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Growing Shale Resources: Understanding Implications for North American Natural Gas Prices

Prepared for the State of Alaska

November 2010

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1.0 EXECUTIVE SUMMARY

1.1 Statement of Study Purpose

Black & Veatch's Management Consulting Division (Black & Veatch) was engaged by the State of Alaska (the State) to provide an assessment of the long-term natural gas prices in North America during the period 2011-2044. Particular focus placed was on drivers of price uncertainty at the Henry Hub in Louisiana and the AECO (NIT) hub in Alberta, Canada. In addition, the report presents price levels at the regional markets of Malin, Chicago and New York. This study is intended to clarify the nature and extent of future price uncertainty, especially as it is influenced by the availability of and the costs associated with shale gas supply. The impact of the uncertainty in key demand variables, such as gas demand for power generation, was also assessed.

1.2 Summary of Long Term Price Expectation

Natural gas prices at Henry Hub are projected to rise to at least $6.00/MMBtu (real 2010$), on average, by 2015. The projected range of future prices for natural gas in North America by 2020 ranges from $6.00/MMBtu to $8.00/MMBtu (real 2010$), driven by forecasted increases in key shale gas supply cost drivers, as well as uncertainty regarding greenhouse gas emissions policy and the growth in demand for gas-fired power generation.

Natural gas prices in Canada at AECO (NIT) by 2020 are expected to range between $5.00/MMBtu to $6.20/MMBtu (real 2010$), on average, given reasonable potential ranges of key shale gas supply and power-generation demand fundamentals.

1.3 Summary of Key Drivers of Long Term Price Expectations Considered in Study

<u>Recoverable Resources.</u> Industry estimates of North American technically recoverable shale gas resources vary widely by basin and source of estimate. In all cases, the expectations for North American shale based natural gas production and associated resources is substantial. That is, a substantial part of the shale gas technically recoverable resource is also economically recoverable. In the three scenarios considered in this study, shale gas production varied from 15.4 Bcf/d to 28.3 Bcf/d in 2020, or 22% to 49% of total US demand.

<u>Current Finding and Development Costs</u>. Finding and development costs are critical to the question of the impact of shale gas on current and future prices, as they anchor which technically recoverable resources will be economically produced.

> Current market prices for natural gas in North America may not provide adequate return for full development of shale resources in North America. Significant levels of current shale production appear to be driven by requirements to drill to maintain acreage positions. This suggests that current supply may not currently be in normal market equilibrium.
>
> Similar to shale resource estimates, current reported finding and development costs for the development of shale gas vary widely by basin, due in part to geological and geographical factors.
>
> Finding and development costs also vary widely by producer. Publically reported costs often exclude specific items, thereby understating the actual finding and development (F&D) costs. Because some producers dominate publicly available cost reporting on particular basins, basin variation in F&D costs may also be affected by differences in company reporting practice.

<u>Evolution of Finding and Development Costs with Cumulative Production</u>. Given the study's focus on understanding long term natural gas prices in North America, the degree to which shale gas costs can be

expected to rise as a given play's "sweet spots" are exhausted is of critical importance. Except for the Barnett, cumulative production from any given basin is too small to indicate the evolution of future costs. That said, the Barnett's history is indicative and it suggests that costs will rise as a given shale resource is exploited.

Water Acquisition and Treating Costs for Hydrofracturing Shale Gas Wells. Water requirements for shale gas production are significant. Future costs of obtaining, and then treating or disposing of such water once it is produced, are both material and uncertain. Shale resource developments in non-traditional production basins are expected to increase and have potential to materially impact the availability and costs of shale gas production.

Land Use Restrictions. Land use restrictions would effectively reduce the technically recoverable resource base from which economically recoverable resources might be produced. To date, land use restrictions, and the indirect restrictions of some possible environmental regulations, have not yet created major obstacles in the development of shale gas resources. However, in selected basins, there is potential for restrictions to materially reduce shale resource availability and this study considers the impacts on North American natural gas prices should land use restrictions occur in selected regions.

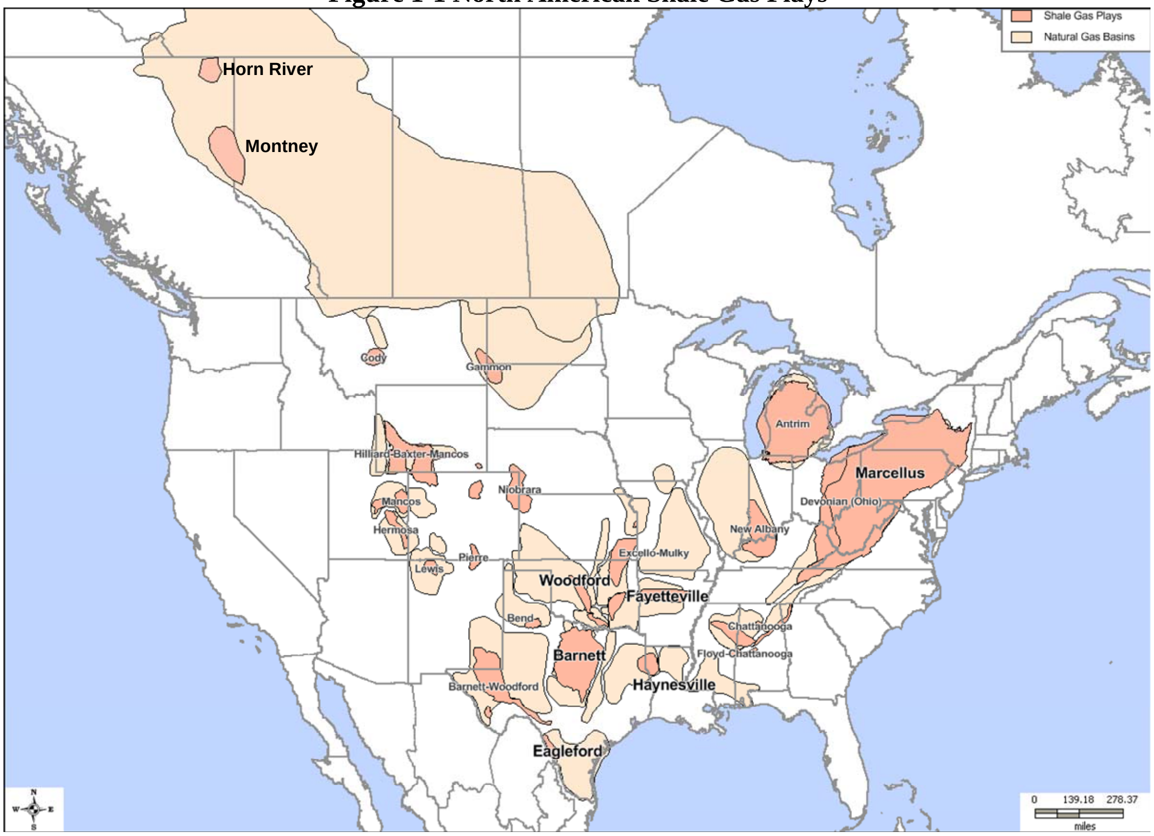
Fiscal Policy. As shale gas production assumes greater importance, it may be viewed by some governments as a potential source of additional revenue. Increases in production taxes could impose additional cost on development. Recent initiatives to introduce severance taxes, such as in Pennsylvania, could increase the cost of affected shale resources. This study considers the implications should selected states adopt more aggressive fiscal policies.

Climate Policy. The current North American gas market is undergoing significant transition due to changing natural gas supply resource expectations and environmental concerns in the electric generation sector that creates demand for cleaner burning fuels such as natural gas. The changing electric generation landscape and potential for greenhouse gas emission restrictions, or taxes, will likely create significant additional demand for natural gas and hence have substantial impact to North American natural gas prices in the coming decades. Such effects can be expected even absent a legislatively-mandated explicit or implicit price on carbon emissions, as utilities and merchant generators make technology decisions on what generating capacity to install in anticipation of the possibility of such mandates.

1.4 Summary of Supply Findings

The technological advances in extracting natural gas from shale rock over the last decade have made a hitherto expensive, but abundant, resource economically available to the North American market. While the technological advances to date have been important, significant uncertainties remain as to the extent of future production of natural gas from shale plays. Figure 1-1 shows a map of North American shale-gas plays.

Figure 1-1 North American Shale Gas Plays



Source: Energy Velocity, B&V Analysis

- This study found that the costs of using water for hydrofracturing shale rock and treating water once it is produced with the shale gas are both potentially material and uncertain. Future costs will depend significantly on costs of wastewater disposal or treatment relative to the productivity of an average shale-gas well in a given play. Using information on water requirements associated with the relatively mature Barnett Shale play, supplemented by cost information available on newer shale plays, this study found that for a shale-gas well with an expected ultimate recovery (EUR) of 3.5 billion cubic feet (Bcf), the incremental cost of water (downhole and uphole combined) is approximately \$0.25 per thousand cubic feet (\$0.25/Mcf); with the potential under unfavorable but credible circumstances water costs could be as high as \$1.38/Mcf.

- Resource estimates associated with shale gas from different industry sources are very wide and reflect the relatively early stages of shale gas development in North America. Uncertainty in the technically recoverable resource base has implications for the natural gas found, developed and produced and resulting price levels in the North American market. Recent shale resource estimates range from 200 Tcf to almost 700 Tcf for the Marcellus, Haynesville, Barnett, Fayetteville and Woodford shale plays in the United States. The recoverable-resource numbers used in this study were near the middle ranges of the available estimates.

- Finding and development (F&D) costs are meant to describe the costs of acquiring and producing hydrocarbons and do not include the costs of subsequent transportation and marketing, nor required return on capital employed. Industry-reported F&D costs for shale resources showed substantial variation and, in general, lacked transparency. This study's company-specific and basin-specific research on F&D costs in emerging shale basins found that finding and development costs for shale plays varied according to time period, location and reporting producers. When normalized, the range of average F&D costs across the different shale plays and producers has ranged in recent years from $2.12/Mcf to $3.11/Mcf.

- Until now land use access restrictions have not directly impacted shale gas development in North America. That said, current drilling permit restrictions, enacted primarily in response to environmental concerns, have acted as de facto land use access restrictions in some regions of North America. Given policy trends among geographic regions, it is possible that 10% or more of shale-gas resources might become unavailable through land-use policy changes.

- While regions with an established history of oil and gas production such as Texas and Louisiana were found to have long-standing and relatively unchanging fiscal structures, states with more recent significance related to shale gas production, especially Pennsylvania, demonstrate greater uncertainty in their potential fiscal structures during the study period. It is anticipated that over the study period, these states will evolve towards imposing severance taxes on natural gas production comparable to current levels at other oil and gas producing states, thereby creating additional costs related to shale gas production.

The combination of these uncertainties related to shale gas development result in potentially large variations in the costs, and indirectly in the volumes of natural gas that can be expected to be produced from North American shale gas. This study estimates that the total natural gas production from shale plays may range from 15.5 Bcf/d to 17.0 Bcf/d in 2015 and from 15.4 Bcf/d to 28.3 Bcf/d in 2020 depending on the realized outcomes of the listed uncertainties such as resource availability, F&D costs, natural gas demand and LNG imports. Accordingly, shale gas volumes under all circumstances are expected to substantially grow from current production levels of approximately 11 Bcf/d.

1.5 Summary of Demand Findings

Future natural gas demand for the power sector will substantially affect overall gas demand levels in North America. Gas needs for power generation will be driven by the relative cost of fuel and installed plant, as well as the real or expected costs of complying with restrictions on emissions of greenhouse gases. This study relied on Black and Veatch's independently-developed assessments of natural gas demand for the electricity sector, used to assist Black and Veatch's clients in the power construction and other sectors. Those assessments are importantly driven by expectations of future greenhouse gas emission restrictions.

Whether in the form of legislative or EPA-driven mandate or voluntary company specific strategy, Black & Veatch expects a widespread and systemic drive to limit greenhouse gas emissions from the power sector. This will, in turn, lead to significant demand growth for natural gas from the electric industry. This is expected to occur in tandem with efficiency gains, renewables growth, and nuclear power plant construction. New coal plants are not expected to be built on a significant scale, in part because carbon capture/storage technology is not anticipated to be a cost effective alternative on a large, commercial scale over the 2010 to 2035 period. Older and less efficient coal plants are expected to be retired with natural gas-fired generation and renewables filling most of the need for this lost capacity. These market expectations generate a growth rate for natural gas demand from the power industry of 2.3% per annum between 2010 and 2035 with a consumption of 26.5 Bcf/d of natural gas for power generation by 2020 and 32.8 Bcf/d of natural gas by 2035 in the Lower 48 United States.

If current market conditions and expected mandates for imposing limits for greenhouse gas limitations shift back to the environment observed in the mid 2000's, coal fired generation would be expected to capture a much larger share of the generation fuel mix either in the form of new plant construction or in continued operations of existing, older, coal fired units. The implication for this market shift is that the consumption of natural gas for power generation will be approximately 50% of Black & Veatch's current expectation with 13.3 Bcf/d of natural gas for power generation by 2020 and 16.4 Bcf/d of natural gas by 2035 in the United States.

This wide range of demand for natural gas driven by power generation demand contributes to significant uncertainty in natural gas prices in North America during the study period.

1.6 Summary of Price Findings

The study summarized the key supply and demand uncertainties considered within the three following scenarios.

Mid-Price Scenario: Shale Supply Growth with Growing Demand from Power Generation

Supply: In this scenario, shale production costs rise following the historically trajectory observed at the Barnett Shale as producers move away from current basin sweet spots to less productive areas. Current fiscal regimes in traditional producing areas such as Louisiana, Texas, Alberta and British Columbia are assumed to continue with new "middle of the road" severance taxes imposed in Pennsylvania and New York. Water use costs are assumed to be higher than the current Barnett shale experience. For the portion of Marcellus in New York state, water costs average $0.70/Mcf of gas produced; for all other shale plays water costs were $0.25/Mcf.

Demand: In part because shale gas remains relatively inexpensive, the expectation of moderate gas prices helps facilitate policy and company-driven initiatives to reduce greenhouse gas emissions. The demand assumptions in this scenario reflect an expectation of constraints or costs associated with greenhouse gas emissions. The resulting higher emissions costs, or prohibition of higher emissions, provide natural gas-fired generation an advantage over existing and new coal generation. Renewables and nuclear generation will also have a significant role in new power generation capacity.

Natural Gas Prices: The natural gas prices resulting from this scenario rebound from current levels with excess supply gradually absorbed by the market, equilibrium conditions associated with a more robust economy and the curtailment of lease-required excess drilling:

- Real (2010$) Henry Hub prices reach $7.50 by 2020, and $7.80 by 2030
- Real (2010$) AECO Hub prices reach $5.80 by 2020 and $7.00 by 2030

High-Price Scenario: Shale F&D Costs Increase with Growing Demand from Power Generation

Supply: Costs of land acquisition and the technological costs of shale production costs remain low. However, environmental compliance requirements associated with water treatment raise production costs to $1.38/MMbtu. Direct or indirect land use restrictions limit Marcellus reserves by 35% and all other shales by 10%. Severance taxes in Louisiana, Texas, Pennsylvania and New York are assumed to be 10% reflecting higher taxes than the Mid Price Scenario and current royalty rates in Alberta and British Columbia are assumed to be increased by 15%.

Demand: Restrictions on greenhouse gas emissions, either in the form of tradable emissions credits or a carbon tax, are expected. The resulting higher emissions costs provide natural gas-fired generation an advantage over some existing and most new coal generation. Renewables and nuclear generation have a significant share of new power generation capacity.

Natural Gas Prices: The natural gas prices resulting from this scenario rebound from current levels with current excess supply gradually absorbed by the market, and equilibrium conditions associated with a more robust economy and the curtailment of lease-required excess drilling. Prices further strengthen as the requirements to curtail carbon emissions grow more costly.

- Henry Hub prices reach $8.00 by 2020, and $9.00 by 2030
- AECO Hub prices reach $6.20 by 2020 and $8.00 by 2030

Low-Price Scenario: Shale F&D Costs Remain Low with Limited Demand Response Due to Resurgence of Coal Fired Generation

Supply: Abundant shale gas resources and favorable geological conditions allow producers to continue producing at low costs, following the same general cost pattern as for conventional gas resources. Fiscal regimes in traditional producing areas such as Louisiana, Texas, Alberta and British Columbia continue under their current guise, while new “middle of the road” severance taxes are imposed in Pennsylvania and New York. Water use costs are assumed to be the same as for the Mid-Price Scenario. Namely, for the portion of Marcellus in New York state, water costs average $0.70/Mcf of gas produced; for all other shale plays water costs were $0.25/Mcf.

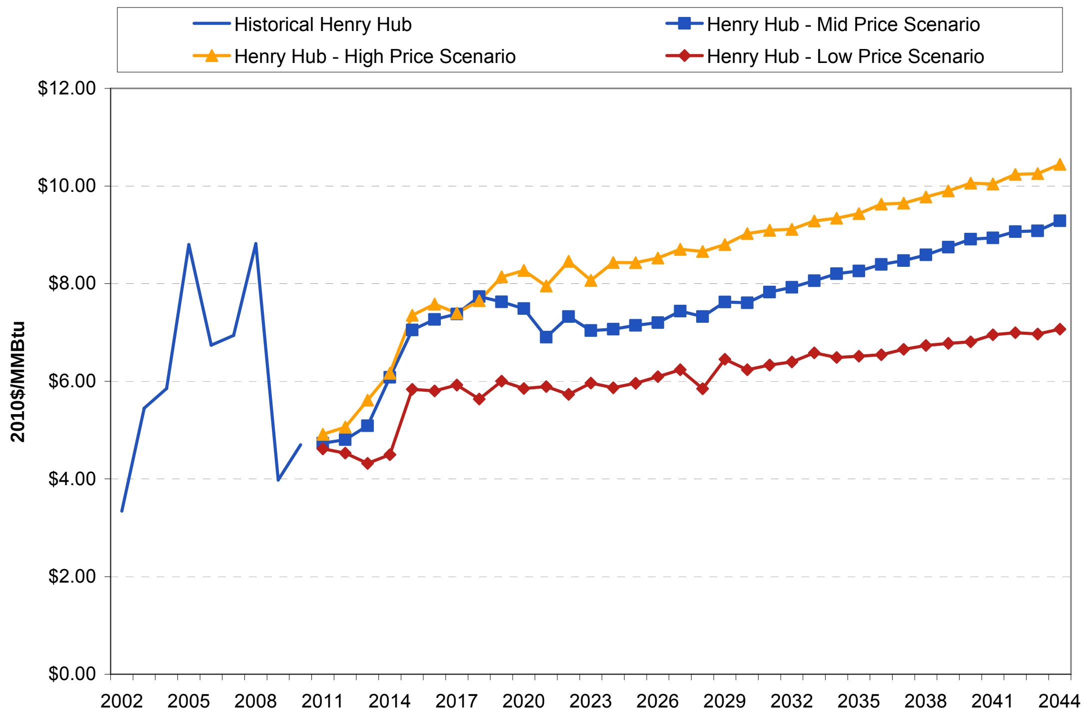
Demand: Despite abundant and inexpensive gas resources, there is no greenhouse gas policy response by the federal government, nor effective policy by state or local governments. Private companies put their emissions compliance plans on the shelf. Existing and new coal generation continues to be preferred over natural gas generation. Efficiency gains coupled with renewables/nuclear generation crowd out significant growth in natural gas-fired generation.

Natural Gas Prices: The natural gas prices resulting from this scenario rises only modestly from current levels with excess supply gradually absorbed by the market, equilibrium conditions associated with a more robust economy and the curtailment of lease-required excess drilling. Production costs remain relatively flat and demand stays stagnant as the expectation of significant natural gas demand increase for power generation is not fulfilled:

- Real (2010$) Henry Hub prices reach $6.00 by 2020, and $6.20 by 2030
- Real (2010$) AECO Hub prices reach $5.00 by 2020 and $5.80 by 2030

The study highlights the potential range of natural gas prices over the next three decades driven by the uncertainties in supply and demand market fundamentals. Overall, the study results indicate robust demand for natural gas and recovery of price levels from their current lows (Figure 1-2).

Figure 1-2 Historical and Projected Henry Hub Prices by Scenario



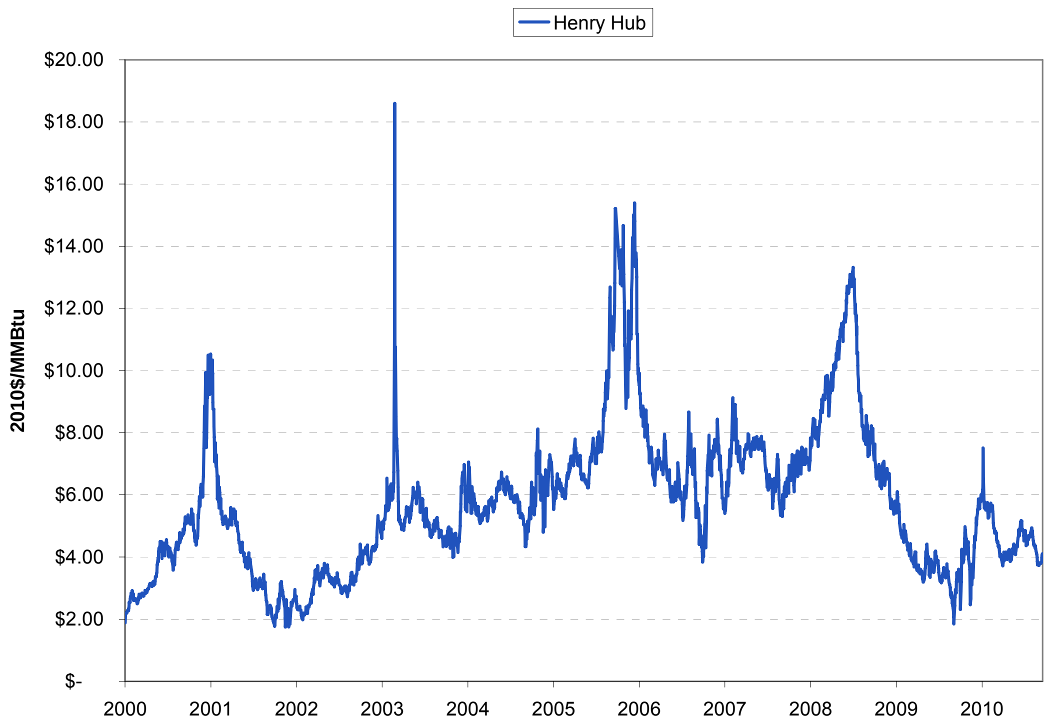
2.0 INTRODUCTION

The largely unanticipated, recent and rapid increase in shale gas production has brought significant additional supply sources to the market and changed the natural gas price landscape. Prices in North America today have essentially collapsed from the high levels reached as recently as 2008. The collapse has been due both to the increase in supply – exacerbated by requirements to drill for shale gas to retain production rights to the acreage – combined with an exceptionally deep economic recession. Against this backdrop the question arises as to when prices may recover, and – given the substantially increased potential contribution from shale gas basins – what their equilibrium trajectory may be. Given that the primary new factor is the emergence of shale gas supply, the answer will depend substantially on the relative costs of that supply and the uncertainty surrounding various factors that will influence those costs. We are in the very early days of shale production from most plays. Other than the Barnett, cumulative production from major shale plays averages just 1.75% of the total technically recoverable resource base. The current study therefore works especially to assess the importance of the drivers of total shale gas costs of supply. The other primary uncertainty, going forward, consists of the demand for natural gas in the power sector – an uncertainty importantly affected by the possibility of future policy measures to address climate change. The result is an updated view of long-term natural gas prices that better reflects more recent developments.

2.1 Natural Gas Market Overview

Keeping with its history of cyclical patterns, the natural gas market in North America has undergone a dramatic shift in the last couple of years. As recently as 2008, the market expectation was for declining natural gas production from conventional onshore and offshore basins, combined with higher demand, to create a supply-constrained market. Natural gas prices at the Henry Hub in Louisiana reached $13.32/MMBtu (Figure 2-1). In response to this general market environment several liquefied natural gas (LNG) regasification projects were proposed, permitted and completed to import natural gas produced in other regions of the world to the North American market.

Figure 2-1 Historical Henry Hub Platts Gas Daily Natural Gas Price



High gas price expectations also helped spur additional investment in unconventional sources of natural gas, including shale plays. Rapid technological advances in horizontal drilling and hydraulic fracturing, partly as a result of these investments, expanded the economically recoverable portion of the shale gas resource that had hitherto been only technically recoverable. As new resources were developed and land positions established, the resulting largely unexpected influx of shale gas has brought abundant supply to the North American market. Simultaneously, an economic downturn has caused a decrease in the demand for this natural gas. The supply surplus natural gas market environment has caused prices to tumble; the average natural gas price at the Henry Hub in 2010 through October is $4.70/MMBtu.

Recent low natural gas prices have affected drilling activity. Some producers have reduced drilling outright; drilling has also migrated towards shale resources with higher natural gas liquids content, where the liquids values help underpin the costs of production. This noticeable slow down in capital spending and development activities related to shale resources are evidenced by several recent indicative market responses[1].

The observed reductions and refocusing of drilling activity and capital spend are expected to bring the over-supplied natural gas market back into balance in the next few years. However, we expect that the near-term North American natural gas market will continue to experience surplus supply, caused by the supply overhang created over the last few years and the continued drilling that will occur given contractual drilling

[1] "Petrohawk reduces Haynesville rig count to concentrate on liquids-rich Eagle Ford." Oil & Gas Financial Journal. Aug 1, 2010.
Phillips, David. "Chesapeake Energy's Shift to Oil Won't Work Without Higher Natural Gas Prices." The CBS Business Network, April 15, 2010.
Starnes, Joshua. "Constraints Aside, Gas Drillers Keep Targeting Liquids." Platts' Gas Daily, October 11, 2010.
Buchta, Cheryl. "Petrohawk to Begin Idling Rigs Due to Low Gas Prices." Platts' Gas Daily, August 25, 2010.
White, Rodney. "New York County Seeks Two-Year Ban on Fracking." Platt's Gas Daily, May 25, 2010.

requirements on shale gas leases. The true evolution of the natural gas market over the long-term will depend on the supply and demand drivers, which will need to adjust to establish a price that provides adequate returns to the overall North American natural gas supply industry.

Given that the recent dramatic shifts in the natural gas market have significantly resulted from the largely unanticipated explosion of shale gas production, this study focuses on drivers impacting shale gas development to understand the likely contribution of shale gas production over the long-term. Additionally, we access the key demand sensitivity of gas demand for power generation in response to climate policy and concern. Of course, other factors such as the resources and costs of development of conventional gas, and the imports of LNG will continue to influence the natural gas market in North America. However, while opinions may differ on the appropriate value and impact of other variables, they are not particularly crucial to understanding the ultimate impact of the uncertainties being investigated here. Further, the work here as well as previous work performed by Black & Veatch suggests that they do not have as wide a range of uncertainty as do shale resources and natural gas demand. Accordingly, this study does not systematically address those uncertainties.

2.2 Summary of Supply and Demand Uncertainties Influencing the North American Natural Gas Market

The improved economics of gas from shale resource has revolutionized the natural gas market. Large shale resources have been discovered, such as Marcellus, Haynesville, Horn River and Montney shales; technology promises that more resources could be discovered in the U.S., Canada and elsewhere in the world. Current industry discussion suggests that the cost of developing shale resources is at or below alternative sources of supply from conventional resources, other non-conventional resources and LNG.

However, the data upon which these development cost assertions are based are actually fairly immature and limited. Current projections for shale gas development rely upon a very short development history. Limited historical data are used to support longer term projections and assumptions. Resources estimates from many shale plays are preliminary, and lack geological consensus and extensive survey data. This is evidenced by the wide range of shale resource estimates, from 200 Tcf up to 700 Tcf depending on the source. Similarly, development cost reports rely upon early stage drilling and development experience; sustainable growth rates for development costs are highly uncertain. Meanwhile, cost estimates are inconsistent in their inclusion and exclusion of different cost components such as water related costs and lease costs; this makes accurate benchmarking of current costs, let alone the projection of future costs, difficult.

Finally, the environmental impacts and costs, and the associated future restrictions related to large scale shale development, are untested in many regions. As the focus area of shale production shifts to regions such as the northeast which is the home of the Marcellus shale, potential costs associated with acquiring fresh water for hydrofracturing and disposing of the water after it is utilized for production are beginning to come under closer scrutiny. These uncertainties create wide ranges in expectations for resource availability and finding and development costs which in turn will impact longer term North American natural gas prices.

Meanwhile, the uncertain level of natural gas demand will clearly substantially affect natural gas prices in North America. Black & Veatch's view is that the key uncertain factor affecting natural gas demand is the future need for gas in the power sector. Residential and commercial demand for natural gas is expected to grow only minimally over the study period, as demand additive to economic and population growth will be largely offset by energy efficiency gains. Meanwhile, while industrial demand in North America will likely recover moderately with the economy, it is very hard to tell a story in which its annual growth rate breaks out of a range of between 0.4% and 0.9%; within this range industrial demand cannot drive meaningful growth in the natural gas industry.

This leaves power generation as the main driving force of potential demand growth for the North American natural gas market. Historically, the fuel generation mix in the U.S. has been dominated by coal given its low and relatively stable price behavior compared to alternate fuels, such as oil and natural gas. However, coal prices have been on the rise since 2005 due to increasing demand pull from developing countries such as China and India. Coal price volatility has correspondingly been impacted. Finally, the relative difficulties of citing and permitting coal plants, the long lead times associated with their construction, and their need for a stable and predictable regulatory environment to ensure capital recovery, have all provided a boost to gas-fired plants.

In tandem, the greater awareness of the impact of greenhouse gas on the environment has increased the focus on the negative environmental footprint of coal-fired power generation. Various legislative actions have been proposed to regulate greenhouse gas emissions by levying additional costs corresponding to these emissions. Political disagreement as well as economic reality have further complicated the debate and delayed implementation. However, it is Black & Veatch's view that some form of regulations controlling greenhouse gas emissions will be adopted in the future. We believe that this view is also widely shared in industry. The expectation of possible climate change emissions-reduction policies will substantially impact the development of coal-fired power generation plants.

When the cost of greenhouse gas compliance for fossil fuel generation is incorporated, natural gas becomes a leading choice of fuel for new generation capacity. While renewables, nuclear and energy efficiency programs can all be viewed as environmental friendly sources of electricity, the limited availability of opportunities, challenges with the transmission grid and long construction periods (especially for nuclear) make it impossible to meet the entire projected load growth with these resources. Natural gas-fired generation is positioned to be key to meeting the twin objectives of satisfying load growth and lowering greenhouse gas emissions. This position has only been bolstered by the substantial increases in natural gas supply that shale gas offers. The pace of economic growth and the timing and extent of costs related to greenhouse gas emissions are key variables impacting natural gas demand for power generation and the ultimate growth of the natural gas industry.

2.3 Study Analysis Methodology

Given the purpose of the study is to examine the impact of key shale gas supply and power industry demand uncertainties on natural gas prices, this study employed a fundamental analysis of the natural gas market using a long term economic equilibrium model for North American energy markets. A key assumption inherent in our modeling structure is that no pricing arbitrage for natural gas is possible across either space or time. The long-term equilibrium model for natural gas is part of Black & Veatch's Integrated Market Modeling (IMM) process, which is used to prepare our integrated long term view on energy markets. To arrive at this market view, Black & Veatch draws on a number of commercial data sources and supplements them with our own view on a number of key market drivers, for example, power plant capital costs, environmental and regulatory policy, fuel basin exploration and development costs, and gas pipeline expansion. B&V uses these data in a series of vendor-supplied and internally-developed energy market models to arrive at our proprietary market perspective. The natural gas market fundamental model estimates the equilibrium price, consumption and production in each defined North American market by balancing natural gas demand and supply. It simulates market behavior by creating a network representation of each economically distinct element of the natural gas industry such as gas reserves, processing plants, storage facilities, transportation pipelines and final market demand by sector. Microeconomic theory is used to simulate the real world interaction of these elements to determine future equilibrium prices, production levels, demand loads, pipeline flows, and storage injections and withdrawals.

The analysis approach that was adopted for the study is as follows:

- Identification of supply and demand drivers expected to have significant impact on long-term natural gas prices with specific focus on shale gas supply and natural gas demand for power generation
- Definition of the range of potential uncertainty related to each driver
- Analysis of the impact of uncertainty in the identified drivers on long-term natural gas prices
- Examination of alternative evolutions of North American natural gas prices given the key potential supply and demand uncertainties

The price impacts of the different drivers in this study were examined within the context of three distinct scenarios spanning the probable evolution of the North American natural gas industry over the study period. These scenarios were designed to capture distinct reasonable "stories" that might characterize potential evolutions of the market as described below. The scenario approach was adopted to characterize a rational span of the uncertainty space for each key driver in this study in order to provide greater clarity on potential events in the future that could lead to these divergent price paths.

> Mid- Price Scenario: Shale Supply Growth with Growing Demand from Power Generation – represented as a baseline scenario where shale gas development is robust but moderated by higher cost structures than currently experienced. Greenhouse gas legislation creates additional demand for natural gas for power generation and absorbs this natural gas supply. Overall, relative long-term price stability prevails.

> High-Price Scenario: Shale F&D Costs Increase with Growing Demand from Power Generation – shale gas development growth, while substantial, is dampened as environmental concerns impose higher cost structures on these plays. Greenhouse gas legislation creates additional demand for natural gas for power generation resulting in a tighter market for natural gas.

> Low-Price Scenario: Shale F&D Costs Remain Low with Limited Demand Response Due to Resurgence of Coal Fired Generation – a less environmentally sensitive world where shale gas development is plentiful and unconstrained by access restrictions or costs related to water treatment. Demand for natural gas from the power sector is moderated, as no greenhouse gas legislation is adopted.

This report is organized as follows. Section 2 offers discussion of key supply and demand uncertainties facing the natural gas market and highlights the scenarios analyzed and their price results. Section 3 highlights key uncertainties on the supply side for the natural gas market with emphasis on shale gas development. Section 4 discusses the uncertainties on the demand side with emphasis on the drivers of natural gas demand for power generation. Section 5 discusses the key assumptions and findings in the Mid Price Scenario. Section 6 highlights the key assumptions and findings in the High Price Scenario. Section 7 highlights the key assumptions and findings in the Low Price Scenario. Section 8 discusses key conclusions from the study. The main body of the report summarizes the central characteristics of the analysis with more detailed and technical information included in Appendix A through Appendix F. All currencies are in real 2010 U.S. dollar, unless otherwise specified.

3.0 DRIVERS OF NATURAL GAS SUPPLY

The drivers of shale gas development examined here are presented in the order of their estimated impact on natural gas prices, as elaborated in Appendix G. First, current finding and development costs and the shape of F&D cost curves as a given shale resource is exploited, are addressed. The drivers impacting the size of the resources base – the in-place technically recoverable resource estimates and potential land use restrictions– are explored next. Uncertain future costs associated with water use for hydrofracturing are subsequently examined. Finally, uncertainty around and possible changes to the fiscal regime that affect shale gas profitability are discussed.

3.1 Finding and Development (F&D) Costs

F&D cost numbers should summarize the out of pocket money spent to recover a certain amount of gas, commonly reported in dollars per one-thousand cubic feet (Mcf), exclusive of operating expenditures and the costs of transportation and marketing. They play a critical role in predicting prices as they largely determine the gas supply curve in a given basin. That is, for markets in equilibrium, F&D figures largely determine whether it is profitable to produce gas from a given basin.

Despite their critical role in the economics of gas-field development, F&D costs continue to evade singular, universal standards for reporting. Level comparisons of F&D costs from one gas play to another, based on publicly available data, remain elusive. Accordingly, meaningful differentiation of gas developments based on F&D costs requires multiple approaches to the analysis.

B&V pursued two types of F&D cost data to find corroborative evidence for current and historical trends of F&D costs in emerging shale-gas basins[2]:

- F&D costs for a gas-producer company (all basins)
- F&D costs for a gas-producing basin (all companies)

Level comparisons of finding and development (F&D) costs for shale gas, both among the various shale-gas plays and against conventional gas plays, are hampered by lack of consistent definitions for numbers reported publicly as F&D costs. For example, most producers have not yet begun to explicitly report water costs as part of F&D, even though costs are known to be an issue and should be expected to influence drilling costs. The lack of transparency as to whether water costs are included or excluded from a given reported number complicates comparative assessments. More dramatically, "drill-bit F&D" costs are more narrowly defined, and provide lower numbers, than "All-In F&D" costs which ultimately are the more meaningful financial metrics.

Table 3-1 summarizes F&D data compiled for different companies and for indicative shale-gas plays. APPENDIX B provides more detailed company level and shale-play specific information.

[2] A hydrocarbon "basin" can contain multiple gas plays – both conventional and unconventional – where a "play" is a specific, geologic reservoir. For shale gas, usually (but not always) there is one major shale-gas play that dominates each basin. In this report, "basin" refers to a "play" in the context of shale gas.

Table 3-1 Basin Specific F&D Costs

Finding & Development (F&D) Costs for Shale-Gas Plays ($US / Mcf)					
F&D Element	**Eagle Ford**	**Haynesville**	**Horn River**	**Marcellus**	**Montney**
F&DX[1] (Average)	1.06	0.97		1.26	
Range		0.91 - 1.48		1.03 - 1.33	
F&DD[2] (Average)	1.00	1.38		1.07	
Range	0.93 - 1.08	1.11 - 1.90		0.87 - 1.33	
Total F&D (Average)	2.06	2.35	3.75 - 4.25[4]	2.33	3.25 - 3.75[4]
Total F&D (Acreage-Weighted)[3]	2.12	2.41		2.23	

Notes

1 F&DX = F&D-related costs excluding the drilling component.

2 F&DD = Drilling costs per well divided by EUR per well, using individual well EURs as reported by producers. EUR (Bcf) values reported spanned ranges of 4-6 (Eagle Ford), 5-7.5 (Haynesville) and 3-4.2 (Marcellus).

3 Average for individual companies with weighting factors proportional to the acreage holding of each company in each shale-gas play.

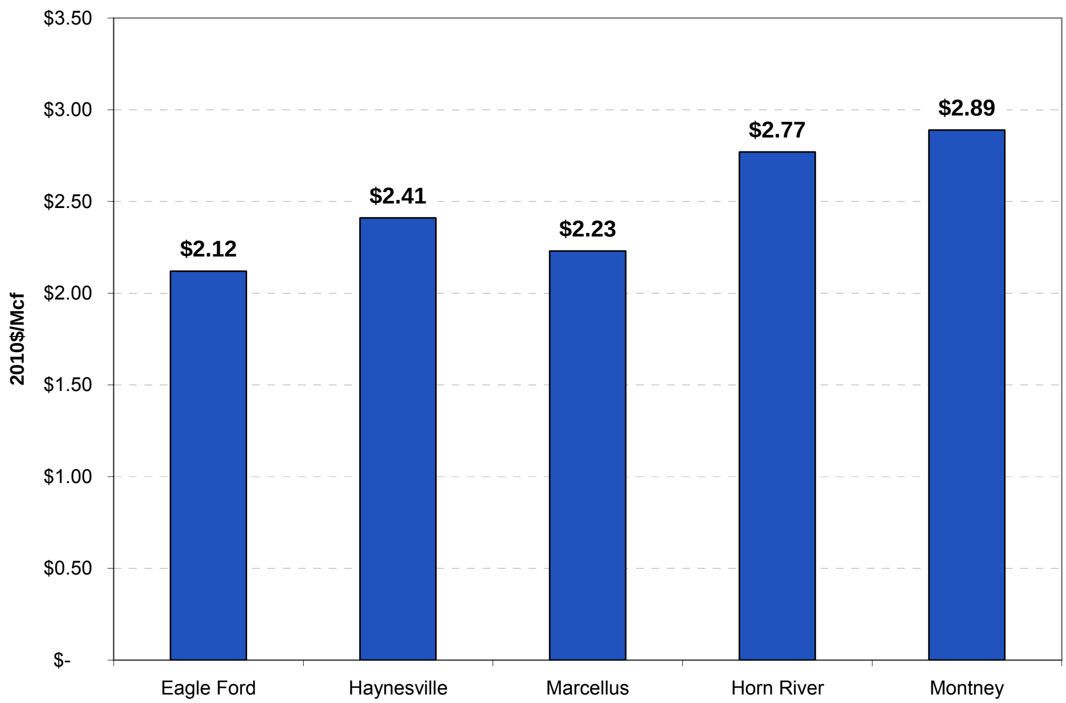
4 Ranges reported by Encana.

Comparing shale-gas F&D costs between the U.S. and Canada involves additional complications. Both Horn River and Montney are notably deep plays and Horn River gas contains high levels of carbon dioxide. Therefore, these plays require additional investments during drilling, hydrofracturing and wellhead operations. The Canadian plays should accordingly be expected to have larger F&D costs associated with geotechnical factors. Also, regulatory reporting rules that pertain to F&D tend to be less flexible in Canada relative to the U. S; this increased transparency tends to discourage Canadian producers from discussing F&D costs except for legal reporting purposes. There are very few F&D cost data currently available for Horn River and Montney and geotechnical effects cannot be fully disentangled from regulatory effects in evaluating the Canadian F&D numbers. But taken at face value, the Canadian shale-gas F&D costs appear higher than those for U.S. shale gas.

In 2009 the Securities and Exchange Commission changed reporting rules that further complicated tracking U.S. F&D costs. In addition to allowing annual-average, rather than end-of-year, commodity prices to be used in converting resources to reserves, the rule change made it easier for producers to grow booked claims for proved, undeveloped resources (PUD). The result of the rule change was systematic increase in PUD claims, and expanded booking of reserves, with corresponding dilution of apparent F&D costs from 2008 to 2009. That rule change, and its instantaneous effects on valuations, could virtually "re-set" F&D cost curves if viewed out of context.

Figure 3-1 summarizes the initial expected F&D cost assumptions utilized by Black & Veatch in the study for the major shale plays considered. The F&D costs selected as model input (Fig. 3-1) are the same as the central-tendency values compiled from research (Table 3-1) except for the Canadian plays (Horn River and Montney). For the Canadian plays, F&D cost ranges from a single, major producer indicated central-tendency values of $4.00/Mcf (Horn River) and $3.50/Mcf (Montney). But for the Mid-Price Scenario, Black & Veatch elected to use a smaller differential between U.S. and Canadian F&D costs so as to reduce prospects that Canadian shale-gas production would be fatally handicapped by their upper-end F&D costs. Adjustments based on locations and production circumstances resulted in model-input F&D costs discounted to $2.77 (Horn River) and $2.89 (Montney).

Figure 3-1 F&D Cost Assumptions by Shale Basin – Mid Price Scenario*



Note: F&D costs assumed for Horn River & Montney adjust Encana's estimates to account for inclusion of cost components comparable to data for other shale plays.

APPENDIX B contains additional data and details about the definition of F&D costs and how F&D costs were researched and compiled.

3.2 Shape of Finding and Development Cost Curves

3.2.1 F&D cost curves for gas price forecasts

The macro economic model utilized by Black & Veatch to develop long term equilibrium prices for natural gas requires input of F&D costs as a function of the resources produced from a given basin. For each shale-gas play, and also for conventional-gas plays, a model-compatible F&D cost curve was constructed (see APPENDIX B for detailed discussion of the shape of F&D cost curves). The cost curves in essence provide schedules of how much each unit of future cumulative production will cost under current technology. Each F&D cost curve rises with time as resources are produced, beginning with the "easiest" or most accessible resources. The three characteristics that are most obvious when comparing F&D cost curves is the current cost, the length of time a curve stays "flat" before climbing to its upper limit, and the average rate of cost increase from current to upper limit costs.

Comparison of F&D costs for shale-gas plays with F&D costs for conventional gas plays must recognize some fundamental differences that affect their respective developments. Those differences account for differences in the F&D cost curves that are used as inputs in the economic analyses.

Conventional gas plays consist of individual gas traps, defined by certain types of sub-surface geologic structures, which are distributed in a discontinuous way. To maximize resource recovery, each trap must be found, drilled and produced. The "finding" step constitutes a significant part of the risk and cost in F&D. But once producing wells are online, they generally will perform with working lifetimes measured in decades. Therefore, conventional gas developments typically see large F&D investments up front followed by many years of strong gas production with little or no additional investments needed. In addition, and importantly, the largest gas accumulations are generally found and produced first. These dynamics combine to generate an initial "flat" period of F&D costs relative to cumulative resources produced. Eventually, however, additional F&D investments become necessary. Those later investments can include re-working of proven wells or additional exploration for other traps which often are smaller gas deposits with less economic payoff. So after an interim period of "flat" F&D costs relative to resources produced, the F&D costs begin to rise as the latter portions of the producible resources are pursued and additional, perhaps less productive, wells are completed and brought online.

Shale-gas plays consist of tabular bodies of gas-bearing rocks where gas content is not controlled by structural geology. Once the depth and orientation of a resource-bearing shale layer is known, the "finding" risk and cost is quite low compared with other factors. Because the shale layers tend to be relatively thin but laterally extensive, the key to maximizing resource recovery from shales is to drill and complete as many wells as possible across the largest possible surface acreage. Although variations in gas concentration occur both vertically and laterally within a shale bed, the main challenge is not necessarily finding the "sweet spots" but expending the substantial effort needed to hydraulically fracture the shale so that the trapped gas will flow into the wells. Horizontal drilling and multiple-stage hydrofracturing are significant costs for shale gas that generally do not apply in conventional gas. Once completed, shale-gas wells tend to decline at least 4-5 times faster than their counterparts in conventional gas fields. As a consequence, the working lifetime of a typical shale-gas well might be only 3 years or so before it must either be re-worked or replaced with a new well. So unlike the decade-scale production periods enjoyed after initial F&D in conventional gas fields, shale-gas fields must be under continuous development for resource recovery to be grown and maintained at a predictable pace. And as development progresses within a shale-gas play, escalations of the unit cost of technology applied per volume of gas recovered (including drilling and water costs), can equate to decline of resource quality as less favorable locations become the dominant opportunities.

The Barnett Shale is the only play with sufficient track record to permit meaningful assessment of the cost-effectiveness of shale gas investment over time in a given play. Examination of the production cost data there is perhaps surprising. Since the early 1990s, the development of horizontal drilling and the refinement of hydrofracture methods, have substantially increased year-on-year gas production. However, F&D costs from the Barnett have nevertheless increased with cumulative production. The lesson from Barnett appears to be that marginal reductions in F&D unit costs per average well can be more than offset by the need to continuously drill and complete new wells in less productive resources to overcome the naturally rapid rates of well decline. APPENDIX B highlights this historical experience at Barnett Shale with empirical evidence indicating the increase in F&D costs through time at this shale play despite technological advances.

The shapes of the shale-gas F&D curves means that profitability of shale gas will require not only favorable wellhead prices but also effective and efficient growth of large numbers of highly productive wells. As the numbers of wells continues to climb, shale drillers seem likely to face cost bottlenecks in the support industries that place further pressures on development costs. Compared with conventional gas plays, shale-gas plays will require more frequent decisions about re-working or replacing declining wells and achieving maximum leverage of marginal costs within and among different plays. The keys to cost control will require reasonable limits to land costs, reduction of unit costs for water and wastewater and highly effective use of drilling and well-completion capacities. Based on the data available to date, it appears that F&D cost curves for shale gas will trend continuously upward without the early- to mid-life cost-relief periods that conventional gas plays typically enjoy. The result should be continuing squeeze on the margins between wellhead prices and production costs for shale gas.

3.3 Shale Resource Estimates

Current industry estimates of natural gas technically recoverable shale reserves exhibit high levels of variability on an aggregate level and between basins (Table 3-2). Since such large deviations between estimates have significant impacts on price forecasts, the underlying assumptions and methodologies which yield these reserve estimates were examined. Black & Veatch elected to utilize third-party, publicly available estimates as an input in its price forecast which met the criteria of being: (1) based on the recent data; (2) conservative in its outlook; (3) based on a rigorous estimation methodology.

Table 3-2 Natural Gas Resource Estimates[3]

	Theal	Dawson		FERC		Medlock	ARI - Kuuskraa
Field (Tcf)	Unrisked	Low	High	2006	2008	Mean	& Stevens
United States							
Marcellus	56			34	262	134	200
Haynesville	73			34	251	90	131
Fayetteville	34			26	42	36	53
Barnett	31			62	97	54	59
Woodford	13			12	17	12	32
Canada							
Montney	23	150	300			35	110
Muskwa/Horn River	23	75	170			50	130
Utica	4	7	42			10	

Notes:
Mohr, S.H., and Evans, G.M., "Shale gas changes N. American gas production projections," OGJ, July 1, 2010

After taking these criteria into account, Black & Veatch chose Advanced Resources International, Inc.'s (ARI's) natural gas shale technically recoverable resource estimates as an input for the study's Mid Price Scenario. ARI's estimates were derived using more recent historical data over a more consistent time period than many other publicly available estimates. For example, estimates by the Federal Energy Regulatory Commission utilize historical data up to July 2008, while ARI's estimates utilize historical data through December 2008. Such discrepancies in the timeliness of historical data may have large impacts on reserve estimates, given the rapid development and quickly changing outlook of North America's emerging shale gas resources. In addition, ARI's resource estimates were seen as a good midpoint when compared to other shale reserve estimates. ARI utilizes a rigorous estimation methodology to derive its reserve estimates, accounting for various factors such as the geographic area, gas-in-place, well drainage, well spacing, well performance and success rates, field case studies, technical performance data, and the accessibility/productivity of various leases within a play.

The shale plays above represent the largest and most significant of the plays known today. While production from other shale plays has been included as generic supply or as part of resources from unconventional sources, they have not been considered individually in the study due to lack of data and time constraints.

It should be noted that to the extent available resources are higher than the levels estimated by ARI and utilized in this study, or that new shale plays emerge that are not considered here, natural gas supply in North America will be higher than this study estimates and result in lower natural gas price levels than anticipated

[3] Resource estimates for Eagle Ford shale from these sources were not available because of the recent vintage of this shale play.

here. For example, some estimates of the resources in Marcellus Shale are as high as 500 Tcf. If this level of resource estimates proves to be accurate and economically recoverable during the study period, it could have a significant impact on North American natural gas prices, especially in the later forecasted periods of the study.

3.4 Land Access

The study considered the potential implications of government restrictions to land access on the development of North American shale gas resources. B&V closely examined federal, state, and provincial land ownership in addition to recent land access legislation in the states and provinces encompassing major shale plays. In addition, comparable land access restrictions enacted during the development of natural gas production in the Rocky Mountains region were examined as a historical guide to possible future restrictions on the access to emerging shale plays (Table 3-3). This experience in the Rockies has been utilized in this study as indicative of potential land use restrictions that may become applicable in a more restrictive regulatory and environmentally sensitive world. As a result, B&V assumed that approximately 10% of the total available resources are inaccessible due to land access restrictions

Table 3-3 Access to Federal Lands in the Rockies

Gas Resource (Tcf)	Inaccessible (Categories 1-4)	Accessible with Restrictions (Categories 5-8)	Accessible (Categories 9) and Non-Federal Land	Total Gas Resource
Denver Basin	31	46	2,645	2,722
Montana Thrust Belt	6,243	43	2,352	8,638
Paradox Basin	398	378	788	1,564
Powder River Basin	874	7,035	11,385	19,294
San Juan Basin	3,199	15,267	34,135	52,601
Southwestern Wyoming	12,310	47,715	35,108	95,133
Uinta-Piceance basin	2,243	8,780	13,991	25,014
Williston Basin	212	241	3,559	4,012
Wyoming Thrust Belt	87	480	1,122	1,689
All Rockies	**25,597**	**79,985**	**105,085**	**210,667**
% of Total	**12%**	**38%**	**50%**	**100%**

Source: American Petroleum Institute, "Strengthening our Economy: The Untapped U.S. Oil and Gas Resources". December 5, 2008.

Louisiana and Texas

Louisiana and Texas do not have a history of restricted land access or proposals to restrict access going forward. This study therefore does not anticipate major land access restrictions to be put into place in these states which will affect natural gas production in the Haynesville, Eagle Ford or Barnett Shales in the future. In the more restrictive High Price Scenario, the study assumes that either state, local governments or environmental agencies impose restrictions on access to the Barnett and Haynesville shale resources to mitigate either local water or emission concerns. The current level of restrictions in the Rockies i.e., 10% is used as a yard stick for estimating potential restrictions that may become applicable to Louisiana and Texas shale plays in a more restrictive High Price scenario. It should be recognized that this is a projected scenario obtained by translating events that occurred in another region i.e., Rockies, to the Texas and Louisiana shale resources. Actual outcomes will likely vary from this historical experience.

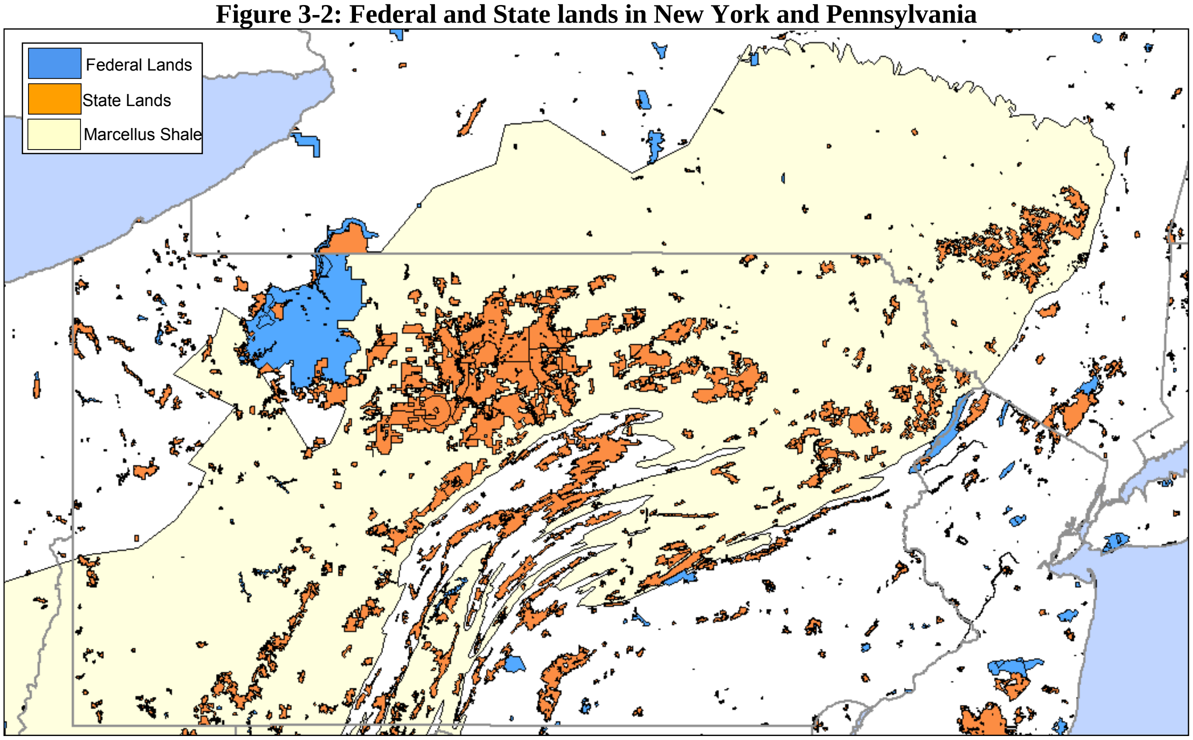
Alberta and British Columbia

Alberta and British Columbia have enacted no specific restrictions concerning shale gas development in the Horn River and Montney Shales. This study therefore does not anticipate major land access restrictions to be put into place in these provinces. In the more restrictive High Price scenario, the study assumes that 10% of Horn River and Montney Shale resources are inaccessible drawing upon current experience in the Rockies. As noted above, actual experience is likely to vary from the experience in the Rockies.

New York and Pennsylvania

Potential land use restrictions in New York, and especially Pennsylvania, could have significant effects on production in the Marcellus Shale. Environmental issues associated with drilling in the Marcellus Shale are a mounting concern in both states and are expected to significantly affect access to land in the area going forward. Figure 3-2 displays Federal and state land ownership in New York and Pennsylvania.

Figure 3-2: Federal and State lands in New York and Pennsylvania



Source: Energy Velocity

Federal and state ownership of land within Pennsylvania and New York currently has little impact on natural gas production in the Marcellus Shale. The federal government owns little land within the Marcellus formation, with the Allegheny forest in Pennsylvania comprising the only significant amount (800 square miles) of federally owned land which overlaps the Marcellus formation in Pennsylvania. Furthermore, Pennsylvania State is actively engaged in a leasing program of state 32,000 acres of state owned land. It should, however, be noted that Pennsylvania's land access policies could become more restrictive as more environmentally sensitive acreage is reached and as public concern over watershed protection increases.

Federal and state land ownership in New York overlapping the Marcellus formation is limited, especially when the formation's limited reach into the state is considered. Limited federal and state ownership of New York land makes it unlikely that direct drilling bans will be utilized to implement future land access restrictions in the state. Instead, B&V believes it is more likely that future land access restrictions will be enacted via regulations related to environmental issues and permitting. This is supported by the fact that a number of active Marcellus wells in New York sit atop the Syracuse watershed. Recent policies and regulations on drilling in New York already indicate increasing environmental concerns. Increased regulation of drilling in the Allegany State Park (Bill #S8011)[4] and more restrictive review procedures enacted by the New York Department of Environmental Conservation in the New York and Syracuse Watersheds suggest that there is a distinct possibility of future restrictions.

Given concerns for future land use restrictions in Pennsylvania and New York, the study assumed that 10%-20% of technically recoverable resources in the Marcellus Shale could be inaccessible for production. This reflects a higher level of environmental concern in this region relative to others, such as Louisiana and Texas, with a longer and more established history of meaningful oil and gas production. Similarly, in the more restrictive High Price scenario, 35% of technically recoverable Marcellus resources are considered inaccessible to reflect a higher level of concern regarding restrictions. The levels assumed here are intended to capture the general magnitude and direction of the uncertainty related to land use restrictions; actual restrictions are likely to be different.

3.5 Water Usage and Costs

3.5.1 Overview

While requirements vary from well to well and from play to play, an individual shale gas well commonly will require the acquisition and treatment or disposal of 2-6 million gallons of water. The large “water footprints” associated with shale-gas development complicate forecasting the pace and cost of bringing shale gas to North American markets. Water costs must be included in finding and development (F&D) costs for shale plays, but the costs of water and acquisition and treatment or disposal in newer shale plays is currently not well understood. They could potentially materially raise the cost of gas from shale.

Whereas a vertical well in a conventional gas play typically requires thousands of gallons of water to drill and complete, a horizontal well in a shale play typically requires millions of gallons of water. The upward trend in the number of horizontal wells multiplies the “water footprint” for each shale-gas play.

The shale-gas “water footprint” consists of the downhole volume of fresh water that is needed to drill and complete a well plus the volume of flow-back water which must be safely handled as the uphole wastewater return associated with actual production. Especially for the newer, and still emerging shale-gas plays, treatment and disposal of flow-back water has become the leading cost and regulatory issue.

Information from the relatively mature Barnett Shale play, supplemented by information from newer shale plays, suggests that future water costs will depend significantly on the economics of wastewater disposal or treatment relative to the productivity of an average shale-gas well. For a shale-gas well with an expected ultimate recovery (EUR) of 3.5 billion cubic feet (Bcf), the average additional cost of water (downhole and uphole combined) appears to be about $0.25/Mcf; in highly unfavorable circumstances it could be as high as $1.38/Mcf (Table 3-5).

Water-related costs can be expected to decline over time if water-treatment technologies are aggressively pursued and regulatory environments are not excessively punitive. But if water-treatment technology lags or water regulations become severe, water costs could become a significant inhibitor to shale-gas development over multiple decades.

[4] S8011: Relates to oil and gas drilling in Allegany state park sponsored by New York State Senator, José M. Serrano

3.5.2 Drilling & well considerations for shale gas vs. conventional gas

Resource-bearing shales are favored for their high concentrations of natural gas (often expressed as standard cubic feet of gas per ton of rock) although the trapped gas can be recovered only through extensive fracing efforts. Unlike conventional gas reservoirs, where formation pressures encourage upward flow once a well is completed, gas trapped in shale reservoirs does not flow spontaneously. Instead, shale reservoirs, which naturally exhibit very low porosities and permeabilities, must be artificially fractured using hydraulic pressure before the gas readily enters and flows through the well bore. Also in contrast with conventional reservoirs, the relatively thin layers in which gas-bearing shales often occur means that the only efficient way to extract the gas is to construct wells that precisely follow the underground geometries of the shale layers – a type of well usually described as a "horizontal" or "lateral" well. Typical drilling strategy for shale gas is to penetrate the shale layer with a vertically-drilled well and then tap into the shale resources using one or more laterals connected to the vertical well. When both vertical and lateral legs of a well complex are considered, the total depth (TD) of shale-gas wells tend to be greater than for gas wells in many conventional gas reservoirs.

Neither vertical nor lateral shale-gas wells will produce significant amounts of gas until the shale layer has been artificially fractured by pumping water from the surface into the formation at high pressure. Hydraulic fracturing or hydrofracturing involves multiple stages of downhole pumping followed by allowance of time for uphole return of the hydrofracture water. Each hydrofracture stage is customized for each well according to water volume, pressure and minor amounts of chemical additives that are used to optimize performance. Indeed water issues comprise a major distinguishing factor for shale-gas wells relative to other types of gas wells.

3.5.3 Water issues in shale-gas production

Table 3-4 outlines the key differences for how water costs might affect the pace and cost of shale-gas development in different scenarios. The Mid Price Scenario, which is the default scenario for analyses presented in this report, includes water as a significant development cost.

Table 3-4 Differences among scenarios for how water costs might affect shale-gas development

Water-Related Scenario for Shale Gas Development	Water Availability	Disposal of Wastewater	Practical Example
LOW	• No limits on water used • Water purchased at utility rates or lower	• Untreated • Disposal down injection wells.	Barnett Shale (through 2009)
MEDIUM	• Special permits for water supply • Possible limits on volumes	• Treatment before surface release • Injection wells rarely permitted	Marcellus Shale (WV and PA)
HIGH	• Special permits for water supply • Probable limits on volumes • Possible limits on hydrofracturing fluids	• Significant treatment before surface release • Injection wells rarely or never permitted	Marcellus Shale (NY)

The Barnett Shale, which underlies north-central Texas, was the first North American shale-gas play to be developed to a high level of productivity and technological maturity. Comparatively mature, it has been producing from the late 1990s. It is, therefore, understandable that the Barnett Shale commonly is used to project the development of other, emerging shale-gas plays.

However, in the context of water issues, the Barnett Shale is atypical. It was developed with essentially no water-related hurdles. Effectively unlimited water supplies were available on demand. More importantly, untreated wastewater was readily discharged into injection wells re-commissioned from among plentiful, abandoned oil and gas wells. As a result, water costs were so low, relative to other development costs, that they remained invisible to most observers. “Water is cheap” was taken as given by many in the oil & gas industry who assumed that the Low Price Scenario would prevail elsewhere as it did for Barnett.

After 2005 the Marcellus Shale, which principally underlies New York, Pennsylvania and West Virginia, became a serious development target. Water issues have since become prominent. Unlike the situation for the Barnett Shale, some state and local stakeholders for the Marcellus Shale have put particular scrutiny on water quality issues. Concerns have focused on whether hydrofracturing might directly affect aquifer water quality, and whether treatment of produced water is adequate. The result has been slower development of various parts of the Marcellus shale-gas play.

The most persistent and strenuous objections have occurred in New York. Very little gas has been produced from the Marcellus Shale there because permitting has been exceptionally difficult and debates about water have been forceful. Development drilling and well completions have been faster in West Virginia and Pennsylvania although both of these states have launched significant regulatory changes. This will affect shale-gas development. The Marcellus Shale is thus emerging as an example of the new paradigm where “water is a significant cost” (Mid Price Scenario) or even where “water is expensive” (High Price Scenario).

More information about water issues in shale-gas production and how water costs factor into finding and development (F&D) cost can be found in APPENDIX A.

3.5.4 Outlook for future water costs

Table 3-5 summarizes a range of water-related impacts on shale gas in terms of dollars spent on water issues per one-thousand cubic feet of gas produced. The figures were generated based on water needs per well, the costs of that water (acquisition and disposal), and total gas produced per well. Data were taken from historical information from mature developments such as the Barnett Shale and on information now emerging from recent developments such as the Marcellus Shale. The range is very wide for two main reasons. First, the table is meant to broadly cover all North American shale-gas plays and is not specific to any individual play. The volumes of water required to drill and complete wells depend on geology, depth and the degree of difficulty in hydrofracturing, and the required number of hydrofractures. Also, there are regional differences in the unit costs for obtaining drill/hydrofracture water and for handling the leftover wastewater. Second, the productivity of a "typical" or "average" well varies among plays and can change during the course of development. A well that requires large volumes of water and disappoints on lifetime gas production will tend to occupy the upper end of the water cost spectrum. Details of the water-related cost projections are provided in APPENDIX A.

Table 3-5 Variation of marginal cost of water with productivity of gas wells

Incremental Cost of Water* ($US / Mcf) for a Shale-Gas Well						
Cost Scenario for Water Issues*	Single-Well EUR (Bcf)					
	1	2	3	***3.5***	4	5
High	$4.84	$2.42	$1.61	***$1.38***	$1.21	$0.97
Medium	$0.86	$0.43	$0.29	***$0.25***	$0.21	$0.17
Low	$0.06	$0.03	$0.02	***$0.02***	$0.02	$0.01

* Includes procurement of water needed to drill and complete the well, plus all necessary hydraulic-fracturing operations, plus disposal of all flow-back and formation water.

The rate of progress on reductions in water costs depicted here will depend on the rate of capital investment and the favorability of wastewater regulations. For the mobile wastewater treatment systems that are currently being field-tested in some shale-gas plays, development through venture capital took the better part of a decade. Gas producers have helped sustain the development by becoming customers of the companies behind the water-treatment technologies and, in some cases, gas producers have become investors in those same companies[5]. But progress at rates faster than the decadal timescale will require increased rates of investment, else the technology may be cash-constrained by dependence on sales alone to finance continuing development. If gas producers remain the principal source of investments in wastewater-treatment technologies, it seems inevitable that those investments will be counted as F&D costs and therefore effectively function as an additional hurdle to shale-gas development. The fastest possible progress in reducing wastewater treatment costs will require sources of funding that will not inflate F&D costs. The latter investments could appear as government-provided grants or tax incentives, but preferably would become manifest from private-sector investors who visualize a greater potential of the technologies for longer-term returns in worldwide applications.

3.6 Fiscal Regime

Severance taxes and royalty represent incremental costs to natural gas producers and hence have an impact on the economics of production. This study examined state and provincial fiscal regime in the U.S. and Canada that are home to the largest estimated shale resources to-date to gauge the level of uncertainty that faces shale gas development from fiscal changes. Primary shales and states/provinces examined are, respectively:

- Haynesville – Louisiana, Texas
- Eagle Ford – Texas
- Marcellus – Pennsylvania, some New York
- Horn River – British Columbia
- Montney – British Columbia, Alberta

The highlights of the fiscal regime at these states and provinces are presented below.

Louisiana: The severance tax structure in Louisiana was established in 1990 and remains largely unchanged. It incorporates a base tax rate of $0.07/Mcf that is adjusted each year by an annual rate adjustment factor that incorporates the ratio of current price levels to prices in 1990.[6] There are special provisions for shale gas production wherein, for any horizontally drilled well from which production commences after July 30, 1994, all severance tax shall be suspended for a period of 24 months or until payout of well cost is achieved, whichever comes first.

Texas: The severance tax structure in Texas was also established in 1990 and remains largely unchanged. The applicable severance tax is defined as 7.5% of the market value of the gas produced.[7] As in Louisiana, there are special provisions that are applicable to shale gas production wherein any gas produced from wells defined as high-cost gas wells is eligible for a severance tax reduction until 50% of the drilling costs are recovered. The level of reduction in severance tax for high cost wells is based upon drilling and completion costs and ranges from 0.0% to 7.4%.

[5] "The future of water recycling." Basin Oil & Gas, 30, June 2010, 11 p.
[6] Louisiana Department of Natural Resource, Louisiana Severance Tax
[7] Texas Window on State Government, Natural Gas Production Tax

Pennsylvania: There is currently no severance tax applicable to the production of natural gas in Pennsylvania. The rise of Marcellus Shale has however, spurred multiple proposals that call for the imposition of severance taxes on natural gas production from this shale play. Some of the proposals that are being considered are:

- The initial proposal by Governor Ed Rendell would impose a 5% severance tax plus $0.047/Mcf on natural gas production from Marcellus shale.[8]
- The Pennsylvania House of Representatives passed the bill S.B. 1155 on September 29, 2010 approving a $0.39/Mcf severance tax on natural gas production from Marcellus shale at the wellhead, a minimum floor price that would be adjusted annually if the price of natural gas rises.
- An alternate proposal touted by Senate Republicans would impose a 5% tax rate that is reduced to 1.5% during the initial five years of production to allow producers to recover their drilling costs faster.

These severance tax proposals represent a meaningful uncertainty for producers in the Marcellus shale.

New York: There is currently no severance tax applicable to the production of natural gas in New York. Additionally, there are no material proposals calling for the imposition of severance tax that would impact Marcellus shale. Given the geographic proximity to Pennsylvania and sharing of the estimated Marcellus shale resources, there is a theoretical possibility that New York could impose severance tax on Marcellus shale production in the future. It should be noted that any severance tax imposed by New York is not likely to have a significant impact on Marcellus shale production since the majority of these resources are in Pennsylvania.

The two main Canadian provinces that house the Horn River and Montney shale plays are Alberta and British Columbia. These provincial governments rely on royalty rather than taxes as the primary method to collect revenues from oil and natural gas production. While freehold taxes are imposed on non-Crown lands, these lands constitute a small portion of the oil and gas rights in these provinces and these taxes are not considered in this study.

British Columbia: Royalty rate for all conservation (or associated) gas is 8% while the royalty rates for non-conservation (non-associated) gas vary based on the development date and range from 9% to 27%.[9] There are special incentive provisions applicable to shale gas production including the Two-per-cent Relief Royalty Program which allowed a 2% royalty rate for all gas wells drilled for one year between Aug 31, 2009 and Jul 1, 2010. In addition, the Deep Royalty Credit Program for deep well production (depth of 1,900 meters or more for horizontal wells) provides royalty credit based on location and depth. Most gas wells in Horn River and some wells in Montney would be eligible for the Deep Royalty Credit Program. The royalty rate calculation in British Columbia was changed in 1998 and again in 2002 with incentive programs being introduced over time.

Alberta: Royalty rate in Alberta is based on a single sliding rate formula sensitive to price and production volume. The applicable royalty rate in the first year of production is 5%. Royalty rates in Alberta that were established in 1974 were modified in 2009 and are set for a pull back starting in 2011. The royalty rate currently ranges from 5% to 50% but effective in 2011 is expected to range from 5% to 36%.[10] The slope of the royalty rate curves of the current and new royalty rule are essentially the same except that the maximum rate is capped at a lower rate under the new royalty rule. As an incentive, new shale gas wells are allowed to extend the 5% royalty rate up to 36 months with no volume limit.

[8] Maykuth, Andrew. *"Rendell Signals Flexibility on Tax"*, The Philadelphia Inquirer, May 2 2010.
[9] British Columbia, Ministry of Energy, Mines and Petroleum Resources, Natural Gas: Definitions and Rate Details
[10] Government of Alberta, Alberta Energy, About Royalties

Implications of the various fiscal regimes observed on a state level on specific shale resources costs are presented below.

Haynesville & Eagle Ford: There is a demonstrated history of fairly stable fiscal regimes favorable to oil and gas production in both Texas and Louisiana. Historically, taxes have been nominal with various incentives designed to promote oil and gas production, and especially, unconventional gas. The baseline assumptions for severance tax imposed in Texas and Louisiana during the analysis period is that the fiscal regime in these states is not expected to change significantly and impact production at the Haynesville and Eagle Ford shales.

Marcellus: Severance taxes, while considered, have not yet been established in Pennsylvania and New York. The analysis assumes that some form of severance taxes will be imposed on Marcellus shale development. As a baseline, study assumes Pennsylvania Governor Ed Rendell's proposed 5% plus $0.047/Mcf (representing a middle of the road tax level relative to the other proposals being considered) as the applicable severance tax for Marcellus shale.

Horn River & Montney: British Columbia has a fairly stable royalty structure history. No changes to the royalty structure are under consideration. Alberta's royalty structure was stable from 1974 through 2009 but experienced a hiccup between 2009 and 2011. Alberta has recently rescinded the higher royalty structure proposed in 2009 and will retreat to lower royalty levels in 2011. The baseline assumption in the study is that the current royalty structure in British Columbia and the rescinded royalty structure effective in 2011 in Alberta are expected to continue and be applicable to natural gas production from Horn River & Montney shales.

Table 3-6 highlights the baseline assumptions on severance taxes and royalty applicable to the shale plays considered. It should be noted that the baseline royalty rate assumed in the lower-48 states may be considered conservative with empirical evidence suggesting that current royalty rates associated with shale plays are higher than the 12.5% assumed here.

Table 3-6 Baseline Assumptions on Severance Taxes and Royalties

	Severance Tax			Royalty		
Gas Price	$3/MMBtu	$6/MMBtu	$9/MMBtu	$3/MMBtu	$6/MMBtu	$9/MMBtu
TX	7.50%			12.50%		
LA	$0.12/Mcf	$0.24/Mcf	$0.36/Mcf	12.50%		
PA	5% and $0.047/Mcf			12.50%		
NY	5% and $0.047/Mcf			12.50%		
AB	0%			6%	18%	24%
BC	0%			27%	27%	27%

Although recent history and current trends indicate that the existing fiscal and severance tax structures may not change and materially impact shale production, the analysis period encompasses a long enough period to support critical assessment of the implications to shale production should these regimes change. As states come to depend on shale gas severance tax revenues, the temptation to impose higher taxes may prove strong. In certain circumstances, it is possible that higher severance taxes could be seen as a way to also reduce industry activity and perceived associated environmental impacts. The analysis therefore examines the impact of more aggressive taxes and royalties on shale gas development during the analysis period. As a sensitivity analysis, for Texas, Louisiana, Pennsylvania and New York, the study considers the impact of imposing severance taxes of 10%, with royalty remaining unchanged. For Alberta and British Columbia, the study examines the impact of royalty increases of 20% from current levels. These levels have been assumed in order to capture the direction of higher taxes and royalties. It should be noted that actual levels can vary and be higher or lower than these assumptions.

Table 3-7 highlights the key assumptions for the sensitivity analysis incorporating these more aggressive severance taxes and royalty rates.

Table 3-7 Sensitivity Assumptions on Severance Taxes and Royalties

	Severance Tax			Royalty		
Gas Price	$3/MMBtu	$6/MMBtu	$9/MMBtu	$3/MMBtu	$6/MMBtu	$9/MMBtu
TX	10%			12.50%		
LA	10%			12.50%		
PA	10%			12.50%		
NY	10%			12.50%		
AB	0%			7%	22%	29%
BC	0%			32%	32%	32%

4.0 DRIVERS OF NATURAL GAS DEMAND

4.1 Natural Gas Demand Growth

Natural gas demand in North America is comprised mainly of demand from the residential, commercial, industrial and power generation sectors. In this section we review the importance and uncertainty of natural gas demand from each of these sectors. Black & Veatch's view is that the largest source of uncertainty lies in the demand for gas in the power sector, and that demand for gas in the power sector is likely to increase significantly.

Traditionally, residential and commercial demand for natural gas has been the largest of these components. Demand for natural gas for residential and commercial needs declined from 2000 to 2009 at an annual rate of -0.37%, due in part to the recent economic downturn. While moderate population and economic growth served to increase gas demand, these forces were more than offset by efficiency gains. Estimates of natural gas demand for residential and commercial uses from different sources do not vary significantly, and future trends in residential and commercial demand are not considered a significant uncertainty affecting total North American natural gas demand.

Industrial demand for natural gas in North America experienced a significant drop starting in 2005 as some gas intensive industries shifted their production to other countries. Industrial consumption has since stabilized as manufacturing outsourcing slowed. While the recent economic recession has depressed industrial consumption slightly, it is expected to recover when economy rebounds. However, minimal growth in industrial demand is expected from this reduced baseline even after the economy recovers.

Given the relative stability in residential, commercial and industrial demand for natural gas, power generation demand for natural gas is projected to be the most significant growth engine for natural gas demand. Eighty three percent of the total generation capacity additions in the United States between 2000 and 2009 have been natural gas-fired. Natural gas demand in the Lower 48 for power generation has grown correspondingly from 14.3 Bcf/d to 18.9 Bcf/d during the same time period, or at an average growth rate of 3.3% per year.

Several factors point to increased use of natural gas for power generation. Chief among these is the increasing awareness of the detrimental environmental effects of greenhouse gas emissions. As the fossil fuel with the lowest level of greenhouse gas emissions, natural gas is poised to take a meaningful role in the future power generation capacity mix. Older and less efficient coal plants are likely to get replaced by newer and cleaner gas-fired units. Meanwhile, concerns over increased dependency on and the adequacy of supplies of natural gas, prominent a few years ago when gas prices spiked, have substantially abated with low natural gas prices and the emergence of shale gas resources.

While it is generally accepted that natural gas demand for power generation will increase during the study period, key uncertainties remain and affect the magnitude of future demand projections. This study considers the following uncertainties that could impact power generation natural gas demand:

- Load Growth and Efficiency Gains – the ultimate size of the power generation market during the study period is expected to be a function of economic growth offset by the effectiveness and success of demand side management and energy efficiency efforts
- Greenhouse Gas Limitation – although national legislation is currently at a political road block, some form of greenhouse gas emissions restrictions are anticipated during the study period. Even absent federal legislation, a patchwork of state and local efforts to address climate change such as in California, combined with possible EPA rules to limit greenhouse gas emissions, seem likely to

proceed. The ambitiousness and effectiveness of these greenhouse gas emissions restrictions will determine the extent of the push to natural gas and other cleaner sources of energy.

- Nuclear and Renewables – nuclear and renewable energy are considered as both complimentary to and substitutes for natural gas-fired power generation. The viability, in a meaningful scale, of these technologies during the study period constitute an important uncertainty impacting the ultimate demand for natural gas-fired generation.

The Black & Veatch Energy Market Perspective (EMP) is prepared every six months to provide B&V clients a fresh and insightful assessment of the current state of North American energy markets. It includes a Base Case long term view of how those markets may function. Black & Veatch's forward expectations for North American energy markets incorporate a transparent and internally consistent approach to analysis of the energy markets and the government policies that influence them: a view of the markets for generation fuel sources; a view of the electric power markets; and an Integrated Market Modeling process designed to capture both the broad policy level assumptions and detailed structural market representations to arrive at a consistent, integrated market view. To arrive at forward view for the electricity market, Black & Veatch draws on a number of commercial data sources and supplements them with its own view on a number of key market drivers, for example, power plant capital costs, environmental and regulatory policy, fuel basin exploration and development costs, and gas pipeline expansion. The sections below highlight key assumptions that underlie this view and will critically affect demand for natural gas for power generation.

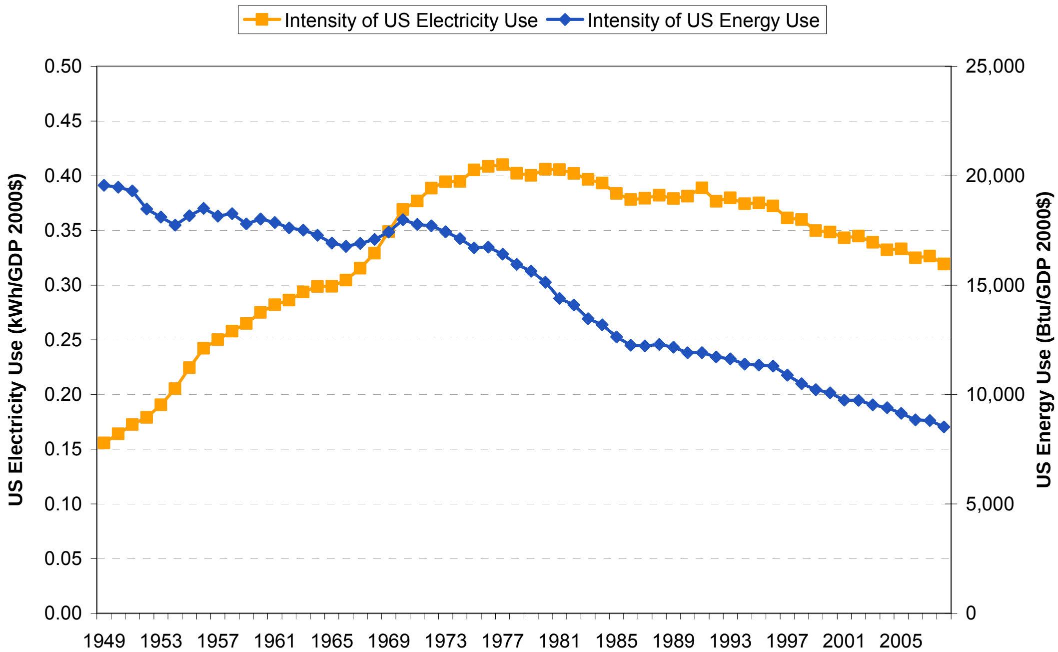
Overall, Black & Veatch expects longer-term resource needs will be met by natural gas resources, with a growing role for nuclear and possibly Integrated Gasification Combined Cycle (IGCC) with Carbon Capture Sequestration (CCS) for meeting base load growth. The likelihood of this future will be bolstered if the costs of greenhouse gas (GHG) allowance costs, taxes, or emissions compliance costs cause retirement of some of the smaller, older, less efficient coal fired units. The development of nuclear power, wind, solar and natural gas resources and acquisition of offsets are all expected to be part of the compliance stew.

4.2 Efficiency Gains and Projected Net Load Growth

4.2.1 Energy Efficiency – DSM and Smart Grid Developments

Energy intensity (energy consumption per dollar of GDP) has declined continually since WWII, and electricity efficiency has been improving since 1970 (Figure 4-1), indicating that economy-wide energy efficiency has steadily increased. Energy intensity declined slowly prior to the 1970s, but its rate of decline has subsequently increased significantly. Since 2000, average annual growth in electricity use has been 1.1% lower than the GDP growth during the same period. Various efforts to enhance energy efficiency are underway that are expected to have an impact on the total load growth during the study period.

Figure 4-1 U.S. Energy and Electricity Intensity of Use 1949-2008



Demand side management (DSM) and energy efficiency (EE) programs reduce electricity consumption and peak demand on the customer's side of the meter, allowing load-serving entities to deliver less energy and to reduce the need for new infrastructure investment. Smart Grid is a broad terminology for a wide range of enabling procedures and technologies to allow DSM/EE programs to be successful, as well as giving the power industry new mechanisms to more efficiently manage their assets.

The net impact of DSM/EE and smart grid investments is incorporated into the electric load forecasts Black & Veatch has compiled from load-serving entities and is used as the basis to develop our long term power demand view. To understand the net impact of efficiency gains of all types, a comparison can be made to the role of electricity in the economy. In the decade prior to the recession (1998-2007), GDP grew at 2.9% per year while electricity demand grew at 1.8% per year or 1.1% lower than the GDP growth. If GDP growth of 2.5 to 3.0% per year is a reasonable level of expected future growth, then, assuming no more efficiency gains and a power demand that is 1.1% lower than GDP growth, the long run rate of growth in power demand would be 1.4% to 1.9% per year. As discussed in more detail in the next section, the long term electric power demand growth rate projected by Black & Veatch is about 1.1% per year. This is an indication that continued efficiency gains from all sources are contributing to a demand growth reduction of about 0.3 to 0.8 percentage points per year.

4.2.2 Power Demand Growth

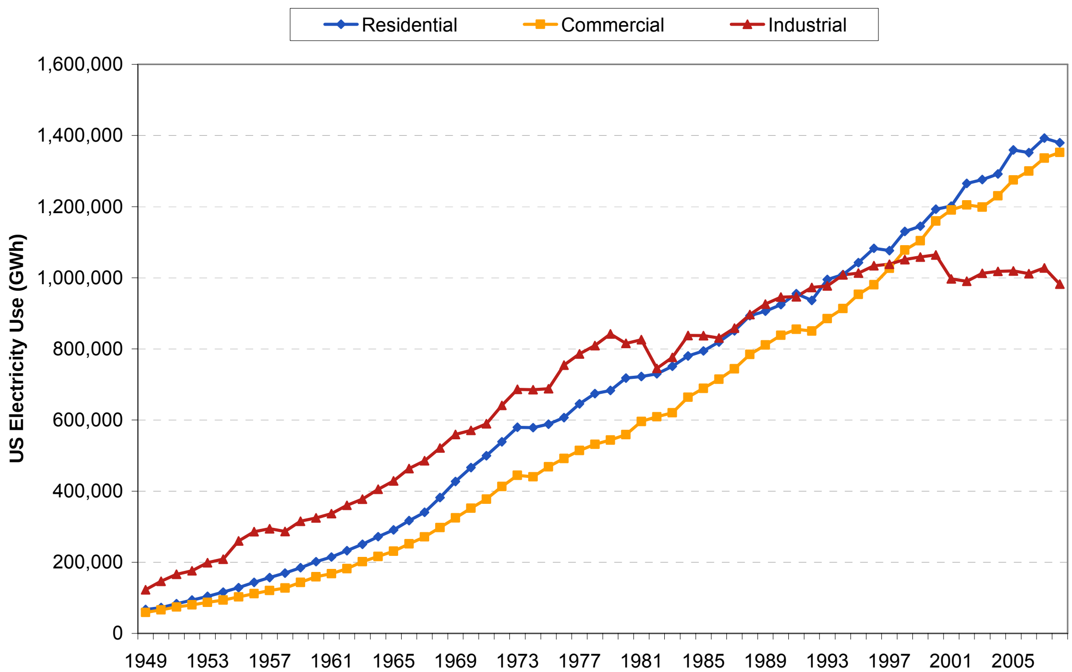
Taking the long view of electricity use over the latter portion of the last century (see Figure 4-2), the industrial sector was hit hard by the general increases in energy prices after the OPEC I and II embargoes in the 1970s. Industrial gas demand growth has remained sluggish since then. In 2009, industrial demand was at its lowest since 1987. Overall, electricity consumption during the 2007-2009 period has decreased by 5%, broken out by sector as follows:

- Residential: -2.1%

- Commercial: -1.0%
- Industrial: -14.1%

Recovery of energy demand growth requires growth in the overall economy. Recently, U.S. GDP growth has been positive, though this has largely been an inventory recovery so far with growth rates of 2.2%, 5.6% and 3.2% respectively in the 3rd quarter in 2009, 4th quarter in 2009 and 1st quarter in 2010.

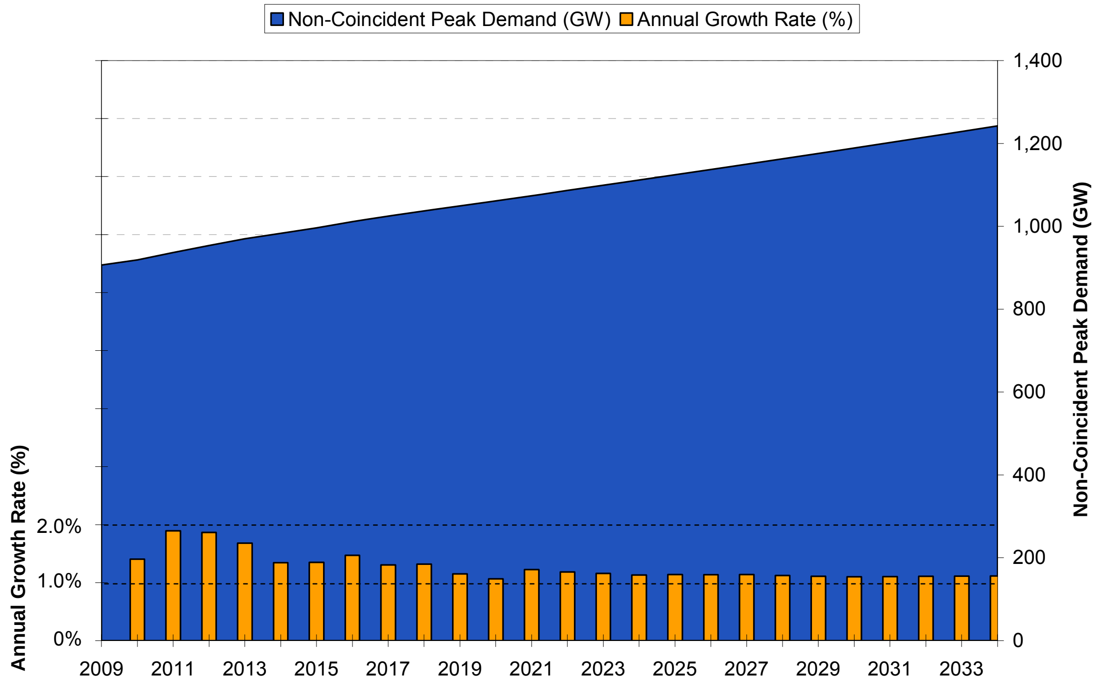
Figure 4-2 Electricity Use by Sector 1949-2009



Black & Veatch's forecasted energy and peak demand data for the next ten years or so are developed from a combination of data and market intelligence gathered directly from sources at NERC regions and ISOs, FERC 714 filings, ISO and RTO publications and data. Some agencies provide more than 10 years of data projections and these are used when available. Extrapolation beyond the reporting periods assumes that peak demand and energy grow at 80% of the average energy growth rate over the last several years of the forecast reporting period. This acknowledges the aggregated effects of long term economic trends, including increased social and political emphasis on DSM, and real dollar increases in retail electricity prices due to natural gas prices and GHG emission costs.

Black & Veatch's expectation of electricity demand growth in 2010-2013 is 1.7% per year in peak demand, a cumulative bounce of 7% in 4 years reflecting a moderate economic rebound, before reverting to a long term load growth trend of about 1.1% per year with regional variations. This is illustrated in Figure 4-3.

Figure 4-3 Forecasted Peak Demand – North America



4.3 Projections for Greenhouse Gas (GHG) Emission Limits

GHG legislation will raise costs of carbon emission. It will change the expected relative costs of meeting future electricity demand. The need for future gas demand for power generation depends on the relative contribution of renewables and nuclear generations as other lower-carbon electricity sources.

4.3.1 Analysis Assumptions for GHG Emissions Control

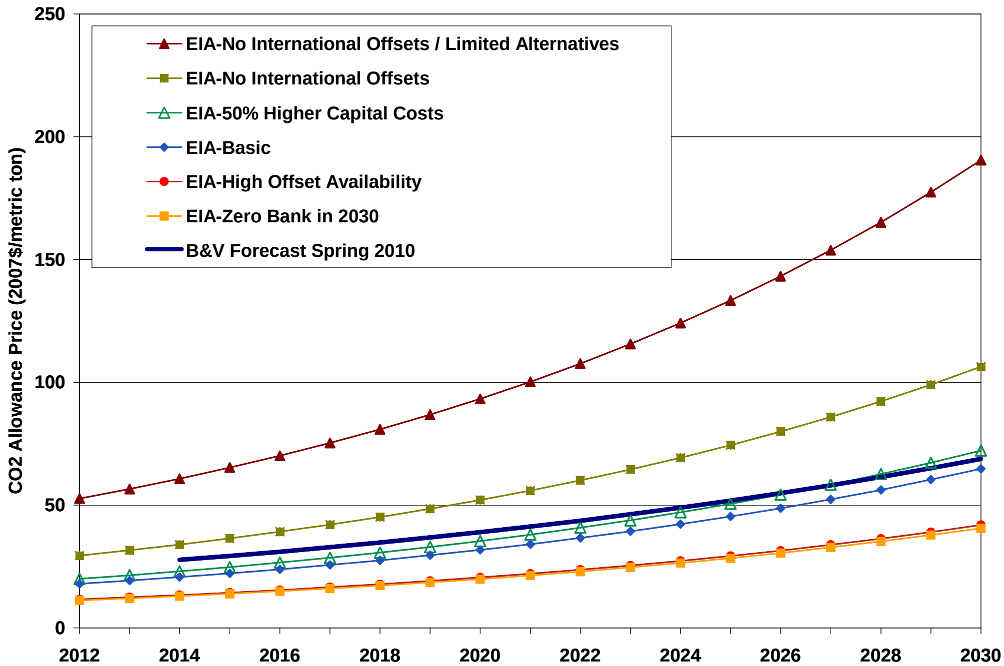
Black & Veatch used an in-house fundamental model that assumes that compliance is centered on a cap and trade program, using the Waxman-Markey bill as a proxy. Legislative delays make 2016 the first year of implementation. The program is assumed to cover electric generation, transportation and other fossil fuels used by residential, commercial and industrial sectors. The CO2 emission caps assumed were:

- 6.5% of 2005 GHG emission levels by 2014 (2.7 billion short tons – 2.5 billion metric tons)
- 17% by 2020 (2.4 billion short tons – 2.2 billion metric tons)
- 42% by 2030 (1.7 billion short tons – 1.5 billion metric tons)
- 83% by 2050 (0.5 billion short tons – 0.45 billion metric tons)

For a detail discussion on the treatment of allowance offsets and other compliance measures in the B&V analysis, please see APPENDIX E.

Studies by both the U.S. EPA and U.S. DOE-EIA clearly demonstrate that GHG allowance prices would be much higher if the availability of international offsets is limited. This seems to be the key risk driver for GHG allowance prices. As seen in Figure 4-4, the Black & Veatch baseline forecast for GHG allowances falls squarely in the middle of the scenarios forecasted by EIA and is consistent with mid-range assumptions on technology and offset availability:

Figure 4-4 EMP and EIA GHG Allowance Price Forecasts



4.4 Renewables

Increasing the use of renewable sources of power generation is an important long-term policy objective for the United States and other countries. However, depending on a number of characteristics of the power generation industry structure, renewable energy may not be cost effective without carefully designed incentives. In the short term, policy support for renewables is and has been characterized by the application of federal production tax credits (PTC) or investment tax credits (ITC). The continued integration of renewable resources will depend increasingly on the construction of new transmission infrastructure to move the electricity generated by often remotely located power generation sources to load centers. Finally, in the medium to long-term, the place of renewable power generation in the overall U.S. electricity supply is expected to be institutionalized through Renewable Portfolio Standards at both the state and/or federal levels.

4.4.1 Overview of Current State Renewable Portfolio Standards

Black & Veatch has reviewed the State RPS targets with respect to the RPS cost-management features and other factors. In Black & Veatch's judgment, some states will not be able meet their RPS due to the overall high costs. A summary of states that currently have a renewable portfolio standard in effect is shown in Figure 4-5. The model assumptions for this study, therefore, are based on somewhat lower levels of renewable penetration. In aggregate, these programs collectively result in the level of construction shown by region in Figure 4-6, which has also been incorporated into the power model used to model the overall generation of electricity, and resulting natural gas demand. The Midwest, Northeast, and Southeast are combined into a single region (the Eastern Interconnect), and the total nameplate capacity of all renewable technology in the Black & Veatch model is plotted (Figure 4-6),. The majority of the capacity is from wind, though small amounts of geothermal hydro are also assumed in the West. A cost of electricity analysis (as detailed in APPENDIX C) and the availability of different technologies were utilized to determine which renewable resource is utilized to meet the RPS targets.

Figure 4-5 Renewable Portfolio Standards Requirements by State

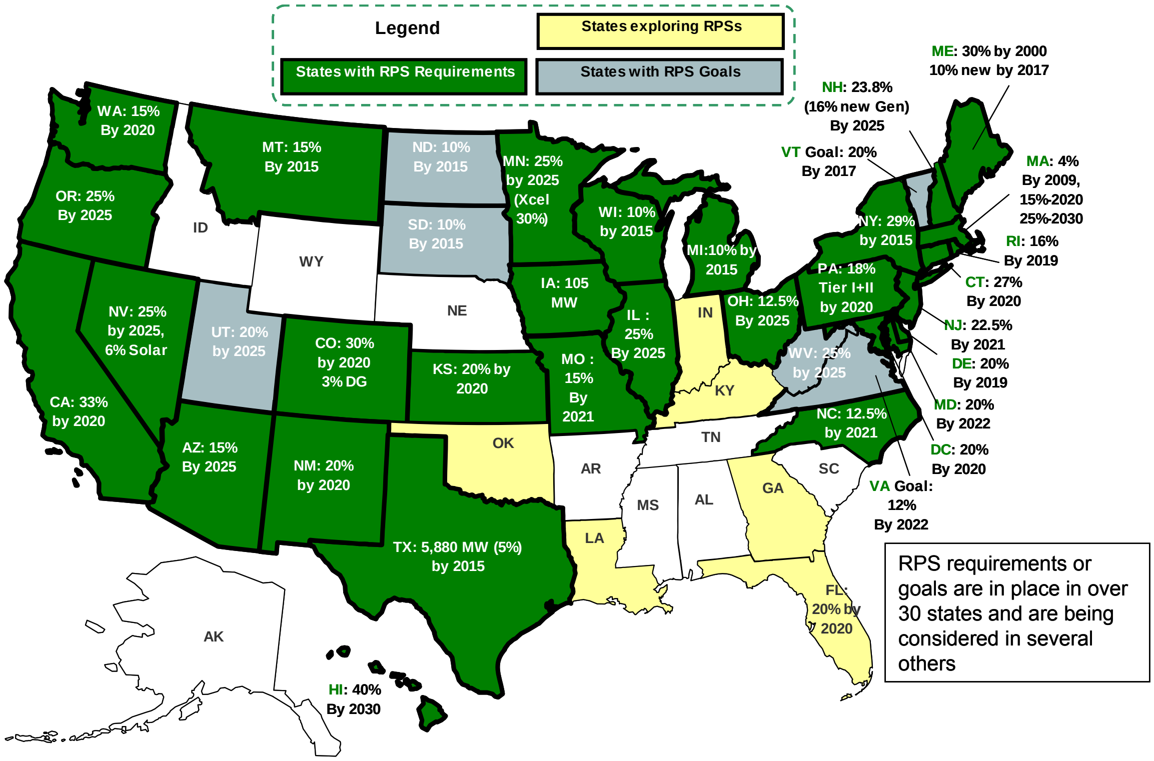
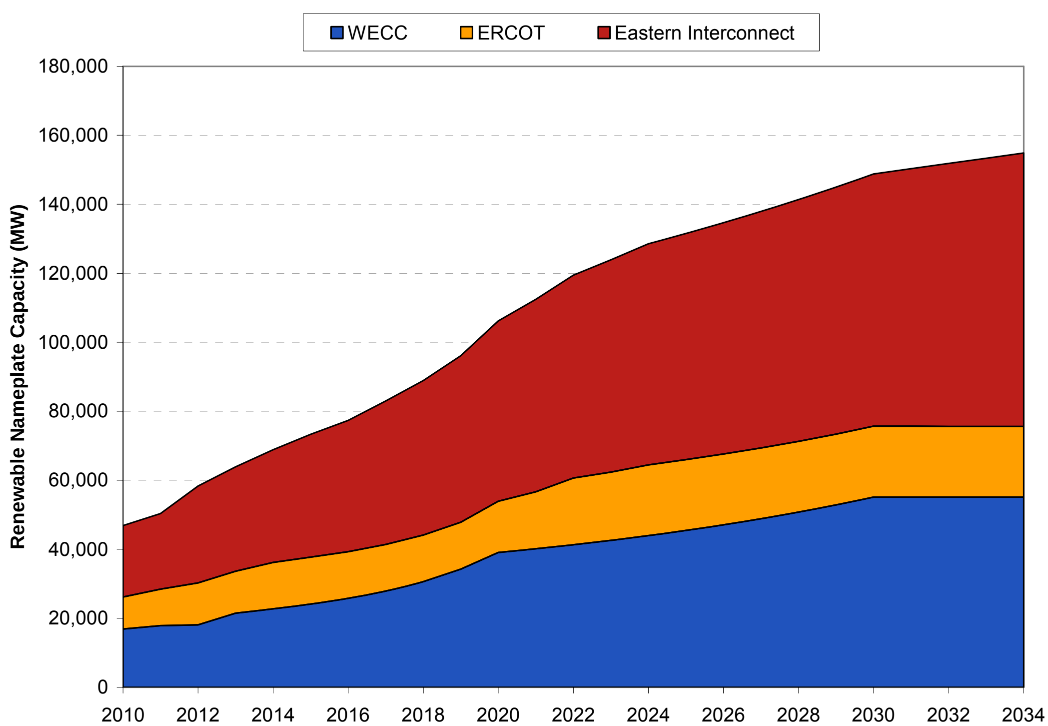


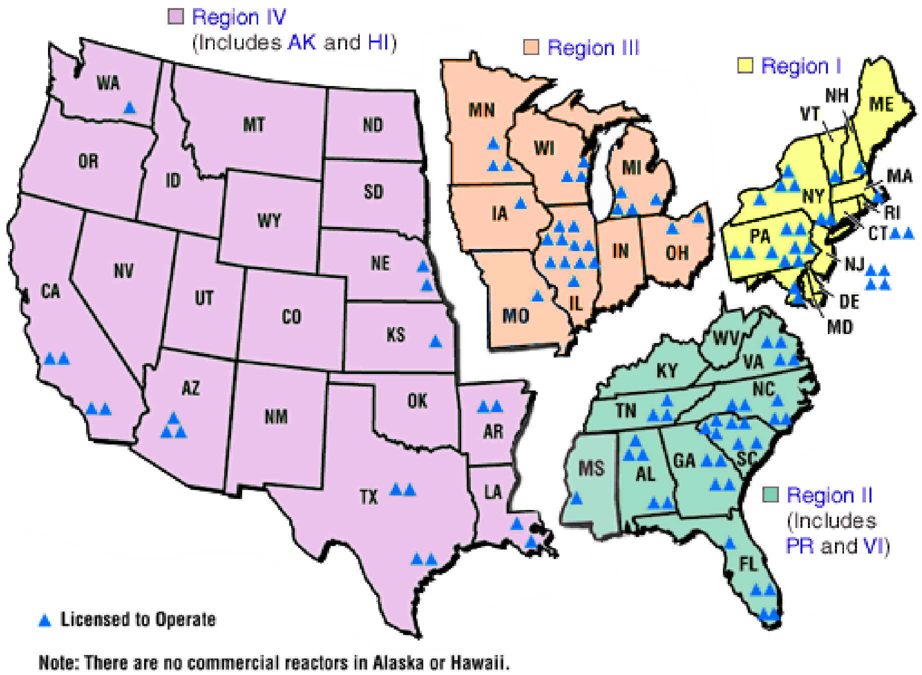
Figure 4-6 Regional Aggregate RPS Model Assumption



4.5 Nuclear

Currently there are 104 licensed operating nuclear generating units in the United States, accounting for about 97,000 MW of generation capacity and about 20% of the energy generated in the country. The approximate locations of this nuclear capacity are displayed in Figure 4-7 below. In addition, there are 16 fully-operating units in Canada with a total capacity of about 11,300 MW (and there are several other inactive units that are planned for re-starting).

Figure 4-7: Distribution of U.S. Nuclear Power Plants



Sources: U.S. Nuclear Regulatory Commission and the OECD Nuclear Energy Agency.

Nuclear power in the U.S. may now be entering a period of resurgence, prompted by growing concerns over greenhouse gas emissions from fossil fueled technologies and the difficulty experienced by industry in the permitting of new coal-fired capacity. In order to support financing for this strategic but capital intensive technology, the U.S. federal government is facilitating nuclear development through two major policy initiatives: Nuclear Power 2010 Program, and the Energy Policy Act of 2005.

Over the last few years interest in developing new nuclear power plants has grown substantially. In part this is driven by the need for new base load generation capacity to meet demand growth and replace retiring assets, and in part by the re-characterization of nuclear energy as a green technology due to its lack of greenhouse gas emissions. The provisions of the Nuclear Power 2010 program set events in motion as development consortia were pulled together and Combined Construction and Operating License (COL) applications were prepared. Furthermore, the nuclear provision of the EP Act 2005, in particular the production tax credits for the first 6,000 MW completed, created a "land rush" mentality for the filing of COLs and the beginning of campaigns to design and build the new generation of nuclear plants.

APPENDIX D shows the assumptions for new nuclear capacity in the B&V base case model. Currently, the B&V long-term view reflects the following roles for nuclear power in North America:

- Nuclear capacity 11% in 2010, and 11% in 2034.

- Nuclear generation is 19% in 2010, and 22% in 2034.

Although additional plants may have been announced, B&V has not necessarily included them due to high-level judgments about the overall momentum of the projects. Although these conditions can change, the table represents a reasonable forecast of new nuclear capacity. In 2009-10 a few plants at least temporarily left the development queue, including Amarillo and Victoria County in Texas and Hammett in Idaho, and others are reconsidering their technology choice. Within the nuclear power and financial industries there is a widely-shared belief that financing a major nuclear resurgence will require more financing capability than sponsors currently have, necessitating greater government support in the form of loan guarantees. Supporters see additional financial support for nuclear power may come from amendments to any Greenhouse Gas legislation that is ultimately passed by Congress.

4.6 B&V View and EIA Annual Energy Outlook 2010 on Future Capacity and Energy

The Black & Veatch view on the changing mix in power generation technology over time is somewhat different than the EIA Annual Energy Outlook 2010 (EIA AEO 2010). It is not surprising, therefore, that project power generation produced by each technology also differ. These differences may be understood by examining, in turn, the differences in several of the key structural assumptions that underlie each perspective.

Considering the power generation mix, Figure 4-8 shows the annual net additions and retirements of power generation capacity by technology according to the B&V perspective; the same is shown for the EIA AEO 2010 in Figure 4-9. The B&V view is characterized by a steady retirement of conventional coal plants over the first portion of the study, based on our understanding of the effects of 1) an expected cost of CO2 emissions, and 2) forthcoming and increasingly stringent environmental regulations primarily related to air emissions. Based on our experience in working with the power generation industry, we believe that the set of these coal plant retirements will be comprised of smaller, older plants which cannot be reasonably expected to bear the cost of upgrades to their air quality control systems. In contrast, the EIA AEO 2010 Outlook reflects comparatively few retirements of coal plant capacity.

The B&V view reflects the assumption of a slightly higher rate of growth in electricity demand than the EIA AEO 2010 Outlook. This is in part due to different expectations for the role of energy efficiency. The next effect is that the B&V view adds somewhat more net capacity than the EIA AEO 2010.

Nuclear capacity is assumed to be added in the B&V view, based on our Spring 2010 assessment of the pace of nuclear generation additions in the U.S., which is markedly higher than in the EIA AEO 2010 Outlook. Conversely, the B&V view also reflects a much more moderate pace of addition of renewable capacity than the EIA AEO 2010, which shows significant renewable capacity additions through 2013, related to the tax incentives and grants provided via the 2009 economic stimulus package (ARRA). B&V also considers it necessary to add considerably more combustion turbine peaking capacity than in the EIA AEO 2010, even though this capacity rarely produces power except during peak summer periods.

Figure 4-8 U.S. Total Nameplate Capacity - B&V Spring 2010 EMP

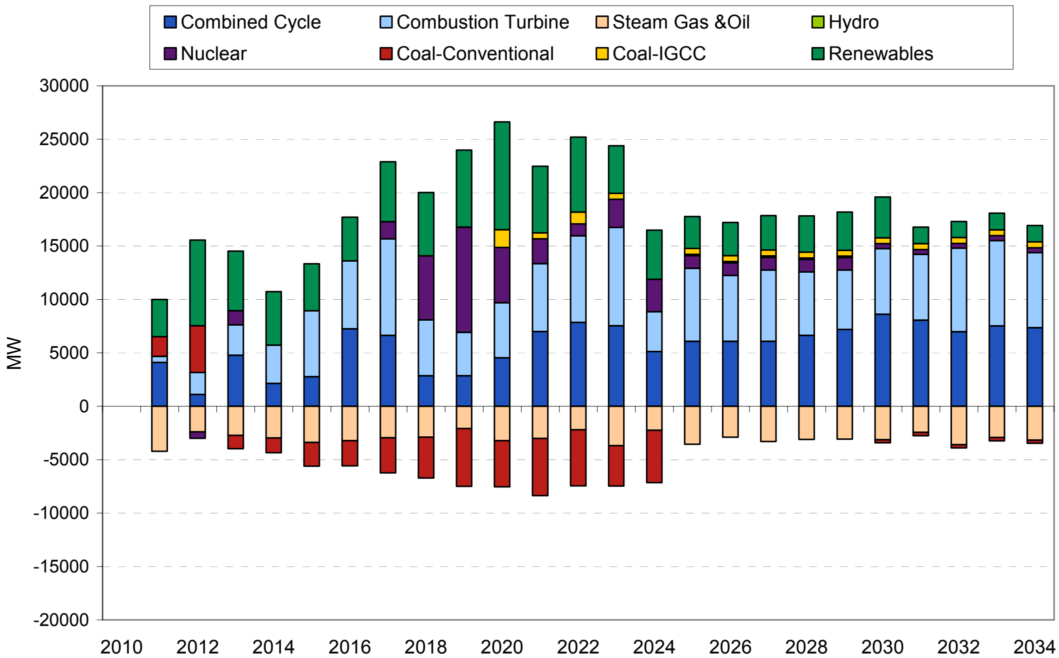
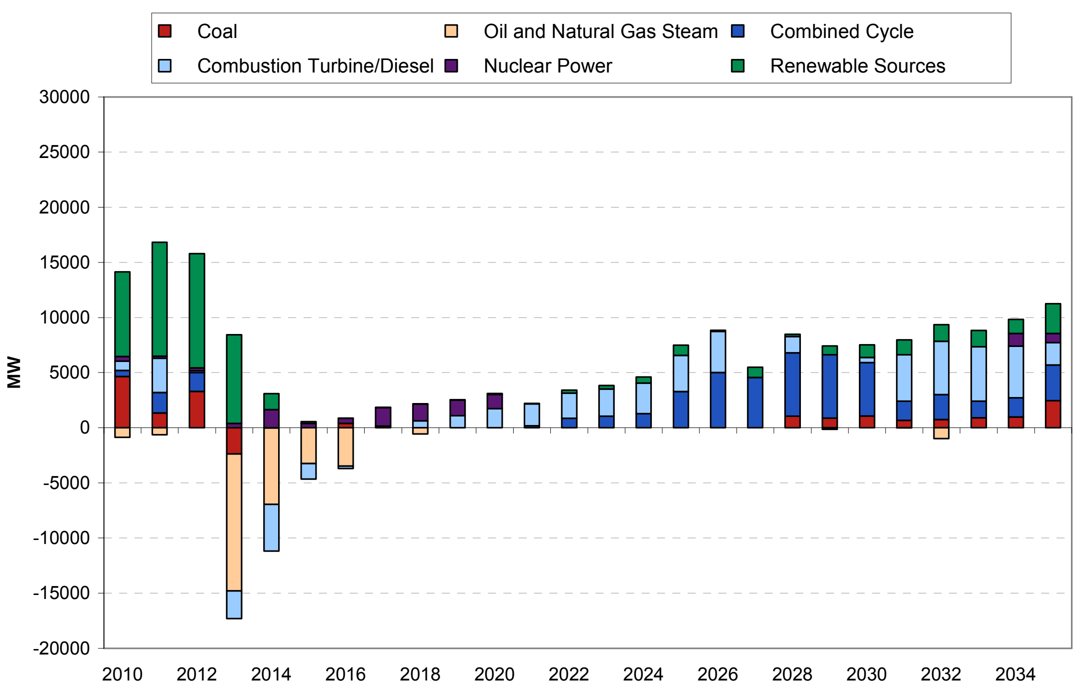


Figure 4-9 U.S. Total Nameplate Capacity - EIA AEO 2010



These differences in the type of generating capacity are reflected in the future generational levels by each technology found in the B&V view (Figure 4-10) and the EIA AEO 2010 (Figure 4-11). The most significant difference is the coal generation levels, which increase in the EIA AEO 2010, while decreasing in the B&V view in response to CO2 allowance costs and retirements of old coal capacity having high rates of air emissions. In this respect, we believe that the B&V view is informed by more reasonable structural assumptions than is the EIA AEO 2010. Of course, the difference in level of coal generation has complementary implications for the higher levels of generation from natural gas-fired generation in the B&V view than in the EIA AEO 2010. Generation levels from renewable energy sources between the two perspectives are similar, which indicates a difference in understanding between B&V and the EIA of typical capacity factors associated with renewable energy. The B&V view has somewhat higher levels of generation from nuclear power plants, which operate at baseload and as a low-cost generating technology therefore produces in proportion to its aggregate capacity.

Figure 4-10 U.S. Total Generation - B&V Spring 2010 EMP

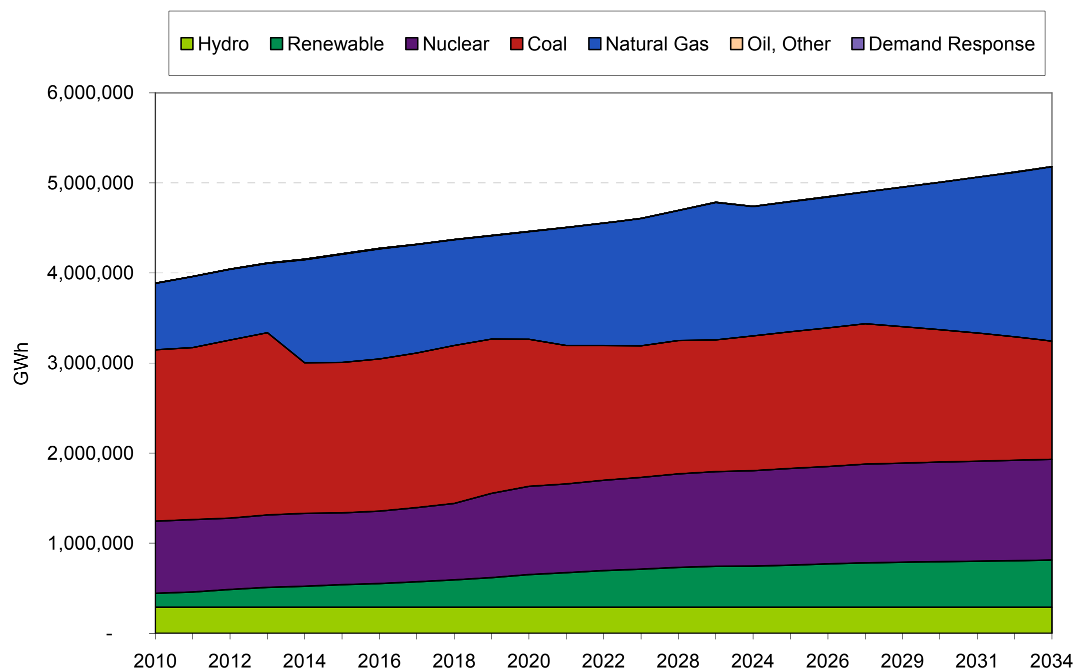
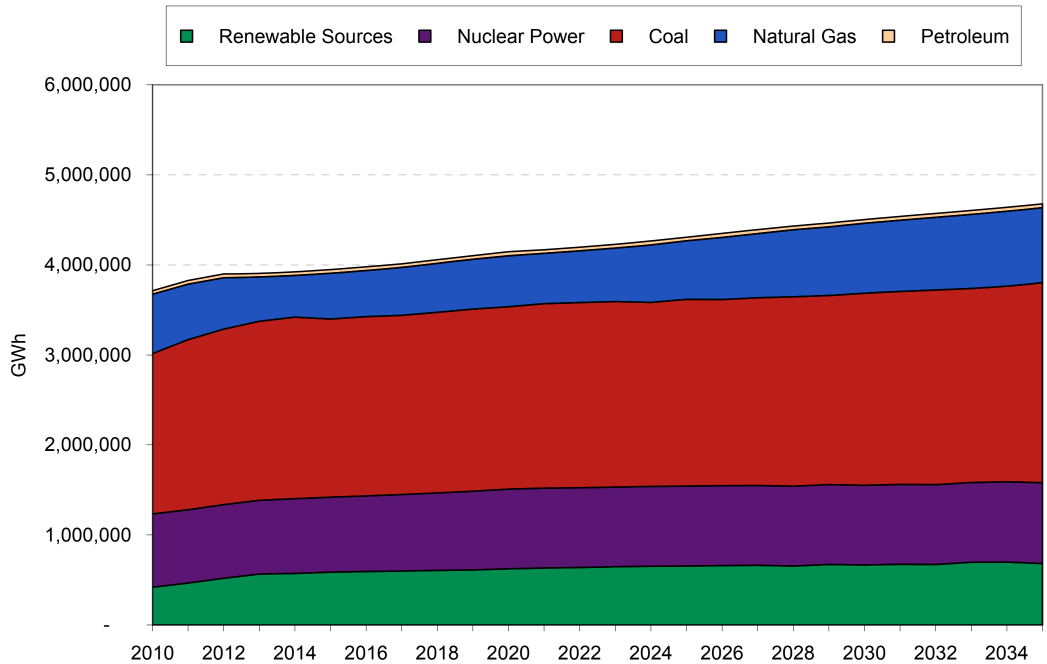


Figure 4-11 U.S. Total Generation - EIA AEO 2010



5.0 ANALYSIS OF NATURAL GAS PRICES - MID PRICE SCENARIO

5.1 The Mid Price Scenario Description

In the Mid Price Scenario, shale gas development is robust but somewhat moderated by higher cost structures than currently experienced. Greenhouse gas emission limits create additional demand for natural gas for power generation to absorb this natural gas supply. The increased availability and moderating price effects of shale gas supply help facilitate policy action on GHG emissions control.

The Mid Price Scenario assumes that greenhouse gas emission limits are adopted and implemented by 2016. As a result, natural gas-fired generation becomes the leading technology for electric capacity additions after long-term efficiency gains, renewable generation, and nuclear generation are accounted for. This is largely due to the fact that its lower costs associated with CO_2 gives natural gas a price advantage over coal as a fuel for electric generation. Fewer coal plants are to be built and in the long run a number of inefficient coal-fired units are to be retired.

Vast North American natural gas shale supplies are projected to provide an adequate resource base which is capable of meeting growing natural gas demand from the power sector. The F&D costs of these shale plays are assumed to remain low – in line with best estimates, discussed above – in the near term, but grow over time as the core areas of shales are developed and producers spud wells in peripheral areas with less favorable drilling economics. Production costs could also potentially escalate due to the costs of water treatment associated with fracing. This could be a very significant issue in Marcellus shale production in Northeast Pennsylvania and Southern New York, where natural gas development occurs in close proximity to densely populated metropolitan areas and watersheds.

Sections 3 and 4 discussed in detail the key drivers of supply and demand incorporated in this study. Table 5-1 summarizes of the main inputs related to those drivers that are incorporated in the Mid Price Scenario.

Table 5-1 Summary of Assumptions on Key Drivers for Mid Price Scenario

Drivers	Mid Price Scenario
Supply:	
Land Use	10%-20% of Marcellus reserves inaccessible
Fiscal Regime	Baseline Severance and Royalty Assumptions for U.S. and Canada
Shape of F&D Curve	Moderate Cost Escalation
Water Costs	\$0.75/Mcf for Marcellus, \$0.25/Mcf cost for all other shales
LNG	2011 to 2014 Compound Annual Growth Rate of 3.6% 13.4 Bcf/d by 2044
Demand:	
Assumption Source	B&V EMP Spring 2010
Residential and Commercial	0.7% Compound Annual Growth Rate for 2010 to 2035
Industrial	0.9% Compound Annual Growth Rate for 2010 to 2035
Power Generation	2.3% Compound Annual Growth Rate for 2010 to 2035
Electricity Load Growth	1.1% Compound Annual Growth Rate for 2010 to 2034
Renewable	108 GW additional nameplate capacity by 2034
Nuclear	41 GW additional nameplate capacity by 2034
GHG Allowance Prices	\$29/short ton of CO2 in 2016

The aggregate impacts of these assumptions on supply and demand are highlighted in Section 5.2 and Section 5.3 respectively.

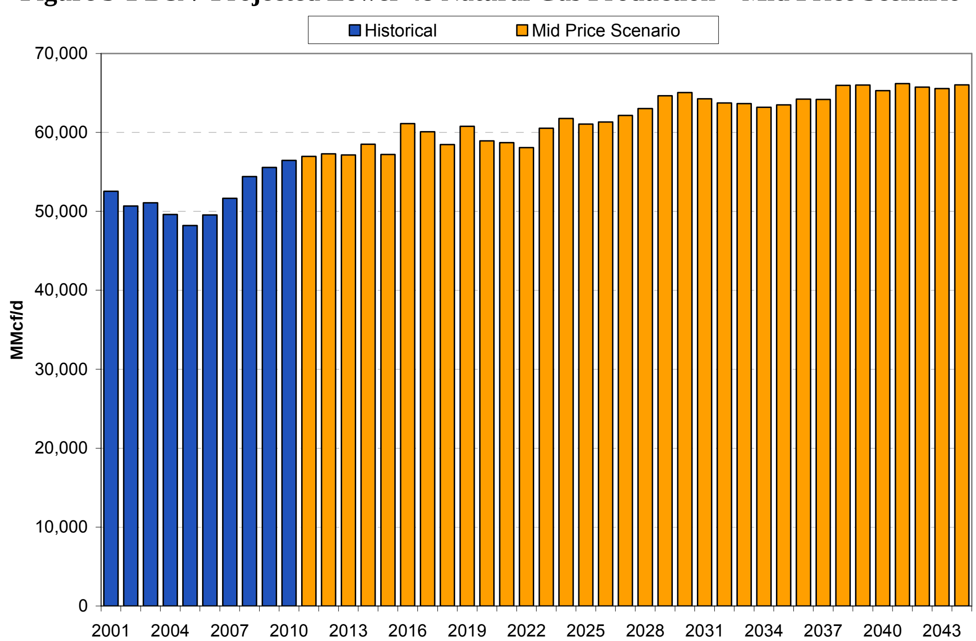
5.2 The Mid Price Scenario Supply – Key Supply Assumptions

F&D cost curves drive the production results of the study's long term price forecast. As discussed in Section 3, B&V derived F&D cost curves for the major North American natural gas basins using reported F&D costs provided by exploration and production firms in addition to several adjustments according to historical production data[11]. F&D cost curves associated with major shale plays have continuous upward growth, rather than an initial "flat" spot of constant costs. Based on early and indicative data, the study assumed that Horn River and Montney, the major Canadian shale plays, experience F&D costs which average approximately $0.7/Mcf to $1/Mcf higher than Lower 48 shales. APPENDIX B contains detailed discussion of F&D costs.

5.2.1 Projected Production from Major North America Basins and Shales

In the Mid Price Scenario, North American natural gas production grows from 70.9 Bcf/d in 2011 to reach 81.5 Bcf/d in 2044 to meet increased demand. Lower 48 state production increases from 55.6 Bcf/d in 2010 to 66 Bcf/d in 2044, growing at an average rate of 0.44% per annum (Figure 5-1). Output of emerging shale plays drives the steady increase in overall production, in spite of a general decline in conventional production. Growth in Rockies production continues to 2030 until it is displaced by lower-cost Canadian shale gas. Regional shale production growth of the Eagle Ford and Haynesville shales in Texas and Louisiana offsets declines in conventional offshore production as well as eventual declines in production at the Barnett, Woodford, and Fayetteville shales. Total North American shale gas production grows at an average 0.5% per year.

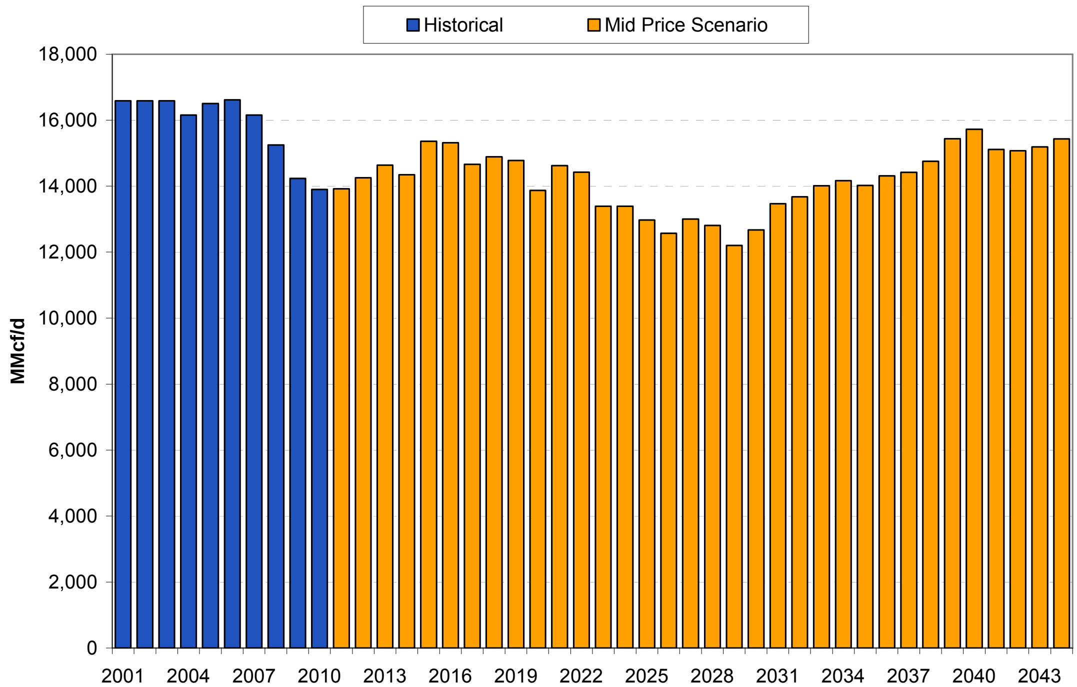
Figure 5-1 B&V Projected Lower 48 Natural Gas Production – Mid Price Scenario



Continued decline in conventional production in the Western Canadian Sedimentary Basin (WCSB) drives the overall decline of Canadian natural gas production for the next 20 years. Eventually, increased Horn River and Montney shale production lifts in Canadian production, which grows at an average annual rate of 1.3% from 2030 to 2044, reaching 15.4 Bcf/d in 2044 (Figure 5-2)

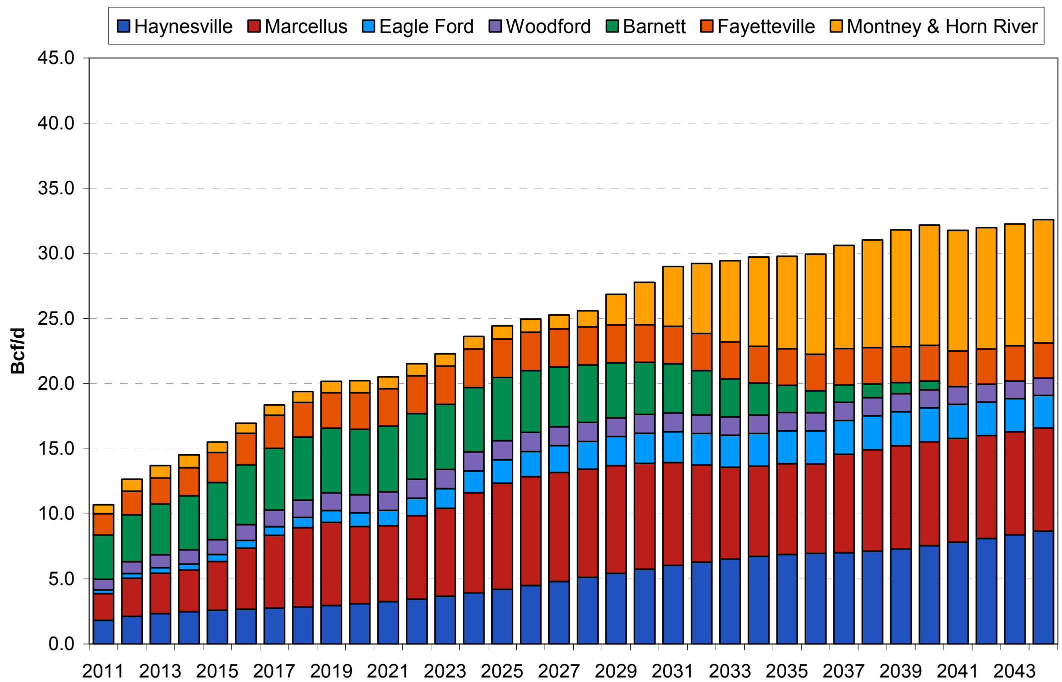
[11] See APPENDIX B for a detailed overview of B&V's derivation of F&D cost curves

Figure 5-2 B&V Projected Canadian Natural Gas Production – Mid Price Scenario



Based on available data, the assumptions for resources and expected shale plays F&D costs, highlighted in Section 3.0 and APPENDIX B of this report, Haynesville and Marcellus shale production is projected to be the largest shale resource until the 2030 time period. After 2030, these resources level off or decline, with the Montney and Horn River resources showing substantial growth and contribution to the overall North American supply mix (Figure 5-3).

Figure 5-3 B&V Projection of Emerging Shale Production – Mid Price Scenario

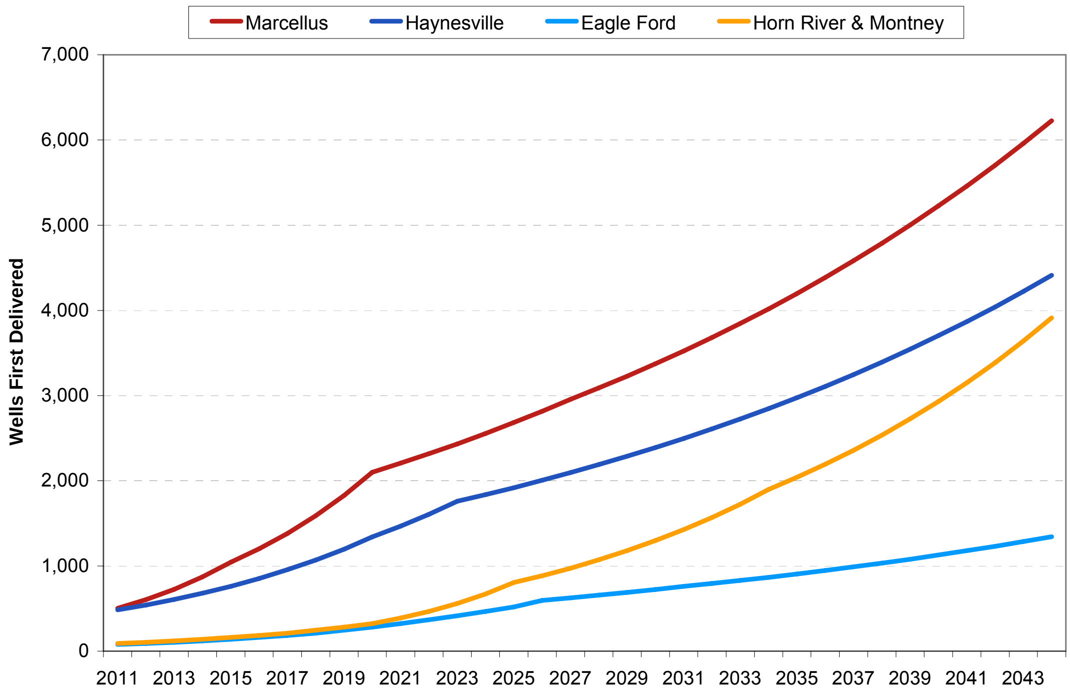


As a test on scenario realism, the study assessed the number of new production wells necessary to reach the projected levels of production for each emerging shale play. With an average EUR of 3.0 Bcf per well and the majority of production occurring in the first few years, Figure 5-4 shows the necessary wells first delivered by emerging shale play that corresponds with the shale production profiles in Figure 5-3. B&V expects annual average well growth between 12%- 19% over the next five years from 2011 to 2016. In the past 5 years, the compounded annual growth rate for wells first delivered was 10.6 % in the Barnett Shale.

B&V assumes that the Alaska Pipeline project will bring 4.5 Bcf/d natural gas into Alberta by 2020. The North Slope of Alaska has about 35 Tcf of proven gas resources and an estimated 100-200 Tcf of yet-to-find resources.

Based on recent announced delays, B&V did not include the Mackenzie Pipeline in this analysis. The Mackenzie Pipeline Project was designed to transport production from the Mackenzie delta in Canada's Northwest Territories south to Alberta. While originally expected to come online as early as 2014, a March 2010 announcement by Imperial Oil Ltd delayed the project to 2018. Given the long-drawn regulatory hurdles and access issues faced by this project, it is excluded from this study.

Figure 5-4 Projected Wells First Delivered by Shale Basin – Mid Price Scenario

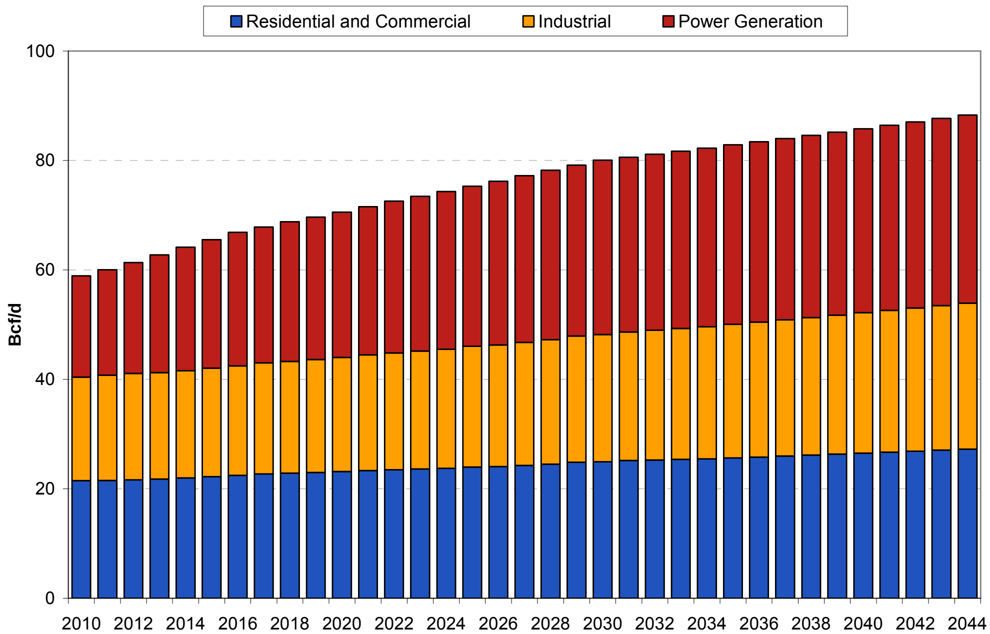


5.3 The Mid Price Scenario Demand – Key Demand Assumptions

5.3.1 Lower 48 Natural Gas Demand

In the Mid Price Scenario, Lower 48 natural gas demand grows from 58.9 Bcf/d in 2010 to 88.3 Bcf/d in 2044. This growth is largely driven by natural gas demand for electric generation, which grows at 2.3% per annum through 2035. The study assumes that Lower 48 core (residential and commercial) demand growth flattens due to increasing efficiency of consumption, averaging annual growth of 0.7% between 2010 and 2044. Industrial demand experiences a post-recession rebound starting in 2010, growing at about 1% per annum through 2044. See Figure 5-5 for a summary of projected Lower 48 natural gas demand to 2044.

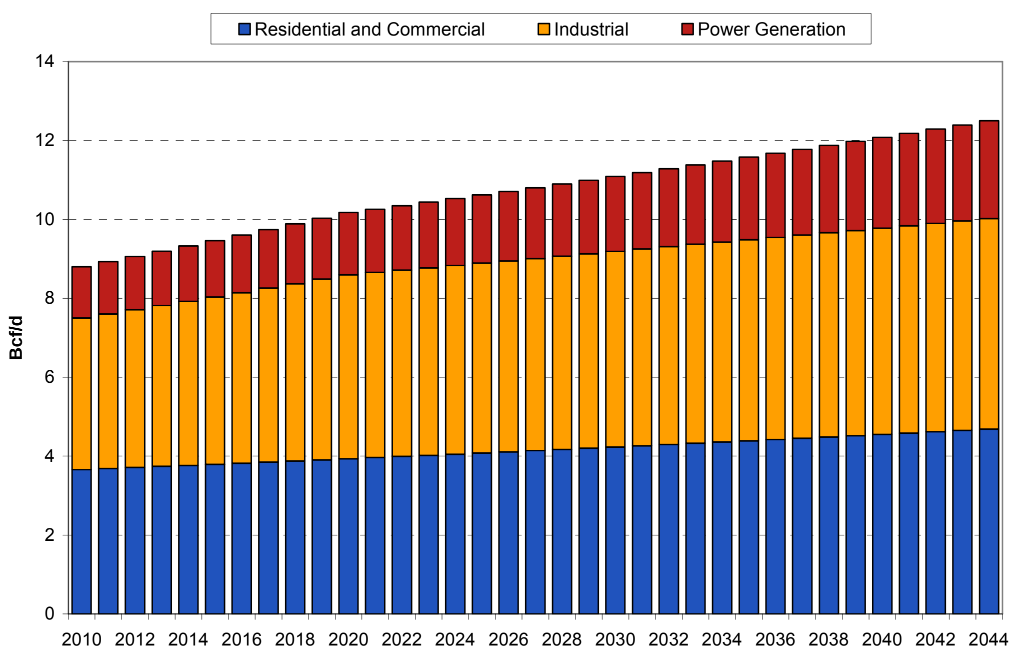
Figure 5-5 Lower 48 Natural Gas Demand – Mid Price Scenario



5.3.2 Canadian Natural Gas Demand

Canadian Natural gas demand grows from 8.8 Bcf/d in 2010 to 12.5 Bcf/d in 2044, largely driven by natural gas consumption in Alberta associated with oil sands production, along with East Canadian power generation demand. Canadian industrial and electric generation demand grow at rates of 1.09% and 1.85% per annum, respectively (Figure 5-6).

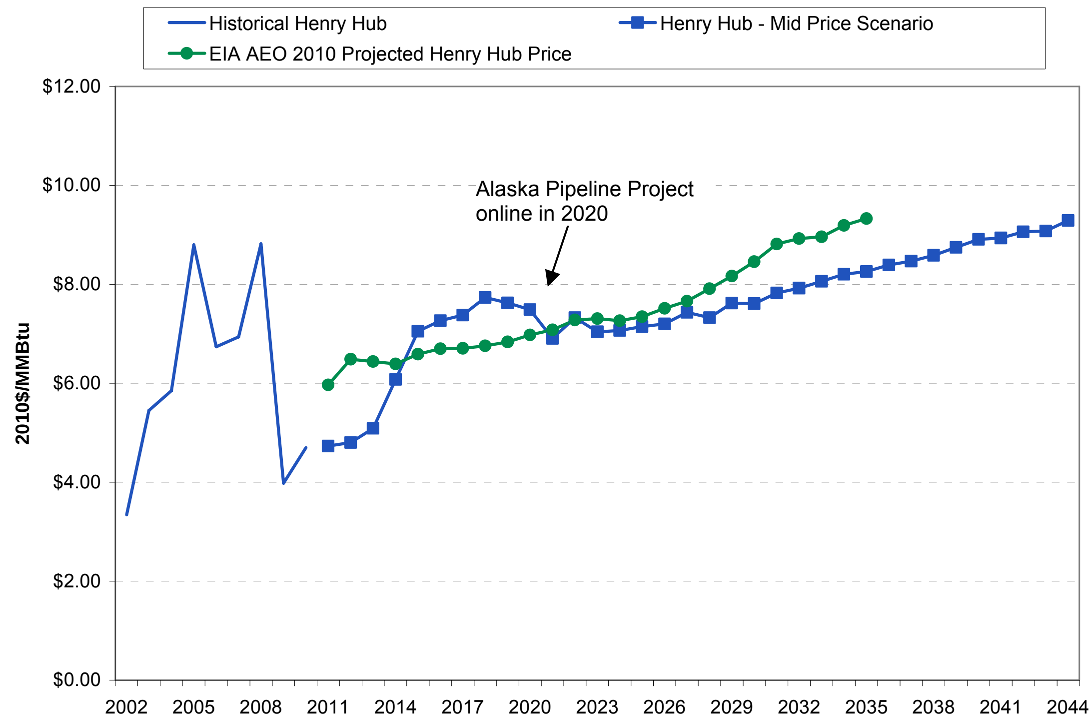
Figure 5-6 Canadian Natural Gas Demand – Mid Price Scenario



5.4 The Mid Price Scenario - Projected Henry Hub Price and Regional Bases

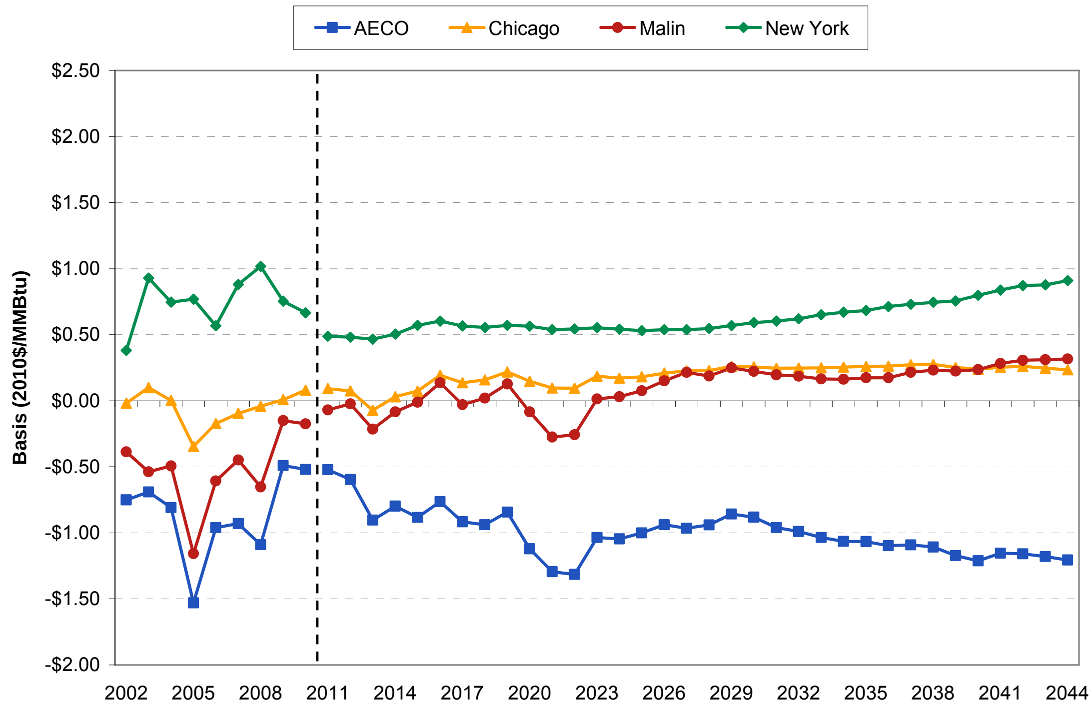
In this scenario, the Henry Hub spot price remains depressed in the near term, but then recovers with the general economy (Figure 5-7). The near term depressed prices persist longer than in EIA's AEO 2010 price forecast, largely because B&V assumes that shale production will continue to increase at a greater rate than does EIA during this period. From 2015 onwards prices tend to remain above $7.00/Dth (real 2010 dollars) as demand grows and the supply overhang from drilling activities related to lease requirements diminishes. In this scenario, prices continue to grow after 2015 due to the introduction of greenhouse gas limits and demand growth. The arrival of Arctic gas helps moderate price growth beginning in the 2020 time period.

Figure 5-7 Historical and Projected Henry Hub Prices – Mid Price Scenario



AECO basis to Henry Hub dramatically widens in 2020 due to the entry of the Alaska pipeline into the market, but moderates over time due to strong demand from Canadian oil sands operations and East Canadian power generation demand (Figure 5-8). After 2030, the emergence of Canadian shale production dampens AECO prices and widens the basis to Henry Hub. Malin basis begins to widen due to demand growth, but narrows in 2020 due to the entry of the Alaska pipeline. New York and Chicago bases growth is due in part to demand growth but moderated by emerging shale supplies in the Marcellus.

Figure 5-8 Historical and Projected Regional Basis – Mid Price Scenario



Analysis examining the sensitivity of production and prices in the Mid Price Scenario to variations in the key drivers indicates that the demand for natural gas and the cost of shale gas development are the drivers with the largest impact on North American natural gas production and prices. APPENDIX F presents this sensitivity analysis in detail.

6.0 ANALYSIS OF NATURAL GAS PRICES – HIGH PRICE SCENARIO

6.1 The High Price Scenario Description

The High Price Scenario represents a world in which supply in the North American market is constrained by a strong environmental regulatory environment, while natural gas demand is stimulated through greenhouse gas emission restrictions. Environmental concerns restrict access to shale gas resources such that 35% of Marcellus shale and 10% of all other major North American shales are inaccessible to producers. These assumptions are intended to capture the direction and general magnitude of movement of land use restrictions; actual land use restrictions are likely to be different (see Section 3). In addition, due to water costs and other issues, shale resource F&D costs are assumed to be higher than in the Mid Price Scenario. Water costs average $1.38/gallon, while higher severance taxes and royalty rates are expected to be levied in both the U.S. and Canada.

As in the Mid Price Scenario, the High Price Scenario assumes that greenhouse gas emission limits are in place by 2016. As a result, natural gas-fired generation is the leading technology choice for electric capacity additions after accounting for long-term efficiency gains, renewable generation, and nuclear generation. This is largely because lower costs associated with CO_2 give natural gas a price advantage over coal as a fuel for electric generation. Fewer coal plants are built; a number of inefficient coal-fired units are retired in the long run.

Sections 3 and 4 discussed in detail the key drivers of supply and demand incorporated in this study. Table 6-1 summarizes the key inputs that are incorporated in the High Price Scenario.

Table 6-1 Summary of Assumptions on Key Drivers for the High Price Scenario

Drivers	High Price Scenario
Supply:	
Land Use	35% Marcellus, 10% of all other shale reserves inaccessible
Fiscal Regime	10% Severance Tax in U.S.; 15% increase in BC and AB Royalty Rates
Shape of F&D Curve	Rapid Cost Escalation
Water Costs	$1.38/Mcf cost for all shales
LNG	2011 to 2014 Compound Annual Growth Rate of 3.6% 13.4 Bcf/d by 2044
Demand:	
Assumption Source	B&V EMP Spring 2010
Residential and Commercial	0.7% Compound Annual Growth Rate for 2010 to 2035
Industrial	0.9% Compound Annual Growth Rate for 2010 to 2035
Power Generation	2.3% Compound Annual Growth Rate for 2010 to 2035
Electricity Load Growth	1.1% Compound Annual Growth Rate for 2010 to 2034
Renewable	108 GW additional nameplate capacity by 2034
Nuclear	41 GW additional nameplate capacity by 2034
GHG Allowance Prices	$29/short ton of CO2 in 2016

The aggregate impacts of these assumptions on supply and demand are highlighted below in Section 6.2 and Section 6.3 respectively.

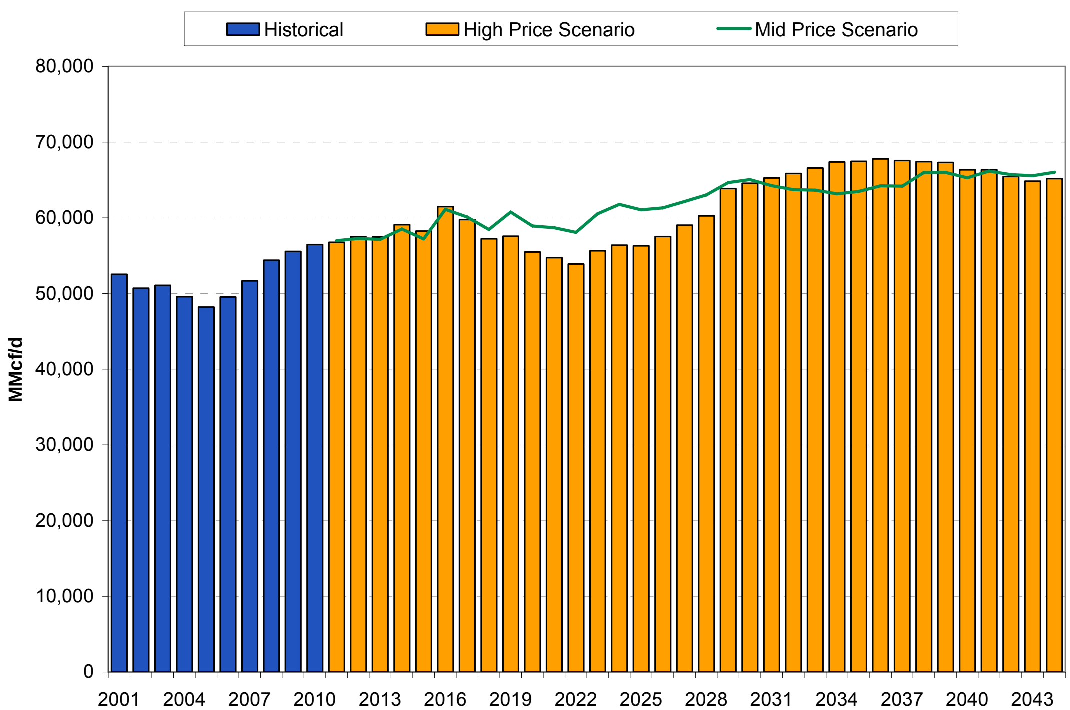
6.2 The High Price Scenario – Key Supply Assumptions

Finding and development costs for shale gas are assumed to be higher in this scenario. F&D costs escalate at a greater rate than is assumed in the Mid Price Scenario, reflecting greater environmental sensitivity and tighter regulatory control. Production costs also increase due to water treatment and disposal costs, increased severance taxes and royalty rates, and restrictions to land access. For more detail discussion of F&D costs, please see APPENDIX B.

6.2.1 Projected Production from Major North America Basins and Shales

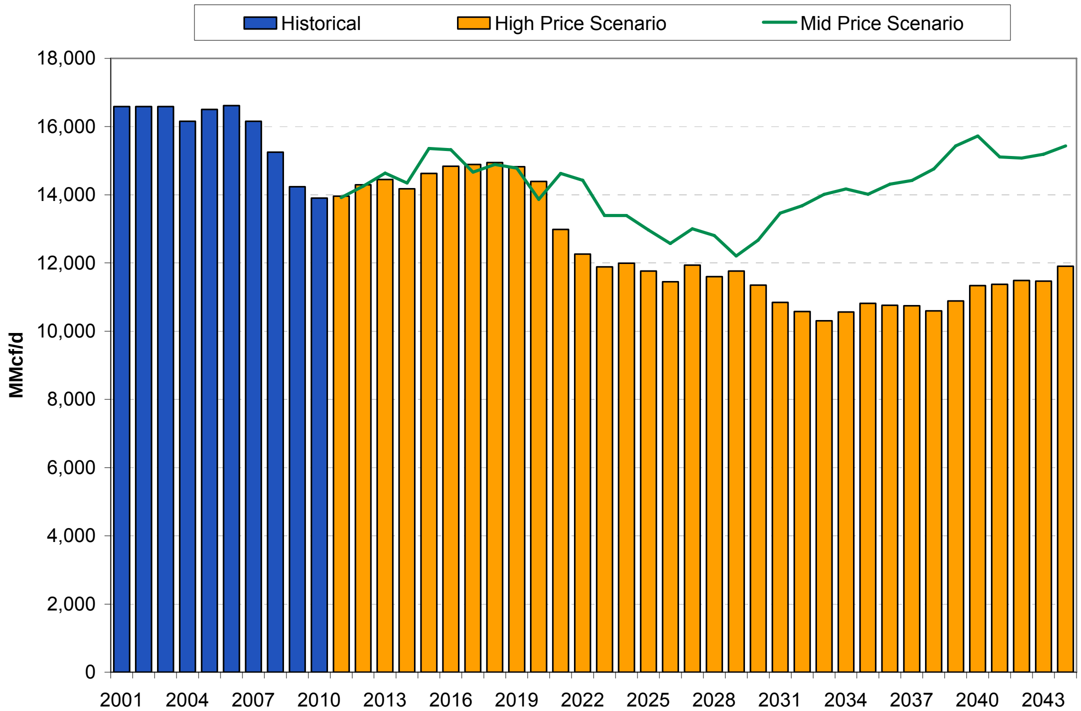
In the High Price Scenario, total North America production will occur at higher supply costs than in the Mid Price Scenario due to the more restrictive environment. This puts upward pressure on F&D costs. Higher supply costs drive prices higher, and in turn reduce total market consumption. Lower 48 gas production grows from 55.6 Bcf/d in 2010 to 65 Bcf/d in 2044, at an average rate of 0.44% per year, rates essentially unchanged from the Mid Price Scenario (Figure 6-1).

Figure 6-1 B&V Projected Lower 48 Natural Gas Production – High Price Scenario



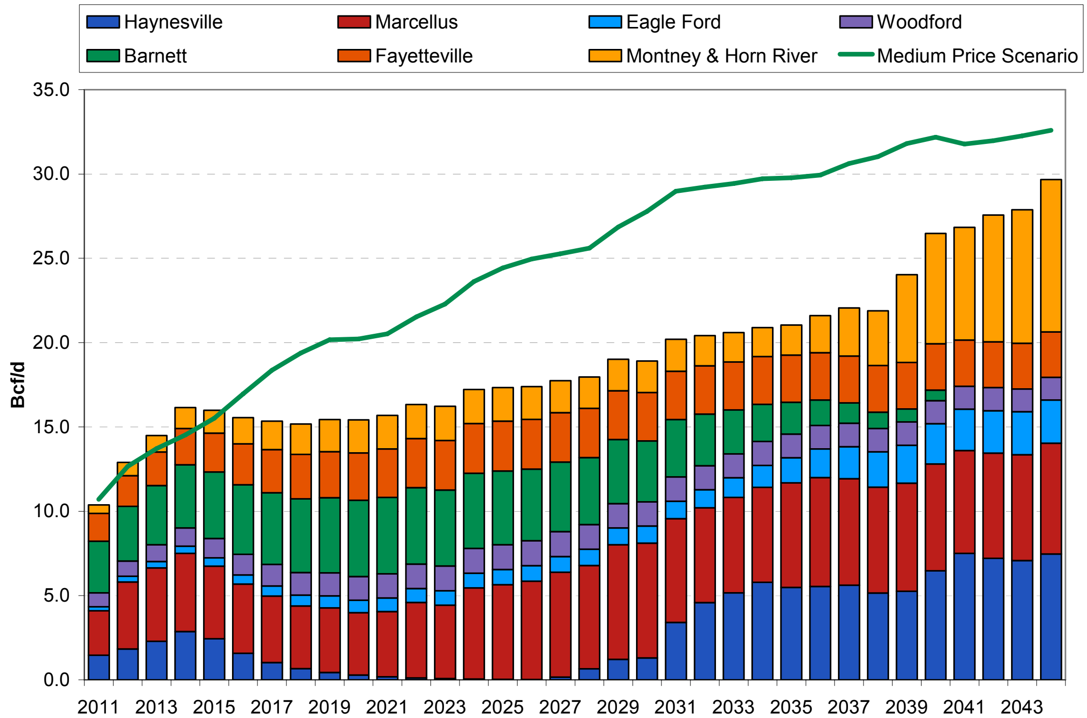
Canadian natural gas production declines from 14 Bcf/d in 2011 to 12 Bcf/d in 2044, at an average rate of -0.43% per annum from 2011 to 2044 as total demand is cut back due to higher prices (Figure 6-2).

Figure 6-2 B&V Projected Canadian Natural Gas Production – High Price Scenario



In the High Price Scenario, North American shale gas production grows at an average rate of 3.14% per annum from 2011 to 2044, reaching 29.7 Bcf/d in 2044. Production in the High Price Scenario grows at a slower rate than in the Mid Price Scenario, especially from 2011 to 2030, and does not reach the same level (Figure 6-3). In the High Price Scenario, more conventional gas is produced at the expense of shale gas production.

Figure 6-3 B&V Projection of Emerging Shale Production – High Price Scenario



6.3 The High Price Scenario – Key Demand Assumptions

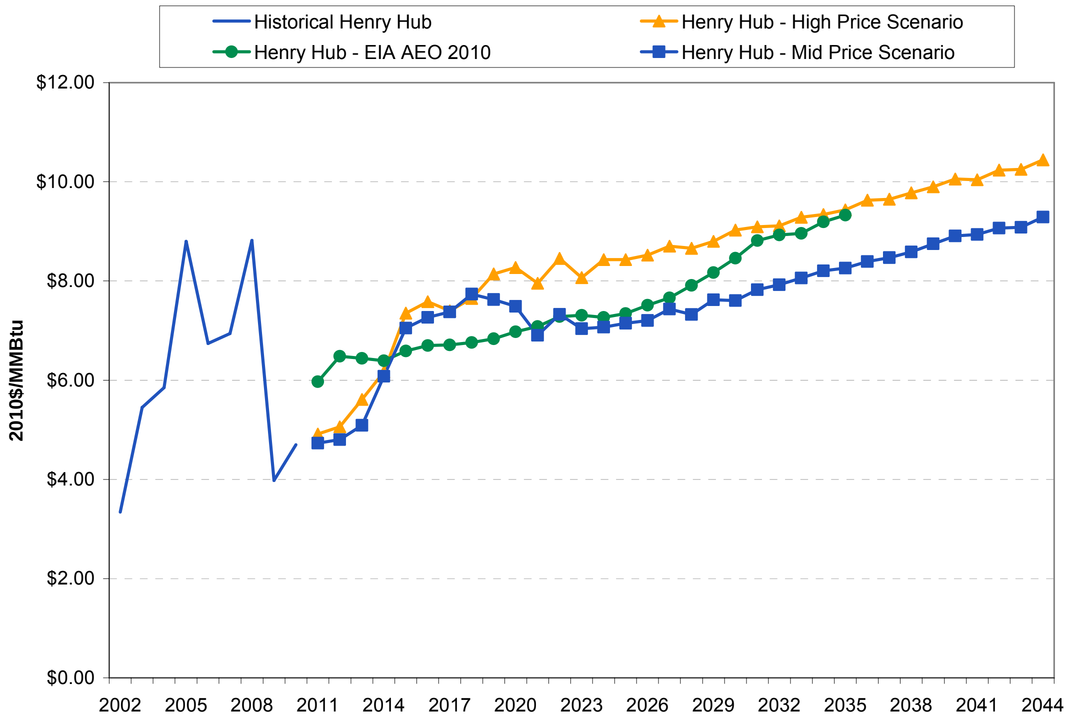
The High Price Scenario contains the same demand expectations as the Mid Price Scenario. Greenhouse gas legislation is expected to be passed by the U.S. Congress within the analysis period, and natural gas demand is expected to be driven by demand from the electric generation sector.

Section 5.3 provides detailed demand assumptions applicable to this scenario.

6.4 The High Price Scenario – Projected Henry Hub Price and Regional Bases

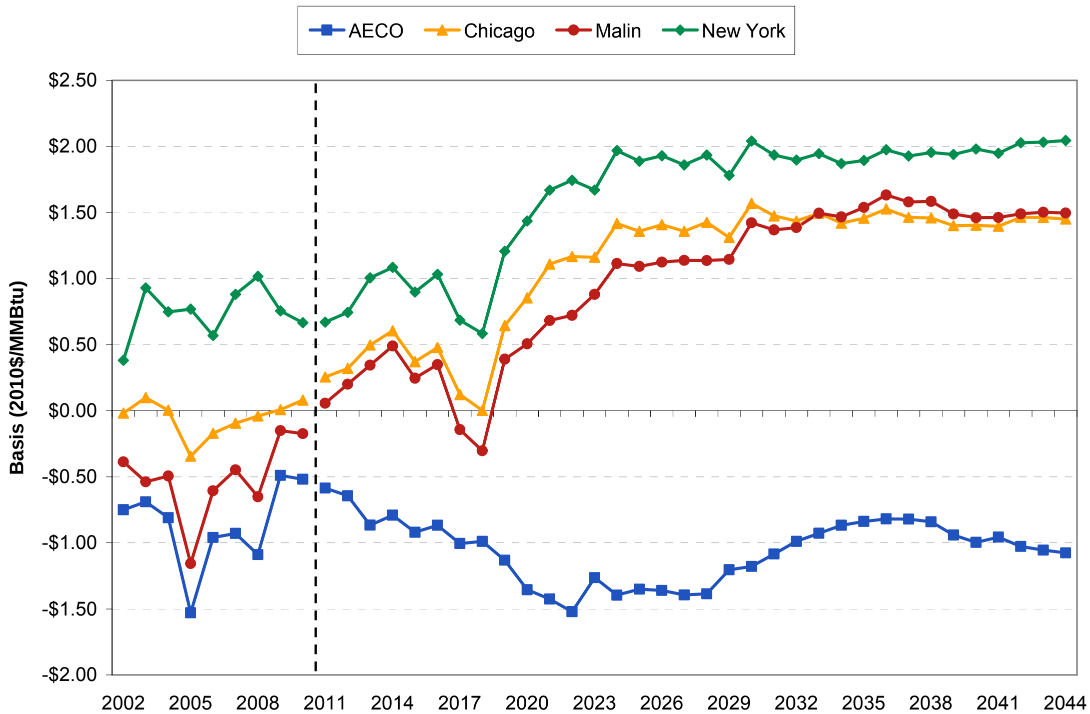
The High Price Scenario's assumed escalation of production costs lead to significant price increases as compared to the Mid Price Scenario. Henry Hub spot prices reach $8/Dth by 2020 and $9/Dth by 2030 (Figure 6-4).

Figure 6-4 Historical and Projected Henry Hub Prices – High Price Scenario



AECO basis to Henry Hub widens in 2020 due to the emergence of Canadian shale production and the possible introduction of Arctic supply through the Alaska Pipeline. The AECO basis begins to narrow thereafter as WCSB productions declines continue and the production growth from Canadian shale plays moderate. Market area bases in the Northeast and Midwest dip prior to 2020 due moderate production growth and then increases dramatically after 2020 due to the higher cost of the shale supplies required to meet demand growth. Regional basis projections for the High Price Scenario are displayed in Figure 6-5.

Figure 6-5 Historical and Projected Regional Basis – High Price Scenario



7.0 ANALYSIS OF NATURAL GAS PRICES – LOW PRICE SCENARIO

7.1 The Low Price Scenario Description

The Low Price Scenario represents a favorable supply scenario in which the absence of greenhouse gas legislation mitigates growth in natural gas-fired power generation. North American supplies of natural gas are characterized by having moderate production costs unaffected by substantial regulatory intervention. The scenario represents a market characterized by low or limited environmental sensitivity and loose regulatory controls.

Despite an abundance of moderately priced natural gas to serve as a “bridge fuel”, the scenario assumes that no coordinated federal action is taken to impose greenhouse gas emission limits. Because carbon emissions remain unpriced, coal-fired capacity is preferred over natural gas-fired capacity as a cost effective way to meet load growth. Efforts to encourage the efficient use of electricity and increase in usage of renewable energy are assumed to increase renewable penetration in the long run, but will cannibalize the near-term need for natural gas-fired power generation. Inefficient gas and coal units are in the short run, while a moderate level of coal-fired and gas-fired electric generation capacity is expected to be added in the long run. In the aggregate, natural gas demand from the power sector remains stagnant through the analysis period.

North American shale supplies are assumed to provide a large resource base in the Low Price Scenario. F&D costs for North American shales are expected to be relatively low in the long run and continue to reflect the current drilling experience. This scenario assumes minimal environmental regulation impacting shale gas development.

Sections 3 and 4 discussed in detail the key drivers of supply and demand incorporated in this study. Table 7-1 summarizes key inputs for the Low Price Scenario.

Table 7-1 Summary of Assumptions on Key Drivers for Low Price Scenario

Drivers	Low Price Scenario
Supply:	
Land Use	10% of Marcellus reserves inaccessible
Fiscal Regime	Moderate Severance and Royalty Assumptions for U.S. and Canada
Shape of F&D Curve	On par with Conventional Resource Cost Escalation
Water Costs	$0.75/Mcf for Marcellus, $0.25/Mcf cost for all other shales
LNG	AEO 2010 Assumptions:4 Bcf/d in 2020 declining to 2.3 Bcf/d from 2030-2044
Demand:	
Assumption Source	EIA AEO 2010
Residential and Commercial	0.3% Compound Annual Growth Rate for 2010 to 2035
Industrial	0.4% Compound Annual Growth Rate for 2010 to 2035
Power Generation	0.5% Compound Annual Growth Rate for 2010 to 2035
Electricity Load Growth	0.9% Compound Annual Growth Rate for 2010 to 2035
Renewable	40.5 GW additional nameplate capacity by 2034
Nuclear	10.4 GW additional nameplate capacity by 2034
GHG Allowance Prices	No CO2 cost

The aggregate impacts of these assumptions on supply and demand are discussed below, in Section 7.2 and Section 7.3 respectively.

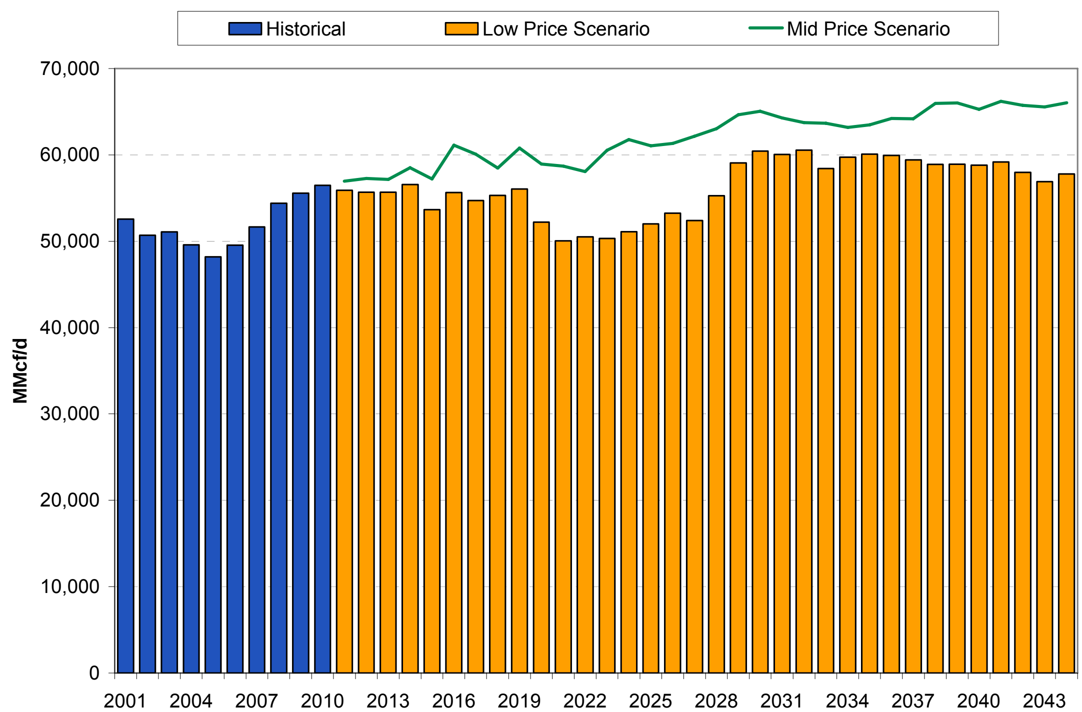
7.2 The Low Price Scenario – Key Supply Assumptions

Natural gas production in the Low Cost Scenario is driven by flatter F&D cost curves. B&V applied the F&D assumptions of the Flatter F&D Cost Curves described in APPENDIX B to the Low Price Scenario. These F&D cost curves have relatively flatter slopes in the early stage but steeper slopes in the later stage than the F&D cost curves in the Mid Price Scenario.

7.2.1 Projected Production from Major North America Basins and Shales

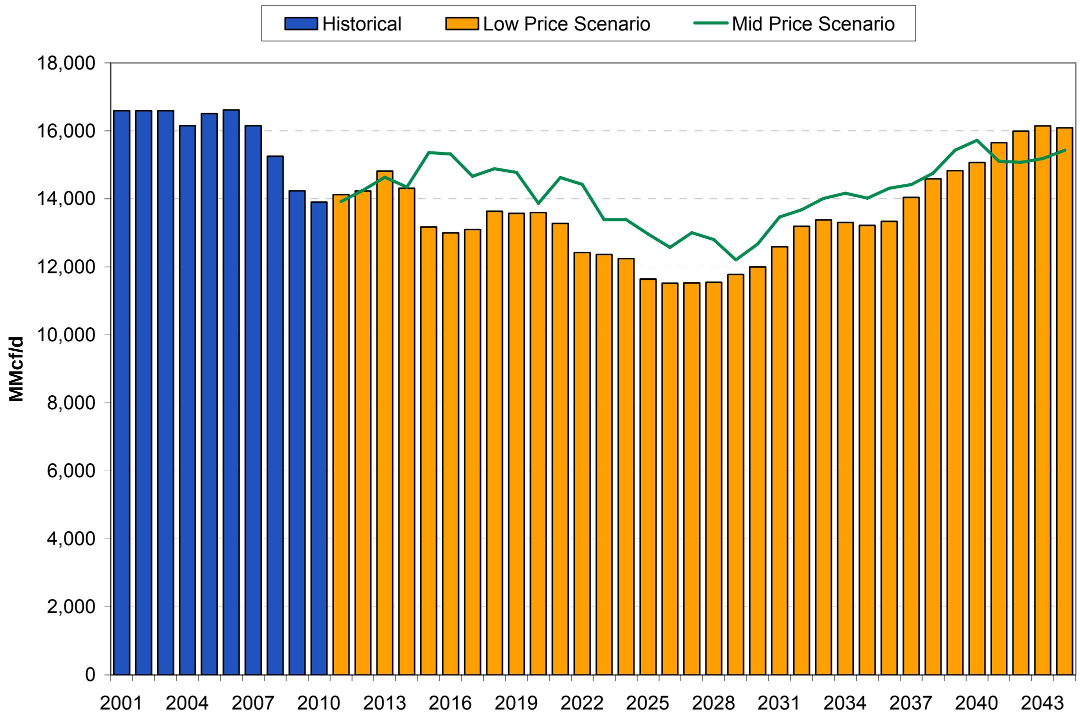
In the Low Price Scenario, the study projects that the Lower 48 gas production grows slightly from 56 Bcf/d in 2011 to 58 Bcf/d in 2044, at an average rate of 0.14% per year. The Lower 48 gas production in this scenario is lower than the Mid Price Scenario reflecting that although supply is plentiful and cheap, the lack of demand to absorb this supply constrains production (Figure 7-1).

Figure 7-1 B&V Projected Lower 48 Natural Gas Production – Low Price Scenario



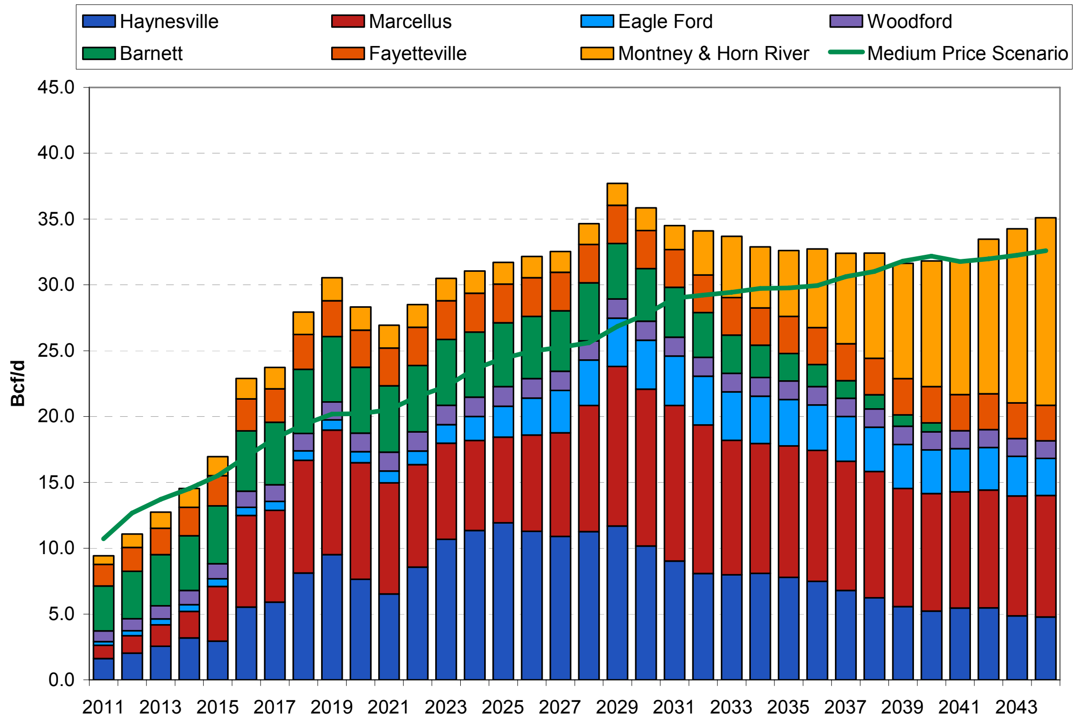
Canadian natural gas production grows from 14 Bcf/d in 2011 to 16 Bcf/d in 2044, at an average rate of 0.44%, about the same level as the production in the Mid Price Scenario (Figure 7-2).

Figure 7-2 B&V Projected Canadian Natural Gas Production – Low Price Scenario



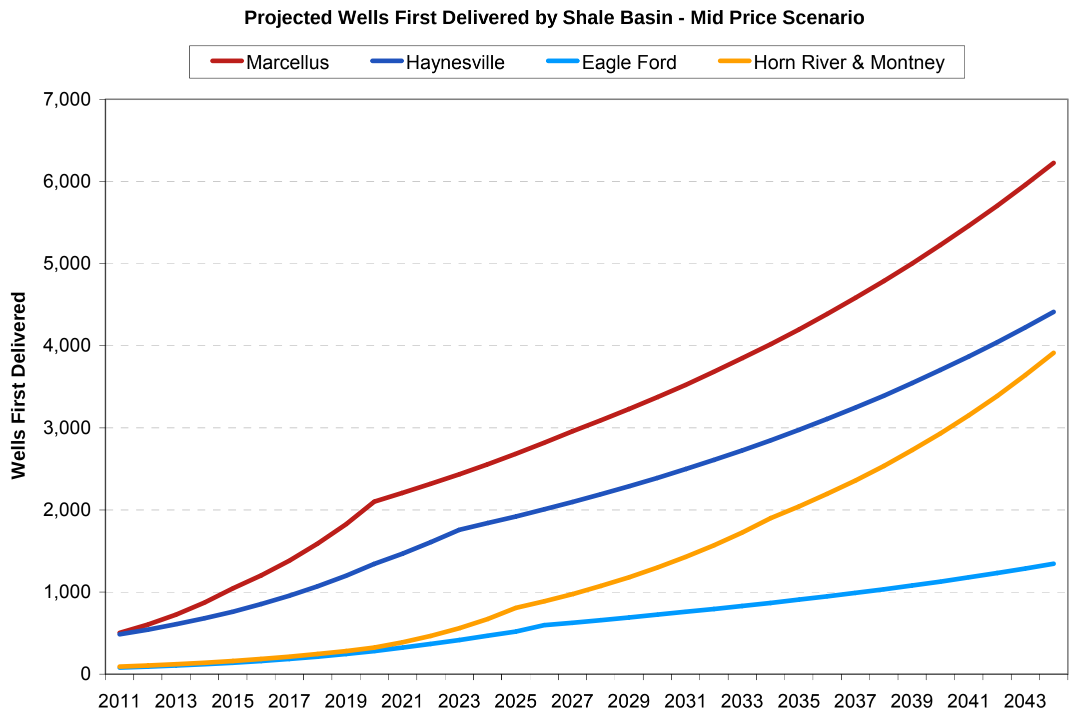
Lower production cost expectations clearly stimulate shale gas production in the Low Price Scenario. North American shale gas production grows at a rate of 3.94% per annum from 2011 to 2044, reaching 31.4 Bcf/d (Figure 7-3), compared with the Mid Price Scenario's average annual growth rate of 3.5%

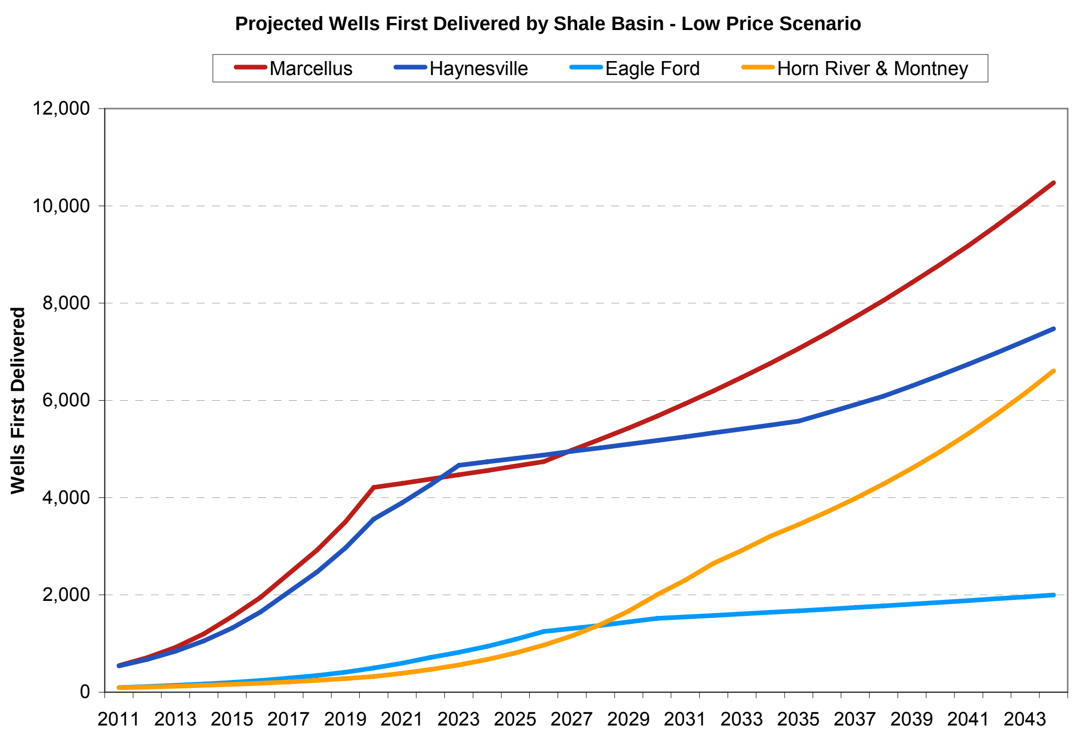
Figure 7-3 B&V Projection of Emerging Shale Production – Low Price Scenario



As in the Mid Price Scenario, the study examined the number of new production wells required to meet this aggressive projected production for each basin for the Low Price Scenario. Figure 7-4 shows the implied well counts derived in the Low Price Scenario compared to those derived in the Mid Price Scenario. In the Low Price Scenario the study finds that an annual average increase of 15% to 29% in initial well completions for each shales is required in the next five years from 2011 to 2016 to support the shale gas production levels indicated here. Such a growth rate is higher than in the Mid Price Scenario, which experiences an annual average increase in wells first delivered of 12% to 19% during the same period and the historical experience in the Barnett Shale which shows a 10% increase in wells first delivered over the last 5 years. The study concludes that the growth in initial well completions implied by the Low Price Scenario constitutes an unlikely yet plausible situation, in which a large number of resources are utilized to support high levels of shale production. In effect, the scenario assumes that despite the substantial increase in demand for drilling the service industry does not materially increase costs, allowing F&D costs to remain low.

Figure 7-4 Projected Wells First Delivered and Rig Count

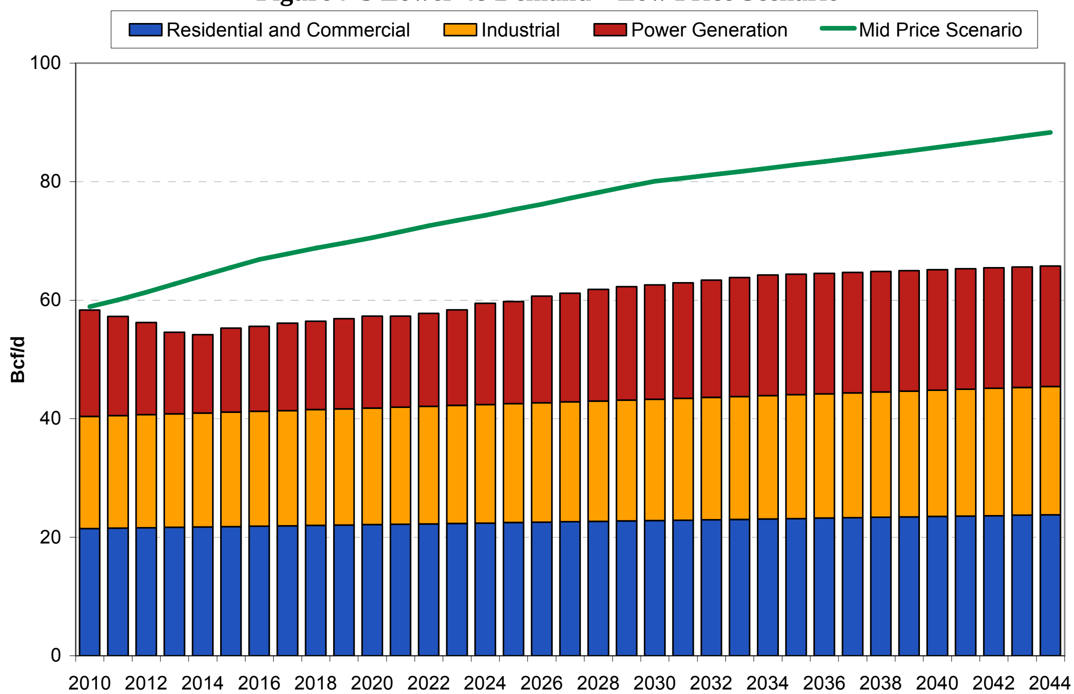




7.3 The Low Price Scenario – Key Demand Assumptions

As discussed, the study applies a low natural gas demand assumption to this scenario, per EIA's AEO 2010 assumptions. An overview of this assumption is discussed in APPENDIX F. Under this assumption, total demand for natural gas is muted due to anemic demand growth for gas-fired power generation (Figure 7-5).

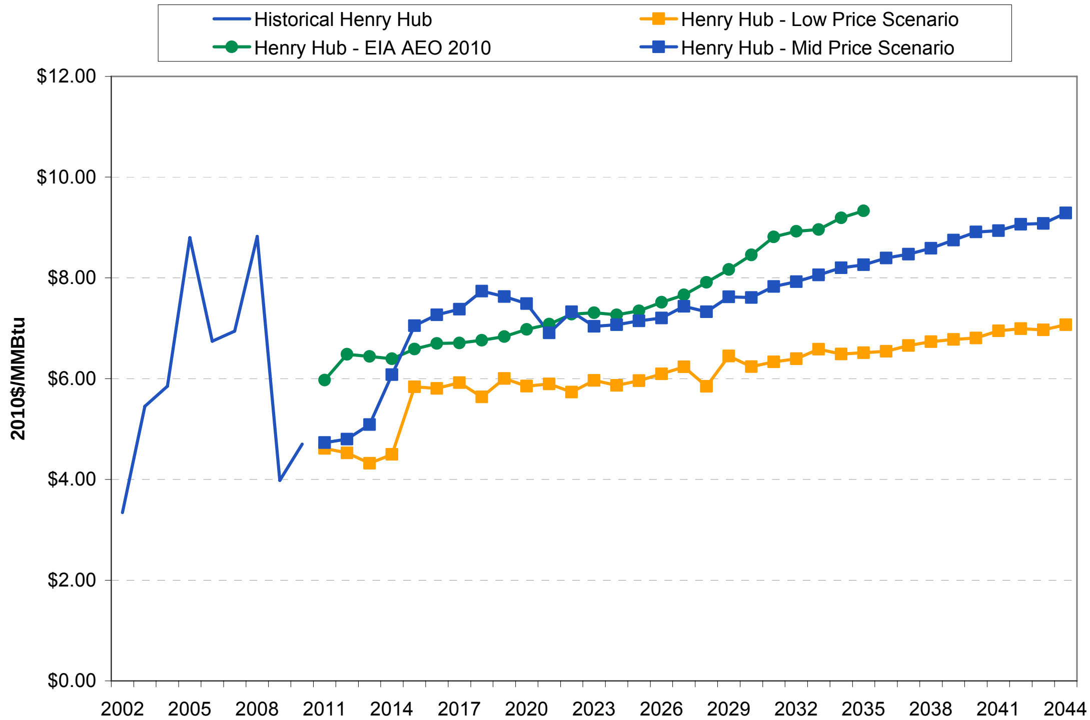
Figure 7-5 Lower 48 Demand – Low Price Scenario



7.4 The Low Price Scenario – Projected Henry Hub Price and Regional Bases Projections

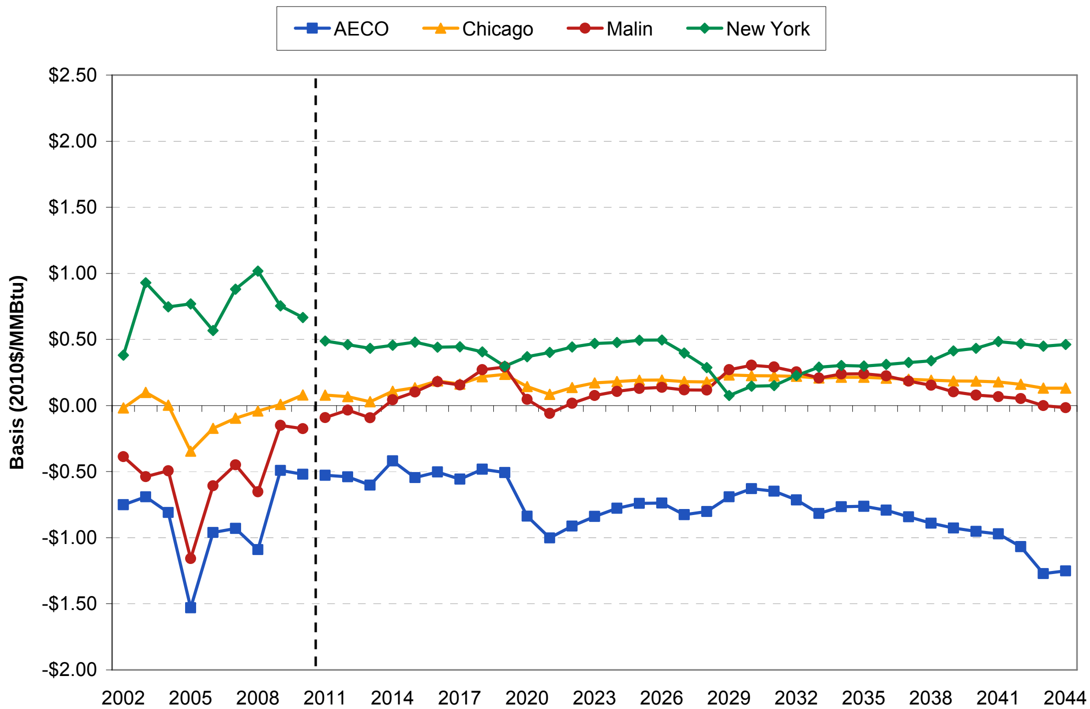
Lower demand growth expectations and lower production costs have a pronounced effect on price results in the Low Price Scenario when compared to the Mid Price Scenario. Henry Hub spot prices reach $6/MMBtu ($2010 dollar) by 2020 and $6.20/MMBtu by 2030 (Figure 7-6).

Figure 7-6 Historical and Projected Henry Hub Prices – Low Price Scenario



In the Low Price Scenario, AECO and Malin basis widens due to the Alaska pipeline in 2020, but continues to narrow until the emergence of Horn River and Montney production after 2030. Market area basis dampen as lower levels of demand are met with lower cost supplies. New York basis dampens as lower cost Marcellus supplies are delivered to meet low demand growth expectations. Regional basis projections for the Low Price Scenario are shown in Figure 7-7.

Figure 7-7 Historical and Projected Regional Basis – Low Price Scenario



8.0 CONCLUSION

Shale gas production is in its early stages of development in North America. This study highlights that there are significant uncertainties that will affect shale gas development during the study period. These include the size of the resource base, potential restrictions on land use, current finding and development costs, the evolution of the finding and development costs with cumulative production, water costs of hydrofracturing shale gas wells and treating produced water, and the fiscal policy. The combination of these uncertainties results in potentially large variations in the costs, and indirectly in the volumes of natural gas that can be expected to be produced from North American shale gas.

Power generation demand for natural gas is the largest variable impacting natural gas demand during the study period given the relative stability in residential, commercial and industrial demand. The changing electric generation landscape and potential for greenhouse gas emission restrictions, or taxes, will likely create significant additional demand for natural gas and hence have substantial impact to North American natural gas prices in the coming decades. Projections for natural gas demand from power generation in the Lower 48 considered in the study range from 20.3 Bcf/d based on EIA's AEO 2010 forecast to 34.4 Bcf/d in Black & Veatch's Spring 2010 Energy Market Perspective reflecting different views on greenhouse gas restrictions, nuclear and renewable capacity additions and the fate of coal-fired generation.

Together, these supply and demand uncertainties can generate significant ranges of outcomes of North American gas prices, and ultimate shale gas production. Across the scenarios considered, natural gas prices at Henry Hub rise to at least $6.00/MMBtu (real 2010$). The projected range of future prices for natural gas in North America by 2020 is wide, from $6.00/MMBtu to $8.00/MMBtu, driven by uncertainty in key shale gas supply cost drivers, as well as uncertainty regarding greenhouse gas emissions policy and the associated demand for gas-fired power generation. Total natural gas production from shale plays may range from 15.5 Bcf/d to 17.0 Bcf/d in 2015 and from 15.4 Bcf/d to 28.3 Bcf/d in 2020, with total production figures especially influenced by power generation demand.

Although the scenarios considered all represent potential paths going forward for the natural gas industry, the relative likelihood of the scenarios is influenced by the assumptions underlying each scenario.

The Low Price Scenario represents unmitigated, low cost production from shale plays, with no corresponding demand pull associated with greenhouse gas restrictions. Under the Low Price Scenario, annual average increases of 15% to 29% in initial well completions for each shale play are required to maintain the production levels indicated here. Such growth rates are higher than historical experience in the Barnett Shale, which has experienced annual growth rates of 10% over the last 5 years. This study therefore concludes that the growth in wells first delivered by the Low Price Scenario constitutes an unlikely yet plausible situation, in which a large number of resources are utilized to support high levels of shale production with no corresponding rise in rig rate, hydrofracturing, or other service industry costs, thereby allowing F&D costs to remain low. It also seems unlikely that the plentiful and cheap gas supply assumed in the Low Price Scenario would not spur a demand response via greenhouse gas policy designed to capitalize on the availability of a cleaner and less expensive alternative to coal-fired generation.

The High Price Scenario assumes a push towards a greener economy during the study period. Greenhouse gas legislation is enacted even in the face of higher natural gas prices driven by lower resource estimates and higher costs of production for shale plays. This is an aggressive view of the evolution of the natural gas market with a strong demand pull and constrained supply. It should be noted that the price levels projected in this scenario during the study period remain lower than the recent historical prices experienced in 2008.

The Mid Price Scenario reflects the evolution of a natural gas market with increased supply from economical shale gas resources, as well as high demand, and probably represents the most likely of the scenarios examined here. While greenhouse gas policy has been halted by recent political developments, it is highly likely that even absent a legislatively-mandated explicit or implicit price on carbon emissions, utilities and merchant generators will make technology decisions on what generating capacity to install in anticipation of the possibility of such mandates. These decisions can be expected to include additional natural gas-fired generation capacity driving increased demand for natural gas. The estimated level of shale gas resources in North America and the costs associated with producing these resources suggest that natural gas will be a sufficient and economic resource to meet the projected demand growth.

APPENDIX A. WATER USAGE AND COSTS

Water issues in shale-gas production

There are two main water issues involved in shale-gas wells:

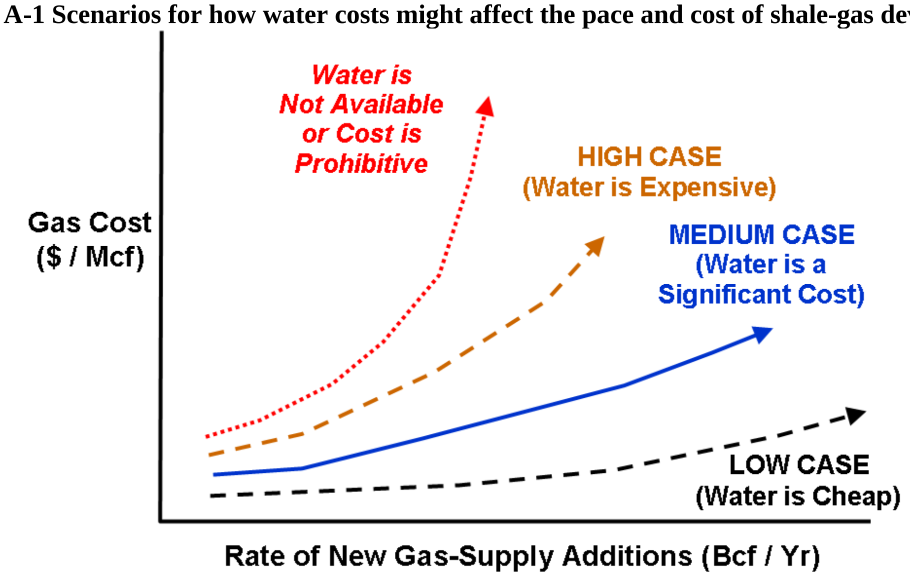
- Acquiring and managing the supply of water needed to drill, complete and hydrofracture each shale-gas well: The "Downhole" Issue.
- Recovering and managing the wastewater leftover from each shale-gas well: The "Flow-back" Issue.

Those two issues affect the finding and development (F&D) costs for shale gas in terms of the volumes of water involved and the unit-volume costs of supply and disposal. A closely related issue is the perceived safety of the chemical additives used in hydrofracture operations[12]. The following cost analysis assumes that the hydrofracture process continues to be permitted, and is available as a standard tool for shale-gas development. It also assumes that other key factors, including the costs involved in accomplishing hydrofracture operations, likely will vary from one shale play to another. The key factors include:

- Any limits placed on the sources or amounts of water that can be used for well operations.
- Any requirements for standards to which wastewater must be treated before disposal.
- Any restrictions on avenues for disposal of (treated or untreated) wastewater.

Figure A-1 illustrates scenarios for how water costs might affect the pace and cost of shale-gas development and Table 3-4 outlines the key differences. The main point of Figure A-1 is that any increases in water restrictions or water costs will increase the cost of the produced shale gas and could slow down the overall rate at which shale gas is developed and brought to market. The Mid Price Scenario, which is the default scenario for analyses presented in this report, includes water as a significant development cost for reasons discussed below.

Figure A-1 Scenarios for how water costs might affect the pace and cost of shale-gas development



Three plausible scenarios (LOW, MEDIUM, HIGH) for how water costs might affect the rate of shale-gas development. A fourth scenario ("Water is Not Available"), considered to be highly unlikely, would effectively curtail shale-gas development.

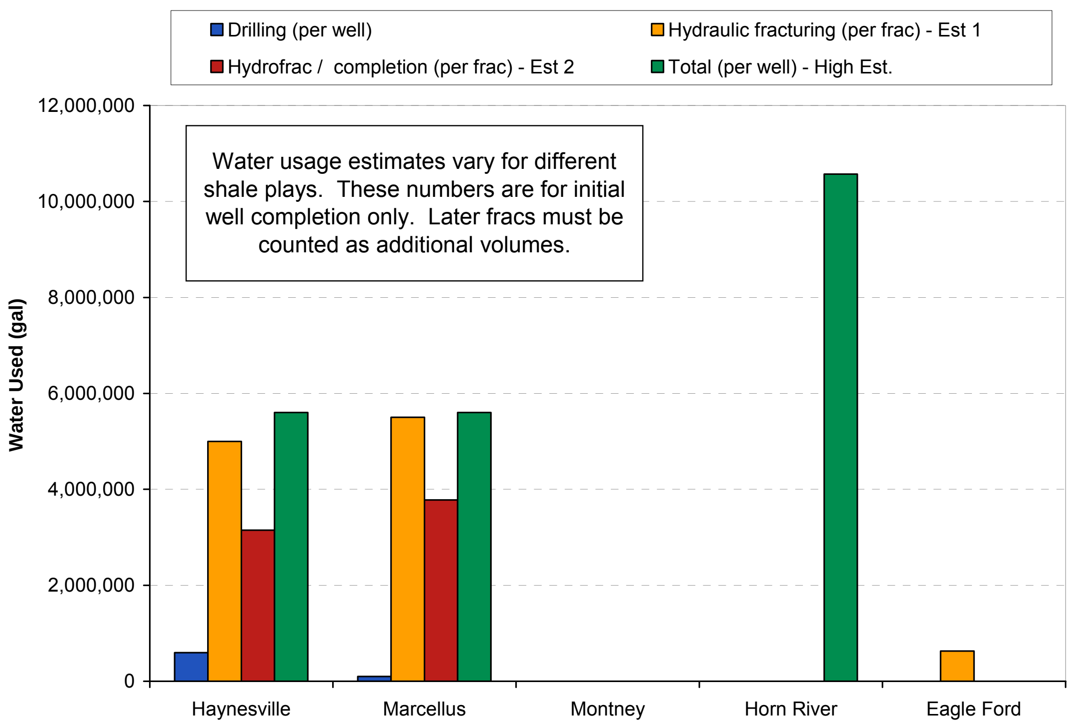
[12] As of September 2010, the U.S. Environmental Protection Agency (EPA) is engaged in a broad review of chemicals used in hydrofracturing fluids, including related public commentary, in the context of protecting of drinking water supplies from contamination. If the hydrofrac process was to become significantly limited in practice, as a result of new EPA regulations, the outlooks on feasibility and cost of shale-gas development might require substantial revisions.

Factoring water into finding and development (F&D) costs

Figure A-2 shows typical water volumes involved in shale-gas development and Table A-1 summarizes indicative water costs, including procurement of water supplies needed for drilling and hydrofracturing as well as disposal of the flow-back wastewater. For reasons discussed above, quantitative data on water volumes and costs have not been publicly available until recently. Therefore, Table A-1 mostly is a current snapshot of the ranges of water-related costs that are beginning to emerge from the shale-gas industry.

Although horizontal wells cannot be drilled without first drilling a vertical well to the depth of the shale bed, the largest volumes of water involved in shale-gas well completions are indeed traceable to laterals. Each lateral tends to be as long as or longer than its associated vertical well and requires hydrofracturing in several successive stages – meaning that there are large cumulative volumes of water going downhole and returning to the surface as wastewater. The water volumes vary among the different shale plays but the typical range is about 5-10 million gallons per lateral (Figure A-2) that must be procured, delivered to the drilling site and then safely handled through disposal once the well is completed. The volume of flow-back water could be either more or less than the amount sent downhole for hydrofracturing. Any hydrofracture water that becomes trapped underground in the reservoir rock will reduce the amount in the flow-back. On the other hand, any geologic formation water that is released from underground by well completion will add to the flow-back. In either case, recovery of flow-back water occurs over an extended period of days or weeks after the end of well completion, thereby prolonging the time, effort and cost of dealing with water issues.

Figure A-2 Typical water volumes used to complete individual wells in shale-gas plays



Footnote: "Est 1" and "Est 2" refer to two different volume estimates obtained from industry literature. Volumes of flow-back plus formation water that require disposal could be less or more than the volumes sent downhole for well completion. The high volume indicated by one research source for Horn River (Encana) is consistent with the fact that the Muskwa play is much deeper than most other North American shale-gas plays and that wells delivered since 2009 have evolved from 10 to 13 to more than 21 hydrofracture stages per well.
Data sources:

(1) "Modern Shale Gas Development in the United States: A Primer." Prepared for U.S. Department of Energy Office of Fossil Energy and National Energy Technology Laboratory, Work Performed Under DE-FG26-04NT15455, Ground Water Protection Council, Oklahoma City, OK and ALL Consulting, Tulsa, OK, April 2009, 116 p.
(2) Mantell, Matthew E. "Deep Shale Natural Gas: Abundant, Affordable, and Surprisingly Water Efficient." 2009 GWPC Water/Energy Sustainability Symposium, Salt Lake City, Utah, September 13-16, 2009, 15 p.
(3) Unpublished sources.

Table A-1 Indicative volumes and costs of water involved in drilling and hydraulically fracturing reservoir units as needed to complete shale-gas wells

Parametrics for Water Issue	Estimated Values		
	Low	Medium	High
1. Water to drill TD[5] & complete each well (millions of gallons)	0.06[1]	0.5	1.0[1]
2. Water per frac job (millions of gallons)	1.2[2]	2.4	3.8[1]
3. Number of frac jobs needed to maximize gas production from each well	1[3]	4	10[3]
4. Wastewater (flowback & formation) produced from each well per frac job (millions of gallons)	1.2[4]	2.4	3.8[4]
5. Cost of water to drill / complete / frac ($ / gal)	0.001[7]	0.005	0.014[7]
6. Cost of wastewater treatment & disposal ($ / gal)	0.05[6]	0.08	0.11[6]

Data Sources and Comments:
(1) Range for Barnett, Fayetteville, Haynesville and Marcellus; "Modern Shale Gas Development in the United States: A Primer." Prepared for U.S. Department of Energy Office of Fossil Energy and National Energy Technology Laboratory, Work Performed Under DE-FG26-04NT15455, Ground Water Protection Council, Oklahoma City, OK and ALL Consulting, Tulsa, OK, April 2009, 116 p.
(2) For Barnett; Bené, James; Harden, B.; Griffin, Stephanie W.; and Nicot, Jean-Phillippe. "Northern Trinity/Woodbine GAM Assessment of Groundwater Use in the Northern Trinity Aquifer Due To Urban Growth and Barnett Shale Development." Prepared for Texas Water Development Board, TWDB Contract Number: 0604830613, R. W. Harden & Associates, Inc., Austin, Texas, 247 p..
(3) For Barnett; "Changing Geography of North American Natural Gas." INGAA Foundation, April 17, 2008, 16 p.
(4) Assumed to be same as for drilling / completion / frac; could be either smaller or larger, depending on amounts of water lost to or gained from formations.
(5) Total depth (TD) includes vertical and horizontal legs of the well.
(6) For Barnett, attributed to "Devon Barnett Shale Q&A." Devon Energy, May 20, 2010, 2p.; "The future of water recycling." Basin Oil & Gas, 30, June 2010, 11 p.
(7) For Marcellus; Gaudlip, A. W.; Paugh L. O.; and Hayes T. D. "Marcellus shale water management challenges in Pennsylvania." Society of Petroleum Engineers, SPE Paper No. 119898, 12 p.

Table A-1 was compiled as a survey across several different shale-gas plays and with the intention of documenting the range for each of the key variables. Therefore, Table A-1 should not be interpreted as depicting any individual shale-gas play. Many of the numbers are traceable to the Barnett Shale development which is the most mature shale-gas development and the one with the most extensive public records for water use and costs. The "Low" numbers tend to reflect the early days of the Barnett Shale development where vertical wells were dominant, drill/hydrofracture water volumes were comparatively small and untreated wastewater was readily disposed into injection wells. Many of the "High" numbers reflect later stages of Barnett development involving long horizontal wells which required extensive hydrofracture effort followed by chemical treatment of the wastewater. Research showed that the newer developments, such as Haynesville and Marcellus, are associated with water volumes and costs close to the "High" numbers because complex, horizontal wells are dominant and wastewater treatment is the most common disposal solution. The "Medium" numbers simply are mid-points chosen from the ranges uncovered by the research. For purposes of cost projections, the "Medium" numbers can be viewed as amalgamated averages of water costs for a wide variety of shale-gas plays and, therefore, a reasonable long-baseline reference scenario. It should be expected that, as more information becomes publicly available, the data in Table A-1 will require updates and revisions.

Using the data in Table A-1, ranges of total water costs can be estimated for shale-gas wells by calculating the cost for each state in the well development:

Water-Stage Cost = (Water for Activity) x (Times Activity Performed) x (Water Unit Cost)

For an individual well, the total water cost is the sum of water costs for all development stages, including water going downhole and returning to the surface for disposal. Example calculations are provided in the later section from which the following results are drawn:

- Low Case: Water costs of $65,000 per well (97% for wastewater treatment and disposal)
- Medium Case: Water costs of $860,000 per well (94% for wastewater treatment and disposal)
- High Case: Water costs of $4.8 million per well (87% for wastewater treatment and disposal)

An important point is that the major cost in each case (87-97%) is for treatment and disposal of the wastewater leftover from the well-development work. Indeed, the apparent proportion of costs attributable to wastewater is very large compared with general experience in other commercial or industrial sectors. Black & Veatch found in their annual survey[13] of the 50 largest U.S. cities that the proportion of water costs attributable to wastewater treatment averages about 59-60% for high-volume commercial and industrial water users and up to 72% for the most costly environments. Therefore, it is clear that the cost of shale-gas wastewater treatment could be a key leverage point for future shale-gas development.

Among the indicative unit costs for wastewater (line 6 in Table A-1), the low end of the scale represents disposal though injection wells (where essentially no treatment is required) that in some cases can be obtained by re-commissioning previously drilled but abandoned oil or gas wells – effectively the scenario that enabled development of the Barnett Shale play. The high end of the scale represents chemical technologies including oxidation, reverse osmosis, forward osmosis and other processes to remove hydrocarbons and heavy metals from the flow-back water prior to release of the treated water into surface water bodies or onto selected land acreage. Because injection wells are not as readily available in many of the emerging shale-gas plays, the most likely unit cost for wastewater (Medium case) will be significantly higher than the legacy Barnett Shale reference.

Of course, the economic implication of real interest is the incremental cost of water on the final cost of the produced gas. Given the Low, Medium and High water-cost cases presented above, the remaining variable is the volume of natural gas that can be expected from a given well. The cost calculation is:

Incremental Cost of Water = (Water Cost per Well) / (Gas Produced from Well)

Table A-2 shows how the Low, Medium and High water-cost cases translate for wells of different productivity as expressed in the estimated ultimate recovery (EUR)[14] volume for the well. Clearly, at some

[13] "2009/2010 50 Largest Cities Water / Wastewater Rate Survey." Black & Veatch Corporation, 18 p.
[14] Gas production expected over the lifetime of a gas well is referenced as the expected ultimate recovery (EUR) volume in billions of cubic feet (Bcf).

combinations of water cost and EUR, the incremental cost of water will be too high to make operation of the wells economical (that is, the final cost of the gas is not supportable by the prevailing wellhead price). Bearing in mind that the Low case ("water is cheap" Barnett Shale premise) is unlikely to be available in the emerging shale-gas plays, development efforts could be expected to avoid the High case wherever possible and to strive for average well productivities of 3 Bcf-EUR or higher. Based on wells completed in some shale plays since 2008, a 3.5 Bcf-EUR well (highlighted in Table A-2) is a useful benchmark[15].

Table A-2 Variation of marginal cost of water with productivity of gas wells

Incremental Cost of Water* ($US / Mcf) for a Shale-Gas Well						
Cost Scenario for Water Issues*	Single-Well EUR (Bcf)					
	1	2	3	***3.5***	4	5
High	$4.84	$2.42	$1.61	***$1.38***	$1.21	$0.97
Medium	$0.86	$0.43	$0.29	***$0.25***	$0.21	$0.17
Low	$0.06	$0.03	$0.02	***$0.02***	$0.02	$0.01

* Includes procurement of water needed to drill and complete the well, plus all necessary hydraulic-fracturing operations, plus disposal of all flow-back and formation water.

Mcf = One thousand cubic feet. Bcf = One billion cubic feet. EUR = Estimated ultimate recovery.

What would be economically acceptable relative to the indicative results in Table A-2 should be expected to vary among shale-gas plays and with commodity prices. As discussed elsewhere, water is only one of several elements within finding and development (F&D) costs involved in producing marketable gas. But if all other F&D costs were constant at $3.00/Mcf, for example, and water was the remaining variable F&D cost, resource fields that could operate within the Medium water-cost cases might be profitable at a wellhead price of $4.00/Mcf even if each well averaged only 2 Bcf-EUR (that, is $3.00 plus $0.43/Mcf for water vs. $4.00 sale); a 3.5 Bcf-EUR well would be even more profitable with a water cost of only $0.25/Mcf. But for the same circumstances and the same wellhead price, a field located in a High water-cost environment could find that even a 5 Bcf-EUR well might be only barely profitable (namely, $3.00 plus $0.97/Mcf for water vs. $4.00 sale); a 3.5 Bcf-EUR well would be distinctively unprofitable with a water cost of $1.38/Mcf. Because producers cannot pre-ordain the EUR performance of any individual well, the imperative becomes control of F&D costs, including water costs.

<u>Outlooks for future water costs</u>

Trends of future water costs for shale-gas development will be determined by the interplay of technology and regulations. As long as regulatory policies allow flexibility for technical innovations, progress can be expected on methods for reducing the overall water footprints of shale-gas development, including the impacts on F&D costs. As should be apparent from the foregoing discussion, the main challenges will be to keep hydraulic fracturing available as a safe and acceptable development tool and to reduce the unit cost for treatment and disposal of wastewater leftover from completed wells.

The following factors will be significant in determining whether – and how fast – water costs can be reduced:

- Technology
    1) Develop ability to fully recover and cheaply treat wastewater

[15] The trend of wells completed in the Haynesville Shale through June 2010 has been toward an average of 3-4 Bcf-EUR based on independent research and analysis conducted by Black & Veatch Management Consulting.

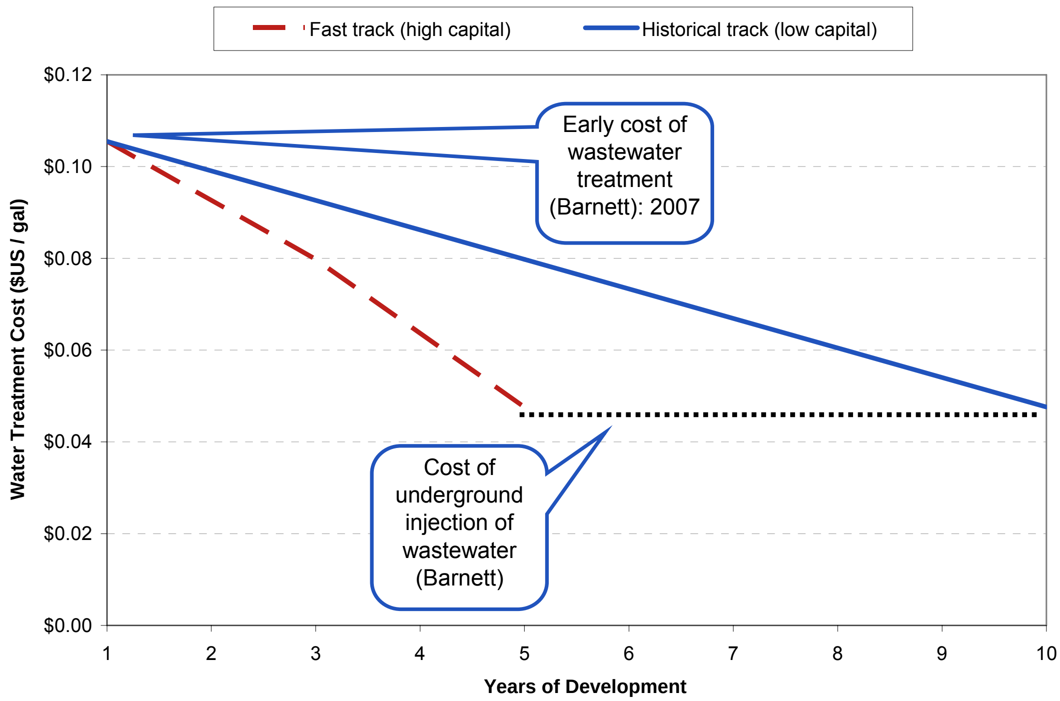
    a) Wastewater = Flow-back plus formation water (leftover from drilling, well completion and hydrofracturing)
    b) Recover and make re-usable, or releasable, the highest possible proportion (90-100%) of the wastewater; Current efficiency is only 70-80% of the water as re-usable/releasable.
    c) Adopt treatment and surface release (or recycling) as the default technology, rather than underground injection
    d) Re-design mobile treatment facilities to handle larger volumes of water
2) Develop ability to routinely use non-traditional sources of water for drilling, completion and hydrofracturing
    a) Replace "new" potable/treatable surface or ground water with "used" water
    b) Make routine use of industrial or municipal wastewater
        i) Adjust or re-formulate drilling mud and hydrofracturing fluids
        ii) Build pipelines to replace trucking (which is expensive)
3) Develop methods for drilling, completion and hydrofracturing that use less water
    a) Fundamentally more difficult than challenges (1) and (2)
    b) Key could be hydrofracturing using carbon dioxide (CO_2) or other cheap, alternative fluid

- Regulations
    1) Surface watersheds
        a) Drilling & well development prohibited or highly restricted in certain catchment basins as indentified with urban water supplies
        b) Tighter restrictions on use of surface water in drilling / hydrofracturing or for release of wastewater into surface water systems
            - Increased costs for supply & treatment
    2) Groundwater
        a) One or both of the following may occur after 2012:
            - Stricter interpretation of Safe Drinking Water Act authority by U.S. EPA
            - New regulations restricting use of hydraulic fracturing technology or certain chemical additives
        b) Some land possibly placed off-limits to drilling & development
        c) Some or all wells required to meet stricter contamination-control requirements
            - Increased F&D costs for drilling, completion and hydrofracturing
            - Long-term groundwater monitoring as a new O&M cost

Experience in the Barnett Shale suggests a range of possible cost-reduction timelines for wastewater treatment (Figure A-3). The "target" cost of about $0.05 per gallon of wastewater is premised on making chemical treatments as cost-effective as untreated disposal through injection wells. As discussed above, injection-well disposal of wastewater will not be widely available for many shale-gas plays even though such disposal was a key enabler of development in the Barnett Shale. The "starting" cost of about $0.11/gal is based on early experience with self-contained, mobile wastewater-treatment systems that were tested in the Barnett Shale as alternatives to injection-well disposal. At present, these wastewater costs are significantly higher than the maximum reported cost of $0.02/gal that applies to high-volume industrial enterprises in major cities[16].

[16] "2009/2010 50 Largest Cities Water / Wastewater Rate Survey." Black & Veatch Corporation, 18 p.

Figure A-3 Possible cost-reduction timelines for wastewater treatment needed for shale-gas production



Footnote: Benchmark costs are based on experience in the Barnett Shale. The objective is to drive down the unit cost for chemical treatment ($0.11/gal) toward the cost of untreated disposal through injection wells ($0.05/gal).

Of course, solving the wastewater-treatment problems through technology will occur only if water-related regulations provide reasonable opportunities to do so. In the best case, federal and state regulators will collaborate to develop consistent policies and rules that provide for dependable and timely permitting for water supplies and wastewater disposal as needed for steady shale-gas development. Those policies and rules should make clear the acceptable standards for hydraulic fracturing, which is an essential technology for shale-gas development. That should assure that roles, responsibilities and authorities are clear for all governmental organizations that might variously include environmental protection agencies, oil and gas commissions and watershed or groundwater conservation districts. In the worst case, hydraulic fracturing could become banned or extremely limited in its application[17] or protracted moratoriums could block water supplies, wastewater disposal or other key elements in shale-gas development. Such a negative regulatory environment could bring shale-gas development to a halt in the shale-gas plays where those regulations applied.

[17] "Frac Attack: Risks, Hype and Financial Reality of Hydraulic Fracturing in the Shale Plays." Reservoir Research Partners and Tudor, Pickering, Holt & Co., Houston, Texas, July 8, 2010, 65 p.

Table A-3 Classification of shale-gas plays with regard to water-cost scenarios

Key: ● Historical data □ Best estimate (historical) ○ Outlook

Shale Play	Likely Scenario for Water-Related F&D Costs		
	Low	Medium	High
Barnett	●		
Eagle Ford		○	
Fayetteville	●		
Haynesville		○	
Horn River			○
Marcellus		○ (WV, PA)	○ (NY)
Montney			○
Woodford	□		

* Emerging plays in **bold and underlined** font; other mature shale plays (regular font) included for reference.

Based on the foregoing discussions, Table A-3 summarizes the outlook for shale-gas plays in North America with regard to the Low, Medium and High water-cost scenarios. Only the Barnett Shale (the type example of the Low water-cost scenario) and the Fayetteville Shale are sufficiently mature as producing plays for the water costs to be reasonably well established. For each of the emerging shale-gas plays, the water-cost scenario is surmised based on location and the perceived regulatory environment relative to the Barnett Shale.

The Marcellus Shale is of special interest not only because of its very large, prospective resource potential but also because of the regulatory complexities involving at least three states (New York, Pennsylvania, West Virginia) and the federal government. Although production to date has been small, real well development in the Marcellus Shale is best documented[18] for West Virginia where state authorities have sought to reach agreements with gas producers on various technologies and practices, including the use of hydraulic fracturing. In contrast, New York has reacted to Marcellus Shale prospects with political and public objections and calls for moratoriums on drilling. New York has also been supportive of efforts by the U.S. EPA to consider possible new regulations for hydraulic fracturing. The situation in Pennsylvania has been more conducive to development than in New York, including balanced discussions on hydrofracture practices, although in some ways slower than in West Virginia. Therefore, even though per-well water volumes would be similar for all three states, the regulatory atmosphere in New York almost certainly assures a High water-cost scenario whereas the situations in West Virginia and Pennsylvania more likely would support a Medium water-cost scenario.

The Horn River and Montney shale-gas plays are classified provisionally as High water-cost scenarios given the depths of the wells needed (hence the larger water volumes) as well as the uncertain environmental regulatory environment in western Canada. The Eagle Ford and Haynesville shale-gas plays are classified as

[18] The State of Pennsylvania will make Marcellus Shale well and production data publicly available for the first time as of November 1, 2010. Earlier Pennsylvania oil and gas law allowed such data to be treated as proprietary and not subject to disclosure.

Medium water-cost scenarios based on the general public acceptance, and usually favorable regulatory environments, in Texas and Louisiana, respectively.

Estimation of Water Cost for Shale Gas Wells

The following examples utilize input data from Table A-1 to depict the range of possible costs involving water as needed to complete an individual shale-gas well. For each case, the basic calculation is:

- Extended Cost = (Water for Activity) x (Times Activity Performed) x (Water Unit Cost)
- Total Water Handling & Cost = Sum of Extended Costs (downhole and flow-back water)

In each case, the default well consists of one vertical and one lateral (horizontal) leg carried through hydrofracturing and completion of the combined legs. The calculations assume that all water sent downhole is recovered as flow-back water. If substantially less than 100% of downhole water returns as flow-back water, then treatment and disposal direct costs might be less than calculated although other indirect fees and penalties might apply depending on the state of hydrofracturing and groundwater-protection regulations pertaining to the subject well.

Figure A-4 Total Water Handling & Cost by Scenario

Water Volumes and Costs for a Single Shale-Gas Well: Low Case					
Development Activity	Water Required for Development Activity (MMgal)	Times Performed	Total Water Required (MMgal)	Unit Cost of Water ($US / gal)	Extended Cost of Water ($US)
Drilling & Completion (without hydrofrac)	0.1	1	0.1	0.001	$60
Hydraulic fracturing	1.2	1	1.2	0.001	$1,200
Disposal of flow-back & formation water			1.3	0.050	$63,000
TOTAL WATER HANDLING & COST			2.5		$64,260

Water Volumes and Costs for a Single Shale-Gas Well: Medium Case					
Development Activity	Water Required for Development Activity (MMgal)	Times Performed	Total Water Required (MMgal)	Unit Cost of Water ($US / gal)	Extended Cost of Water ($US)
Drilling & Completion (without hydrofrac)	0.5	1	0.5	0.005	$2,500
Hydraulic fracturing	2.4	4	9.6	0.005	$48,000
Disposal of flow-back & formation water			10.1	0.080	$808,000
TOTAL WATER HANDLING & COST			20.2		$858,500

Water Volumes and Costs for a Single Shale-Gas Well: High Case					
Development Activity	Water Required for Development Activity (MMgal)	Times Performed	Total Water Required (MMgal)	Unit Cost of Water ($US / gal)	Extended Cost of Water ($US)
Drilling & Completion (without hydrofrac)	1.0	1	1.0	0.014	$14,000
Hydraulic fracturing	3.8	10	38.0	0.014	$532,000
Disposal of flow-back & formation water			39.0	0.110	$4,290,000
TOTAL WATER HANDLING & COST			78.0		$4,836,000

APPENDIX B. FINDING AND DEVELOPMENT (F&D) COSTS

Multiple definitions for finding and development (F&D) costs

Despite their critical role in determining the economics of gas-field development, F&D costs continue to evade singular, universal standards for reporting. Therefore, level comparisons of F&D costs for one gas play to another remain challenging. Meaningful differentiation of gas developments based on F&D costs requires multiple approaches to the analysis. The basic intent is to summarize the amount of money spent to recover a certain amount of gas as commonly reported in units of dollars per one-thousand cubic feet (Mcf). But a wide variety of inputs are employed to depict what, in principle, is a simple ratio.

The definition of F&D cost that is used for fully-vetted financial transactions, including merger and acquisition deals, is:

F&D Cost ($US / Mcf) = [E&P Capex] / [Reserves Added]

for a specific time period (for example, 1 year or running 3-year average). In applying the rigorous definition for F&D cost, it is expected that the sum of capital expenditures (capex) is comprehensive; namely, all costs involved in exploration and production (E&P) that are needed to discover the gas and bring it to the wellhead as the first point of sale[19]. Also, normalization of capex to reserves added is understood to involve reserves established through formal, certified analysis of economically producible gas – not simply an estimate for how much gas might be under the operator's properties[20]. Less formal reports of F&D costs, especially in reports promoting new developments, sometimes substitute for "reserves" a value of estimated ultimate recovery (EUR)[21] for a well or a field within a play.

Unfortunately, the practice of reporting F&D costs is quite variable both among producers and analysts. Many reports lack clear explanations of what is or is not included as "capex" and "reserve" estimates are subject to change based on market prices for gas, legal reporting rules and how owners might change degrees of certainty for different categories of "reserves". Common versions of reported F&D costs include:

- <u>Drill-Bit F&D</u>: Capex limited to drilling costs (presumably through well completions unless stated otherwise) and normalized to reserves claimed from those drilling efforts. But in some cases, especially for new developments, the EUR for a small number of individual wells – rather than formally booked reserves – is used as the gas volume.
- <u>All-In F&D</u>: Capex inclusive of all costs, not limited to drilling, and normalized to all reserves booked and reported for the same time period as the expenditures. True all-in costs should include the cost of purchased or leased acreage, whether developed or not, although some reports remain unclear regarding the inclusion of land costs.

As defined, drill-bit F&D costs almost always are systematically lower than all-in F&D costs. Therefore, drill-bit F&D costs tend to be the most common convention in public reports where low F&D costs are acknowledged as a competitive advantage.

[19] Capex needed to find and develop marketable gas normally includes land acquisition, geological and geophysical characterization, drilling and well completion plus any gas conditioning needed prior to first sale at the wellhead.

[20] "Reserves" are formally certified by standards of petroleum reservoir engineering that are adopted individually by countries that produce oil and gas. In the U.S., the acknowledged technical authority for reserve-estimation procedures is the Society of Petroleum Engineers (SPE) and reports must be acceptable to the Securities and Exchange Commission (SEC) which considers them to be part of official financial statements from producers.

[21] Estimated ultimate recovery (EUR) is the volume of gas (usually expressed as billions of cubic feet, Bcf) expected from an individual well, field or play. It is not the same as "reserves" which is a volume of gas that is recoverable according to certain technical and economic specifications prescribed by regulatory agencies. Use of EUR in the context of F&D costs usually is done on a per-well basis and is common when a development is young and overall production from a play is low so that realized data are from a relatively small number of wells.

Both for drill-bit and all-in versions of F&D costs, attention must be paid to whether the "reserves" number is a legally booked value or an EUR-based estimate. In many cases, EUR-based values can be larger than the eventual "reserves" value because the former are not economically constrained whereas the latter, by definition, are economically constrained by dependence on commodity prices as well as technical requirements for levels of reservoir-engineering certainty.

Company-specific vs. basin-specific F&D comparisons

B&V pursued two types of F&D cost research to find corroborative evidence for current and historical trends of F&D costs in emerging shale-gas basins[22]:

- F&D costs for a gas-producer company (all basins)
- F&D costs for a gas-producing basin (all companies)

Major shale-gas producers' press releases, investor reports, quarterly and annual reports and presentations over the last several of years were reviewed to derive four information threads:

- F&D costs (as reported)
- Capex per well, including drilling costs and any other itemized costs
- Estimated ultimate recovery (EUR) of gas per well
- Acreage holdings

The foregoing types of information were utilized to derive basin-specific F&D costs using the process defined below:

- F&DX costs[23] were denoted as F&D-related costs excluding the drilling component. This concept accommodates the practice of some producers who list bundled costs exclusive of drilling. These usually were numbers reported as companions to "drilling" costs.
- F&DD costs were denoted to represent drilling costs per well divided by EUR per well to get an average cost as $US/Mcf. This concept, which is equivalent to the "Drill-bit F&D" metric, accommodates the practice of some producers who specify drilling costs separate from other costs.
- The total F&D cost was the sum of the two components: F&D = F&DX + F&DD.
- The combined F&D cost was calculated in two ways:
    - Sum of simple averages of F&DX and F&DD, respectively, across all companies.
    - Weighted average of F&D across all companies where the weighting factors were the acreage numbers held in the shale-gas play by each company.

[22] A hydrocarbon "basin" can contain multiple gas plays – both conventional and unconventional – where a "play" is a specific, geologic reservoir. For shale gas, usually (but not always) there is one major shale-gas play that dominates each basin. In this report, "basin" refers to a "play" in the context of shale gas.
[23] "F&DX" "and "F&DD" are notations created here to denote partial F&D costs that can be considered as components of the complete F&D cost.

Figure B-1 F&D costs for Range Resources, Inc. which is heavily invested in the Marcellus Shale gas play

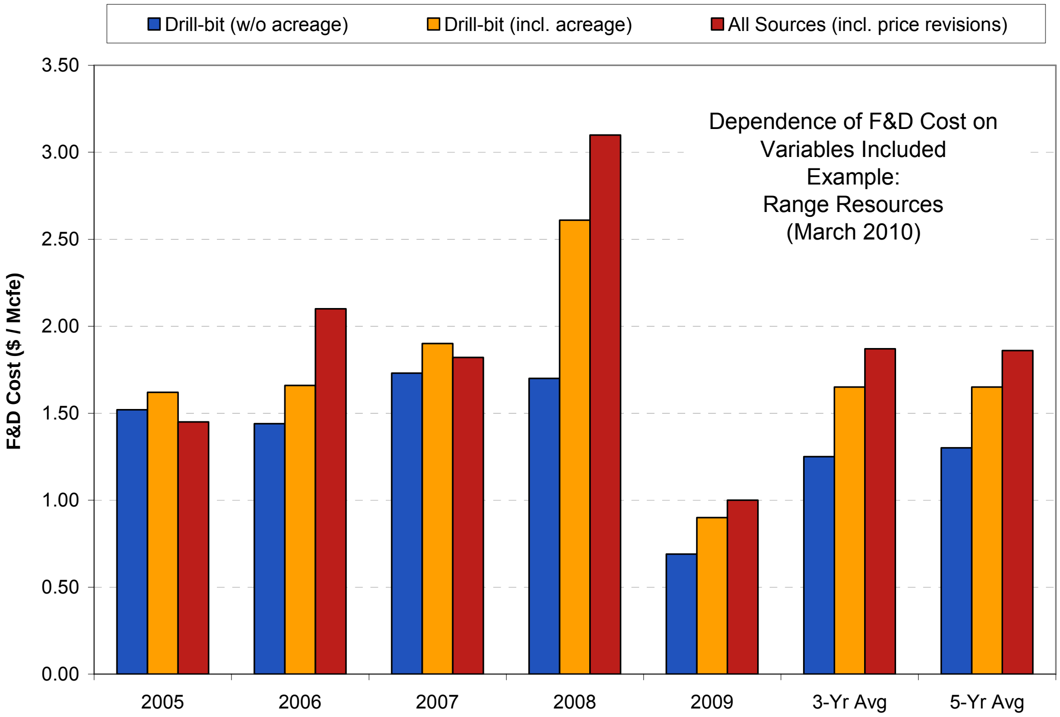


Figure B-1 illustrates variations of F&D costs for a single company (Range Resources) [24] that is heavily invested in shale-gas production and makes three points that are especially informative. First, F&DD cost (i.e., "Drill-bit w/o acreage") is the minimalist view of the real F&D cost. Land costs for shale-gas plays are significant and, when included (i.e., "Drill-bit incl. acreage"), serve to substantially increase the F&D cost. Second, there are significant variations of F&D costs among shale-gas plays which might not be reported explicitly but which can become manifest in company-wide F&D numbers (i.e., "All Sources incl. price revisions"). The combination of those two points can account for apparent variations of F&D costs over a range wider than $1.50/Mcf for the years 2005-2008. Third, changes in reporting rules can generate apparent, if not real, changes in F&D costs. F&D costs for the year 2009 appear conspicuously lower than for the years 2005-2008 as a consequence of regulatory changes which happened to increase the amount of gas that could be booked for 2009 as proved, undeveloped (PUD) reserves[25]. So the drop-down effect seen in Figure B-1 for 2009 reflects use of re-defined, larger numbers for PUD reserves[26]. If the context and artificiality of

[24] "Howard Weil 38th Annual Energy Conference." Range Resources Corp., March 23, 2010, 8p.

[25] The Securities and Exchange Commission (SEC) implemented 17 CFR Parts 210, 211, 229, and 249 (*Federal Register, Vol. 74*, p. 2158-2197; January 14, 2009) which changed procedures for gas valuation and definition of proved, undeveloped (PUD) resources. The 2009 rule change allows producers to use an annualized average commodity price for valuing their reserves instead of the previous prescription that the end-of-year price must be used. Depending on price trends during a given year, either the annual average or the end-of-year price might produce the highest apparent value for booked reserves. As it happened, the annual average gas price produced a distinct advantage in 2008 over 2009. In 2008, U.S. national annual-average wellhead gas price according to EIA was $8.07/Mcf ($5.87 in December) whereas for 2009 the annual average was $3.71/Mcf ($4.44 in December). But more significantly for 2009, the rule change introduced large, new flexibility in claims of PUD reserve volumes by requiring only "reasonable certainty" that available (if not already in-use) technologies could recover additional gas -- and without a "drilling unit" limitation that formerly was interpreted as a strict or regulated well-pad spacing.

[26] Range Resources (2010) attributed a value of $1.22/Mcf (i.e., apparent cost reduction) for their 2009 F&D costs, and 40% savings over their 5-year average F&D costs, through application of the SEC 2009 rule change.

the rule-driven change was not understood, the one-year F&D costs reported for 2009 could make it appear (erroneously) that shale-gas production suddenly became dramatically more economical in just one year.

The vagaries discussed above highlight why one-year F&D costs should be viewed with less regard than 3-year or 5-year averages; the running averages are more likely to be representative and trustworthy for purposes of recognizing and forecasting trends.

Figure B-2 F&D cost variations among companies heavily invested in different shale-gas plays

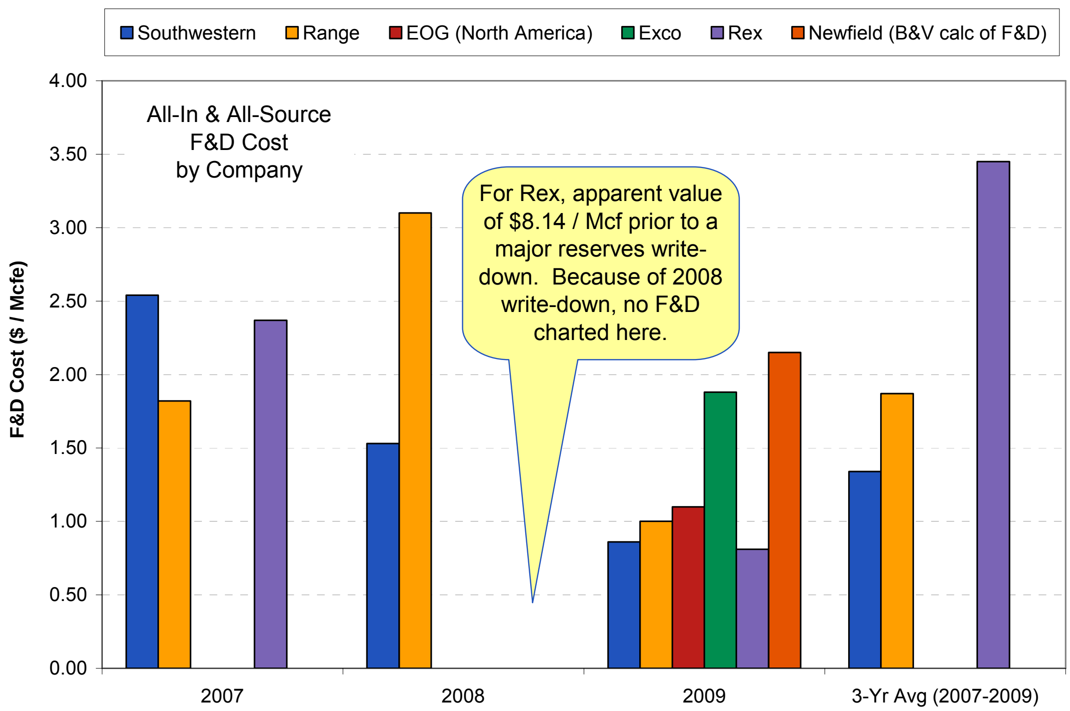


Figure B-2 illustrates variations in F&D costs among companies that are heavily invested in shale-gas developments and makes two main points. First, when reasonably level comparisons are made among companies, using "All-In" F&D costs (which should be equivalent to F&DX + F&DD), there appear significant ranges that can be understood from the proportions of their respective investment in different shale plays. For example, Southwestern[27] reported 85% of its reserves portfolio in the relatively less expensive Fayetteville Shale while Rex[28] has yet to produce gas from a portfolio weighted with 51% of its acreage in the relatively more expensive Marcellus Shale. Indeed, sizable purchases of unproved acreage, combined with a reserves write-down, led to absence of a self-consistent F&D report from Rex for 2008 but with a sizable uptick for their three-year average F&D cost[29]. Second, the 2009 SEC rules change provided a significant, but

[27] "Investor Presentation July 2010 Update." Southwestern Energy Company, July 2010, 6p.

[28] "2010 Annual Meeting of Stockholders." Rex Energy Corp., 24 July 2010, 4p.

[29] Rex Energy showed that for the year 2008, the company spent a total of $143.854 million on F&D, including some additional reserves but mostly non-reserves-evaluated and non-producing shale-gas acreage. The reserves accounting showed an apparent corresponding addition of an equivalent 17.683 million Mcf for the same year (to a previous base of 0.992 million Mcf). Therefore, the apparent F&D cost for 2008 could have been $8.14/Mcf (=$143.854/17.683). But Rex separately showed a write-down of 31.489 million Mcf which implied apparent net reserves of -12.814 Mcf (= -31.489 + 17.683 + 0.992) and an F&D cost of - $11.23/Mcf (= $143.854/(-12.814)). Therefore, to avoid a completely artificial outcome for F&D trends, no F&D cost was included for Rex in Figure B-2. But for comparison with the three-year average (2007-2009) of $3.45/Mcf reported by Rex (Fig. C-2), if the reserves write-down of 2008 had not occurred

artificial, reduction of apparent F&D costs for all producers. Therefore, the tracking of trends in F&D costs must account for the synthetic step-down in 2009.

Table B-1 summarizes basin-specific F&D costs that pertain to evaluation of shale-gas development prospects. Significant ranges occurred in the number of different companies for which F&D data were available, including Eagle Ford (3), Haynesville (9) and Marcellus (8). And in all cases, the drill-bit component of the F&D cost (F&DD line in Table B-1) is based on well-specific EUR values rather than formal "reserves" values. Furthermore, the EURs tended toward relatively high values, in excess of 3 Bcf per well, which would have the effect of understating average drill-bit costs when less productive average wells are considered for a shale-gas play as a whole. The effect of overstated EUR leading to understated F&D cost can be further realized by comparing the F&D average values in Table B-1 with those in Figure B-1 and Figure B-2. Therefore, results in Table B-1 are more likely to represent lower limits rather than true central tendencies for the cost distributions.

Using the available data for individual companies, it is possible to calculate either simple averages or acreage-weighted averages to recognize that companies carry difference proportions of their portfolios in different shale-gas plays. But differences between those two respective sets of calculation results are not large or systematic. The first main point of Table B-1 is that the lower limit of F&D cost for the two largest resource prospects among emerging shale-gas plays in the U.S. (Haynesville and Marcellus) is approximately $2.30-$2.40/Mcf. The second main point is that, based on admittedly limited information, F&D costs in the emerging western Canada shale-gas plays (Horn River and Montney) might be more than $1.00/Mcf higher than for U.S. shale-gas plays.

Table B-1 Basin-specific F&D costs

Finding & Development (F&D) Costs for Shale-Gas Plays ($US / Mcf)					
F&D Element	**Eagle Ford**	**Haynesville**	**Horn River**	**Marcellus**	**Montney**
F&DX[1] (Average)	1.06	0.97		1.26	
Range		0.91 - 1.48		1.03 - 1.33	
F&DD[2] (Average)	1.00	1.38		1.07	
Range	0.93 - 1.08	1.11 - 1.90		0.87 - 1.33	
Total F&D (Average)	2.06	2.35	3.75 - 4.25[4]	2.33	3.25 - 3.75[4]
Total F&D (Acreage-Weighted)[3]	2.12	2.41		2.23	

Notes
1 F&DX = F&D-related costs excluding the drilling component.
2 F&DD = Drilling costs per well divided by EUR per well, using individual well EURs as reported by producers. EUR (Bcf) values reported spanned ranges of 4-6 (Eagle Ford), 5-7.5 (Haynesville) and 3-4.2 (Marcellus).
3 Average for individual companies with weighting factors proportional to the acreage holding of each company in each shale-gas play.
4 Ranges reported by Encana.

As discussed in Section 3.3, water costs are becoming prominent as important elements of F&D costs although neither Table B-1 nor its sources include water costs explicitly. Yet the effect of water costs on all-in F&D costs is important to track. In principle, it might be expected that water costs should be part of drill-

the implied three-year F&D cost would have been $3.77/Mcf (= average of $2.37, $8.14 and $0.81) prior to the reduction enabled by the SEC reporting-rule change in 2009.

bit F&D (F&DD in Table B-1) although, from a competitive perspective, producers might find it more advantageous to assign water costs to "other" F&D (F&DX in Table B-1). In that regard, it is possible that relative differences for F&DX vs. F&DD costs in Haynesville compared with Marcellus might be explainable in part by different accounting approaches for water costs.

Finding & development cost from company researches

In Table B-2, F&D costs compiled for individual companies are used to estimate basin-specific F&D costs based on the acreage holdings of each company. For example, for the Eagle Ford shale-gas play ("basin"), the data available for Petrohawk and Talisman are combined in the form:

$$\$2.14*[225{,}000/(225{,}000 + 37{,}000)] + \$1.98*[37{,}000/(225{,}000 + 37{,}000)] = \$2.12 \text{ / Mcf}$$

The premise is that the companies with the largest acreage should reflect the best sample of F&D costs for a given basin/play. It is understood that such estimates are not exact because each company's portfolio will contain different proportions of acreage for different gas plays. But when focused on acreage for a specific play, such "acreage-weighted", basin-specific results should be useful in detecting relative differences in F&D costs from one shale-gas play to another. Unfortunately, available information for Horn River and Montney are limited to much less detail than for Eagle Ford, Haynesville and Marcellus. Nonetheless, evidence from Figure 3-C supports the inference that F&D costs can vary significantly among shale-gas plays. The higher F&D costs implied for Horn River and Montney are supported by the spread among various analysts who estimate break-even costs between $4.00/Mcf and $6.50/Mcf[30].

Company-specific research focused on investor reports and provided historical views and trends for representative companies that have high exposure to shale-gas resources. It is assumed that for an individual company, F&D reporting conventions should be mostly self-consistent so that meaningful cost trends can be recognized. Particular attention was paid to the following companies (with their stock symbols) that have significant investments in shale-gas development in the U.S.:

- Devon Energy Corp. (DVN)
- EOG Resources, Inc. (EOG)
- EXCO Resources, Inc. (XCO)
- Newfield Exploration Co. (NFX)
- Range Resources Corp. (RRC)
- Rex Energy Corp. (REXX)
- Rosetta Resources, Inc. (ROSE)
- Southwestern Energy Co. (SWN)

To expand coverage for the U.S. and Canada, other companies reviewed in the research included Apache, ARC Energy Trust, Atlas, Cabot Oil & Gas, Canada Energy Partners, Carizzo, Chesapeake, CNX Gas, Comstock Resources, Crimson Exploration, El Paso, Encana, Equitable Resources, GMX Resources, Nexen, Petrohawk, Pioneer, Questar, Quicksilver, Swift, Talisman and Ultra.

Basin-specific research focused on producers' press releases, investor reports and conference presentations relevant to a particular basin. Basin-specific F&D costs were checked for consistency against company-specific F&D costs. Particular attention was paid to the following basins which contain conventional gas plays and, as noted, also emerging shale-gas plays of special interest:

- Appalachian Basin (Marcellus Shale)

[30] "RBC: Horn River to thrive if pipelines keep pace", *Platts Gas Daily, 27 (188),* September 30, 2010, p. 4-5.

- Gulf of Mexico[31] (conventional gas plays, including offshore)
- North Louisiana Salt Basin[32] (Haynesville Shale)
- Rocky Mountains[33] (conventional and unconventional gas plays)
- Western Canadian Sedimentary Basin[34] (conventional gas plays plus Horn River / Muskwa Shale and Montney Shale)

Other basins considered relevant to a review of shale-gas F&D costs include:

- Anadarko Basin (Woodford Shale)
- Arkoma Basin (Fayetteville Shale)
- Fort Worth Basin (Barnett Shale)
- Rio Grande Embayment (Eagle Ford Shale)

Table B-2 summarizes F&D data compiled for different companies and for different shale-gas plays.

Table B-2 F&D cost variations among companies heavily invested in different shale-gas plays

Marcellus

Company	Chesapeake	Range Resources	Equitable Resources	XTO Energy	Ultra Petroleum	CNX Gas	Cabot Oil & Gas	Carrizo
F&D Costs ($/Mcf)	$1.26	$1.16					$1.00	$1.03
CAPEX ($MM)	$4.50	$3.50	$4.00	$3.70	$3.80	$3.85	$3.65	$3.50
EUR*/Well (Bcfe)	4.20	3.75	3.00	3.00	3.75	3.50	4.20	3.40
F&D Plus Drilling	$2.33	$2.09	$1.33	$1.23	$1.01	$1.10	$1.87	$2.06
Acreage	1,570,000	900,000	500,000	280,000	250,000	230,000	160,000	216,000
Acreage-Weighted Cost	$2.23							

Haynesville*

Company	Devon	Chesapeake	Encana	Petrohawk	Comstock	Questar	Southwestern Energy	GMX Resources	Crimson Exploration
F&D Costs ($/Mcf)	$0.95	$1.48	$0.95	$0.95	$0.95	$0.95	$0.95	$0.95	$0.95
CAPEX ($MM)	$8.00	$7.20	$9.00	$8.50	$7.75	$8.50	$9.50	$7.50	$9.00
EUR*/Well (Bcfe)	5.50	6.50	6.00	7.50	5.00	7.00	5.00	5.95	7.00
F&D Plus Drilling	$2.40	$2.59	$2.45	$2.08	$2.50	$2.16	$2.85	$2.21	$2.24
Acreage	570,000	535,000	414,500	345,000	73,000	43,000	42,300	42,300	12,000
Acreage-Weighted Cost	$2.41								

Eagle Ford

Company	Petrohawk	Pioneer	Chesapeake	El Paso	Swift	Talisman
F&D Costs ($/Mcf)	$1.06	$1.06	$1.06	$1.06	$1.06	$1.06
CAPEX ($MM)	$6.50	$7.30				$3.70
EUR*/Well (Bcfe)	6.00					4.00
F&D Plus Drilling	$2.14					$1.98
Acreage	225,000	310,000	400,000	165,000	75,000	37,000
Acreage-Weighted Cost	$2.12					

[31] "Gulf of Mexico" as used here denotes offshore plays grouped together as the Gulf Cenozoic Outer Continental Shelf (OCS). In some other reports, "Gulf of Mexico" is used to more broadly include the onshore Western Gulf Basin and the onshore Texas-Louisiana-Mississippi Salt Basin.

[32] Sometimes also called the Texas-Louisiana-Mississippi Salt Basin, of which it is a part.

[33] "Rocky Mountains" in the context of gas resources represents a collection of different basins, including Big Horn, Denver-Julesberg, Green River (or Greater Green River), Paradox, Powder River, Raton, San Juan, Uinta-Piceance and Wind River.

[34] The "Western Canadian Sedimentary Basin" (WCSB) comprises at least 17 different areas across British Columbia, Alberta and Saskatchewan that produce oil or gas from a large number of different plays.

Horn River

Company	Encana	EOG	Quick-Silver	Apache	ExxonMobil	Devon	NEXEN
F&D Costs ($/Mcf)							
CAPEX ($MM)	$8.10			$3.70			$4.80
EUR*/Well (Bcfe)	10.00						6.00
F&D Plus Drilling							
Acreage	256,000	157,000	130,000	425,000	305,000	100,000	128,000
Acreage-Weighted Cost							

Estimated Supply Cost - No Land Costs (Encana) $3.75-$4.25

<u>F&D Differences in the U.S. and Canada.</u>

Comparing shale-gas F&D costs between the U.S. and Canada includes additional considerations. The three main factors include differences in geology and gas chemistry, environmentally-driven differences in drilling programs and differences in regulations on reserves booking and F&D cost reporting.

First, both Horn River and Montney are notably deep plays, with correspondingly greater drilling costs, and Horn River shale gas contains as much as 12% (volume) of carbon dioxide[35]. Therefore, geotechnical issues should be expected to add costs to Horn River, especially, when compared to other shale-gas plays. Also, there are some indications that pre-treatment might be needed in some cases before regional water supplies can be using for hydrofracture operations in the Horn River play[36]. In brief, availability and costs for drill/hydrofracture water are only now being vetted by the producers and Canadian regulators.

Second, whereas shale-gas drilling in the U.S. effectively is a year-round activity, the shale-gas drilling season in Canada is less than one-half of the calendar year. Because of "muskeg" limitations, traffic to/from drilling sites is limited to the core of winter when the ground is solidly frozen and can support heavy equipment. The "muskeg" effect always has impacted Canadian oil & gas development activity but, in the context of F&D, means that large capital investments must be committed over short intervals of time – and possibly with little productivity in terms of proved reserves. That impediment would act to increase apparent F&D costs.

Third, regulatory reporting rules that pertain to F&D are different in the U.S. and Canada[37]. The Canadian rules actually prescribe tighter requirements for how F&D costs can be reported, meaning that Canadian producers have less flexibility than U.S. producers in publicizing "drill-bit" F&D costs or other less-than-whole representations of the legally reported F&D costs.

35 "A Primer for Understanding Canadian Shale Gas - Energy Briefing Note" National Energy Board, Canada, Nov 2009.
36 Pond J., T. Zerbe, K. Odland (2010) Horn River Frac Water: Past, Present, and Future, CSUG/SPE 138222, Canadian Unconventional Resources & International Petroleum Conference, Calgary, Alberta, Canada, October 19-21, 2010.
37 In the U.S., "reserves" reports involve geotechnical analyses prescribed by the Society of Petroleum Engineers (SPE) and legal definitions prescribed by the Securities and Exchange Commission (SEC). In Canada, the corresponding steps follow standards set by Society of Petroleum Evaluation Engineers (SPEE) (geotechnical) and Canadian Securities Administrators (CSA) (legal). Although the SPE and SPEE standards are substantially similar, the SEC and CSA standards show some significant differences. The CSA (as National Instrument 51-101) prescribes two specific F&D cost calculations, one for proved reserves and the other for proved-plus-probable reserves, and stipulates that any report claiming to be an F&D cost must be declared as one or the other of the two calculations. The CSA further excludes "acquired" reserves from being used to dilute apparent F&D costs. In contrast, the SEC (as 17 CFR Parts 210, 211 et al.) does not disallow "acquired" reserves and does not specifically prohibit publication of unofficial F&D costs that are different from the legally-reported F&D costs.

Given the relatively few F&D cost data currently available for Horn River and Montney, the geotechnical effects cannot be fully disentangled from regulatory effects in evaluating the Canadian F&D numbers. But taken at face value, the Canadian shale-gas F&D costs appear higher than those for U.S. shale gas and are likely to remain so unless the regulatory environment in the U.S. takes an unfavorable turn for U.S. producers.

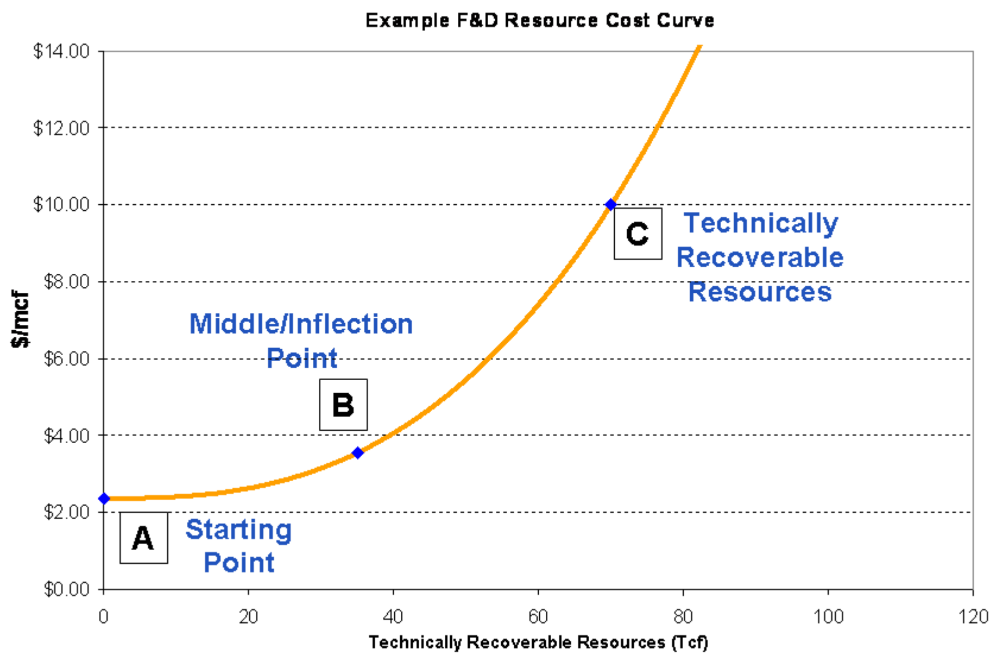
Structure of F&D Cost Curves

F&D Cost curves are represented within the natural gas long term economic equilibrium, model by defining three inputs:

A. Starting Point: Initial F&D cost estimates for a given basin. This is the start-up F&D cost at the beginning of gas production.
B. Middle/Inflection Point: Resources available at the relatively flat portion of the F&D curve prior to the "hockey stick" upturn. This very sensitive point is inferred by analogy with mature gas plays where F&D costs can be tracked as a function of the percentage of the technically recoverable resources actually produced.
C. Upper-Limit Point: The production milestone of technically recoverable resources. Although the curve can be extrapolated beyond this point, in the strict sense no further gas production is possible so that F&D costs have no meaning.

For a given gas play (either conventional or unconventional), numerical values for the three points increase in the order: A < B << C. The precise proportionality among the values of A, B and C define the shape of the F&D cost curve (Figure B-3).

Figure B-3 Construction of a model F&D cost curve



To construct a given F&D cost curve, Point A was taken as the best estimate of all-in F&D cost for the shale-gas play at start of production (that is, cumulative production of 0%). By shale-gas play, the Point A values ($US/Mcf) were as follows:

Eagle Ford 2.12; Haynesville 2.41; Horn River 2.77; Marcellus 2.23; Montney 2.89

The horizontal placement of Point C was defined by the volume of the technically recoverable resources (that is, cumulative production of 100%). By shale-gas play, the Point C horizontal-placement values (Tcf) were as follows:

Eagle Ford 59; Haynesville 131; Horn River 130; Marcellus 180; Montney 110

The inflection point, Point B, was derived from historical data for the Barnett Shale for which F&D cost was analyzed as a function of cumulative production of the estimated technically-recoverable resource base. The key facts derived from the Barnett Shale historical data were applied as follows:

1. During the years 2004-2010, cumulative production[38] from the Barnett Shale increased from 1.8 Tcf to 9 Tcf (where the 9 Tcf value is projected from mid-year 2010).
2. The real F&D costs (deflated using BLS Drilling index[39]) during the same period increased from $0.55 to $0.80/Mcf. (It is assumed here that 1 Mcf = 1 MMBtu.)
3. Using the estimated resource base for the Barnett Shale of 60 Tcf, and combined facts (1) and (2) above, the rate of F&D cost increase was $0.02/Mcf for each 1% of resources produced.
4. From the result in (3), the scaling factor of $0.02/Mcf, for each 1% production, was utilized to define the inflection point, Point B, for each respective F&D cost curve.

Given the uncertainties involved in constructing the F&D cost curves, analytical risks were managed by using different scenarios where each scenario utilized a different F&D cost curve. The number of curves utilized to represent the evolution of the F&D cost profile for each shale play varied depending on the level of detail available to define the complete F&D cost curve for each play:

- The information available on Marcellus shale has made it possible for this play to be represented by 2 curves.
- Montney Shale is reported having four “intervals of play”: upper, middle, middle lower and lower. The most prolific are the upper and the lower plays. Therefore, 2 F&D cost curves are developed assuming the two portions have the same level of resources available for development. Horn River is assumed to have the same structure as Montney.
- Haynesville and Eagle Ford are each represented in the analysis by a single F&D cost curve, while Eagle Ford was assumed to have a similar cost and resource structure as the Barnett Shale.

Growth in finding & development costs

As discussed in Section 3.1 , it is challenging to achieve a level comparison of F&D costs for different shale-gas plays because so much variation exists in the type, amount and clarity of information reported as “F&D”. So a different approach to detecting trends in F&D costs is to focus on individual shale-gas plays with reasonably long development baselines. By far the most mature shale-gas development is the Barnett Shale for which data are available back to at least the 1990s although the main surge in realized production has occurred since 2003.

[38] Texas Railroad Commission
[39] BLS Drilling Index is the Producer Price Index for Industry Code 213111

Figure B-4 F&D costs[40] over time in the Barnett Shale after inflation to 2010 dollars

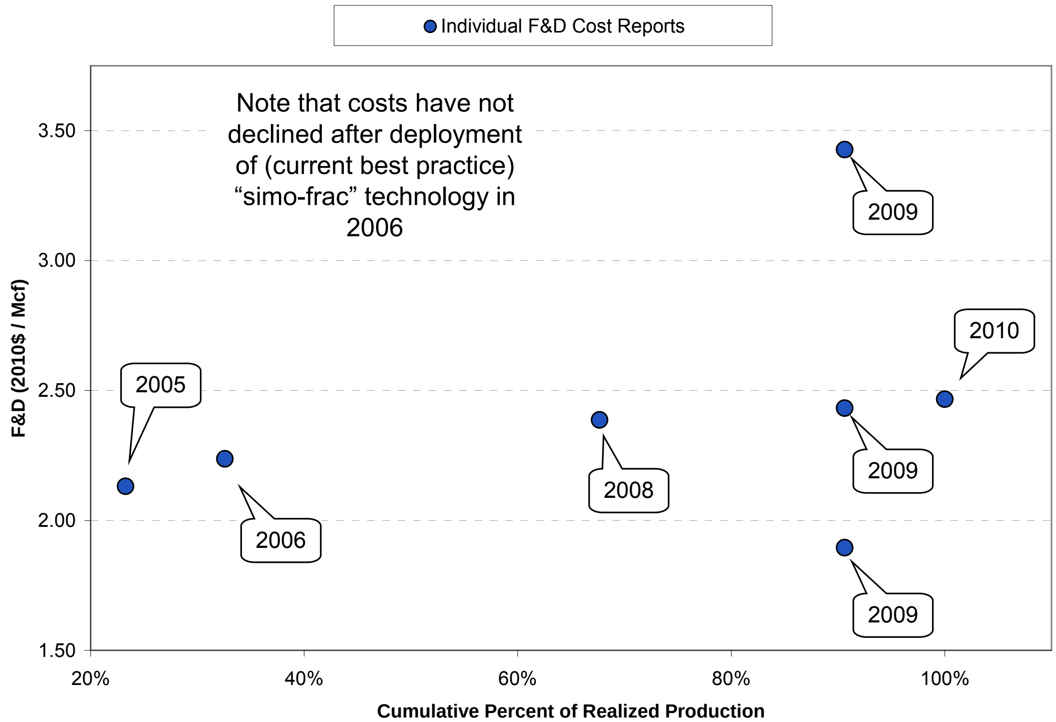


Figure B-4 shows that when F&D costs are viewed on a constant-dollar basis, there is no compelling evidence for a decrease in F&D costs in the Barnett Shale during the years 2005-2010. Of course, the usual argument for the future reduction in F&D costs is that continuous improvement of drilling technology will make well completions more effective and efficient from one year to the next. But as noted by Devon[41], based on their considerable experience in the Barnett Shale, initial well performance (Mcf /d) has not systematically improved over time although development costs have increased as a result of greater dependence on hydrofracturing. As further noted by Devon, even though the cost per hydrofracture stage has gone down, the number of hydrofracture stages needed per well has gone up at a faster pace. So it follows that drill-bit F&D costs – if water costs are booked as such – should be rising from overall growth of hydrofracture costs relative to well productivity. The data in Figure B-4 were compiled for a total of four different producers as reported by three different analysts, making it unlikely that a significant bias survived either by producer or by analyst. Therefore, the upward trend likely is genuine.

The Barnett F&D cost experience likely will apply to other, emerging shale-gas plays as they similarly mature. Therefore, it is reasonable to expect that F&D cost increases, rather than declines, will prevail as shale-gas plays are further developed.

[40] F&D costs in the chart include data from:
"The Barnett Shale: Visitors Guide to the Hottest Gas Play in the US." Tudor Pickering Holt & Company., LLC, October 2005.
Darbonne, Nissa. "The Barnett Shale and Other Shale Dreams." Oil and Gas Investor, IHS Energy User Forum, May 17, 2006, 4-7 p.
"US Equity Research." Jefferies & Company, Inc., June 2008.
"Corporate Presentation," Azimuth Petroleum Corp., March 2010, 26 p.
"2009 Annual Report." Chesapeake Energy Corp., March 1, 2010
"July 2010 Investor Presentation." Chesapeake Energy Corp., July 2010.
[41] "Devon Barnett Shale Q&A." Devon Energy, May 20, 2010, 2p

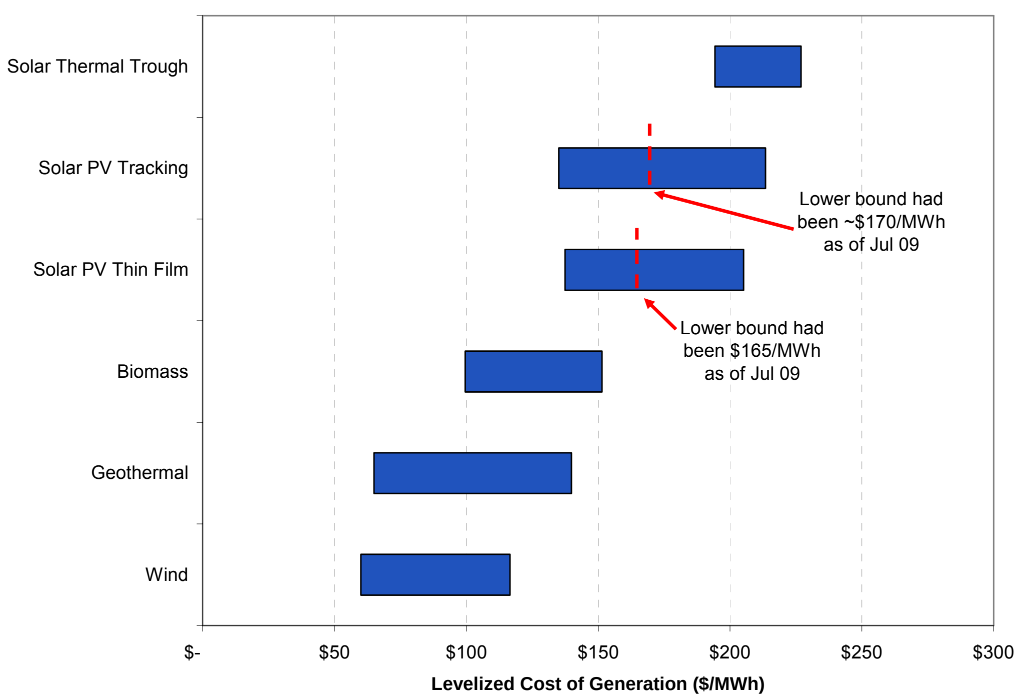
APPENDIX C. RENEWABLE ENERGY – SUPPORTING ASSUMPTIONS & ANALYSIS

Cost of Electricity Analysis for Renewable Technologies

In order to place generating technologies on a comparative basis based on their combined capital and operating costs, a cost of electricity (COE) analysis results in a useful comparison for high-level screening purposes. The COE analysis is a rough estimating tool. It does not consider dispatch dynamics in a competitive marketplace, and is therefore not necessarily well suited to comparisons between dispatchable and renewable technology. Only limited consideration of a local industry structure is possible. Since it is done on a per unit of production basis (MWh), its results can be distorted when considering costs of a 50 MW power plant of one technology with a 1000 MW power plant of a second technology. COE analysis is most appropriate for comparing within a category, e.g.: base load units only, mid-range/CC units only, or simple cycle units only, and careful interpretation is required when comparing across more than one category.

Figure C-1 illustrates the difference in the cost of electricity amongst various types of renewable technology, including wind, geothermal, biomass, and several types of solar technologies. Solar Thermal Trough is actually a component of a steam turbine based technology, except that the steam is being generating by heat that comes from concentrated solar power, rather than combustion of a fossil fuel like coal or natural gas. Solar PV Thin Film is the familiar semiconductor-based photovoltaic cell arranged in an optimal fixed position depending on latitude, while Solar PV tracking has the ability to adjust its position of the course of the day according to the changing position of the sun, thereby optimizing its absorption of radiation. Of course, it is more realistic to consider a variety of capacity factors and costs, and accordingly, the results in Figure C-1 are given as ranges.[42] In general, though Solar PV has recently shown significant reductions in cost, the solar technologies are the most expensive, followed by biomass and geothermal. Wind is the least expensive, and due to this, wind technology is the primary technology that Black & Veatch continues will be employed in response to current and future Renewable Portfolio Standard requirements.

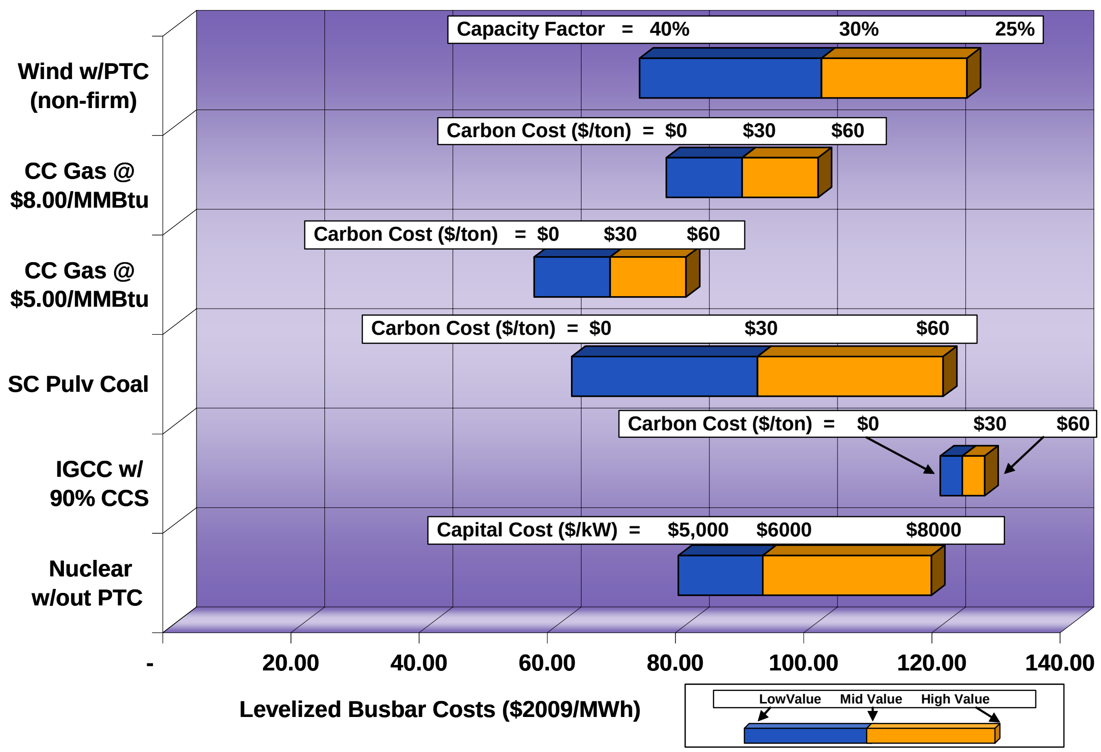
Figure C-1 Cost of Electricity of Selected Renewable Technologies



[42] Estimates assume that ITC is applied per American Recovery and Reinvestment Act (ARRA), effectively lowering the capital costs by approximately 30 percent.

COE for wind varies significantly due to capacity factor, while for conventional, supercritical (SC) pulverized coal it varies significantly according to CO2 allowance price assumptions. Since nuclear power operating costs are very low, the nuclear power COE is chiefly sensitive to capital cost assumptions. Combined cycles, which are most often setting the market price for electricity, have a cost that is mostly sensitive to the price of natural gas. The results in Figure C-2 below show a variety of possible relative positions by COE for various technologies, which underscores the importance of making rational, internally-consistent assumptions when doing economic modeling. On the whole, however, even the lowest-cost renewable, wind, is not necessarily the lowest cost technology in general, explaining the role of RPS in securing a role for renewable technologies.

Figure C-2 Relative Cost of Electricity by Technologies Using Typical Sensitivities



Assumptions:
Capital costs are national average values and will vary widely by region and site.
Coal assumes an average delivered price of $1.50/MMBtu.

APPENDIX D. NUCLEAR - SUPPORTING ASSUMPTIONS & ANALYSES

Summary of Recent Programs and Legislations Supporting Nuclear Power

The Nuclear Power 2010 Program (NP-2010), proposed by the U.S. Department of Energy in February 2002, was designed to reduce technical, regulatory and institutional barriers to the development of new nuclear power plants. NP-2010 is focused on demonstrating an advanced light water nuclear generation technology denoted as "Generation III+," to denote that it is an advancement over the "Generation III" technology certified by the NRC in the 1990s. To achieve this goal with NP-2010, the DOE has:

- Initiated a program with industry to obtain NRC approval of three sites under the Early Site Permit (ESP) process, and
- Developed application guidance and resolve regulatory issues related to filing combined Construction and Operating Licenses (COL).

The EP Act of 2005 contains a number of provisions related to facilitating the development of nuclear power. The Price Anderson Nuclear Industries Indemnity Act was extended to apply to all non-military units built before 2026. This act was created to provide a mechanism for insuring against the event of a major nuclear catastrophe, and is still considered a necessity for the development of new units. The Price Anderson Act included the following provisions:

- Authorized coverage for cost overruns due to regulatory delays of up to $500 million for the first two units and half the cost of overruns (up to a payout of $250 million) for the next four units.
- Authorized a production tax credit of 1.8 cents/kWh for 6,000 MW of new nuclear units during their first 8 years of operation.
- Authorized $1.25 billion for the U.S.DOE to fund construction of a Next Generation Nuclear Plant at Idaho National Laboratory that produces both electricity and hydrogen.
- Mandated the U.S.DOE to report in one year on how to dispose of high-level nuclear waste.
- Loan guarantees for up to 80% of the cost of new "innovative technologies" to reduce greenhouse gas emissions, which could include new advanced design power plants.
- Updated tax treatment of decommissioning fund payments to allow regulated and merchant owned nuclear plants similar tax impacts.
- Updating nuclear power plant security provisions.

Figure D-1 B&V Assumption of Proposed Nuclear Unit In-Service Schedule

Name	Location	Company	Capacity (MW)	Spring 10 EMP Model COD
Amarillo	TX	Amarillo Power	2,700	Unit 1: Jan-29 Unit 2: Jan-31
Bell Bend	PA	Pennsylvania Power and Light	1,600	Jan-20
Bellefonte 1 & 2	AL	TVA	N/A	Unit 1: Jan-17 Unit 2: Jan-18
Bellefonte 3 & 4	AL	NuStart Energy, TVA	2,234	Unit 3: Jan-24 Unit 4: Jan-25
Blue Castle	UT	Transition Power Development	3,000	Never
Callaway	MO	Ameren UE, UniStar Nuclear, LLC	1,600	Never
Calvert Cliffs	MD	UniStar, Nuclear, LLC, Constellation	1,600	Jan-17
Comanche Peak	TX	Energy Future Holdings [Luminant]	3,400	Unit 3: Jan-19 Unit 4: Jan-21
Fermi	MI	Detroit Edison Company	1,520	Jan-24
Grand Gulf	MS	NuStart Energy	1,500	Jan-19
Hammett	ID	Alternate Energy Holding, Inc	1,600	Never
Levy County	FL	Progress Energy	2,234	Unit 1: Jan-18 Unit 2: Jan 19
Nine Mile Point	NY	UniStar Nuclear, Constellation	1,600	Jan-24
North Anna	VA	Dominion	1,520	Jan-19
River Bend	LA	Entergy	1,520	Jan-24
Shearon Harris	NC	Progress Energy	2,234	Unit 2: Jan-22 Unit 3: Jan-23
South Texas Project	TX	NRG Energy, South Texas Project	2,700	Unit 3: Jan-18 Unit 4: Jan-20
Turkey Point	FL	Florida Power & Light	2,200	Unit 1: Jan-20 Unit 2: Jan-21
Victoria County	TX	Exelon Nuclear	3,040	Never
Virgil C. Summer	SC	Scana [South Carolina Electric and Gas], Santee Cooper	2,234	Unit 2: Jan-19 Unit 3: Jan-20
Vogtle	GA	Georgia Power, Oglethorpe Power, Municipal Electric Authority of Georgia, City of Dalton	2,234	Unit 3: Jan-17 Unit 4: Jan-18
Watts Bar II	TN	TVA	1,167	Jan-13
William States Lee III	SC	Duke Energy	2,234	Unit 1: Jan-18 Unit 2: Jan-19
Bruce A	ON	Bruce Power	1,650	Unit 1: Dec-10 Unit 2: Dec-12

APPENDIX E. GREENHOUSE GAS EMISSION LIMITS – SUPPORTING ASSUMPTIONS AND ANALYSIS

Expectation of Greenhouse Gas Emission Limits

The Obama administration has pledged to establish a national CO2 cap & trade program which will include an economy-wide cap on CO2 emissions. In the summer of 2009, much attention was focused on HR 2454, the American Clean Energy and Security Act of 2009 (ACES), drafted by Reps. Henry Waxman and Ed Markey. The U.S. House of Representatives passed the bill on June 26, 2009. Intended to reduce domestic emissions of greenhouse gases, ACES contains four main mechanisms for reducing greenhouse gas emissions in the economy:

- A cap and trade emissions trading system geared at the electric utility sector and large emitters of greenhouse gases;
- New Source Performance Standards for non-trading CO2 emitters;
- A mandatory federal renewable electricity standard requiring electric utilities to generate 20 percent of their power from renewable sources and through efficiency gains by 2020;
- Various energy efficiency standards for buildings, equipment, and appliances.

These mechanisms are in turn calibrated to the following more specific policy objectives:

- Reduce greenhouse gas (GHG) emissions by 17% in 2020 compared to 2005 levels; 42% by 2030, and 83% by 2050.
- 85% of the GHG allowances will be allocated to retail electric companies and generation owners; 15% will be auctioned.
- Combination of Demand-Side Management and Energy Efficiency (DSM/EE) and RPS in a single program called Combined Efficiency and Renewable Electricity Standard (CERES). Sets a combined target of 6% in 2012 rising to 20% in 2020.
    - Up to 25% of target can be met with DSM/EE: In that case, 15% of electricity to come from renewable energy sources and there is a 5% demand reduction from energy efficiency measures.
    - Generation from new nuclear, new CCS and existing hydro are deducted from retail sales for calculating the CERES requirement.
    - Creates RECs which can be banked for 3 years after generation.
    - REC prices capped by an Alternative Compliance Payment (ACP) of $25/MWh.
    - Retailers selling less than 4,000,000 MWh/yr are exempt.

In the Spring of 2010, another GHG bill, the American Power Act, was introduced as a discussion draft on May 12, 2010, by Senators John Kerry and Joseph Lieberman. Some common features of Waxman-Markey and Kerry-Lieberman include:

- Reduction Goals – 17% by 2020, 42% by 2030, 83% by 2050
- Economy-wide cap-and-trade with unlimited banking, borrowing with interest
- Allows up to 2 billion tons in offsets annually for compliance
- New coal plant CO2 performance standards
- Financial incentives and guarantees for nuclear power, carbon capture and storage development
- Prohibits EPA regulation under Clean Air Act provisions

Some of the key differences between the two bills are summarized side-by-side in Table E-1 below:

Table E-1 Summary of Key Differences

Waxman-Markey American Clean Energy & Security Act (Passed by House June 2009)	Kerry-Lieberman American Power Act (Introduced into Senate May 12, 2010)
Cap-and-trade begins 2012	Cap-and-trade begins 2013
50/50 historic emissions/retail sales allowance distribution formula	75/25 allowance distribution formula
Unlimited trading participation	Trading restricted to regulated entities; Allowance “price collar” - $25/tonne ceiling and $12/tonne floor (adjusts with inflation plus real growth of 3% for floor and 5% for ceiling)
National RES 20% by 2020	No RES or transmission planning provisions
Moratorium of state programs from 2012 to 2017	Prohibits state GHG trading programs

Although recent economic and political realities have made the likelihood of a comprehensive greenhouse gas legislation mandating a cap and trade program low, the analysis assumes that federal and state actions in some form will lead to restrictions on greenhouse gas emissions.

GHG Regulations – EPA Actions

The U.S. Environmental Protection Agency’s (EPA’s) endangerment finding (in response to 2007 Supreme Court ruling) states that GHG emissions from motor vehicles “cause or contribute to pollution that endangers public health & welfare”. This gives the EPA authority to regulate GHG emissions from mobile and stationary sources under the Clean Air Act. Thus far, it created the GHG Mandatory Reporting Rule, and the GHG Tailoring Rule, which subjects new sources emitting 100,000 tons per year, and modification of existing sources emitting 75,000 tons per year, to Best Available Control Technology (BACT) requirements under Clean Air Act PSD program. Both rules have been issued, but BACT guidelines are still under development, and application to smaller emitters will be part of a 5-year study. As above, if implemented, potential GHG legislation would essentially nullify such EPA regulations.

The Treatment of Allowance Offset and Other Compliance Measures in the B&V model

Allowances can be banked for future use. Some technical assumptions inherent in B&V Baseline Forecast are that a CO2 cap & trade program will induce the application of the most cost-effective avoidance and abatement measures first and additional measures in order of increasing cost until total emissions are under the targeted cap; therefore, allowance prices are determined by the marginal cost of control of the last measure required to meet the cap. In addition, the cost of control in the industrial, transportation and domestic sectors are assumed to be sufficiently similar to the costs for the electric industry such that the trading of allowances between the electric and other sectors is minimal. Therefore, electric industry caps and use of offsets are in proportion to economy-wide caps. Currently electric generation contributes 39% of covered emissions.

Offsets are essential for cost-effective compliance. Offsets are permanent greenhouse gas emission reductions or avoidance (including sequestration) not required by any law or regulation or commenced prior to 2009. According to Waxman-Markey, the offset project developer is issued one credit for each CO2e that the project reduces, avoids or sequesters. Waxman-Markey allows for 2 billion metric tons (2,204,623 short tons) in offsets. In the model it is assumed that the electric power industry uses only 50% of it “pro-rata share” of offsets, on based on the expectation that other sectors will have more difficulty in compliance and therefore need more than their share.

In the Black & Veatch model, compliance with GHG regulations can be met from a variety of measures. The current avoidance and abatement measures applicable to the electric industry include the following:

Table E-2 Advantages and Disadvantages of Different Compliance Measures

Compliance Measure	Advantage(s)	Disadvantage(s)
Offsets	Allows for compliance with less reduction in carbon-based fuel use	Uncertain availability and costs
Nuclear	May be cost effective based on today's costs	Siting and permitting difficult; capital cost uncertainty; ability to raise adequate capital
Coal IGCC w/ CCS	Abundant domestic energy source	Expensive and still in demonstration stage; uncertain environmental impacts
Retrofitted Carbon Capture and Sequestration	Reduces carbon emissions of existing carbon-based generation assets	Existing assets were not designed for CCS, so retrofitting costs are relatively high and technology is uncertain
Wind	Zero carbon, abundant resource, favorable economics	Needs PTC/ITC and/or RPS/REC; Intermittency
Solar	Zero carbon, abundant resource	Cost; regional resource; intermittency
Natural Gas	Proven technologies, short development lead time; less carbon than conventional coal; virtually no SO2 or Hg	Exposure to volatile commodity pricing
Demand Side Management and Energy Efficiency	Uses proven technologies	Regulatory risk related to revenue de-coupling and proof of "negawatts"

GHG allowance prices will lead to retirement of some of the smaller, older, less efficient coal fired units. The development of nuclear power, wind, solar and natural gas resources and acquisition of offsets will also all be part of the compliance stew. Wind energy offers a very large opportunity to further reduce CO_2 emissions in the U.S., but has a high cost of transmission. International offsets are vital for compliance at reasonable costs.

Available CO_2 allowances will likely be distributed with a combination of auction and allocation processes to current and future producers. Over time, more will be auctioned and fewer will be allocated. The implication is that over time the cost of CO_2 emission allowances becomes a cash operating cost for all carbon-emitting entities. This is in sharp contrast to the SO_2 cap and trade system in the 1990 Acid Rain Program, in which SO_2 emission allowances were allocated at zero cost to existing emitters.

APPENDIX F.IMPACT OF KEY DRIVERS

Range of Key Drivers

Flatter F&D Cost Curve Scenario

In order to examine the price and production impacts of lower F&D costs, Black & Veatch reconfigured the shape of the F&D cost curves of major shale plays. In essence, such a scenario assumes that the escalation of shale production costs are mitigated to due technological gains, better than expected production profiles of active wells in a play, or a number of other unforeseen circumstances. The "flattening" of the F&D cost curve assumptions applied to conventional shale plays creates a scenario in which the cost of production escalates at a rate more akin to the cost escalation of a conventional play. See Figure F-1 for examples of several F&D cost curves for conventional plays. Alterations to shale F&D cost curves for the "Flatter F&D Cost Curve Scenario" may be found in Figure F-2.

Figure F-1 WCSB, Rockies, and GOM Offshore F&D Costs

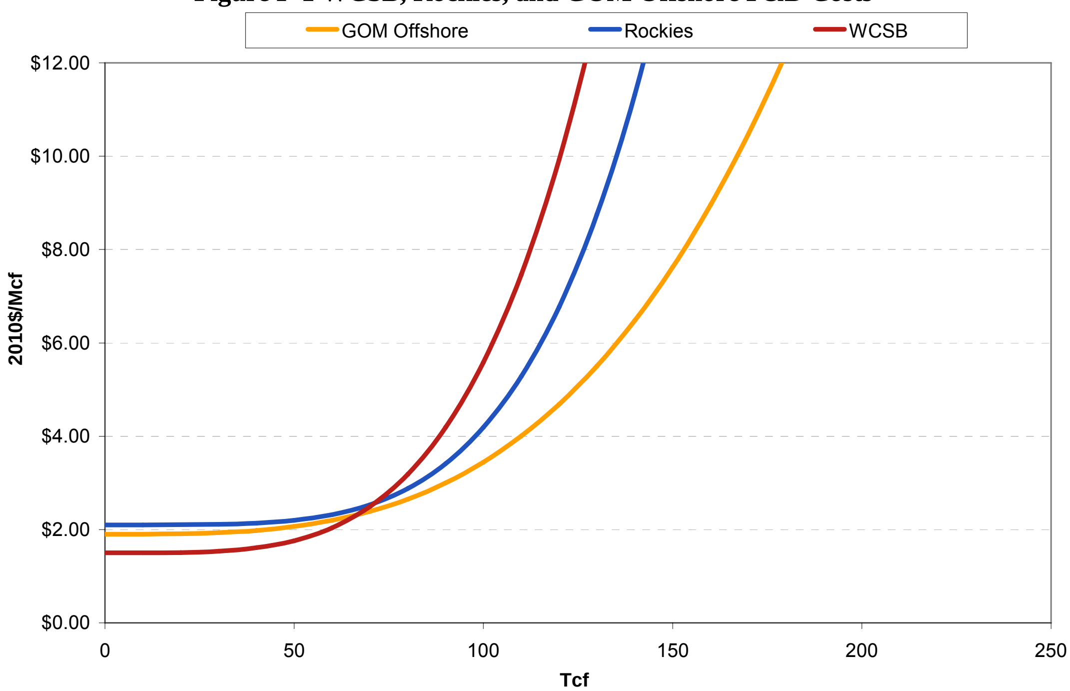
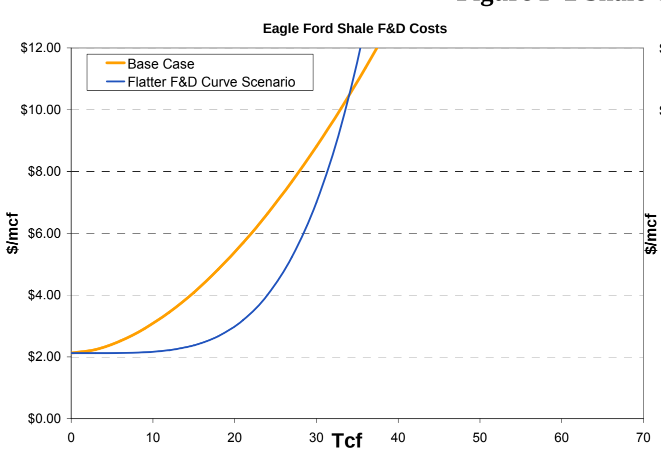
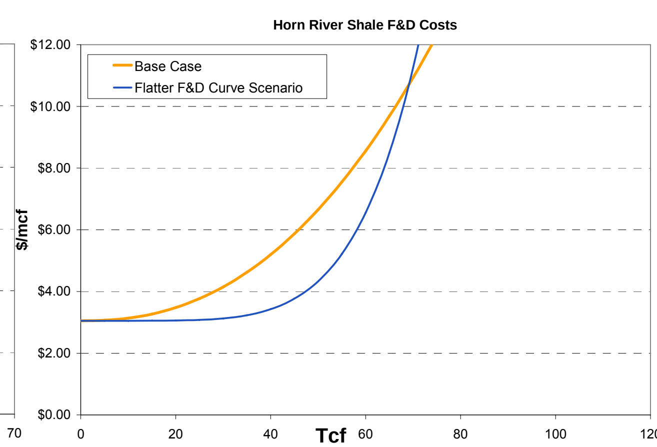


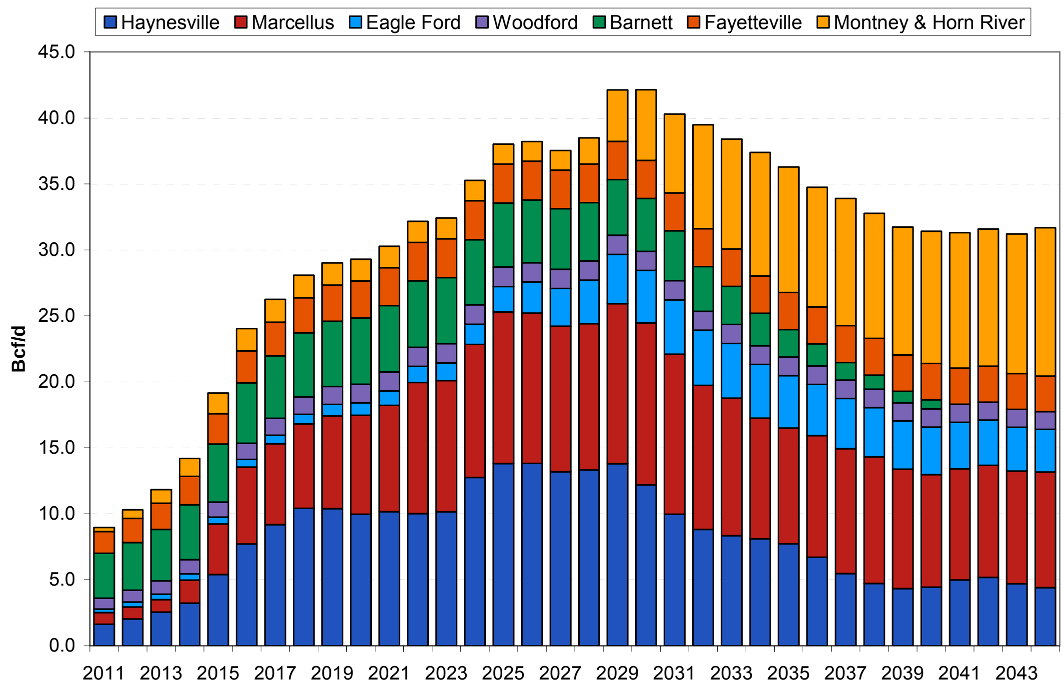
Figure F-2 Shale Gas F&D Costs





With flatter F&D cost curves, emerging shale production grows at an average pace of 8% per annum from 2011 to 2030, reaching 42 Bcf/d by 2030. Production begins to decline after 2030, reaching 31.7 Bcf/d in 2044. Projected production from emerging shales under the Flatter F&D Cost Curve Scenario is displayed in Figure F-3.

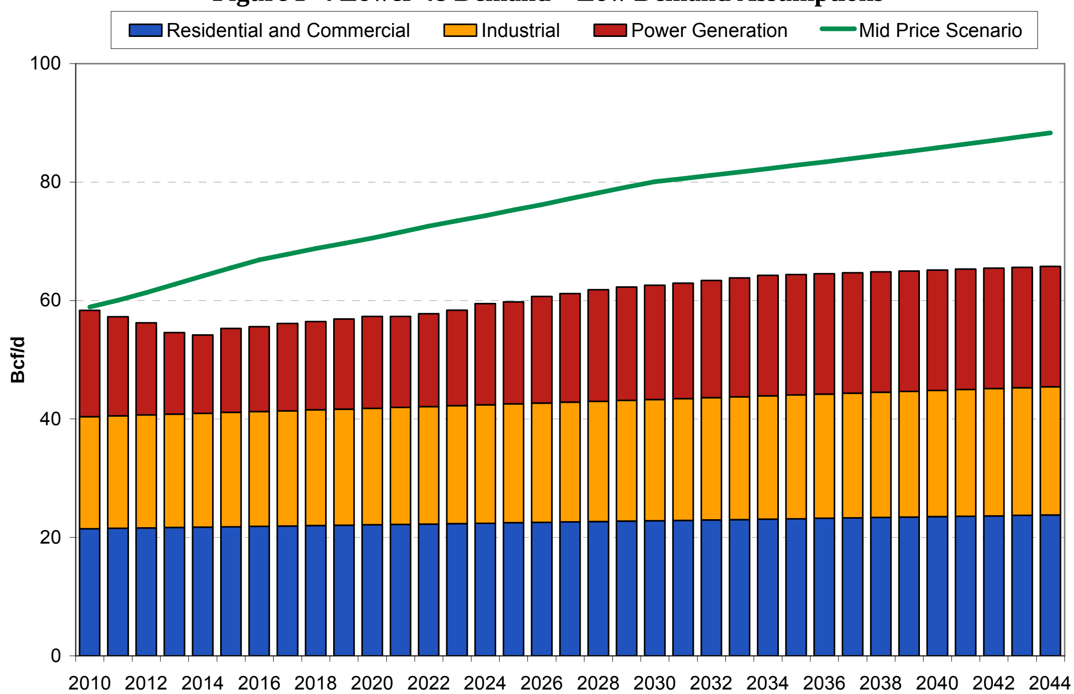
Figure F-3 B&V Projection of Emerging Shale Production – Flatter F&D Cost Curve Assumptions



Low Demand

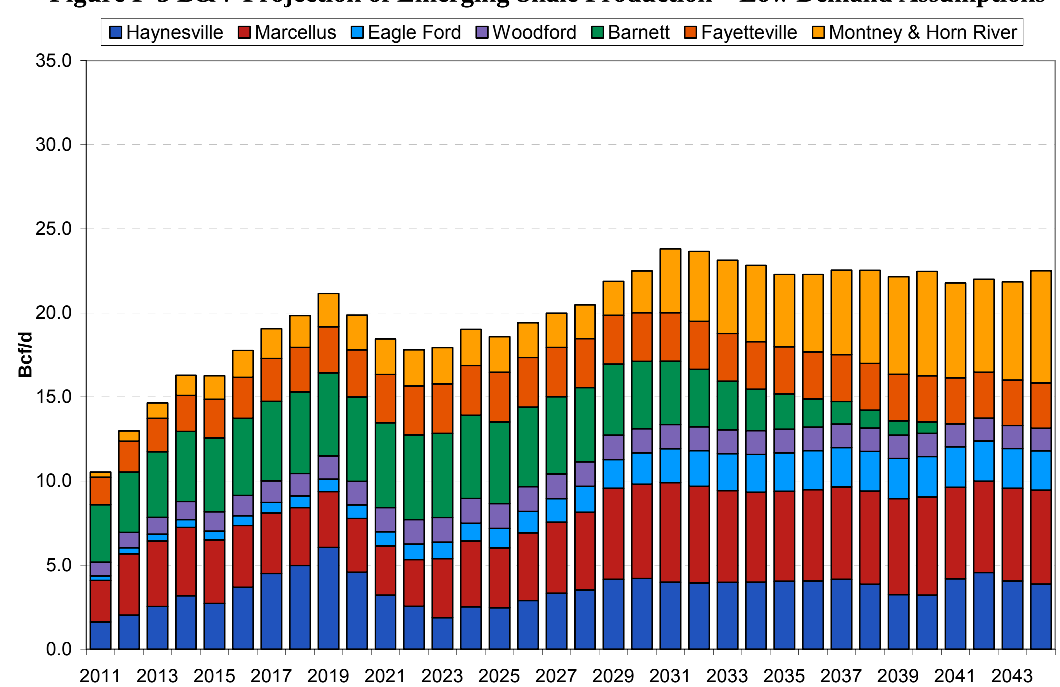
B&V also ran a sensitivity case in which demand assumptions were altered to fit the demand assumptions of the EIA's AEO 2010 reference case. One reason for divergence in B&V's Mid Price Scenario and the EIA's AEO 2010 demand assumptions is a difference in the assumed growth rate of natural gas demand for power generation. The EIA anticipates power generation demand to grow at an average annual rate of 0.5%, while B&V anticipates that this demand will grow at an average rate of 2.3% per annum between 2010 and 2044. Another reason for this divergence is the fact that the EIA AEO 2010, unlike B&V, includes no expectations for greenhouse gas legislation in its model. Due to these differences, the Low Demand Scenario explores the effect of lower than expected growth in electricity demand on the natural gas market. A comparison between the two annual projections may be found in Figure F-4.

Figure F-4 Lower 48 Demand – Low Demand Assumptions



Under this scenario, emerging shale production grows at a significantly lower rate, reaching 22.5 Bcf/d in 2044, as compared to the 32.6 Bcf/d of total shale production reached in the Mid Price Scenario. Projected production from emerging shales under the Low Demand Scenario is displayed in Figure F-5.

Figure F-5 B&V Projection of Emerging Shale Production – Low Demand Assumptions

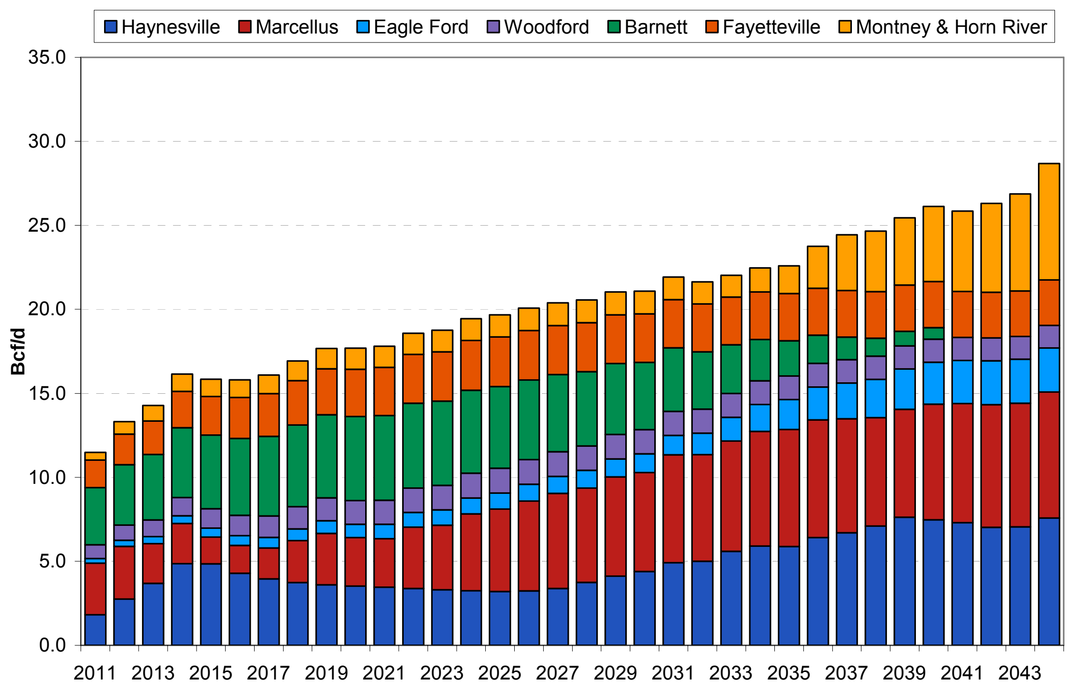


Higher Water Costs

The High Water Costs Scenario explores the possibility of higher than expected shale drilling costs due to water treatment and usage issues. A water cost adder was therefore included in the assumptions for this scenario. These assumptions are displayed in Table 3-5 in Section 3.5.

With higher water costs moderate the growth emerging shale production, which is expected to reach 28.6 Bcf/d under this scenario. Projected production from emerging shales under the High Water Cost Scenario is displayed in Figure F-6.

Figure F-6 B&V Projection of Emerging Shale Production – High Water Cost Assumptions



Land Restrictions

As discussed above, B&V's Mid Price Scenario applied a land access assumption of land access issues in which 10-20% of Marcellus Shale's technically recoverable reserves were considered inaccessible. None of Eagle Ford, Haynesville, Horn River, and Montney Shale's technically recoverable reserves were assumed inaccessible in Mid Price Scenario because Black & Veatch does not view land access as a major uncertainty in these shales.

In the Land Restrictions Scenario, Black & Veatch increased land access restrictions in the Marcellus shale to render 35% of technically recoverable resources inaccessible while 10% of the technically recoverable resources of Eagle Ford, Haynesville, Horn River, and Montney Shale were assumed to be inaccessible. Technically recoverable resources assumed for each basin in the Mid Price Scenario and Land Restrictions Scenario are summarized in Table F-1.

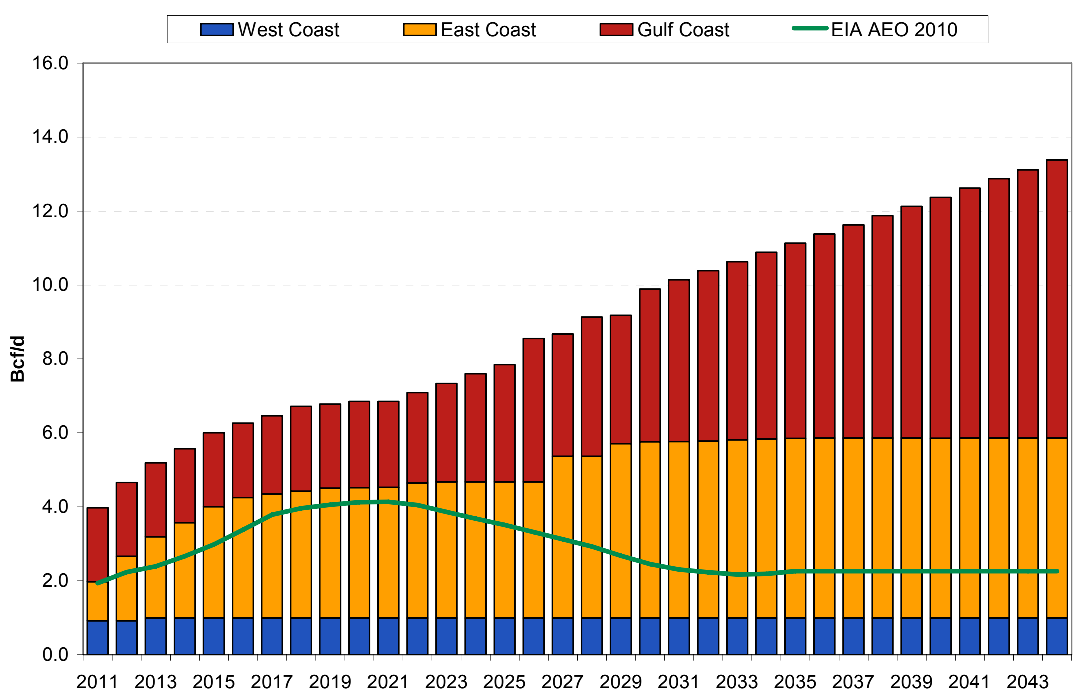
Table F-1 Summary of Technically Recoverable Resources by Basin

Basin (Tcf)	B&V Base Case	Lower Resource
Marcellus	200	130
Haynesville	131	118
Eagle Ford	50	45
Montney	110	99
Horn River	130	117
Total	**621**	**509**

Low LNG Imports

The Low LNG Import Scenario explores the effect of a significantly curtailed LNG import assumption in which North American prices will not reach adequate levels to attract cargoes from the Atlantic and Pacific Basins, therefore delaying the construction of additional North American Liquefaction capacity. In the Low LNG Import Scenario, B&V adopted the EIA's AEO 2010 LNG import assumptions, in which imports peak at 4 Bcf/d in 2020 and decline until they reach a stable level of 2.3 Bcf/d in 2035. This stands in contrast to B&V's LNG import assumptions in the Mid Price Scenario, in which imports grow with a CAGR of 3.6% between 2011 and 2044, reaching 13.4 Bcf/d in 2044. Figure F-7 compares the B&V Mid Price Scenario and EIA AEO 2010 LNG import assumptions.

Figure F-7 LNG Import to North America – Mid Price Assumptions



High Severance Tax and Royalty Costs

In the High Severance Tax and Royalty Costs Scenario, Black & Veatch increased assumptions of severance taxes and royalty rates in key states and provinces to levels which are viewed to lie at the upper bound of potential rate possibilities. Such a scenario could occur due to mounting environmental concerns, leading to rate increases enacted to disincentives production. In this scenario, severance taxes for Louisiana, New York, Pennsylvania, and Texas were raised to 10% while the royalty rate for each of these states remained at 12.5%. Severance taxes for Alberta and British Columbia remained unchanged, while royalty rates were ramped up according to price levels in the High Severance Tax and Royalty Costs Scenario. Table F-2 compares severance tax and royalty rate assumptions across scenarios.

Table F-2 Summary of Severance Tax and Royalty Rate Assumptions

Mid Price Scenario

	Severance Tax			Royalty		
Gas Price	$3/MMBtu	$6/MMBtu	$9/MMBtu	$3/MMBtu	$6/MMBtu	$9/MMBtu
TX	7.50%			12.50%		
LA	$0.12/Mcf	$0.24/Mcf	$0.36/Mcf	12.50%		
PA	5% and $0.047/Mcf			12.50%		
NY	5% and $0.047/Mcf			12.50%		
AB	0%			6%	18%	24%
BC	0%			27%	27%	27%

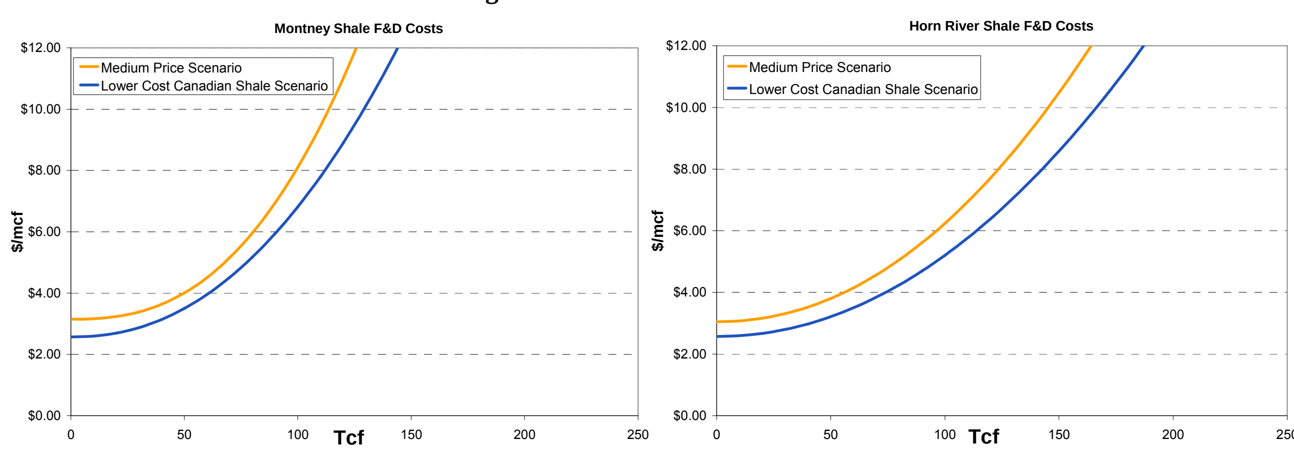
High Severance Tax & Royalty Case

	Severance Tax			Royalty		
Gas Price	$3/MMBtu	$6/MMBtu	$9/MMBtu	$3/MMBtu	$6/MMBtu	$9/MMBtu
TX	10%			12.50%		
LA	10%			12.50%		
PA	10%			12.50%		
NY	10%			12.50%		
AB	0%			7%	22%	29%
BC	0%			32%	32%	32%

Lower Cost Canadian Shales

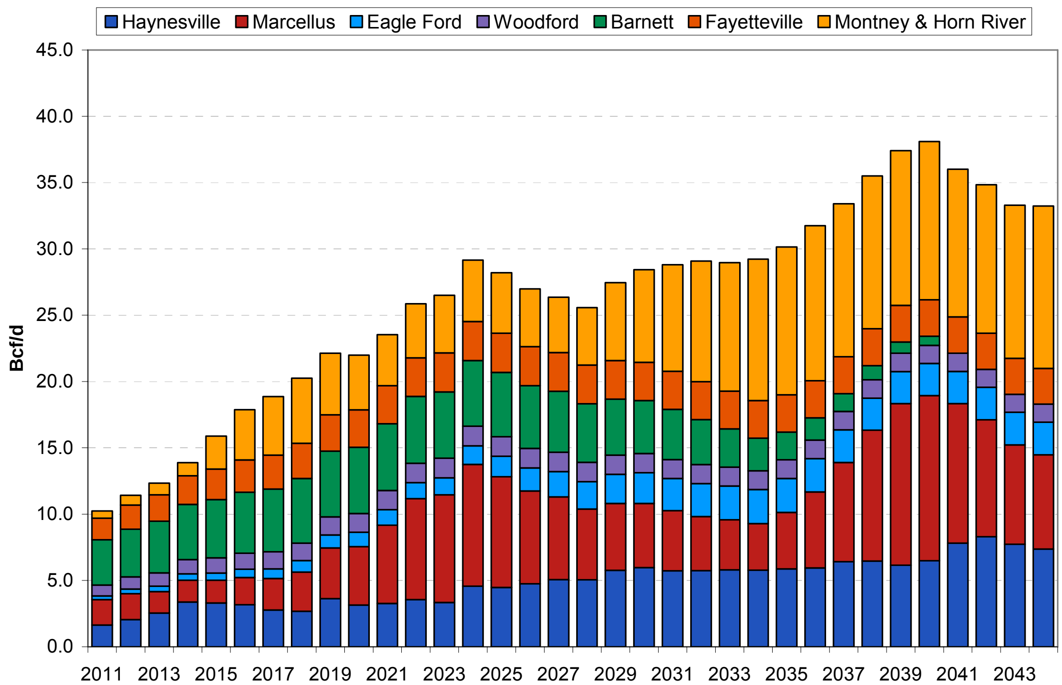
In the Lower Cost Canadian Shales Scenario, Black & Veatch explored the possibility of increased Canadian shale production, assuming that F&D costs for Horn River and Montney shales are on par with Lower 48 shale plays. Comparisons of these assumptions across scenarios are displayed in Figure F-8.

Figure F-8 Shale Gas F&D Costs



Lower production costs of the Canadian shales significantly increase their production to ramp up earlier and grow at a higher rate than in the Mid Price Scenario. Under this scenario, the combined production of Horn River and Montney peaks at 11.3 Bcf/d in 2040 as opposed to their peak of 9.5 Bcf/d in 2044 under the Mid Price Scenario. Projected production from emerging shales under the Low Cost Canadian Shale Scenario is displayed in Figure F-9.

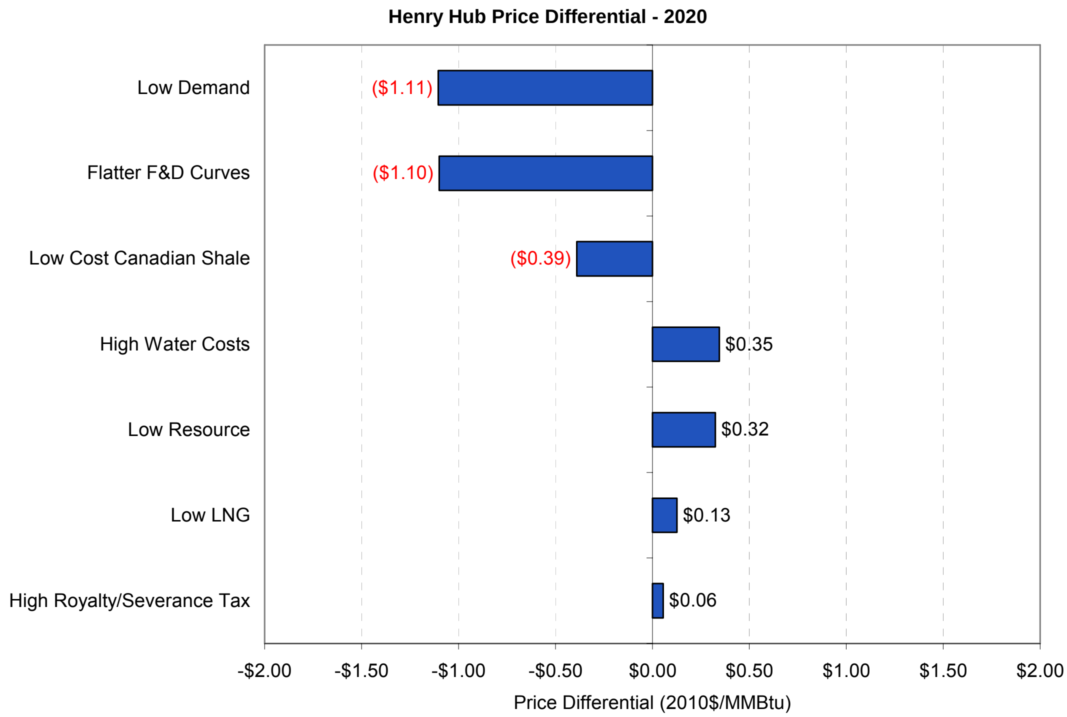
Figure F-9 B&V Projection of Emerging Shale Production – Low Cost Canadian Shale Assumptions



Price Impact

The price results of B&V's sensitivity analysis indicate that lowering demand and flattening F&D curves have the most significant effect on natural gas prices. This is likely because adjustments to demand and F&D cost expectations most directly alter the price charged for each marginal unit of production. It is also notable that the assumptions of the Low LNG scenario have a significant impact on prices in the long run; as expected, lowering expected supply by approximately 10 Bcf/d greatly influences the price environment. Figure F-10 and Figure F-11 display the impacts which the seven assumptions have on Black & Veatch's natural gas price forecasts for Henry Hub and AECO, displayed as a differential to the Mid Price Scenario.

Figure F-10 Henry Hub and AECO Price Differentials for 2020



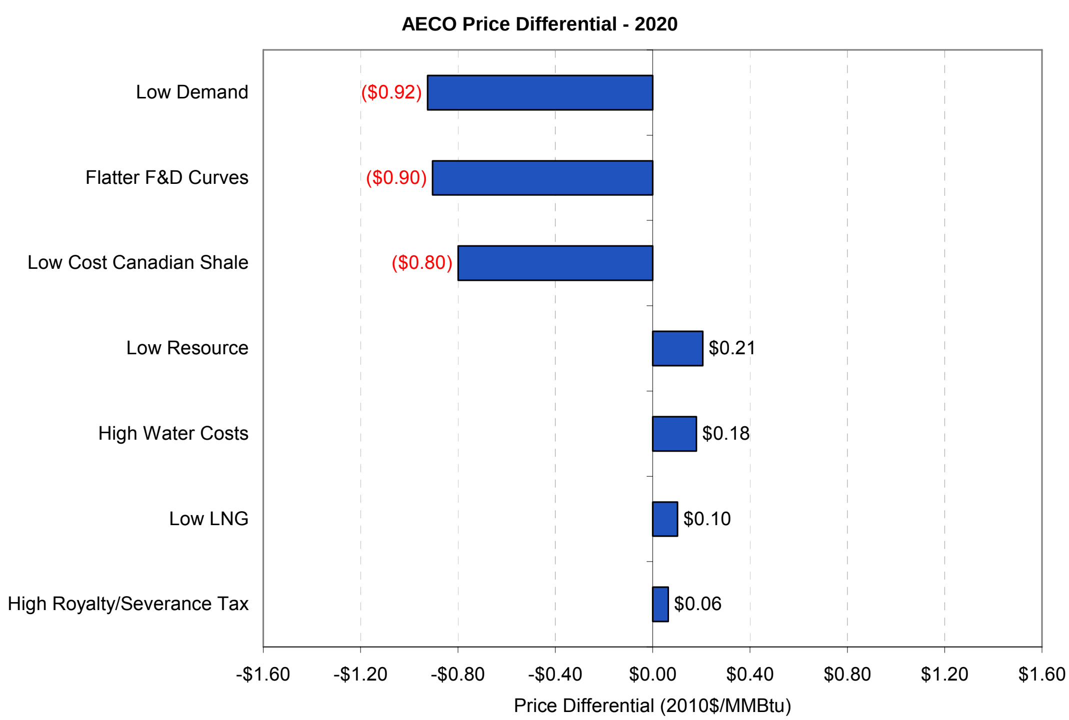


Figure F-11 Henry Hub and AECO Price Differential for 2040