportunity cost of the investment. Actual producer returns will fluctuate depending on energy prices and changing costs.

Cost data are not as readily available as production data, however, systematic review and collection allows information to be leveraged from these sources:

- from proprietary drilling, operating and F&D cost databases

- public data from corporate presentations, press releases, and Annual Reports

- key regional producer interviews.

Where only partial cost data is available, typical values of other cost components for that area may be used to calculate the full cycle cost. Press releases and similar sources should be used with caution – the data presented are often for the best wells, and may not be representative of typical wells (or even close to the average for a play/basin). Costs may be calculated by basin, gas type, or play; for example:

- Green River basin, Piceance, & Western Canada Sedimentary Basin

- Unconventional Gas – Shale Gas, Tight Gas, & Coalbed Methane

- Conventional Onshore Gas & Offshore Gas

- LNG & Northern gas

- Mesaverde, Williams Fork, Marcellus, & Horn River.

These costs, relative to each other source, together with an understanding with the play or basin maturity, allow the analyst to identify which basin or play will see greater development and, hence, higher production.

Once the cost data set has been started, it can be expanded to including costs over time and new plays. Other cost analyses – drill only cost (ignores sunk costs), carried interest in a joint venture (reduces the original producer's costs) can provide insight into producers' behaviours and the resulting production.

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[3] about 10-12% return after taxes, the approximate long term cost of capital.
For each cost data set, the model generates a production profile for the EUR used to calculate F&D cost. This is used to calculate the discounted cash flows (using a constant netback) and the cost of capital invested in $/Mcf

RESULTS

Since 2007, enhancements in horizontal drilling, multistage hydraulic fracturing, micro seismic, and other technology innovations have led to a surge of gas production, negating the need for the much anticipated Liquefied Natural Gas import boom.

Green River Gas Production

The analysis methods described above have been applied to many basins, gas types and plays. To showcase the results, a case study analysis of the Green River basin in the U.S. Rockies is presented:

- main production growth driver in the Green River basin has been development (infill drilling and down-spacing) of the Jonah and Pinedale Anticline fields
- other fields have contributed to the growth, though at lower volumes
- analysis of well spacing indicates that:
  - o Jonah has limited opportunity for growth; new wells will slow declines
  - o Pinedale production can continue to expand, however, will peak this decade.

Figure 4 shows Green River Basin model inputs and expected gas production outlook to 2020. Green River gas production will grow to 5 Bcf/d by 2015.

Figure 4
Green River Basin Model Inputs and Production Outlook

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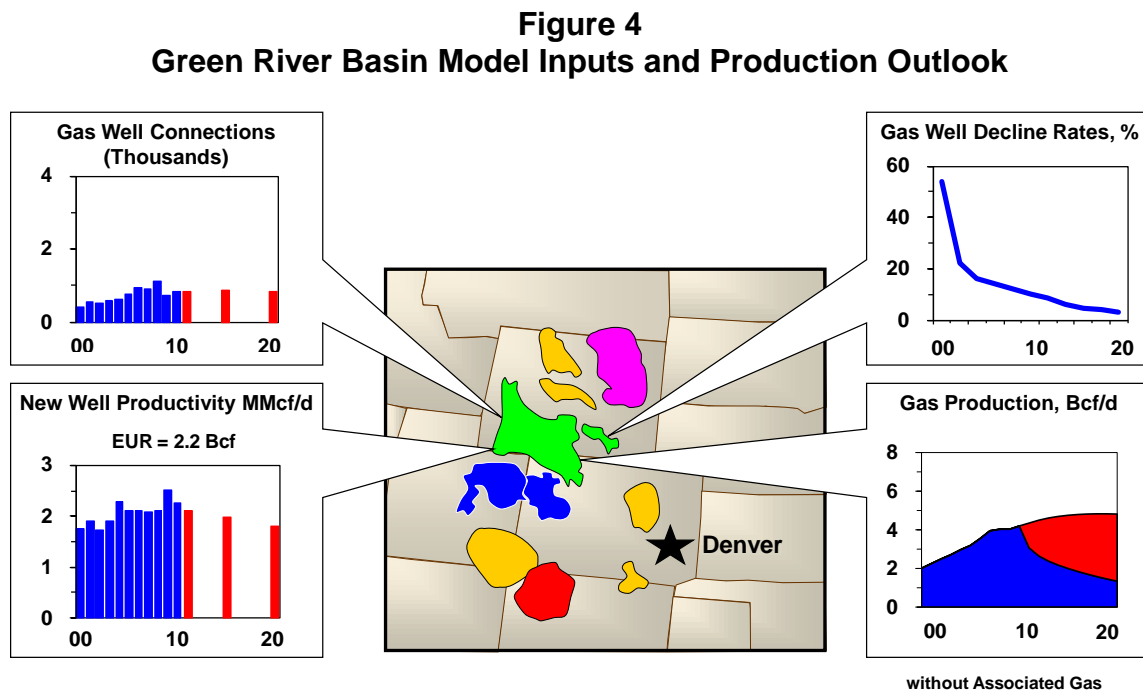
Analysis of the short term factors described above helps to explain why the drilling rig count has not fallen in this 'low' gas price environment. Long term leases need to be validated by production; hedging programs, financing through joint ventures, high liquid content in some plays, and government incentive programs enable producers to continue drilling.

Gas Supply Costs, 2009

A comparative analysis of full cycle gas costs using late 2009 data[4] was carried out for two dozen significant North America gas basins. The average full cycle cost is US$5.60/Mcf, ranging[5] from US$4.15/Mcf to US$7.35/Mcf. Within a gas basin, the full cycle costs of new gas range more broadly. Figure 5 presents another way of viewing natural gas economics by considering the analogy of an iceberg:

- the 'cash' costs are seen above water (operating costs, transportation and basis differential, royalty production taxes)

- hidden costs include:
  o Finding & Development cost – seismic land, drilling, casing, & completions
  o Overhead
  o Cost of Capital (most important, provides a Rate of Return for shareholders)

- from this perspective, on an average full cycle basis, producers were not returning their cost of capital at a gas price of US$4/Mcf.

**Figure 5
Sinking Gas Fortunes @$4/Mcf Price**

Source: 2010 Ziff Energy North American Gas Basin Study
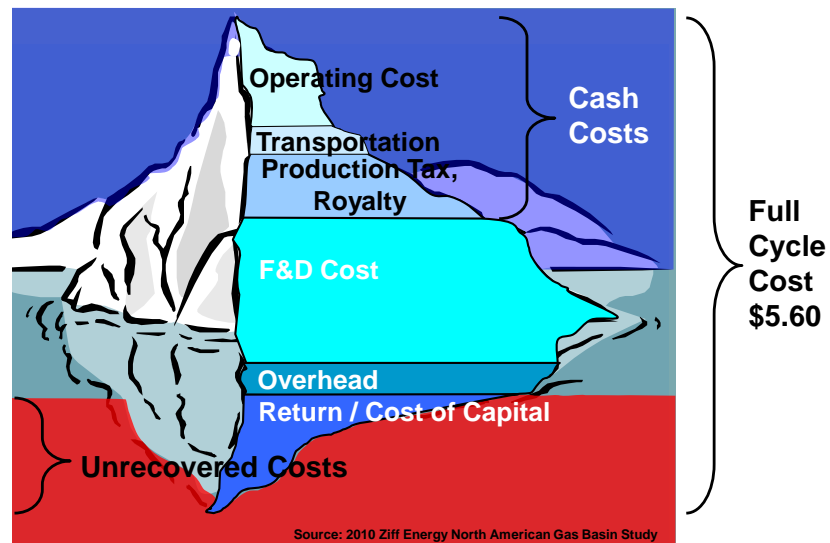
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[4] representing a low cost environment relative to the high inflation that existed during the first assessment using late 2007 data
[5] these values reflect the average of the sample points for each basin/gas type, excluding, LNG and Northern Gas

Figure 6 provides the cumulative new 'cash' (red curve) and full cycle (blue curve) gas supply costs referenced to Henry Hub, using late 2009 data and estimates of new gas production additions; U.S. Rockies costs for Tight Gas are shown by blue arrows. The 2007 full cycle gas supply cost (green curve) is provided to demonstrate how costs have fallen from the high inflation high cost environment of 2007; results are ordered, left to right from low to high cost. This chart provides an answer to the question of how much new gas can be added and at what cost. Observations:

- 2009 simple average gas cost[6] was US$5.60/Mcf, 19% lower than 2007

- costs are lower due mainly to lower F&D cost, Royalties and Production Taxes

- each basin has its own cost curve and limits to the gas volume which can be added without increasing costs due to prospect inventory, rig, service, supply, and personnel limitations

- in 2009, the Green River Tight Gas average full cycle cost was US$4.90/Mcf[7], lower than average, led by low Pinedale Anticline costs

- other U.S. Rockies basins have higher than average costs

- when basin production is compared with full cycle costs, those basins with low costs, generally, have growing production.

Figure 6
New Gas Supply Cost, 2009 vs. 2007
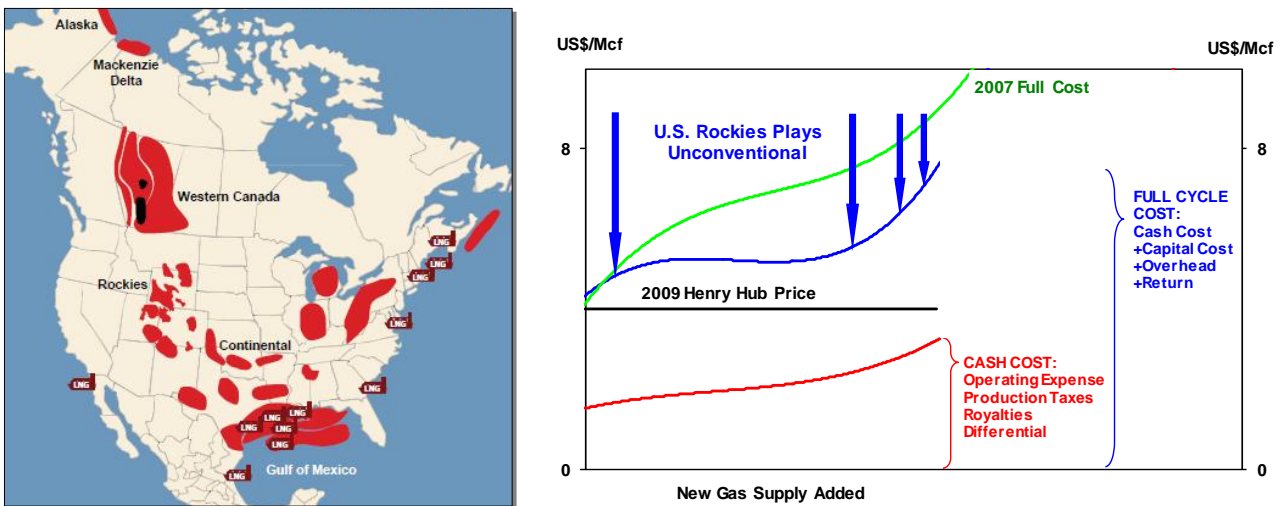
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[6] excludes LNG, Alaska, and Mackenzie Delta
[7] referenced to Henry Hub

CONCLUSIONS

Several conclusions were made from the gas production and full cycle cost analyses:

- systematic analysis of production and cost drivers allows for greater accuracy in forecasting production

- new, low cost Shale Gas production will continue to have a significant impact on overall North American gas supply

- in the Western U.S., low cost Tight Gas production from the Green River basin will continue to grow over this decade

- production in other U.S. Rockies basins will plateau or decline due to higher than average full cycle supply costs

- unit cost reduction and increasing productivity enable producers to explore and develop even further

- changing technology has contributed to lower full cycle gas cost

- lower gas prices cut Royalty and Production Taxes in half from 2007

- short term factors are driving current drilling and growing production

- activity is high in NGL/condensate rich parts of basins/plays

- strong recovery in horizontal rig activity since 2008 is growing U.S. gas production.

BROADER APPLICATION

The Production and Cost Models may be extended to each gas producing basin or to individual plays, such as the Haynesville or the Marcellus Shale to generate natural gas production forecasts. These forecasts may be aggregated to provide a regional or total North America outlook for production. Such models can generate sensitivities or be used to evaluate scenarios by varying the input parameters (while staying within the limits provided by the evaluation of the contributing factors) giving the modeller insight into the reasonableness of the forecast. Figure 7 shows the aggregation of over 20 production models to provide a natural gas supply forecast by gas type. Observations of modeling results by gas type:

- forecasts total North America sales gas supply to grow to over 80 Bcf/d
- conventional gas declines primarily due to traditional play maturity and high full cycle costs − Unconventional Gas grows to 64% of the supply mix in 2025
- as relatively low cost Shale Gas plays develop, strong growth of the last 5 years continues beyond 2020 then slows with maturity
- developing Tight Gas plays partially offset declines in the maturing U.S. Rockies
- Coalbed Methane (CBM), is mature; declines due to high maturity and costs
- Northern Gas or LNG may be required to balance supply with demand.

Figure 7
Growing Unconventional Gas
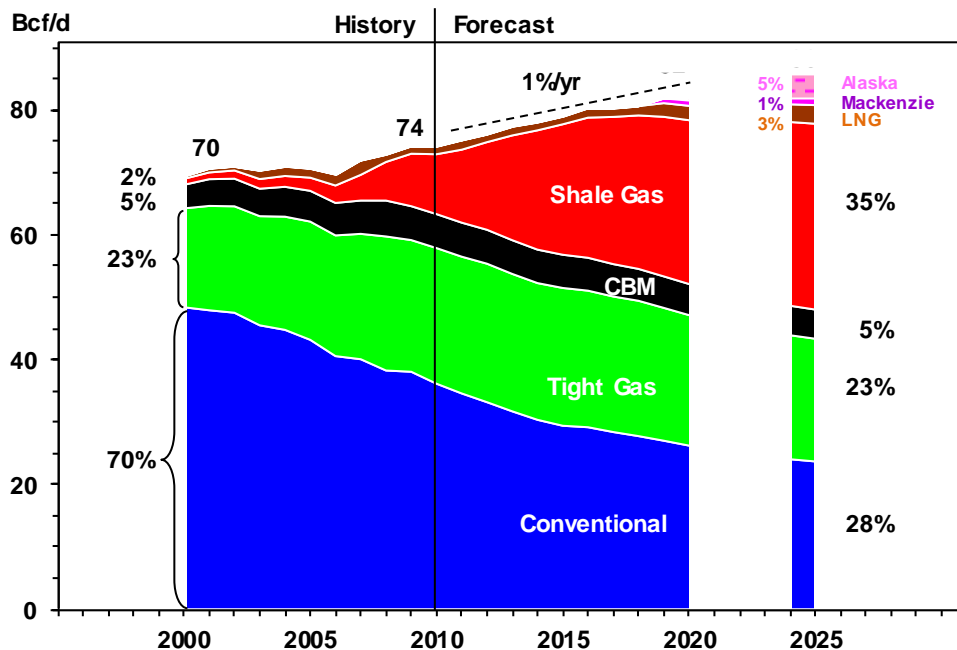
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In the future, the models could incorporate probabilistic methods, relating dependent variables. When summed using these methods, such models would likely provide a more accurate forecast than summing deterministic outlook.
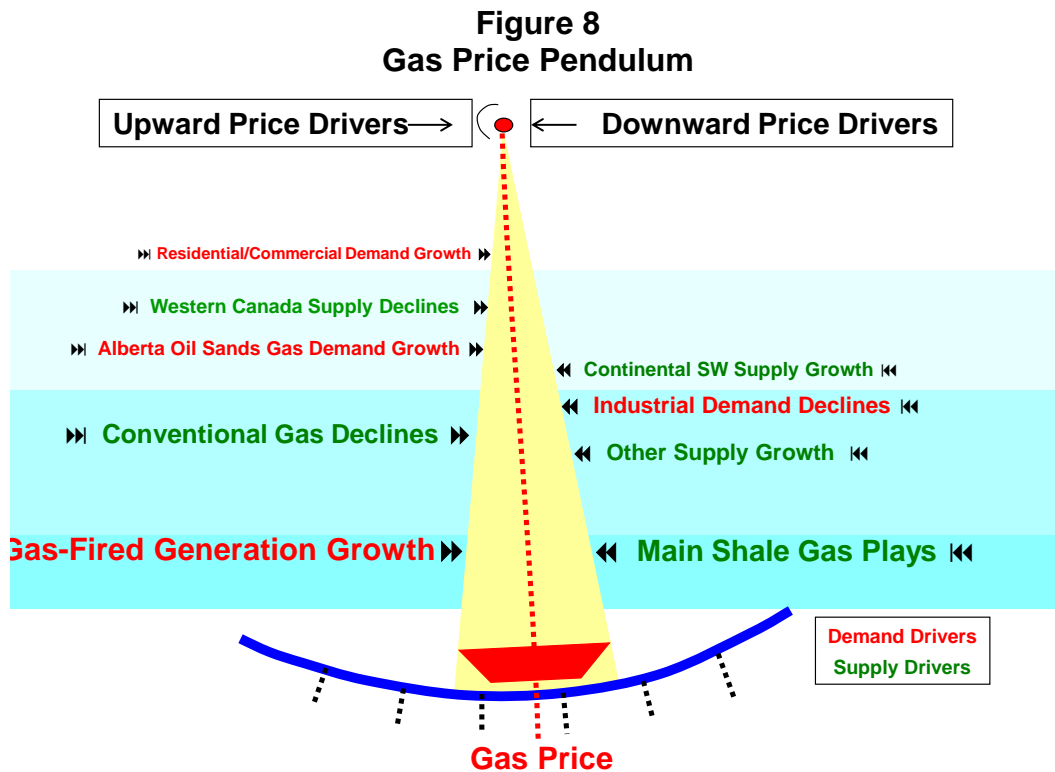
Gas Price Impact

Surging North America gas supply has had a major impact on natural gas prices. When will (or if) we see a return to 'normal' gas prices?

The North American gas market is comprised of a large numbers of competing buyers and sellers with a multitude of purchase and sale instruments. Energy pricing is transparent and facilitated via electronic trading systems, a vigorous futures market, and various financial instruments. The North American gas supply system is characterized by a sophisticated network of transmission and storage infrastructure. Gas buyers will continue to be incented to minimize delivered gas costs in a functioning North American natural gas market. Supply will preferentially flow to the markets providing highest netbacks. New North American gas supplies, principally from Shale Gas are expected to more than offset declines in conventional gas and alter continent wide gas flows.

The model considers both gas supply drivers (increase or decrease gas supply) and gas demand drivers (increase or decrease gas demand) in the assessment of natural gas prices. Some price drivers can have both a supply and a demand influence. Additionally, the model considers over a dozen primary supply and demand price drivers that influence natural gas prices. The factor that exerts the most upward influence on gas prices over this decade is the North American shift for incremental power generation to be fuelled by natural gas.

Figure 8 shows the impact long term major supply and demand price drivers have along with their directional influence on the forecast gas price. The size of the font used for each driver reflects its relative influence on the gas price; the larger font has more impact.

Figure 8
Gas Price Pendulum

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A CAUTIONARY TALE

As simple as a cookie recipe huh?

Maybe not.

It is worthwhile revisiting some recent gas supply projects in Canada:

- for example, the Ladyfern and Ft. Liard and other North of 60 gas fields were developed in the early part of this decade. Producers and analysts were optimistic about the growing gas supply from these fields to over 1 Bcf/d each. Instead, production fell 90 to 95% within 4 to 6 years

- on the Canadian East Coast, the Sable Island natural gas project began production in 1999 with expectations of producing over 1 Bcf/d, and some analysts even projecting 2 Bcf/d from the basin. Production peaked at just under 0.6 Bcf/d

- similarly, expectations of CBM growth in Western Canada have been scaled back from 2-3 Bcf/d to less than 1 Bcf/d.

Figure 9 illustrates the rapid decline in North of 60 and Ladyfern gas production.

Figure 9
A Cautionary Tale
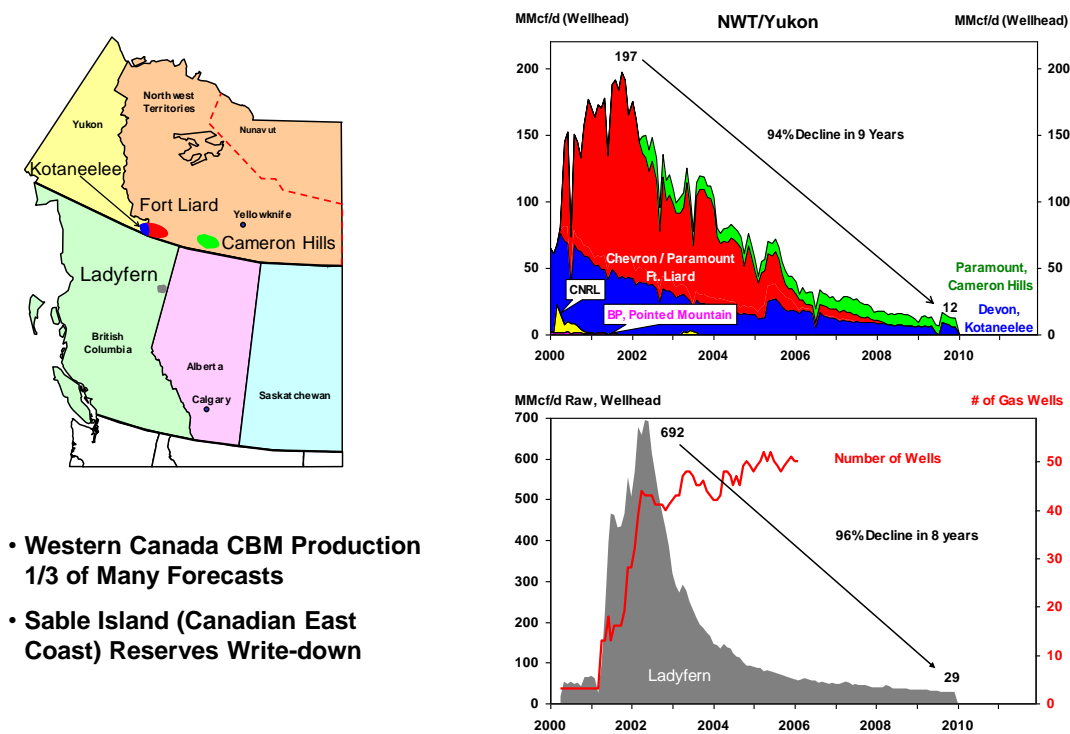
- **Western Canada CBM Production 1/3 of Many Forecasts**

- **Sable Island (Canadian East Coast) Reserves Write-down**

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