Paper #1-8

ONSHORE NATURAL GAS

Prepared by the Onshore Gas Supply Subgroup
of the
Resource & Supply Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

Onshore Gas Subgroup		
Cochairs		
Douglas J. Tierney	Vice President, Business Development	Encana Corporation
Alan P. Wilson	Team Leader, Business Development	Encana Oil & Gas (USA) Inc.
Members		
Clayton A. Carrell	Senior Vice President, Chief Engineer	El Paso Exploration & Production Company
R. Dean Foreman	Chief Economist	Talisman Energy
Edward M. Kelly	Vice President, North American Gas & Power	Wood Mackenzie Inc.
Christopher M. McMahon	Manager Engineering – Corporate New Ventures	Devon Energy Corporation
Paul Mortensen	Technical Leader, Hydrocarbon Resources	National Energy Board
Robert H. Sterling, Jr.	Senior Geologist	Cirque Resources LP

Abstract

New techniques, particularly cost-effective multiple-stage fracture stimulations in horizontal wellbores, have recently and rapidly enabled production from vast resources of shale gas and tight gas never before considered economic at any reasonable price. These advances in technology have been instrumental in reversing the decline in North American natural gas production, onshore particularly, virtually eliminating the need for natural gas (and LNG) imports into the region. This phenomenon is creating expanded natural gas utilization; opening avenues for affordable, abundant energy and higher employment. This Topic Report examines the U.S. Lower 48 and non-arctic Canada onshore natural gas resource and its ability to provide reliable energy over many decades under various scenarios and ultimate recoverable gas resource volumes.

Executive Summary

The topic of this paper is U.S. Lower 48 and non-arctic Canada onshore gas supply. We examine the present, past, and some possible future scenarios of this versatile energy resource.

There is ample natural gas available in North America to supply current consumption levels for many decades. This supply can support significant growth at reasonable prices for consumers. New

Key Findings for U.S. Lower 48 + Non-Arctic Canada Onshore Natural Gas

- **Recent technology advancements have enabled the development of widespread and large-scale tight gas and shale gas resources in North America**
- **Estimates of remaining resource, and particularly of the shale gas resource, have increased significantly over recent years and throughout resource studies**
  - Horizontal drilling coupled with multi-stage fracture stimulation particularly plays a key part in this increase, enabling the shale gas and tight gas resources specifically
- **The remaining recoverable gas resource (as of 1/2010) is estimated to be between 1,900 and 3,600 trillion cubic feet (TCFG)**
  - Further technological advancements and play delineation beyond the current level are expected to further increase this quantity
  - Legislative or regulatory constraints (particularly on fracture stimulation) upon development activity could drastically reduce the available recoverable resource
- **Between five to nine decades of flat supply at current (2009) levels is estimated to exist, even accounting for substantial (600 - 1,400 TCFG) resource being produced on decline post plateau**
- **Onshore gas supplies can support increased utilization of this resource. Up to three decades of supply is estimated as being available at 50% greater supply levels than today, even accounting for a decade ramp up and decline volumes**
- **Supply costs should remain below $10/mmBTU ($60/boe) through 2030 as long as the industry is not dis-incentivized**
- **Wildcat exploration successes are not included in the estimates above**
- **Requirements to support this resource development are achievable based upon high level scoping:**
  - Directly employed personnel could increase 10 – 25% over 40 years
  - Rig count is manageable and within historical levels, although a higher level of high horsepower rigs is anticipated
  - Well capital and steel needed for pipelines, tubing and casing is similarly manageable and comparable to recent historical levels
  - Proppant needed for fracture stimulation may double or treble versus 2010 estimates (flat to double versus 2008) over 40 years
  - Water (including primary and re-use) needed for fracture stimulation could increase 50 – 150% to approximately 2.5 billion barrel of water (Bbw) annually, less than 0.1% of U.S. water withdrawal in 2000 (less than 0.2% of U.S. water withdrawal in 2000 excluding hydro-electric use)[1].

techniques, particularly cost-effective multiple-stage fracture stimulations in horizontal wellbores, have recently and rapidly enabled production from vast resources of shale gas and tight gas never before considered economic at any reasonable price. This growth exists today as new plays continue to be discovered.

Several historical studies[2-17] were reviewed on the topic, with recent remaining resource estimates generally increasing. The recent studies with the largest supply estimates imply up to ~4,000 TCFG of remaining resource for U.S. Lower 48 and Canada gas, nearly four times cumulative production to-date. Data obtained from the authors[18] and the consultants[19] of the June 2010 MITei Interim Study[9] was used to create scenarios in this paper as that study has the most comprehensive supply basis (with associated supply costs), including both U.S. and Canada, generally available to the public. Results for U.S. Lower 48 and non-arctic Canada onshore gas for three classes of scenario (Flat Supply, Increased Supply, and Restricted Supply) as a function of resource size uncertainty (Case 1 – 3, increasing resource size) are as follows:

Scenario: Onshore Gas Flat Supply at Current 24.1 TCFG/year

Resource Case	Remaining Resource [TCFG]	Years of Plateau Rate	Supply Cost Through 2030 [$/mmBTU]	Estimated Gas Rigs in 2030 / 2050
One	**1,901**	**54**	**< 6**	
Two	**2,890**	**78**	**< 5**	**1,200 / 1,500**
Three	**3,561**	**90**	**< 5**	

Scenario: Onshore Gas Supply Increasing 50% to 36.5 TCFG/year

Resource Case	Remaining Resource [TCFG]	Years of Plateau Rate	Supply Cost Through 2030 [$/mmBTU]	Estimated Gas Rigs in 2030 / 2050
One	**1,901**	**20**	**< 11**	
Two	**2,890**	**31**	**< 8**	**1,800 / 2,200**
Three	**3,561**	**33**	**< 9**	

Several restricted supply scenarios were also developed which imply significant reductions to the above Scenarios; Remaining Resources and Years of Plateau Production range from 692 to 2,694 and 0 to 54 respectively.

Scenario: Extreme Restrictions Placed on Onshore Gas Supply

Resource Case	Remaining Resource [TCFG]	Years of Plateau Rate	Supply Cost Through 2030 [$/mmBTU]
One	**692**	**minimal**	**N/A**
Two	**824**	**none**	**N/A**
Three	**1,013**	**none**	**N/A**

Scenario: Moderate Restrictions Placed on Onshore Gas Supply

Resource Case	Remaining Resource [TCFG]	Years of Plateau Rate	Supply Cost Through 2030 [$/mmBTU]
One	**1,492**	**37**	**< 9**
Two	**2,188**	**49**	**< 7**
Three	**2,694**	**54**	**< 8**

Given the potential for further increases in the remaining natural gas resource particularly with anticipated technology gains, we look forward to revisiting this onshore natural gas picture in three to five years.

Table of Contents

List of Figures

Appendix A - Technology & Natural Gas Supply in North America

Appendix B - Resource Supply Discussion

Appendix C - Data Discussion

List of Tables

Introduction

Natural gas, already a significant source of low-emissions energy, is the second leading source of energy in North America, supplying 27% of the total energy demand in 2009[20] and has the potential to supply a much larger share in the future. This potential stems from both the energy marketplace, in which natural gas use is likely to grow, especially for power generation, and also from a recent revolution in the natural gas supply potential in North America. The unlocking of the shale resource base within the past five years has opened a vast energy resource for domestic North American production and consumption.

Currently, onshore gas from Canada and the U.S. supplies about 90 percent of the natural gas consumed in those countries. This paper discusses the current state of knowledge regarding domestic onshore natural gas supply potential in the U.S. Lower 48 and non-arctic Canada, starting with a discussion of recent production trends, and the genesis and growth of shale production and related technologies. A description of the state of the art follows, along with a comparison of several different estimates of supply. We then introduce several supply-driven scenarios for the reader to consider. The scenarios rely on supply data provided in the most current studies as well as a "top down" view utilizing some macro assessment techniques. Finally, we draw inferences as to the physical requirements needed to support the primary supply scenarios. Supply numbers developed and discussed herein refer to U.S. Lower 48 and non-arctic Canada onshore gas unless context clearly indicates otherwise.

Production Development ("Where are we now?")

Recent production history illustrates the significance of cost-effective, multi-stage, hydraulic fracturing in horizontal wellbores to the overall North American gas supply mix and resource base. Overall U.S. production has increased significantly since 2005, with U.S. production reaching an average of 57.8 billion cubic feet per day (Bcfd) on a dry basis in 2010; that is, with the natural gas liquids (NGLs - ethane, propane, butane, etc.) stripped out. This dry production level represents an increase of 16% from the recent historic low of 49.7 Bcfd in 2005, and is the highest overall production rate experienced in the U.S. since 1973. Shale production has begun in Canada, most notably in the Montney (siltstone) and the Horn River basin, but has not as yet arrested the decline in overall production there.

Production from shales as a category is largely responsible for the overall production increase in the U.S., having grown the most in both absolute and percentage terms since 2000. In the year 2000 shale gas production was approximately 1.0 Bcfd, or approximately 2% of the U.S. supply mix. Shale production had grown to approximately 11.6 Bcfd by 2010, representing approximately 20% of the 57.8 Bcfd of dry U.S. production expected for this year (Figure 1 and Table 1). Production from tight formations has also increased in both absolute and percentage terms, increasing from 12.0 Bcfd in 2000 to 19.9 Bcfd in 2010, or from 23% to 34% of the total over the period. When adding U.S. coalbed methane (CBM) production, also considered "unconventional", production from unconventional sources has more than doubled in the U.S. since 2000 – increasing by 19.2 Bcfd, from 17.2 Bcfd in 2000, to 36.4 Bcfd in 2010.

Thus, unconventional production has increased from approximately one-third of the total U.S.

supply mix in 2000, to nearly two-thirds in 2010, or from 33% to 63% of the total. However, the increase in U.S. production since 2005 is almost entirely due to shale gas. Growth from this source alone since 2005 exceeds total U.S. production growth. U.S. production overall (all else equal) would have continued to decline without shale production. Shale and CBM represent a growing percentage, currently approximately 11%, of overall production in Canada. Unfortunately, a breakout of tight gas production in Canada was not available as of this writing. U.S. Lower 48 and non-arctic Canada onshore gas production in 2009 is estimated as 24.1 TCFG/yr.

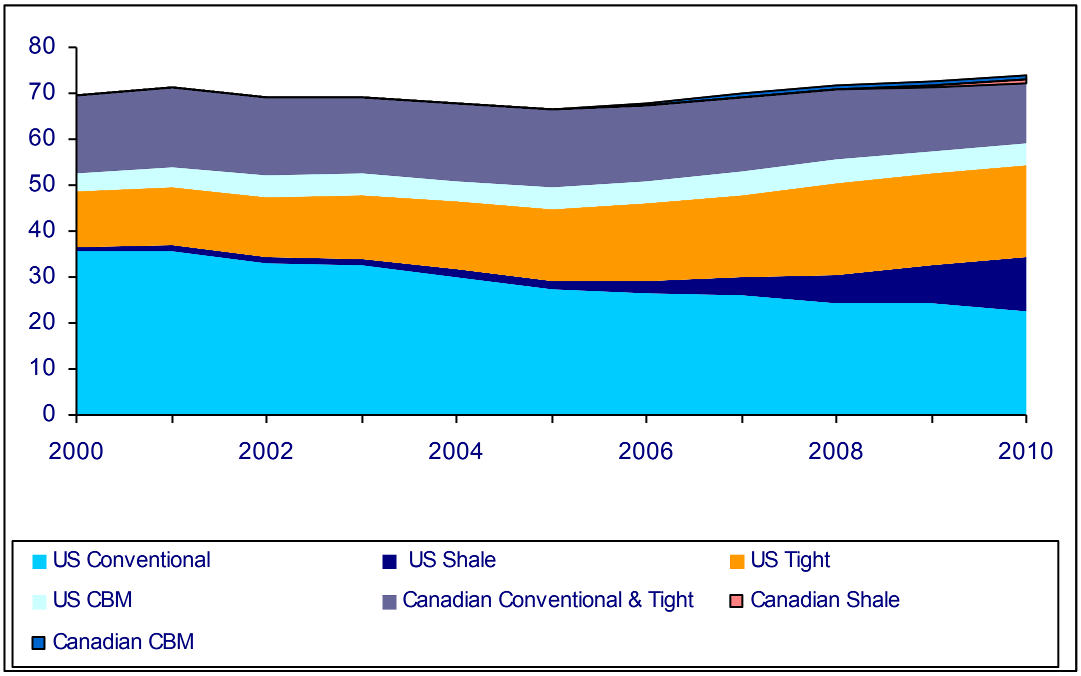


Figure 1: U.S. (Bcfd dry) and Canadian (Marketable) Production Mix – Conventional and Unconventional Sources 2000-2010
Data source: U.S. EIA, Canada NEB, Wood Mackenzie

	US --					Canada---				
	Conventional	**Shale**	**Tight**	**CBM**	**Total US**	**Conv.+Tight**	**Shale**	**CBM**	**Total Canada**	**Total US + Canada**
2000	35.5	1.0	12.0	4.1	52.6	16.8	-	-	16.8	69.4
2001	35.8	1.2	12.8	4.3	54.0	17.5	-	-	17.5	71.4
2002	33.1	1.4	13.1	4.5	52.0	17.3	-	-	17.3	69.4
2003	32.5	1.6	13.9	4.6	52.5	16.7	-	0.1	16.7	69.2
2004	30.0	1.7	14.6	4.6	51.0	16.9	-	0.1	17.0	68.0
2005	27.3	2.1	15.6	4.8	49.7	16.7	-	0.3	17.0	66.7
2006	26.3	2.7	17.1	4.8	50.8	16.5	0.1	0.5	17.1	67.9
2007	26.0	3.9	18.1	5.0	53.0	16.0	0.2	0.7	16.8	69.8
2008	24.5	5.9	19.9	5.3	55.6	15.1	0.3	0.7	16.2	71.8
2009	23.8	8.1	20.1	5.1	57.1	13.7	0.5	0.8	15.0	72.2
2010	21.4	11.6	19.9	4.9	57.8	13.2	0.8	0.9	14.8	72.6

Table 1: U.S. (Bcfd dry) and Canadian (Marketable) Production Mix – Conventional and Unconventional Sources 2000-2010
Data source: U.S. EIA, Canada NEB, Wood Mackenzie

This increase in shale production has been critical to sustaining U.S. natural gas production, and indeed growing it in the face of the recent challenges of a weak economy and relatively low-priced environment for natural gas. As illustrated in Figure 2, gas production reached this new high in 2010 despite an extremely challenging industry context, including hurricane-related interruptions in supply in 2008, and a substantial reduction in the active rig count during the recession of late 2008 and 2009.

Average monthly North American natural gas prices peaked in June of 2008. In that year, horizontal rig activity (approximately 70% of which are gas-directed) was still on the increase, reaching a level above 400 active rigs in May. Vertical rigs were already on the decline, despite then high prices, from the low 800s in an average month in 2007, into the low 700s for most of 2008. Vertical rig activity has since collapsed with low prices in late 2008 and throughout 2009, to a current monthly average of below 200 active rigs. Directional rig activity was also declining. By contrast, horizontal rig activity, after a short-lived decline to 330 rigs active on average in May of 2009, rebounded even in a weak pricing environment, to above 600 rigs currently, an all-time high.

With the third category, directional rigs, also declining, the rebound in horizontal drilling, with shale as the target, is entirely responsible both for arresting the price-driven decline in U.S. production that occurred in early 2009, as well as driving the rebound that has occurred since. As of July 2010, horizontal rigs accounted for 65% of the total active rig count in the U.S. This increase in horizontal rigs, and the production increase that these rigs have enabled despite low prices, illustrates the transformation in productivity that has occurred in the North American drilling sector.

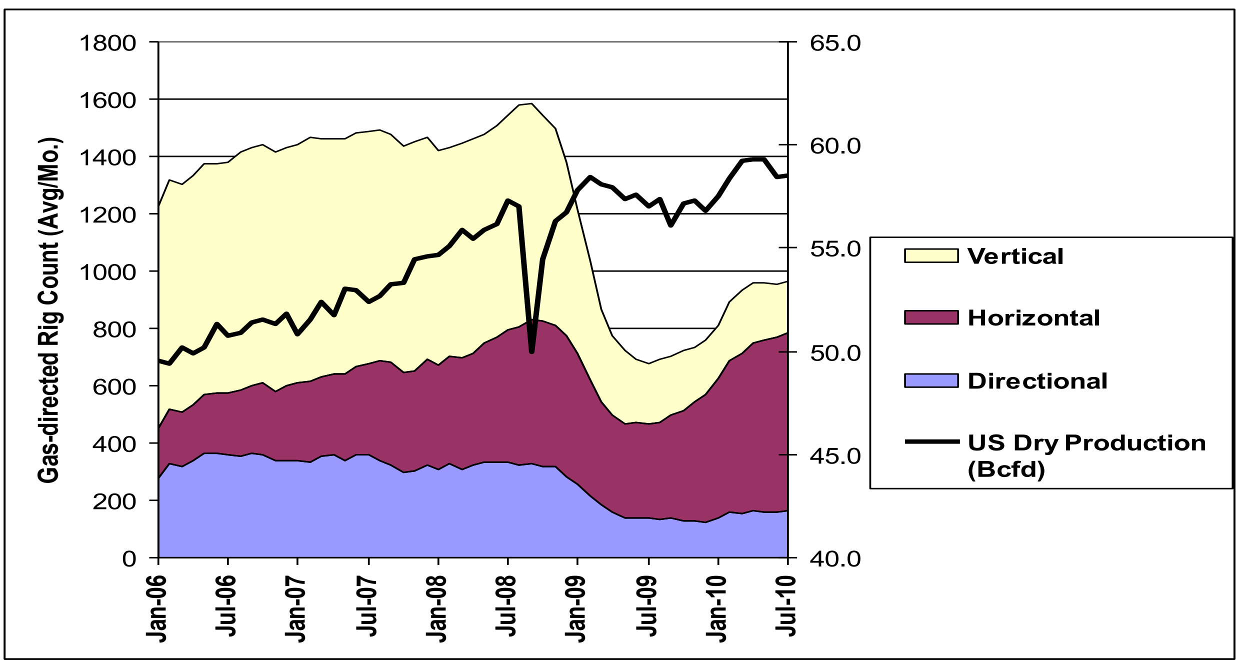


Figure 2: U.S. Monthly Gas-directed Rig Counts by Type, and Production
Data source: Baker Hughes, U.S. EIA

Horizontal and shale-directed drilling has continued in many areas of the U.S. and Canada, despite the recent decline in prices. Largely this is due to significant technological advances and learning that has occurred, enabled in part by the stronger gas pricing environment that existed in much of the

2000-2010 decade. The Barnett Shale, in North Texas, was the progenitor of this shale growth - the play in which several major advances were made and in which large-scale operations first occurred. Long-reach, horizontal (sometimes multilateral) wells coupled with multistage fracturing are the major technologies that have arrested the decline in North American gas production and reserve additions. These advances lowered supply costs such that production has increased despite lower gas prices. Costs are always cyclical in this business; however, it is reasonable to expect that continued improvements in both drilling and completion technology and increasing competition amongst service providers will limit cost appreciation in the future as well.

The focus on unconventional resource plays - tight gas, CBM and shale gas - has also arrested a previous decline in average well productivity, increased reserves per well drilled, and lifted the reserve life index. Shale gas plays are dominating the unconventional spectrum, although both tight gas and CBM continue to contribute to this trend of increased productivity.

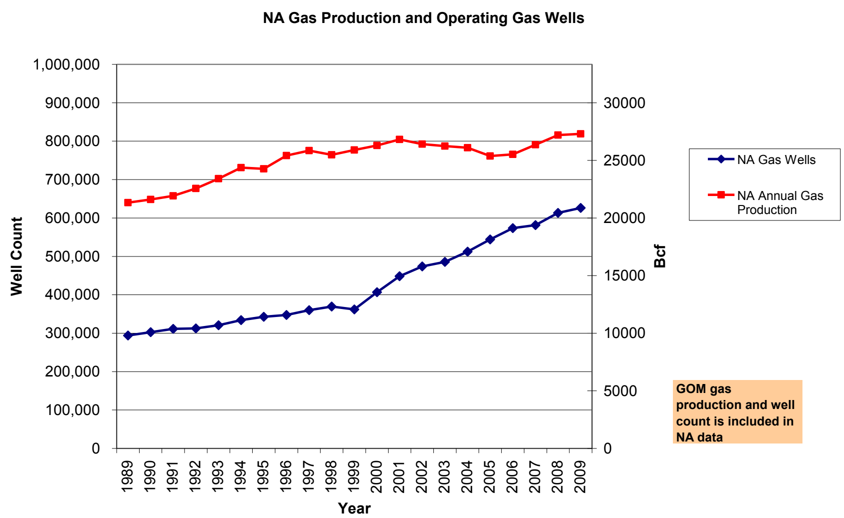


Figure 3: North American Gas Production and Producing Gas Wells
Source: Wood Mackenzie, U.S. EIA

As shown on an annual basis in Figure 3, total North American gas production reached a new high of 27.3 Tcf in 2009 following a period of essentially flat production over the previous nine years, despite a 57% increase in well count. The upturn in production since 2005 is coincident with the rapid development of unconventional gas within North America, particularly shale gas. Figure 3 includes production and well counts from the GOM as the offshore component was not identified separately within this particular 20 year data set. The GOM accounts for about 10% of produced volumes.

The exploitation and development of unconventional gas formations through innovative drilling and completion techniques has arrested the declines in North American gas production and reserve additions. Production rates and reserve additions per drilling and completion (D&C) dollar (with drilling days as a proxy for cost) is significantly greater for unconventional completions than for conventional wells. Competition amongst service providers will continue to push supply cost lower in the future as D&C costs are further reduced by the current low price environment and future enabling

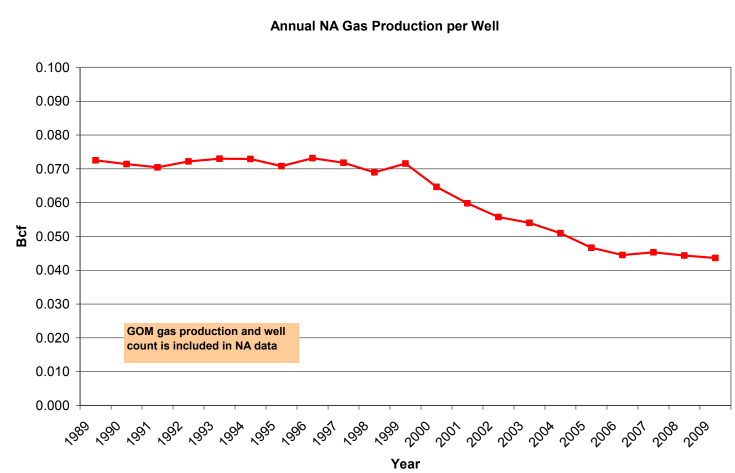


Figure 4: Average North American Gas Production per Well
Source: Wood Mackenzie, U.S. EIA

technologies.

A steep decline in annual gas production per well began in 1999 (Figure 4). New wells drilled between 1999 and 2005 were characterized by relatively lower production rates and smaller estimated ultimate recoveries (EURs) as local companies drilled marginal wells in the Mid-Continent, onshore Gulf Coast and Appalachia areas. Tight gas development was not large enough to offset these declines. Figure 5 indicates that proved reserves per new well drilled have also increased in 2007 and dramatically so in 2009, coincident with unconventional production.

The North American proved reserve life index (RLI) has been increasing since 2000 (Figure 6) as more unconventional proved undeveloped reserves are booked and low productivity, high reserve CBM wells were drilled. However, the increase has become more pronounced since 2004, with the development of shale gas resources.

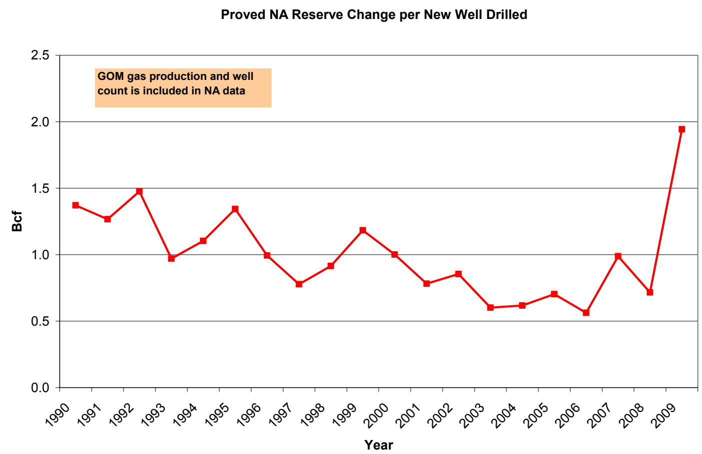


Figure 5: *Average North American Proved Reserve Impacts per New Well Drilled*
Data source: U.S. EIA, CAPP

Production and reserves from newly drilled wells have been increasing since 2006, suggesting that not only do these newly drilled wells replace natural declines in rates and reserves in historic wells but they are adding considerably more incremental rate and reserves per well. Such a reversal of the historic gas production and reserve trends should be expected as tight gas and shale gas production profiles exhibit a much higher initial production rate and recoverable reserves than conventional wells that have made up the bulk of historic production. Notwithstanding that unconventional wells are fewer in number, their prolific production and reserve additions have reversed a declining trend.

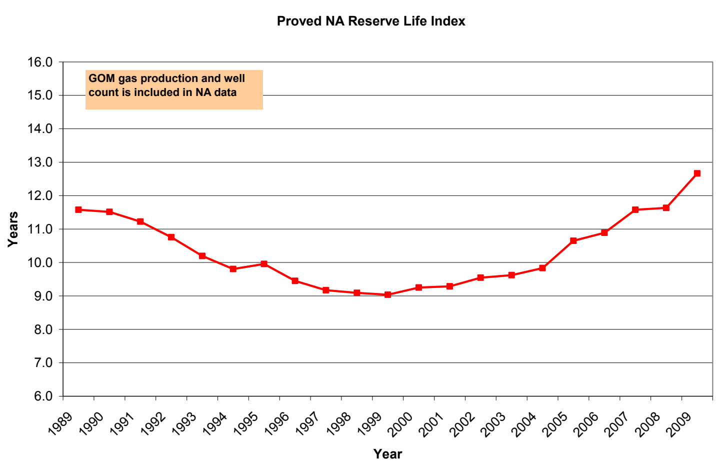


Figure 6: *North American Proved Reserve Life Index*
Source: Wood Mackenzie, U.S. EIA

Research and development and service company competitive pressure to generate revenue from drilling and completion activities have been reducing costs. This allows E&P companies to pursue lower permeability and more marginal reservoirs profitably, adding to continued production and reserve growth.

The development of these technologies was not sudden, even if their effects on overall production are recent. Rather, these advances evolved over a period of many decades as discussed in the Technology section (also see detailed discussion in Appendix A). Rapid advances occurred earlier in the 2000-2010 decade as high prices enabled and financed greater development spending and technological experimentation. The first widespread adaptation of these technologies was concentrated in the Barnett Shale, as illustrated in Figure 7.

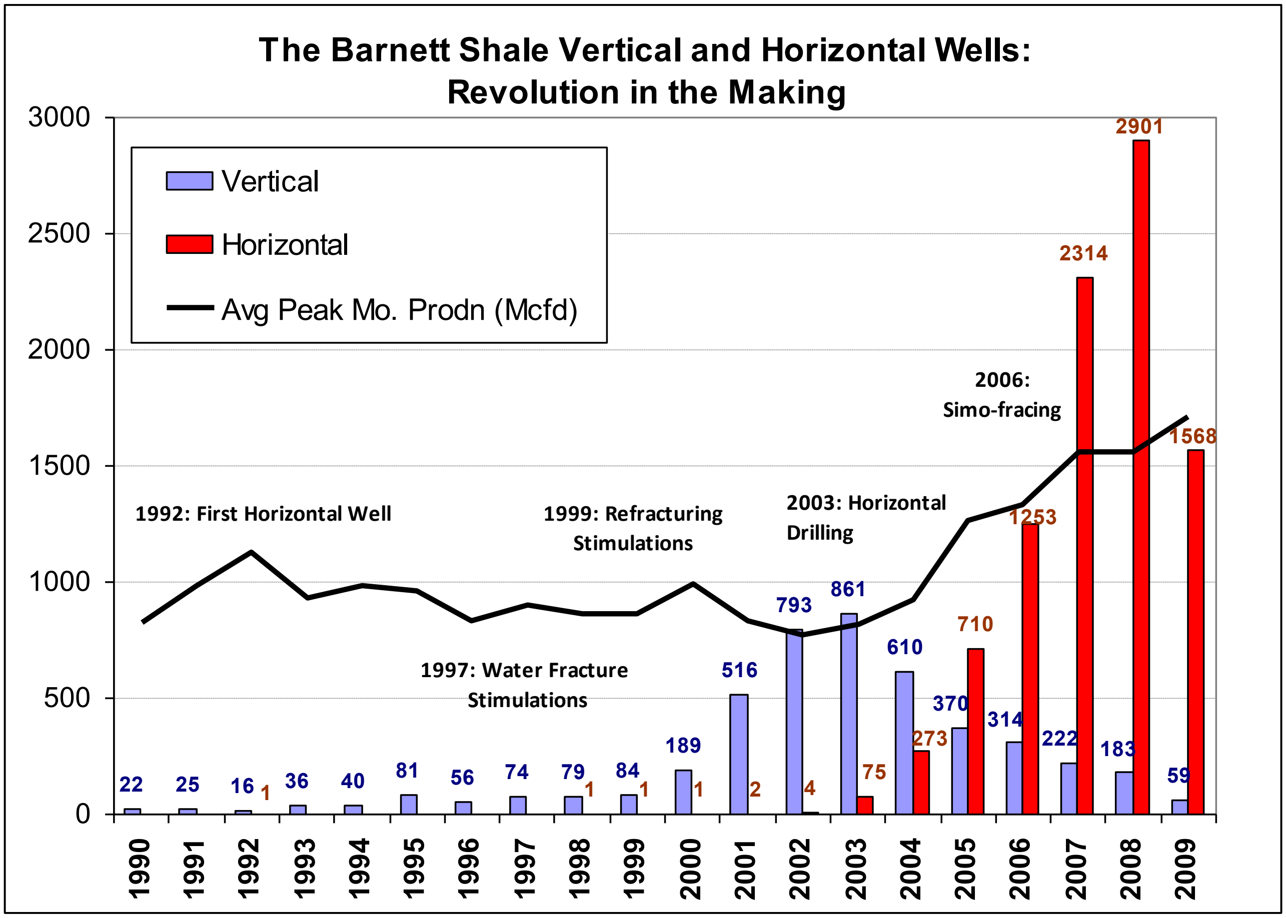


Figure 7: Technology Change, Drilling by Type, and Peak Month Production in the Barnett Shale
Data source: Powell Barnett Shale Newsletter, Texas Railroad Commission

Figure 7 above (adapted from the *Powell Barnett Shale Newsletter*) illustrates the numbers of vertical and horizontal wells drilled each year in the Barnett Shale, with the line showing the average peak month production from all wells drilled in a given year. The first horizontal well in the Barnett was drilled by Mitchell Energy in 1992, and is responsible for increasing average peak production per well to over 1,000 Mcfd in that year. After water fracture stimulation was introduced in 1997, Encana, Range, WG Operating, and XTO initiated horizontal drilling in the play. However, it was not until late 2002, with two wells drilled by Devon Energy (which had acquired Mitchell Energy) that horizontal wells began to significantly outperform vertical wells in terms of peak monthly production. The combination of horizontal drilling and multiple water-driven fracturing stages had begun to bear fruit, and the secret to economic shale production was unlocked.

Since those late 2002 wells, horizontal drilling in the Barnett has increased rapidly, while vertical drilling has dwindled, so much so that by 2008 and 2009, horizontal wells accounted for over 95% of all wells drilled in the Barnett. Technological and operational enhancements continued, an example being the advent of Simo-fraccing in 2006. Simo-fraccing is a process where a single fracturing operation is applied to multiple well-bores at once, reducing the requirements for fracturing services over time and resulting in longer-lasting fractures. With this and other enhancements, even as the total well count increased, average peak month production continued to increase significantly along with it. Peak month production increased by nearly 60%, or by more than 500 Mcfd per well, in the 2005-2009 period, as compared to the 1990-2000 decade.

By 2005-2006, many producers had begun to search for other suitable shale formations around North America to which they could apply their Barnett technology and experience. The effect on production of applying these technologies to a broader array of shale plays is illustrated in Figure 8. By 2007, the advent of Fayetteville and Woodford shale production reduced the contribution from the Barnett to about 80% of all shale production. By the end of 2009, the Barnett share had fallen to less than 50 percent of total shale production with the onset of the Haynesville shale play production in 2008-2009. The Barnett is on track to represent only approximately 35 percent of overall shale production in 2010.

While the Barnett Shale may be relatively mature, additional plays are still being discovered, with development of the Eagle Ford, Montney (siltstone), Horn River, and the huge Marcellus Shale still in early stages. Additional shales, including the Duvernay, Utica, Collingwood, and others wait in the wings, providing a large resource base for the future for North American energy supplies.

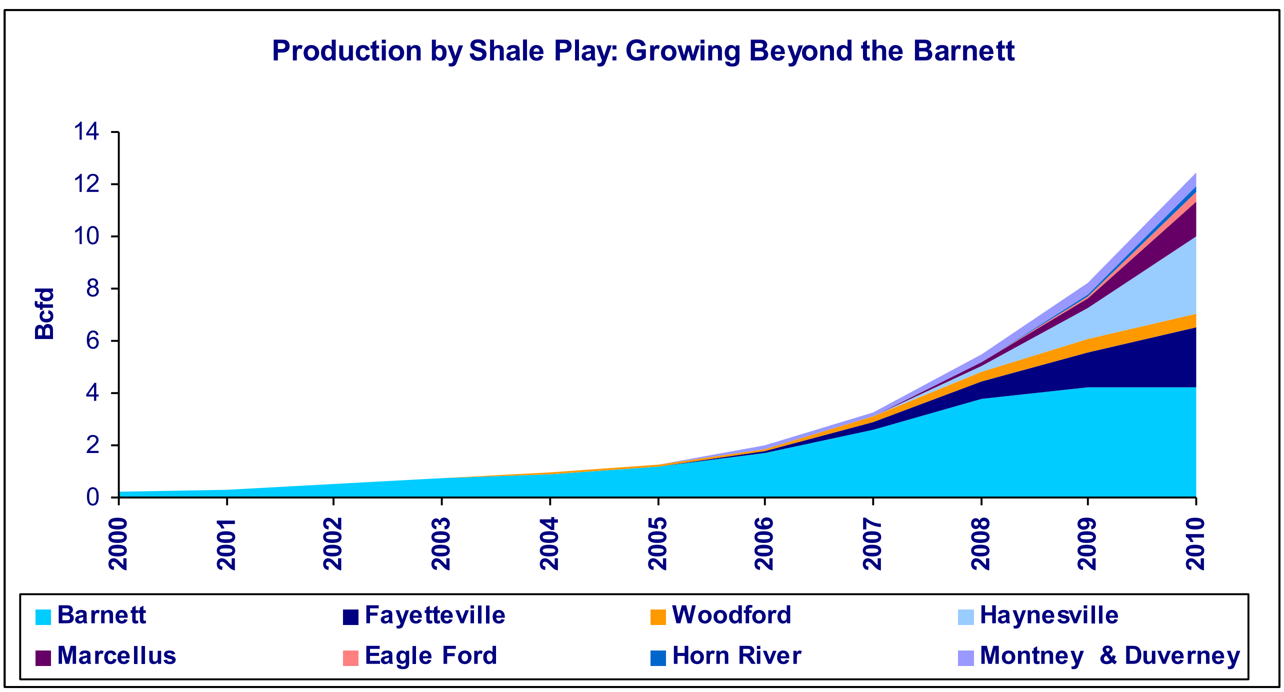


Figure 8: North American Shale Production by Play
Data source: Wood Mackenzie

Meanwhile, improvements in well productivity have not stood still. As more producers and well service companies have gained experience with more shale wells and a greater variety of shale formations, cost savings and productivity increases have continued. Average initial production rates have continued to improve, even as the days required to drill each well have declined. As a proxy for industry trends three examples are shown covering three separate producers - Petrohawk, Cabot, and Southwestern - in three different shale formations – the Haynesville, Marcellus, and Fayetteville respectively – in Figure 9.

All shales are not equal. Note that these three shales differ in terms of either drill days (cost) or performance. However, all three show the same trends. Reductions in drill times and increases in peak month production rates explain how even sharply reduced rig counts, as illustrated in Figure 2, have resulted in increases in overall production in the U.S., and slowed the pace of decline in Canadian production. Simply, each rig is drilling more wells each year, wells that are becoming more efficient in terms of rate and reserves per well.

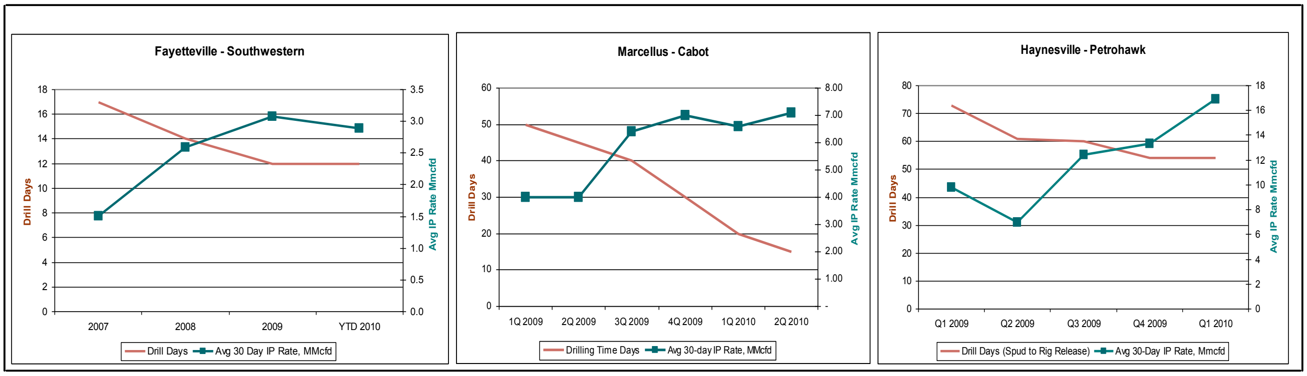


Figure 9: Shale Productivity Improvements
Data source: Southwestern Energy Investor Presentation, Cabot Oil and Gas Investor Presentation, Petrohawk Energy Corp. Investor Presentation

The recent advances in technology coupled with ongoing operational improvements have unlocked a vast potential energy resource in North America – a resource available at reasonable cost. These recent advances are part of a continuum of technological and operational improvements made by the North American gas exploration and production industry over many decades. We expect this progress to continue. The basis of these advances is summarized in the following discussion and further developed in Appendix A.

Technology History ("How did we get here?" Part 1)

Technology drives the present understanding of formations and allows gas to be produced at lower cost. Technology allows probable reserves to be pushed into the proved category. In very recent times the development of natural gas has been dominated by the application of new technology. Recent media buzz has characterized this as "Shale Gas", but what has really been enabling is the development of cost-effective fracture stimulation in horizontal wellbores. Both horizontal drilling and fracture stimulation have been in use for decades. In fact, fracture stimulation was first implemented in 1947 in the Hugoton gas field and gas from shale has been produced for over a century. Although the first notable commercial horizontal well drilled in North America was in the Austin Chalk formation in 1985[9] experimentation with the idea of drilling horizontally through the producing formation occurred in North American as early as 1927. Many of the early advances, however, were made in Russia before reaching North America. Horizontal wells today are routinely being drilled with lateral lengths of 10,000 ft with 20 or more fracture stimulations being applied.

Much can be learned by examining the production profile of North American natural gas production with respect to the timing of technological advances within the industry. It can be seen that major technologies such as hydraulic fracturing, horizontal drilling, and modern seismic have become standard practice and have produced major step-changes in the shape of the natural gas supply curve as shown in Figure 10. The following are some of the key technological milestones. Appendix A provides further discussion of technology milestones and case studies.

Technological Milestones

During the 1930s through the 1950s a number of substantial improvements were made in the oil and gas industry. First generation seismic (2D seismic), rotary drilling replacing cable tool drilling, and electric logging all became standard practice. Many of the technologies first developed between 1930 and 1950 matured and were improved upon during the 1950s to 1970s. As an example, one area of marked improvement is in the understanding of materials science. Superior corrosion resistant alloys and increased tensile strength steel alloys were developed as a result of technology from WWII. As a result of improved material properties, in 1962 coiled tubing was able to become reality[21]. By making use of less steel than standard tubing, coiled tubing can lead to a direct cost-reduction when it is able to be used.

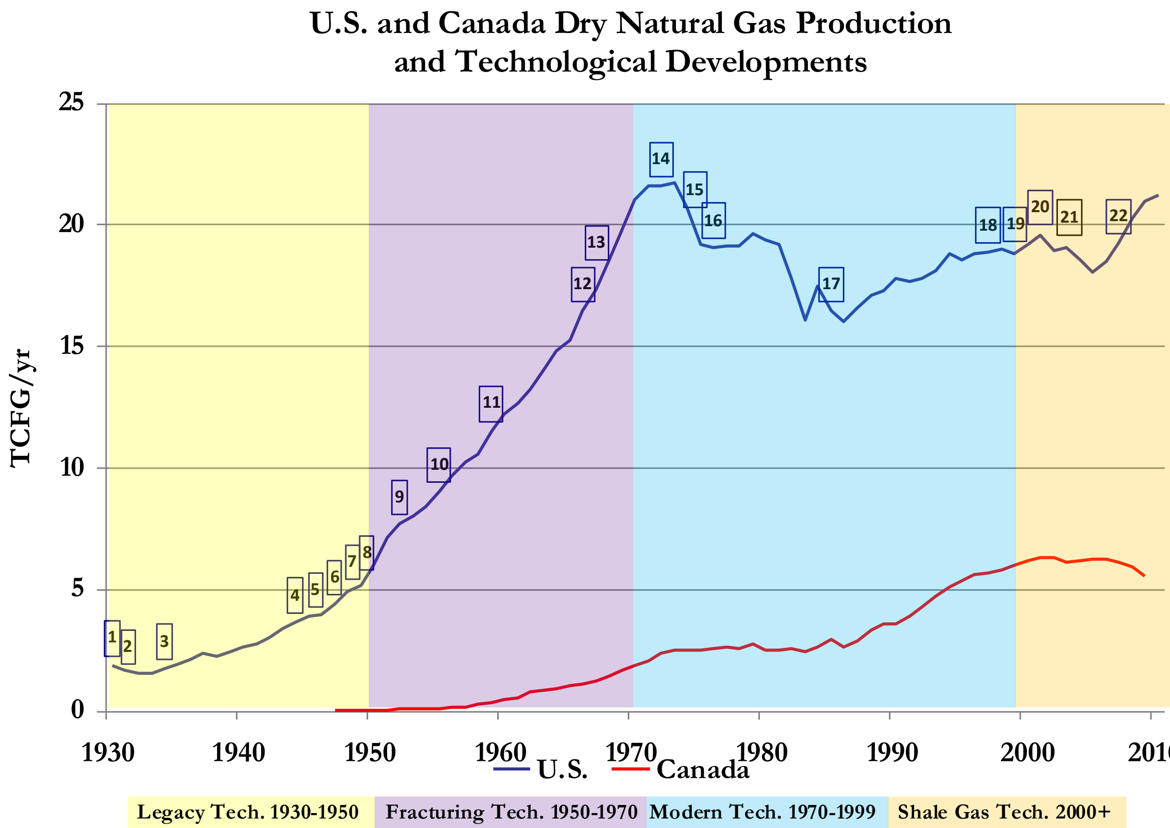


Figure 10: Detailed Timeline of Past Technology Improvements
Data source: U.S. EIA, Petroleum Technologies Timeline www.greatachievements.org/?id=3675

A chronology of some of the more notable milestones is detailed below and plotted in Figure 10.

1 1930 Rotary drilling replaces cable drilling in most areas. 2-D seismic technology leads to the discovery of Seminole Field in Oklahoma.

2 1931 Spontaneous potential (SP) logging is invented. Electric logging technology becomes standard practice.

3 1933 The tri-cone bit is invented. Bits receive less wear and tear and consequently last much longer, increasing well penetration rates and reducing the time required to drill wells.

4 1940s Acidizing to enhance reservoir performance is discovered.

5 1946 Diamond bits for coring are introduced.

6 1947 Gravimeter is developed providing an additional (to seismic) remote sensing tool for exploration of new resource. Hydraulic fracturing is attempted in the Hugoton field, but is not commercial.

7 1948 Oil based mud (OBM) drilling is invented. OBM mitigates reservoir formation damage caused during drilling.

8 1949 Hydraulic fracturing treatment is made commercial.

9 1950s Hydraulic fracturing of vertical wells becomes common practice to improve reservoir performance.

10 1952 Polycrystalline diamond compact bits (PDC) are introduced but expensive.

11 1959 First computer for oil and gas data analysis is created by Texas Instruments.

12 1966 Improved accuracy and reliability of electric logging tools are spurred on by the first transistor-based integrated-circuit digital data system for oil and gas applications.

13 1967 Modern theory of plate tectonics is developed. This concept allows geoscientists to better understand basin modeling which aids in opening up new resources.

Key Milestone – Commercialization of Shale as a Resource

Shale gas production can be traced back to the mid-1800's, but until recently was a rather insignificant source of energy. What was once thought of as only a marginal producer, a source of hydrocarbons, or as an impermeable barrier or seal for conventional reservoirs is now considered as a primary target for commercial drilling. These ultra low-permeability reservoirs are now routinely exploited. This is made possible through a combination of technologies, namely, directional drilling, seismic, lateral wellbores (horizontal wells) and hydraulic fracturing. It should be pointed out that without some or all of these technologies, most shale reservoirs would not be commercial today. Hydraulic fracturing is without question, the most critical advance for natural gas supply for North America.

Key Milestone - Hydraulic Fracturing

First implemented in 1947 in the Hugoton gas field, fracturing treatment provides the means of increasing the contacted surface area within the reservoir. The reservoir rock is fractured by pumping high pressure water with a sand-slurry that maintains fracture conductivity. The first fracturing treatment included no propping agent to maintain conductivity within the induced fractures and therefore proved unsuccessful. By 1949, hydraulic fracturing had been successfully implemented in the Woodbine sands in East Texas and was now commercial[22]. Since that time, there have been numerous improvements to reliability and safety. By hydraulically fracturing a gas reservoir, the effective permeability, that is, capacity to flow, can be increased several orders of magnitude. In fact, without any stimulation treatment, many currently producing reservoirs would be considered impermeable. Successful stimulation treatments are capable of increasing permeability five to six orders of magnitude[23]. By 1955 more than 3,000 fracturing treatments were being pumped each month. Throughout the 1960s and 1970s fracturing became better understood and was now able to be optimized for a particular formation[24]. As time has passed, operational efficiency improvements resulted in cost savings, making more plays economic. Today, coil tubing fracturing technology has resulted in shorter time requirements per fracture induced. Now, multiple zone fractures can be completed within a short period of time.

According to the Independent Petroleum Association of America (IPAA), approximately 90% of new gas wells rely on hydraulic fracturing to produce[25].

14 1970s Directional drilling is enabled by the invention of mud-pulse telemetry. Using real-time data, the downhole location of the bit could now be determined. This technology enables horizontal drilling.

15 1975 First 3-D seismic survey data is processed.

16 1976 Synthetic diamonds are used with polycrystalline diamond compact bits (PDC). PDC bits now used as standard equipment for drilling conventional formations.

17 1980s Horizontal drilling becomes standard practice in the Austin Chalk formation. 3-D seismic begins to be used to explore for new resources. Coal Bed Methane becomes a viable natural gas resource.

Key Milestone – Modern (3-D) Seismic Technology

The increase in activity in the 1980s was also spurred on by the advent of 3-D seismic technology[6]. The rate of exploration success increased, resulting in previous uneconomic plays becoming regularly exploited. Today, seismic data is processed using computer algorithms that assist in identifying anomalies within the data. These anomalies may be identified as hydrocarbon deposits. It is reported that from 1990 through 2001 the overall costs of 3-D seismic imaging decreased by a factor of five. Surveys conducted by *The American Oil and Gas Reporter* as well as the Petroleum Technology Transfer Council indicate that seismic technology has been incredibly beneficial to the industry[26]. Modern seismic imaging techniques allow for improved recognition of formation types and characteristics. The use of modern seismic technology has found application by allowing wells to be drilled while avoiding potential water zones and areas of high faulting. Although much work is still needed in this area, one of the outcomes of this technology is the ability to increase the likelihood of drilling locations of high productivity while decreasing the chances of drilling lower productivity wells.

18 1997 The first slick water frac successfully stimulates a vertical well in the Barnett Shale. Slick water significantly reduces stimulation costs by eliminating the need for expensive and complicated gelled treatment systems.

19 1998 Micro-seismic surveys are used to monitor horizontal well-fracturing simulation treatments in order to determine stimulated reservoir volume. Micro-seismic allows geoscientists to gain insight into the physics of reservoir stimulation. Continued use of microseismic will lead to fundamental understanding of rock-fracturing mechanics.

20 2001 Barnett Shale slick water fracturing technique continues to be refined for vertical wells.

21 2003 Multi-stage fracturing treatments on horizontal wells in the Barnett Shale begins.

22 2005+ Commercial exploitation of Barnett Shale leads to an exponential growth in shale gas exploration with unique engineering solutions for each play.

Key Milestone – Coal Bed Methane (CBM) as a Commercial Resource

CBM, not unlike shale, had a long trial and error period that began in the late 1960s and finally began to yield results in the late 1980s. What initially began as an effort to improve coal miner safety (removal of explosive methane gases from mines), begins to yield dividends as significant amounts of natural gas resource as production first begins to appear in appreciable quantities by early 1990s[27] , (see Figure 11). Commercial exploitation becomes viable as the industry understands adsorption, desorption, cleat systems, and exploitation techniques using hydraulic fracturing. In brief, some of the key milestones of CBM are noted below[28].

- 1969-70: United States Bureau of Mines (USBM) conducts laboratory research on gas storage and flow mechanisms within coal seams
- 1971: USBM installs five-spot well patterns at 11 locations across the US, but production rates are disappointing.
- 1973: USBM hydraulically stimulates one well at each of the 11 sites. Results are mixed with best performance 50 mcfpd at one site.
- 1975: USBM enters a cost-sharing contract with US Steel Corp to demonstrate technology at the Oak Grove Mine; thirty-three wells are ultimately drilled.
- 1980: Windfall Profits Tax Act establishes Section 29 Unconventional Energy Tax Credit. CBM qualifies as "unconventional"
- 1983 Gas Research Institute (GRI) initiates its Warrior Basin CBM research project
- 1987: GRI project successfully demonstrates multiple-seam technology, demonstrates benefits of cross-linked gel fracturing fluids
- 1989: In May 1989 the GRI entered into a cooperative agreement with a 13-company industry consortium to conduct a reservoir engineering study of the Fruitland coal bed methane resources in the San Juan Basin. GRI's objective was to develop a better understanding of the relationships between coal seam gas producibility, reservoir characteristics and engineering practices[29].
- 1990: US Congress extends Section 29 tax credit until 1993. Production becomes significant.

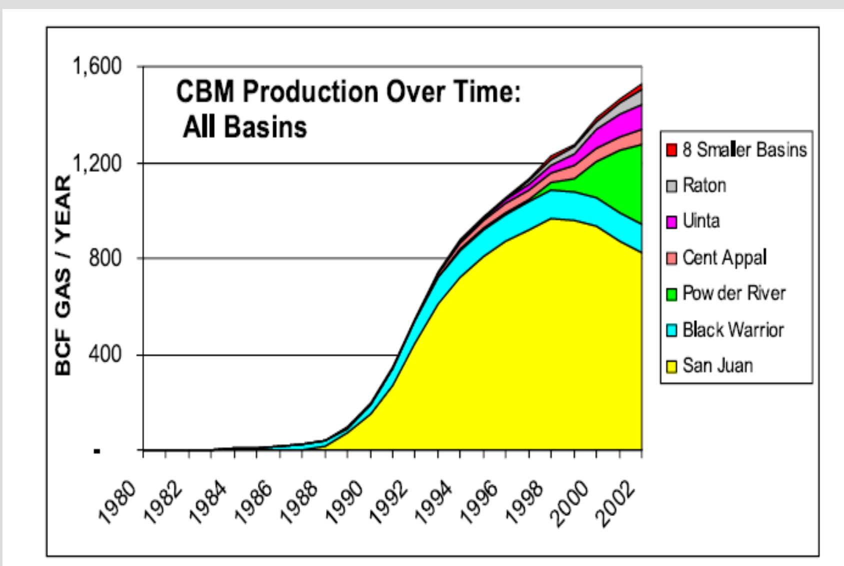


Figure 11: U.S. Lower 48 CBM Production
Data source: U.S. EIA, 2004

Key Milestone – the Personal Computer

Technological improvements in computer processing power have also resulted in tremendous efficiency gains. Prior to the widespread use of personal computers, simulations and other rigorous mathematical modeling required main-frame computer time. This proved both cost and time prohibitive. Since then, personal computers have become ubiquitous in the industry and have allowed engineers and geologists to routinely execute complex mathematical models to simulate reservoirs and basins. This has been reflected in metrics that track worker productivity, as shown in Figure 12.

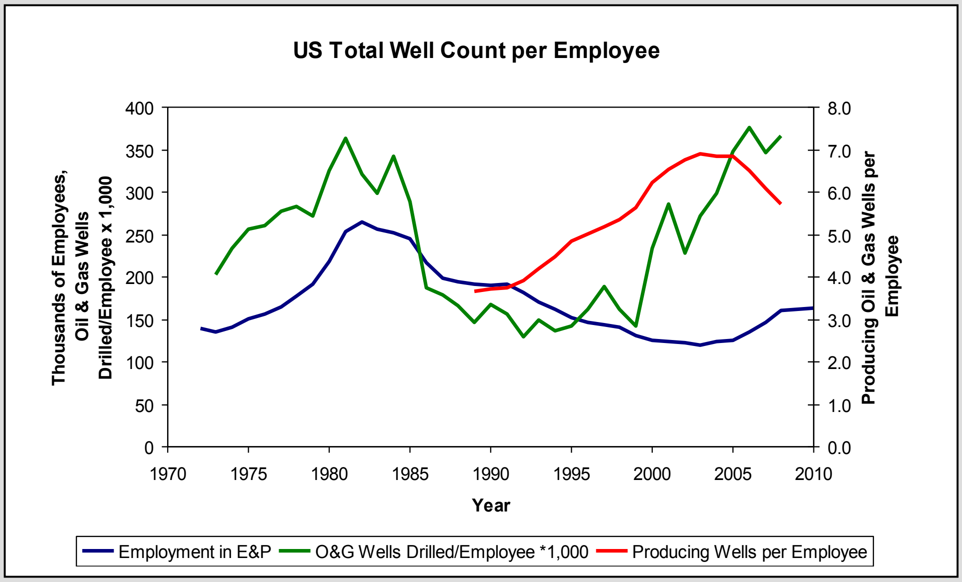


Figure 12: Numbers of Wells per Oil and Gas Industry Employee
Data source: U.S. BLS (2010)

For the onshore natural gas industry, efficiency improvements may be reflected in multiple ways. The total number of wells being operated per employee has increased, representing a substantial increase in worker productivity[30]. The total number of wells being drilled per employee has been increasing, also demonstrating efficiency gains that have occurred during this time period as seen in Figure 12.

Not only has the personal computer led to increases in worker efficiency, but it has also enabled a host of other products. Computer aided design (CAD) software packages are used in conjunction with computer numerical control (CNC) machining to produce sophisticated tools to exact specifications. Because of advances in CNC milling technology, production times have been significantly reduced, while at the same time, downhole equipment is much more robust than in the past. Similarly, robotic controllers are now in use, especially in high-pressure high-temperature environments. Prior to the advances in electronic technology, many hydrocarbon reservoirs would have been off-limits.

Key Milestone - Horizontal Drilling

Horizontal well drilling allows a well to be drilled parallel to the formation, exposing significantly more reservoir rock than would be possible using a conventional vertical completion technique[31]. By increasing the length of the horizontal portion of the well, multiple vertical well locations were replaced with a single horizontal well for a fraction of the cost, minimizing surface disturbance. It should be pointed out that the idea of drilling horizontally through the producing formation was being experimented in North American as early as 1927; however, many of the early advances were made in Bashkiria, Russia before reaching North America.

It was not until the 1980s when notable commercial horizontal wells were drilled in North America in the Austin Chalk, Bakken, and Niobrara formations[32]. As technology improved and prices increased, horizontal drilling enabled previously, non-commercial formations to become economic[33]. By the 1990s, more than 1,000 horizontal wells had been drilled throughout the world[34].

Since initial commercialization of the technique, efficiencies continued to improve, yielding longer lateral lengths per well drilled and ultimately continuing to decrease surface disturbance. For example, in 1987 in the Bakken Shale, the first horizontal wells had relatively modest lengths of approximately 1,000 feet. By the 1990s, as technology improved, lateral lengths of 3,000 to 4,000 ft were possible, and today wells are routinely being drilled with lateral lengths of 10,000 ft.

Advancing Technology

There are a number of areas of ongoing research associated with natural gas production that will result in improved recoveries and operational efficiencies in the near-term. Some of these projects are discussed in greater detail in Appendix A and summarized below:

- Fracturing technology
- Surface disturbance minimization
- Super-pad drilling
- Slim-hole completions
- Fit-for-purpose Coiled Tubing Drilling (CTD)
- Multilateral wells

Future Technology

Of the natural gas production in the U.S. in 2008, it has been estimated that approximately 40% of the wells required hydraulic fracturing stimulation to produce at economic rates[35]. According to the Independent Petroleum Association of America (IPAA), approximately 90% of new gas wells rely on hydraulic fracturing to produce[25]. Without both hydraulic fracturing and horizontal drilling, the base forecasts could not be met and any reservoir termed “unconventional” would be uneconomic. The EIA has modeled natural gas price increases for a scenario with no additional tight gas production. In this scenario, natural gas production from onshore North America had fallen by 39%. From these estimates it can be seen that the future of natural gas supply in North America will rely upon fracturing tight gas formations.

It has been observed that it generally takes approximately 16 years for a new technology to mature from concept to a commercial project[6]. This problem has been exacerbated with an ever declining investment in research related funds as the majors have focused their efforts in the hunt for oil in international plays. Much of, if not all, the current R&D for natural gas resource plays is undertaken by service companies, academia, large independents, GTI and an underfunded DOE/RPSEA/NETL

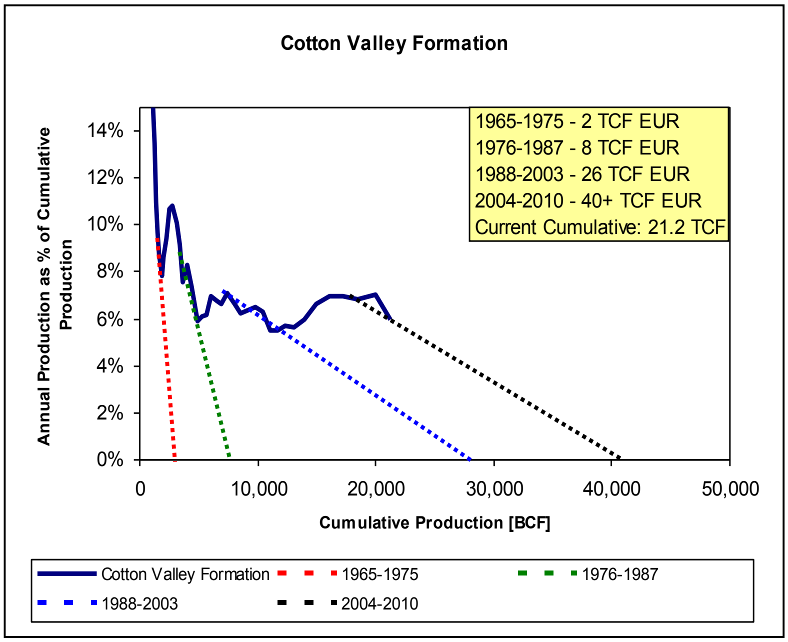


Figure 13: Cotton Valley Hubbert Linearization
Data source: IHS CERA

contingent. Further details are discussed in Appendix A.

Case Studies

Two examples of technology advancements enabling additional resource growth in the Cotton Valley and Barnett Formations are demonstrated. Several detailed case studies are included in Appendix A. What further growth will future technology enable?

The Hubbert trendline in Figure 13 from 1976 through 1987 (green) covers the period of development where well spacing in the Cotton Valley was halved from 640 acres to 320 acres, resulting in greater expected production from the formation. Down-spacing to 160 acres and again to 80 acres occurred between 1988 and 2003 (blue), resulting in a bump in production with a decline that would anticipate 26 TCFG field recovery. Further down-spacing from 80 acres to 40 acres per well resulted in additional recovery, now estimated over 40 TCFG (black). More details of the technologies enabling this remarkable performance are presented in Appendix A.

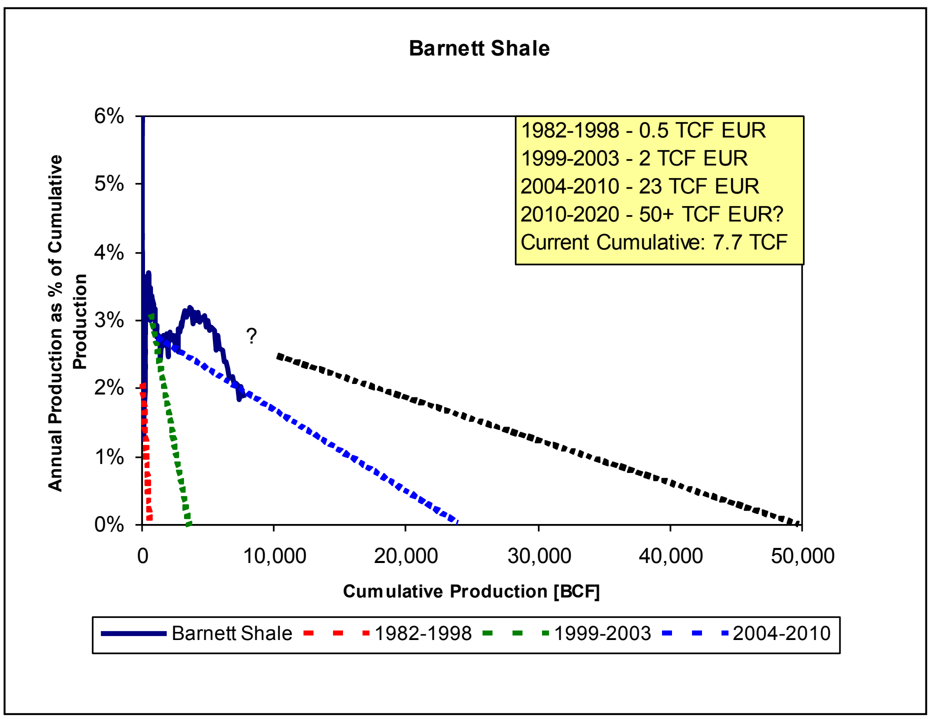


Figure 14: Barnett Shale Hubbert Linearization
Data source: IHS CERA

The Barnett field wide decline profile demonstrates changes in technology and completions that substantially enhanced the ultimate recovery. Prior to 1999, Barnett wells were completed with fracturing treatments making use of gelled fluids. These gels lead to substantial formation damage and as a result, the ultimate economic field-wide recovery was anticipated at less than 1 TCFG. During the period from 1999-2003, slickwater fracturing treatments became commercial. These fracturing treatments resulted in substantially increased fracture lengths with increased productivity. Ultimate economic field-wide recovery would have been estimated at 2 TCFG. Finally, from 2004 to 2010 (blue), as horizontal drilling coupled with slickwater fracturing treatments became standard, the Barnett ultimate recovery may be estimated at 23 TCFG. Based on the known geographic extent of this play, and the known number of drillable locations, the ultimate Barnett recovery is very likely in excess of 50 TCFG as shown in Figure 14. Just as all other fields have shown increased ultimate recovery over time, it is expected that the Barnett will continue to grow.

The following Barnett Shale Completion Technology Timeline is pertinent:

- 1982-1998 (red): Gelled fracture treatments resulting in formation damage
- 1999-2003 (green): Commercialization of slickwater fracture treatments
- 2004-2010 (blue): Horizontal drilling with slickwater fracture treatments

Clearly, the North American natural gas industry has demonstrated how the continuum of technological and operational advances has unlocked substantial natural gas resources associated with increasing formation recovery factors. Such advances alone do not dictate what has been, or could be, supplied; other factors can be leveraging.

Regulatory and Legislative History ("How did we get here?" Part 2)

Significant Natural Gas Regulatory Developments

Onshore natural gas supply development in the United States and Canada has been influenced by regulatory undertakings since the 1930's. Regulatory initiatives are typically intended to protect the public from unsafe or wasteful operating practices or from the abuse of market power. Resource owners, be they private landowners with mineral rights or federal, state or provincial governments on behalf of the public, want to maximize the value of their resources and reduce the risk of injuries, deaths or degradation of the surrounding environment.

While the objectives of regulation may be laudable, the actual application of specific regulations at times may result in unintended consequences that can cause distortions in the smooth functioning of markets. Such has been the case in various periods of the regulation of natural gas markets in the U.S. and Canada. The following is an overview of the past, present and possible future of regulations in these markets and how they might continue to influence the development of natural gas supplies. Additional descriptions of specific regulatory events and challenges are provided in Appendix A.

Regulation of natural gas markets since the 1930's can be described as occurring in five general periods. These periods are indicated in Figure 15 in relation to the overall production levels of natural gas in the U.S. and Canada. Additionally, significant regulatory developments within each period are indicated by the numbers along the production lines in Figure 15, and are further described below.

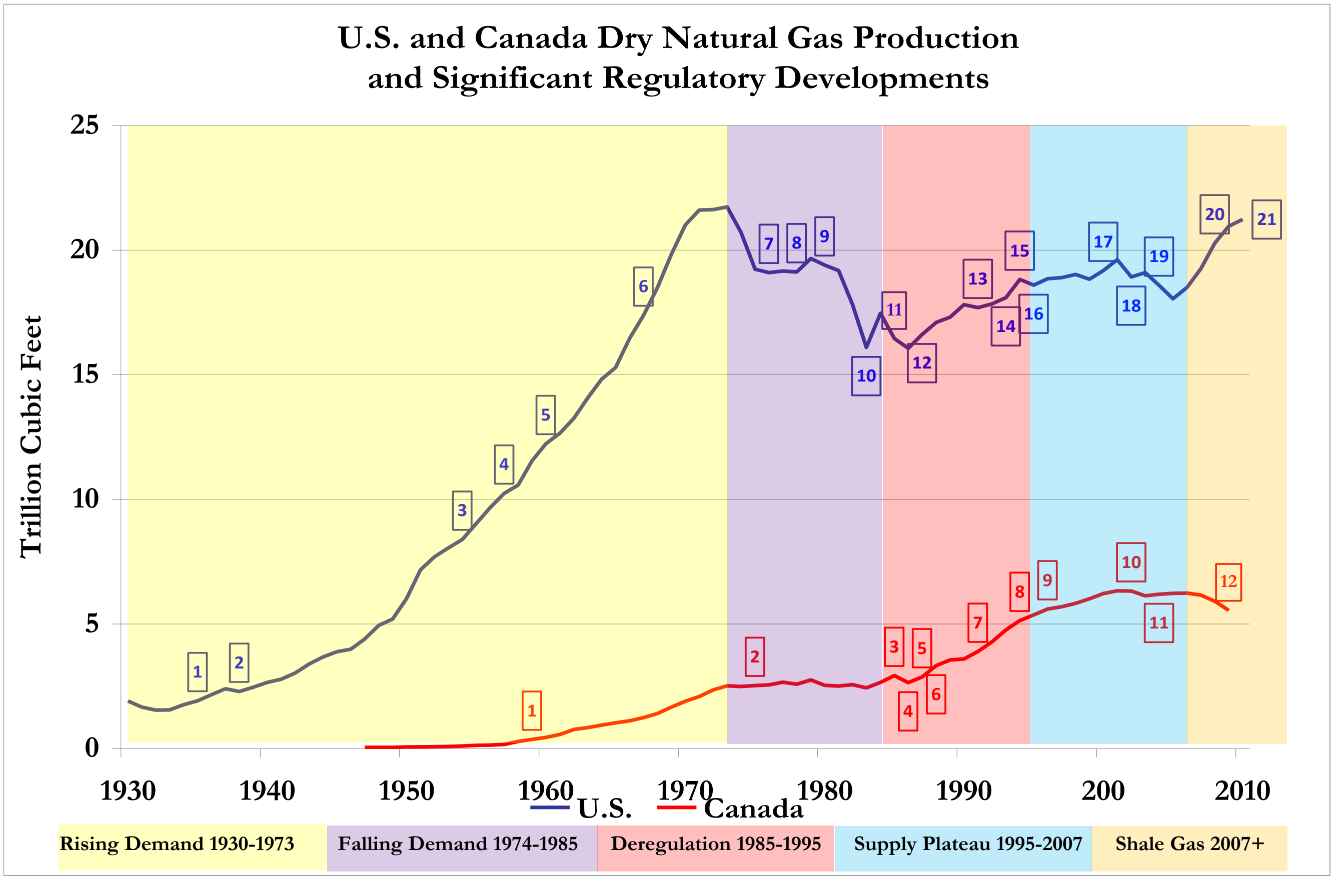


Figure 15: Detailed Timeline of Significant Regulatory Developments
Data source: Canada NEB

1930's to 1973 – Rising Demand at Constrained Prices

During this period, attempts were made to constrain the market power of the relatively few pipelines that delivered natural gas across multiple states by having the market prices set by regulation. Difficulties arose in setting appropriate prices in the U.S. resulting in more supplies being developed for use within producing states and less development of supplies for markets outside these states. Key regulatory developments during the period included:

United States

1 1935 — Public Utility Holding Company Act begins regulation of public electricity and natural gas utilities

2 1938 — Natural Gas Act regulates price of natural gas sold by interstate pipelines

3 1954 — Supreme Court decision on the Phillips Case
- Moves price regulation for interstate gas sales from the pipeline to the wellhead using a cost-of service approach
- The large number of producers and variation in costs between individual wells makes price determination unfeasible

4 1955 to 1959 — Low stable prices encourage gas demand growth
- With no effective means of adjusting prices, prices remain at 1954 levels

5 1960 — Attempt is made to assign the wellhead price using an average for each producing region

6 1960 to 1973 — Failure to determine averages keeps prices capped at the 1959 level

- Fixed interstate gas prices start diverging from rising intrastate prices
- Drilling is directed to intrastate markets and supplies available to interstate markets begin to fall behind

Canada

1 1959 — National Energy Board Act creates a federal pipeline regulator. Exports are authorized if surplus to reasonably foreseeable Canadian requirements (as determined by remaining reserves exceeding 25 times current Canadian demand plus previously approved exports). Export formula encourages extensive development of established reserves.

1974 to 1985 – Falling Demand at Higher Prices

This period was characterized by ongoing attempts to set appropriate prices at a time when recessions, restrictions on natural gas use and rising natural gas prices were causing natural gas demand to decline. Price regulation in the U.S. led to more supply within producing states and less for markets outside these states and caused severe shortages of natural gas outside of the producing states to emerge by 1978. In response, higher prices were set to encourage supply and restrictions were imposed on the growth of natural gas use in power generation and industrial markets. With demand declining, higher prices encouraged the development of more supply than the market wanted, resulting in a buildup of excess supply capability. In a reaction to previous shortages, pipelines made long-term take-or-pay commitments that obligated them to pay producers for set volumes of natural gas, even when demand had fallen to much less. Key regulatory developments during the period included:

United States

7 1974 to 1978 — Price cap doubles for interstate gas, but is still below intrastate prices

- Shortages of interstate gas develop
- To conserve, restrictions are placed on the development of new gas-fired electricity generation and industrial facilities

8 1980 — Natural Gas Policy Act of 1978

- Price cap is raised and eliminates the price differential between intra and interstate markets
- Pipelines make long-term take-or-pay commitments

9 1980 — Tax credits initiated to encourage CBM and tight gas supply

10 1978 to 1985 — Prices rise, demand drops, supply grows and pipelines are committed to pay for gas that the market won't take

Canada

2 1975 to 1985 — Price of Alberta natural gas sold to other provinces regulated by Alberta and Canada governments

1985 to 1995 – Deregulation

Price regulation was scaled back to providing oversight to prevent abuses of market power. These ten years were a transition period that saw declining prices as the excess supply overhang from previous regulatory regimes was consumed. The period was further characterized by market cycles and price volatility as supply and demand attempted to find balance. Key regulatory developments during the period included:

United States

11 1985 FERC Order 436 – Interstate pipelines unbundle sales and transportation.

12 1987 Restrictions repealed on gas use by industrials and electricity generators

13 1989 to 1993 Natural Gas Wellhead Decontrol Act – price controls gradually removed

14 1993 FERC Order 636 – Open access on interstate pipelines, unbundling

- Capacity release creates secondary market for pipeline capacity
- Revised toll design aligns with Canada – enables integrated market
- U.S. imports of Canadian gas rising

15 1994 North American Free Trade Agreement

16 1995 Pipeline capacity growth encouraged by adoption of rolled-in tolls on capacity increases of 5 percent or less
Outer Continental Shelf Deep Water Royalty Relief Act

Canada

3 1985 Agreement on Natural Gas Markets and Prices signed by Governments of Canada, B.C., Alberta and Saskatchewan on October 31.

- Initiates development of competitive markets
- Prices deregulated over one year transition period
- End-users able to purchase natural gas directly from producers
- Assurance of non-discriminatory and flexible access to gas transportation services

4 1985 to 1987 Canadian natural gas wellhead prices fall by 40 percent

5 1987 National Energy Board adopts a Market-Based Procedure (MBP) for assessing applications for long-term natural gas export licenses and eliminates 25 year reserve test

6 1987 to 1995 Canadian natural gas wellhead prices decline a further 15 percent

- Production doubles from 7.2 to 14.5 Bcfd, demand rises 30 percent
- Exports to U.S. almost quadruple
- Pipeline services expand, capacity increases by 50 percent

7 1988 Negotiated toll settlements for pipelines

8 1994 Generic cost of capital for pipelines

1995 to 2007 – Supply Plateaus

Over this period there was little growth from traditional supply sources despite increases in drilling activity and corresponding escalation in supply costs. Traditional supply sources were considered mature and LNG imports and northern pipelines were viewed as primary growth options. Key regulatory developments during the period included:

United States

17 2000 FERC Order 637 adds flexibility and transparency to pipeline secondary capacity markets

18 2002 LNG Rulemaking

- Amendments to Deepwater Port Act
- FERC's Hackberry Decision
- Maritime Transportation Security Act
- The Pipeline Safety Improvement Act

19 2004 Alaska Natural Gas Pipeline Act provides incentives for development of a pipeline from Alaska's North Slope to the Lower 48

Canada

9	1996	Incentive regulation for pipelines – equal sharing of cost savings
10	2002	New Brunswick hearing confirms short-term export procedures and endorses free market over "Canada-first"
11	2004	NEB and FERC sign Memorandum of Understanding to enhance interagency coordination

2007 to Present – Shale Gas Drives to U.S. Growth

Development of shale gas supplies expanded rapidly and displaced some traditional supply as demand growth faltered due to the economic recession. The displacement of supply sources is impacting pipeline utilization on specific routes in the U.S. and Canada. With perceived abundance in natural gas supplies and relative tightness in crude oil supplies, natural gas prices have diverged to be significantly below their 10:1 ($/mmBTU: $/barrel) historical relationship with crude oil and even further below the 6:1 energy equivalent relationship. As prices decline, LNG import growth is being delayed and pricing challenges increase for northern pipelines. In response, there are calls for a push to significantly expand natural gas markets through additional power generation and large-scale conversion of natural gas vehicles. Key regulatory developments during the period include:

United States

20	2008	Lifting of the moratorium on offshore drilling along the east and west coasts
21	2010	Macondo well blowout. Results in restructuring of the Minerals Management Service and a temporary moratorium on Gulf of Mexico drilling,

Canada

12	2009	Multi-pipeline return on equity formula no longer in effect. The cost of capital to be determined by negotiations between pipelines and shippers or by the NEB if an application is filed

Regulatory Challenges

State/Provincial Regulation of Leasing, Drilling and Completion Activity

Lease sales, issuance of drilling permits, and monitoring of operations are regulated by state and provincial regulatory boards or commissions. The regulations include means of addressing landowner concerns, noise, emissions, increased truck traffic, wildlife and habitat disturbance. Inconsistency of state/provincial and local regulations can contribute to delays and increased costs.

Of particular interest are lease retention conditions. U.S. shale gas areas are continuing to experience high levels of drilling activity despite declines in gas prices as a consequence of extensive leasing in recent years and the need to demonstrate production from at least one well per section to retain the lease on that section. Lease retention in Canada requires drilling and a well test, without the need for production. The less onerous conditions in Canada have resulted in some companies reallocating capital to U.S. operations in response to more pressing lease retention conditions.

Issuance of drilling permits has created challenges in some jurisdictions due to rapid increases in activity overwhelming permit processing capacity. In some jurisdictions, temporary permit moratoria have been proposed or enacted to address local concerns. These issues have been more prevalent in the Marcellus area where the region is less familiar with high levels of activity.

Hydraulic Fracturing and Possibility of Groundwater Contamination

Regulations on hydraulic fracturing are under state/provincial jurisdiction and are excluded from federal drinking water regulation in the U.S. and Canada. The U.S. EPA is undertaking a congress-requested study into hydraulic fracturing. The EPA expects to release its report in 2012. The focus of examinations into hydraulic fracturing and the possibility of groundwater contamination appear to focus on three areas:

a) Accidental surface discharges of drilling fluids or of recovered water. Recovered water is often highly saline and may contain chemical additives.
b) Integrity of the wellbore (casing and cement) as wells traverse zones used as sources for potable water. Regulations on setback distances from existing water wells are in place.
c) Possibility of hydraulic fracturing extending beyond the vicinity of the well to allow fracture fluids to migrate into groundwater sources. This risk is generally considered low due to thousands of feet of rock between fracture stimulated zones and relatively shallow sources of potable water. At least one company (Range Resources) is now voluntarily reporting composition of chemical additives to fracture water.

Extent of Water Use, Recycling and/or Disposal of Recovered Water

It appears that additional water requirements associated with hydraulic fracturing requirements would not unduly impact national water withdrawal levels. Localized impacts on the water table within a particular region continue to be monitored.

Water treatment to be able to recycle return water may be highly saline and, without adequate desalination recycling could cause corrosion and scaling of wellbore tubulars and equipment. Reduction of biological components typically involves the use of biocides or UV treatment. Canada does not permit surface disposal of recovered waters and requires all to be re-injected into deeper non-potable water zones.

Regulation of Pipeline Tolls, Tariffs, Construction and Operations

Changes to pipeline utilization are occurring across North America in response to the development of shale gas in locations outside traditional producing areas. These developments could result in the potential underutilization of pipelines, such as those serving the U.S. Northeast from the Rocky Mountains, Gulf Coast and Western Canada.

Reconfiguration of existing pipeline systems may be possible in some cases (such as the reversal of import lines). Some gas pipelines are experiencing significantly lower throughputs as a result of shale gas developments. Higher toll charges are occurring on some systems as a consequence of reduced throughputs. Eventually, further drops in throughput could lead to the shutdown of specific pipeline segments and thereby expose the system to the possibility of decommissioning and abandonment costs.

In locations with growing shale gas production, new pipeline capacity may be required to move new supplies to markets. Constructing new pipeline capacity in a sustainable manner that accommodates social, environmental and economic objectives will present ongoing challenges to industry, land owners and regulators, particularly in more populous regions. Addressing these challenges may result in delays, routing changes and higher costs to achieve effective solutions.

Operational and financial regulations may be required to address pipeline load balancing issues should significant increases in unscheduled gas withdrawals for peaking power generation become a concern.

Future Scenarios ("Where are we going?")

Six future scenarios are developed herein to investigate assumptions regarding the future consumption rates and regulatory impacts on onshore gas production:

1. ***Flat Supply Scenario*** – supply is assumed available at a constant 24.1 TCFG/yr until onset of supply decline.

2. ***Supply Growth Scenario*** – supply is increased by approximately 5% per year to a constant 36.5 TCFG/yr until onset of supply decline.

3. ***Restricted Supply Scenario - Extreme*** – supply is reduced such as may occur with a moratorium on fracture stimulation. Assumption: 100% of shale gas supply and 85% of tight gas/CBM supply is eliminated.

4. ***Restricted Supply Scenario - Severe*** – supply is reduced such as may occur with severe restrictions on fracture stimulation. Assumption: 67% of shale gas/tight gas/CBM supply is eliminated.

5. ***Restricted Supply Scenario - Moderate*** – supply is reduced such as may occur with moderate restrictions on fracture stimulation. Assumption: 33% of shale gas/tight gas/CBM supply is eliminated.

6. ***Restricted Supply Scenario – Increased Cost*** – supply is reduced such as may occur with additional costs on fracture stimulation. Assumption: cost to supply shale gas/tight gas/CBM is increased by $2/mmBTU.

Studies of Remaining Resources

As a result of technology breakthroughs, most, if not all estimates of future indigenous gas supplies for North America have been increasing significantly over recent years. As this is covered quite thoroughly in these studies (see Table 2), we have not attempted yet another estimate, but rather employed a "study of studies" approach.

The most important realization from these studies is that in less than a decade, estimates of the North

America resource base have grown by more than 150%. To illustrate this transformation, the most recent study sponsored by the America's Natural Gas Alliance (ANGA) include a comprehensive geological and engineering based model of 32 unconventional plays, including shale gas, tight gas sands, and coal bed methane formations. Input for the modeling included detailed data submittals from operators with direct knowledge and experience in these areas. These unconventional plays alone were projected to have recoverable reserves over 2,600 TCFG at assessed spacing. This most recent study, in combination with the consistent trend of resource growth, provides a compelling argument that the resource base is large. With sufficient confidence in the underlying resource base, the focus can shift to questions regarding supply and rates of development.

We used the data supporting MITei's report as they provide a reasonable range of estimates in a format useful for the scenario building discussed herein. MITei utilizes the North American supply model developed by ICF, which provides for a high-medium-low look using "current" technology and the same for an "advanced" technology case; resulting in six different model outputs for consideration.

We are appreciative for both MITei and ICF's support in supplying us with U.S. and Canadian model outputs to use in this report. However, it should be noted that "current" referred to technology as applied around 2007 or earlier. Given the very recent breakthroughs, support by the other studies and internal estimates by the authors' organizations, today's application of technology renders the "Advanced Technology" cases more relevant today. As such, for the purposes of this paper we have chosen to focus upon three various cases, as discussed in the following subsection.

Estimates of Remaining Resource [1]

Organization	Date	Offshore	Conventional	Tight	Shale	CBM	Total Lower 48	AK	Total US	Proved reserves	All US	Canada Onshore non-Arctic	Canada Offshore and Arctic	Total Canada	Total North America	Onshore non-Arctic N.A. Total
USGS/MMS/EIA	1997		657	308		50	1,015	223	1,238							
USGS/MMS/EIA	2009		454	276		71	801	362	1,163	245	1,408					
NPC	1999		881	230	52	74	1,252	303								
NPC	2003		691	190	35	58	974	294	1,268	184	1,452	397		397	1,849	
PGC	2001			742		98	840	251	1,091							
PGC	2006			961		166	1,127	194	1,321	211	1,532					
PGC	2008		863		616	163	1,642	194	1,836	238	2,074					
ICF	2009		693	174	631	65	1,563	294	1,857	245	2,102					
INGAA	2008		904	174	385	65	1,528	302	1,830	204	2,034	508		508	2,338	
NEB	2009											627		627		
CSUG	2010											1,020		1,020		
MITei Canada P10 [2]	Q2 2010													1,185	4,035 [6]	
MITei U.S. P10 [2]	Q2 2010										2,850					
MITei Pmean [2]	Q2 2010										2,100			800	2,900	
MITei U.S. P90 [2]	Q2 2010										1,500					
MITei Canada P90 [2]	Q2 2010													460	1,960 [6]	
RSTG Onsh Gas Case 3 [3]	Q3 2010		120	523	1,658	142	2,443					1,118				3,561
RSTG Onsh Gas Case 2 [4]	Q3 2010		120	523	1,198	142	1,983					907				2,890
RSTG Onsh Gas Case 1 [5]	Q3 2010		120	523	514	142	1,299					602				1,901
ANGA	Q1 2010		692	438	1,759	70	2,959	294	3,253	245	3,498	1,026			4,524	
GTI Current	2010		958	223	32	49	1,321	484	1,805	inc.?	1,805					
GTI Advanced	2010		1,002	337	53	77	1,528	530	2,058	inc.?	2,058					
NPC Survey High	Q4 2010	375	440	550	1,800	150	3,315	345	3,660	inc.	3,660	1,025	230	1,255	4,915	3,965
NPC Survey Medium	Q4 2010	260	290	350	1,000	120	2,020	210	2,230	inc.	2,230	695	175	870	3,100	2,455
NPC Survey Low	Q4 2010	160	215	200	700	90	1,365	130	1,495	inc.	1,495	370	130	500	1,995	1,575

footnotes:

1 No adjustments have been made for interim production between years
2 MITei's figures as published
3 NPC RSTG Onshore Gas Sub-Group, sourced from detailed dataset from the MITei Report prepared by ICF; $20/mcf supply cost cut-off assumed; High "Advanced" (2007) Tech Case
4 NPC RSTG Onshore Gas Sub-Group, sourced from detailed dataset from the MITei Report prepared by ICF; $20/mcf supply cost cut-off assumed; Mean "Advanced" (2007) Tech Case
5 NPC RSTG Onshore Gas Sub-Group, sourced from detailed dataset from the MITei Report prepared by ICF; $20/mcf supply cost cut-off assumed; Mean "Current" (2007) Tech Case
6 Sum of U.S. and Canada; but not really a valid statistical function

Table 2: Resource Comparisons

Resource Analysis

This prodigious growth in technology and its applications has resulted in enormous new resource development in recent times from areas previously considered to be uneconomic or marginal. To assess the impact of this breakthrough, we have broken out the North American non-arctic onshore natural gas history curve into three components: (1) conventional, (2) "old unconventional technology" which includes tight gas sands and coalbed methane (CBM), and (3) "new unconventional technology" which includes shale production as well as other plays now utilizing fracture stimulation in horizontal wellbores.

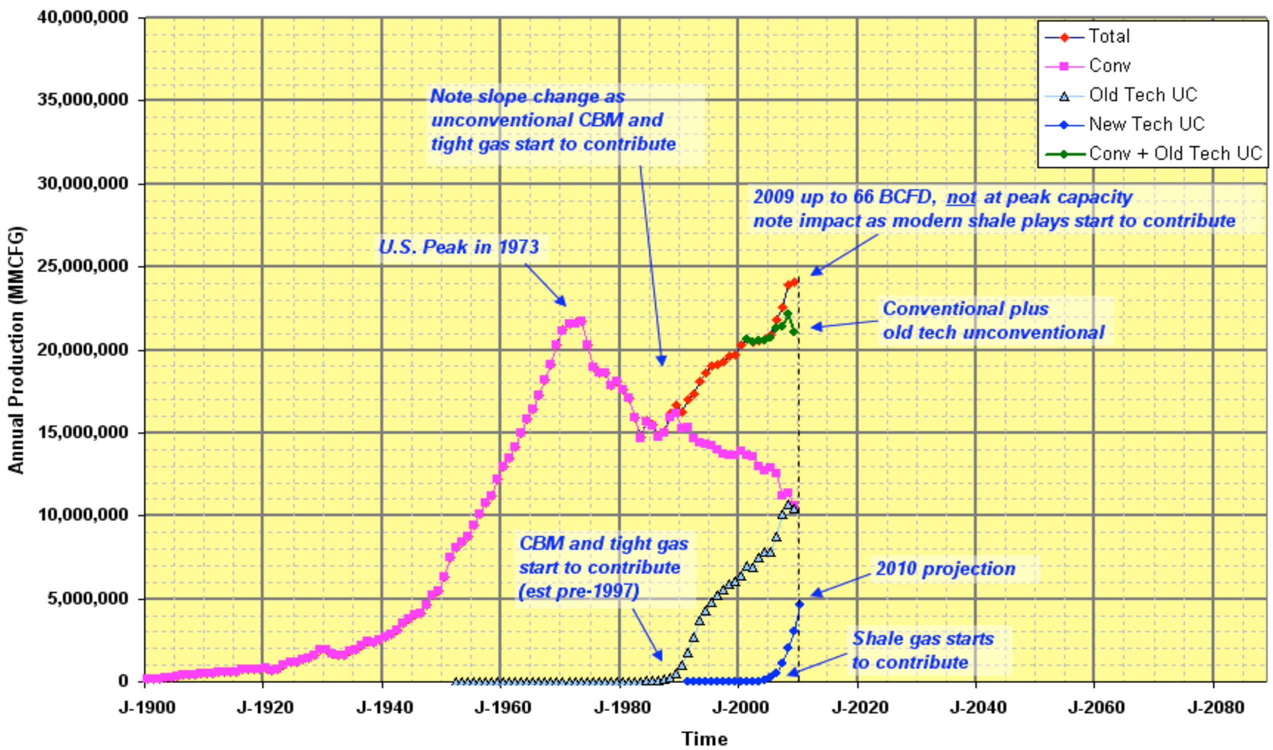


Figure 16: North America Onshore (Non-Arctic) Production History
Data source: U.S. EIA, USGS, CAPP, Canada NEB, Cedigas, IHS CERA

Figure 16 illustrates the breakout of production from these three components. U.S. conventional production hit its peak in approximately 1973 and North American production started declining. Old unconventional technology (tight and CBM – light blue) begins to contribute in approximately mid-1980's, thereby arresting gas production decline. The onset in the mid-2000's of rapid production growth from new unconventional technology (primarily shale gas – dark blue) is responsible for building gas production to the current 24.1 TCFG/yr level.

The previously identified six scenarios are further evaluated via three cases, or estimates of uncertainty, each. These cases are looked at in detail for each scenario. For the flat or supply growth scenarios, the resource range is presented herein as:

Case One – MITei/ICF Mean Resource Base, Current (2007) Technology; Remaining Recoverable Resource 1,901 TCFG, Estimated Ultimate Recoverable Resource 2,996 TCFG. *The consensus view of the sub-group is that this case is quite conservative and it is highly probable that it will be surpassed.*

Case Two – MITei/ICF Mean Resource Base, Advanced Technology, Remaining Recoverable Resource 2,890 TCFG, Estimated Ultimate Recoverable Resource 3,985 TCFG. *The consensus view of the sub-group is that this case is rather conservative and it is probable that it will be surpassed.*

Case Three – MITei/ICF High Resource Base, Advanced Technology, Remaining Recoverable Resource 3,561 TCFG, Estimated Ultimate Recoverable Resource 4,656 TCFG. *The consensus view of the sub-group is that this case is reasonable today and could readily be surpassed.*

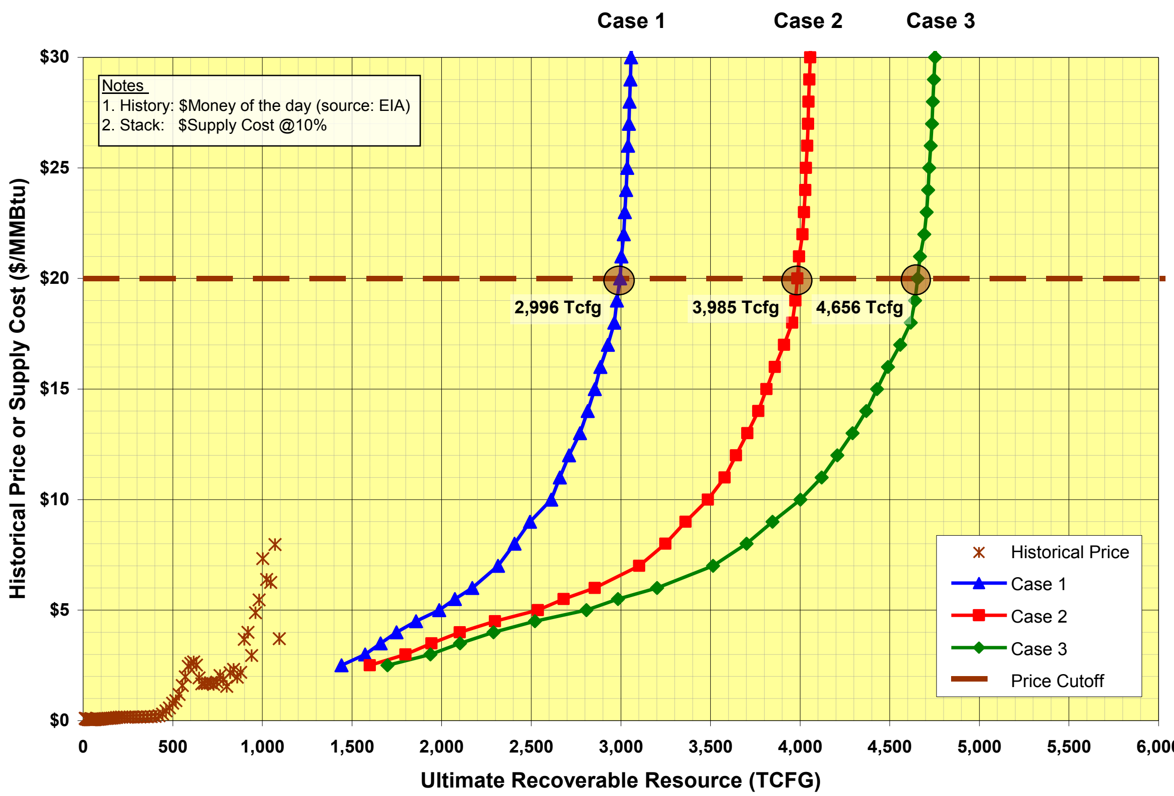


Figure 17: North America Onshore (Non-Arctic) Ultimate Recoverable Resource versus Supply Cost
Data source: U.S. EIA, MITei/ICF

Figure 17 illustrates the supply cost stack for these cases under the flat supply and supply growth scenario assumptions. This Figure shows gas resource volumes on the horizontal axis plotted against market price levels or cost of supply ($/mmBTU) on the vertical axis. Without a loss of generality, the scale is truncated at $30/mmBTU even though the MITei datasets are available up to $70/mmBTU. Historical cumulative gas production, as shown in brown on the lower left, rose above 1,000 TCFG in 2006. By comparison, the estimated ultimate recoverable gas resources are plotted in blue, red and green under for cases one to three, respectively.

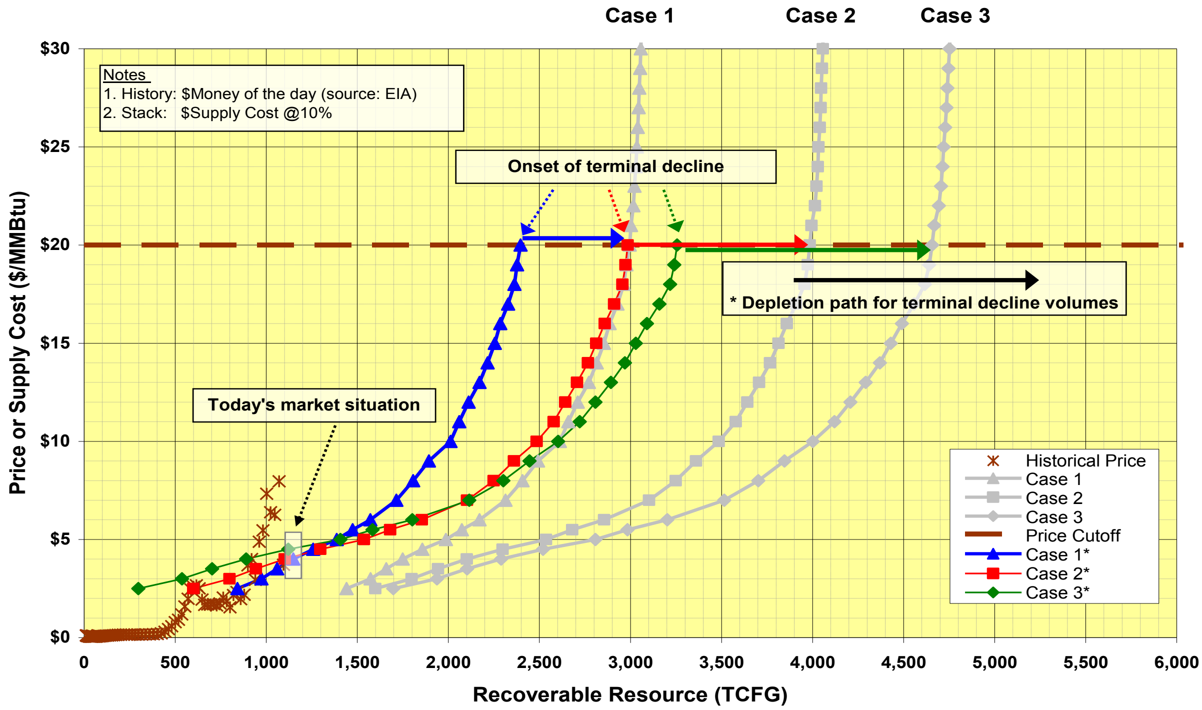
The additional resources that might be recoverable at prices above $20/mmBTU appear to be relatively small, so comparisons among the cases can be made at this level. As highlighted by the dashed brown line (see Figure 17), ultimate recoverable resources range from ~3,000 TCF in the pessimistic Case 1 upwards of ~4,700 TCFG with advanced technology in Case 3 – a difference per se that exceeds cumulative gas production to date. Figure 17 provides historical cumulative production and annual average market price for comparison.

By contrast, many industries will report a reserve life index (RLI or R/P) in terms of "years of supply", implying that current rates of production can be maintained until exhaustion of the resource. While this can be a useful measure for comparison purposes, the terminology unfortunately can be misleading.

Individual wells and fields enter long periods of decline before depletion, so the principles of superposition dictate that the overall production curve will as well. This phenomenon has been observed in other mature depleting resource bases (U.S. Lower 48 oil[36], North Sea Oil[37], Pennsylvania Anthracite[38], black sturgeon caviar[39], etc.) and should be accounted for in future scenarios. The implication for sound analysis is that some volume of resource needs to be banked to support the depletion in the terminal decline phase. The ultimate terminal decline curve will be uncertain but has been estimated in this paper based on idealized Hubbert Curves fit to historical data, as shown in Appendix C. This treatment of terminal decline volume provides a more conservative relationship as shown in Figure 18 – price/resource follows along the colored (displaced supply) curve to the assumed $20/mmBTU cut-off price, then the remaining resource is depleted at that price level during terminal decline. This approach should provide a better tool for understanding the relationship between price and supply cost, all other things being equal.

It is difficult at this point in time to estimate remaining resources. Nonetheless, we use an empirical linearization technique[36] (see Appendix C and Figure 19) to portray the uncertainty. The technique works well as long as the system being measured is in a steady state of exploration and development. If disruptive technologies or vast new resources are discovered, however, the estimates are impacted. For example, recent shale gas developments reversed the slope in the 2005 – 2009 timeframe or 1,000 – 1,100 TCFG range.

Cases one to three can all be supported with reasonable play-by-play "bottom-up" original gas-in-place and remaining resource estimates. There is an argument for further optimism. Old, Holditch, Ayers, and McVay[40], relate the volumes of unconventional gas with measured volumes of conventional recovery; their analysis suggests that conventional gas only represents 10-20% of the ultimate recoverable gas. Using the 1,200 TCFG estimate of conventional gas shown on Figure 19, and assuming 1/6 is from basins with inaccessible unconventional resources, would result in an ultimate recovery estimate of 5,000 to 10,000 TCFG, so future estimates could prove to be much higher than the cases considered here.



* Adjusting for terminal decline volumes provides a better proxy for price than the supply cost curves, albeit still imperfect.

Figure 18: North America Onshore (Non-Arctic) Ultimate Recoverable Resource versus Supply Cost (grayed-out) and Price Proxy
Data source: U.S. EIA, MITei/ICF

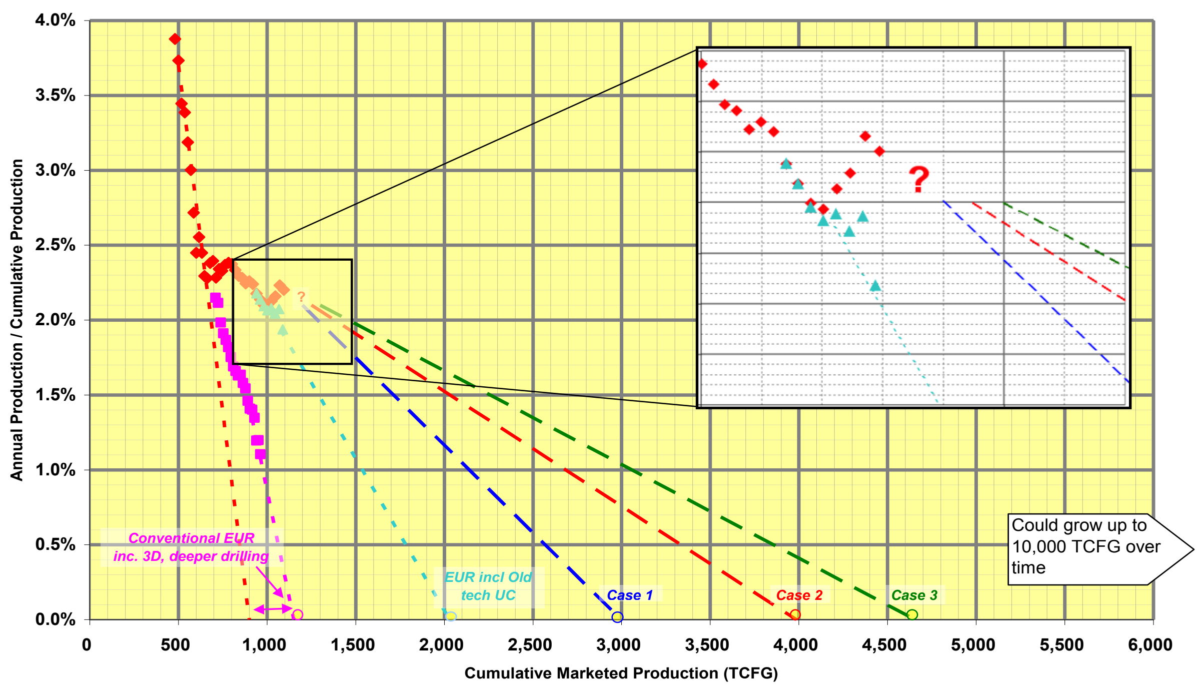


Figure 19: North America Onshore (Non-Arctic) Hubbert Linearization Uncertainty (each point is one year)

Scenario Analysis

Flat Supply Scenario

The remaining resource uncertainty estimates (different cases, same scenario) have significant effect on the duration of plateau supply length. As illustrated in Figure 20, approximately five to nine decades, followed by significant post-plateau supply, are possible under this Scenario's (flat supply) assumptions.

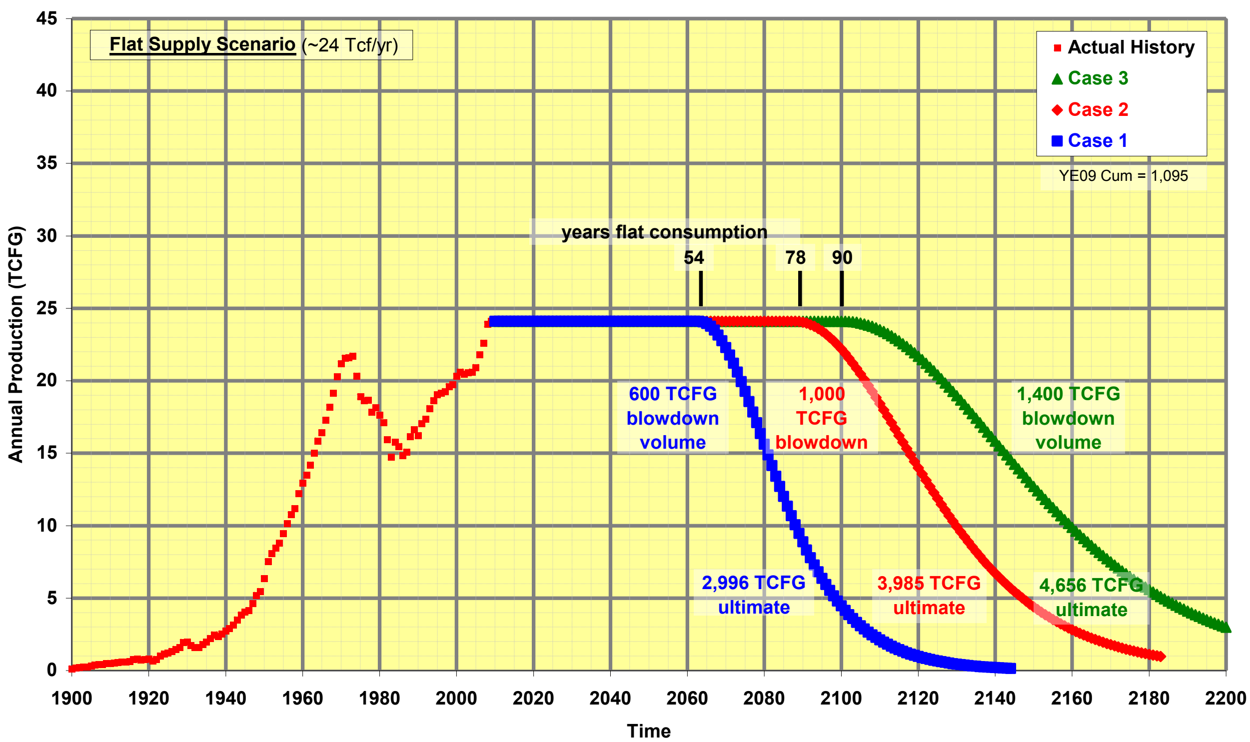


Figure 20: North America Onshore (Non-Arctic) Plateau Supply - Flat Supply Scenario
Data Source: US EIA, USGS, CAPP, NEB Canada, Cedigaz

Supply Growth Scenario – Increased Rate of Supply

The trajectory of supply along extrapolated lines in Figure 19 is independent of time. An increased rate of supply scenario is developed, whereby supply is *assumed* to increase approximately 50% from 24.1 TCFG/yr to 36.5 TCFG/yr (100 Bcfd). The increase takes place at similar growth rates as seen before, and achieves this higher supply plateau in approximately one decade. This assumed supply scenario is illustrated in Figure 21. It is important to note that the scenarios contained herein are *not* actually forecasts but rather supply possibilities – we do not consider competing resources such as LNG or arctic gas, nor make any real demand assumptions/forecasts.

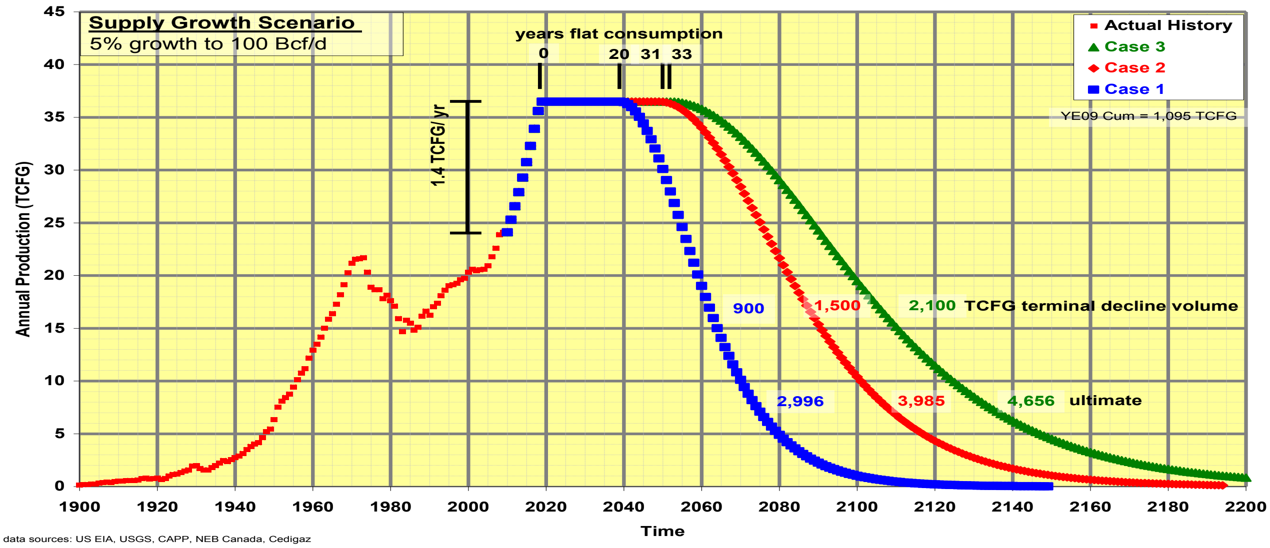


Figure 21: North America Onshore (Non-Arctic) Plateau Supply - Supply Growth Scenario

Restricted Supply Scenarios

As described in the preceding Resource Analysis section, assumptions are introduced to estimate the effects of various possible restrictions (such as limitations on fracturing and resource access, or increased unconventional gas costs) on industry's ability to supply onshore gas. Two of these scenarios are illustrated in the following figures; from extreme limitations to supply (Figure 22) to moderate limitations to supply (Figure 23). A further limited scenario is discussed in Appendix C. Clearly, these assumptions have a drastic effect on the ability to supply North America gas domestically. The remaining resource is reduced by 71% compared to the unrestricted Flat Supply scenarios and potential plateau supply is eliminated entirely under extreme restrictions. Plateau (flat) supply would be reduced from the approximate 80 – 90 years, to approximately 40 – 50 years by assuming 33% restrictions on unconventional supply.

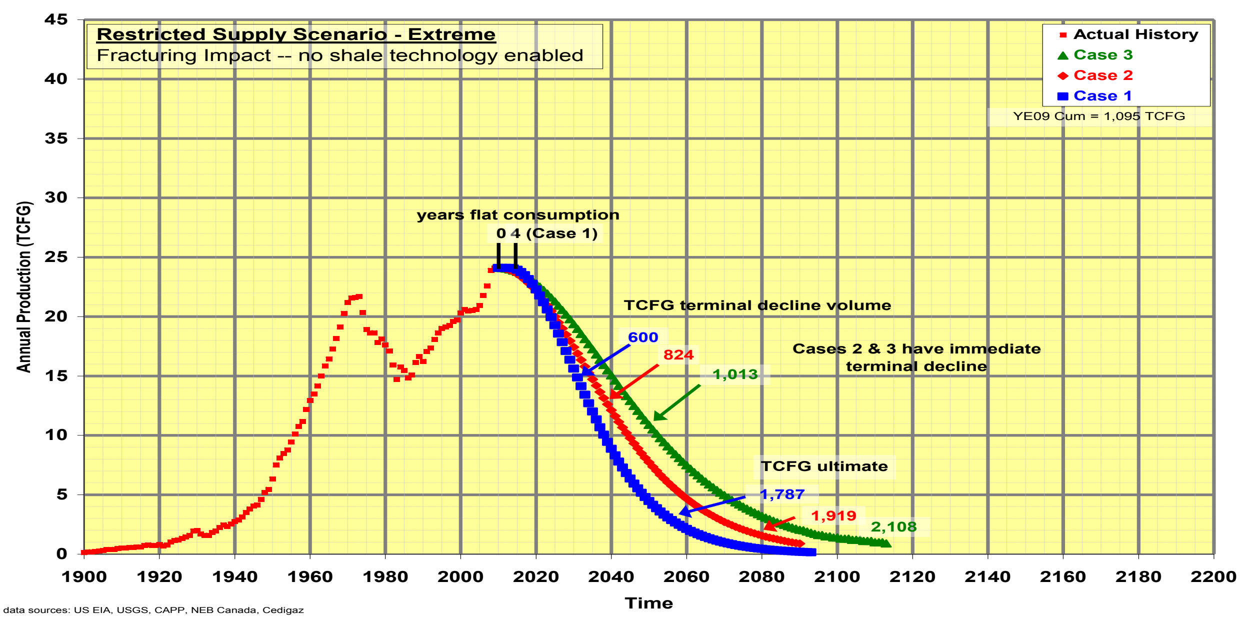


Figure 22: North America Onshore (Non-Arctic) Plateau Supply - Extremely Restricted Supply Scenario

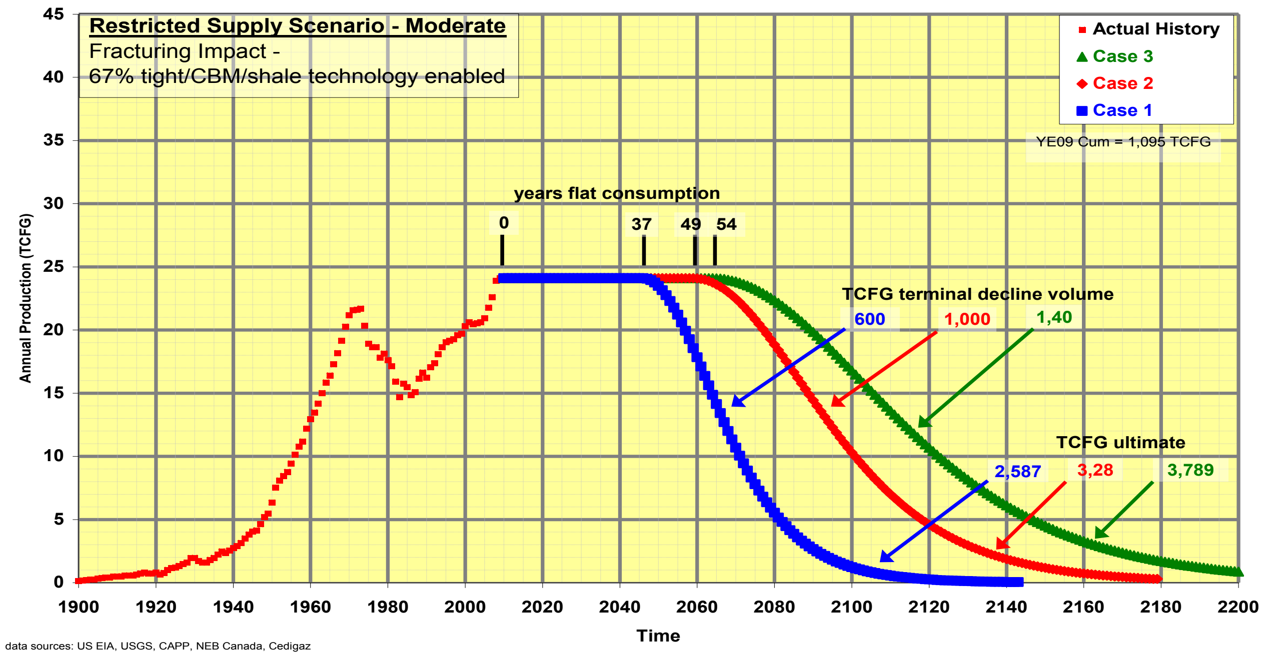


Figure 23: North America Onshore (Non-Arctic) Plateau Supply - Moderately Restricted Supply Scenario

A moderate increased cost of supplying unconventional gas, such as the $2/mmBTU assumption in the Increased Cost Scenario (Figure 24), has a limited effect on supply and associated potential plateau supply duration. The steepening curvature of the supply cost stack translates to a minimal 15 – 20 TCFG reduction in resource across the low-to-high range of resource, and a small reduction in plateau supply potential. However, the supply cost, and associated market equilibrium pricing increases by approximately $1 - 2/mmBTU as the unaffected conventional resource supply is diminutive to the price effect.

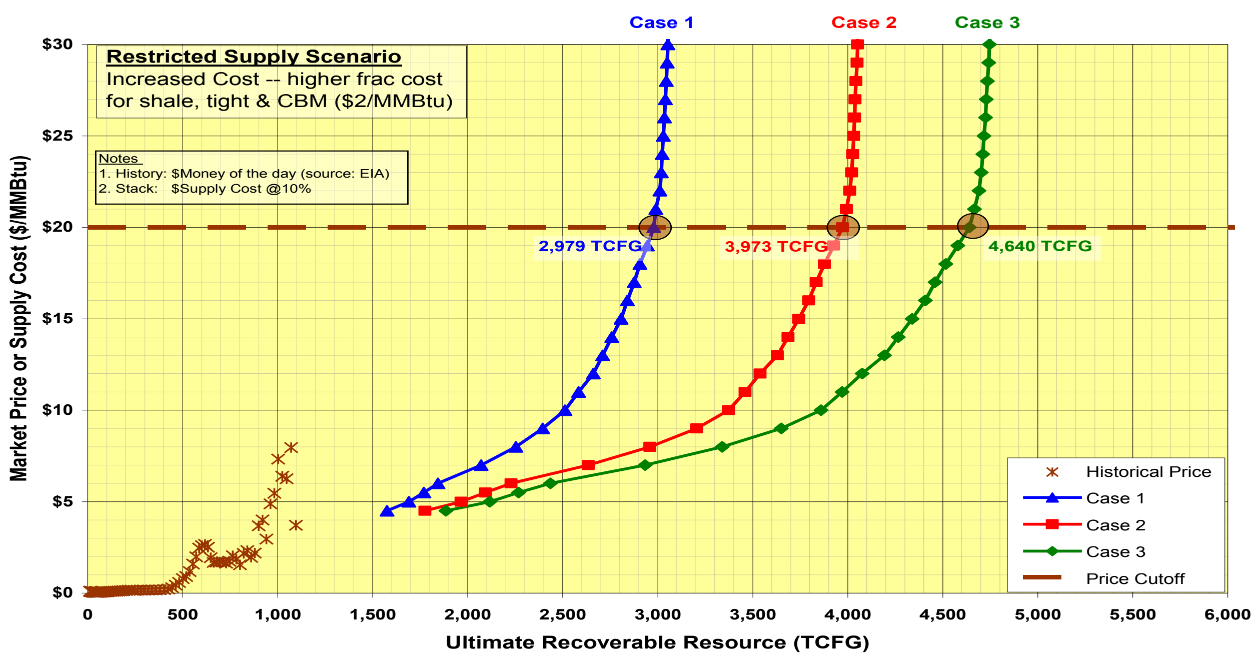


Figure 24: North America Onshore (Non-Arctic) Increased Cost of Unconventional Supply Scenario

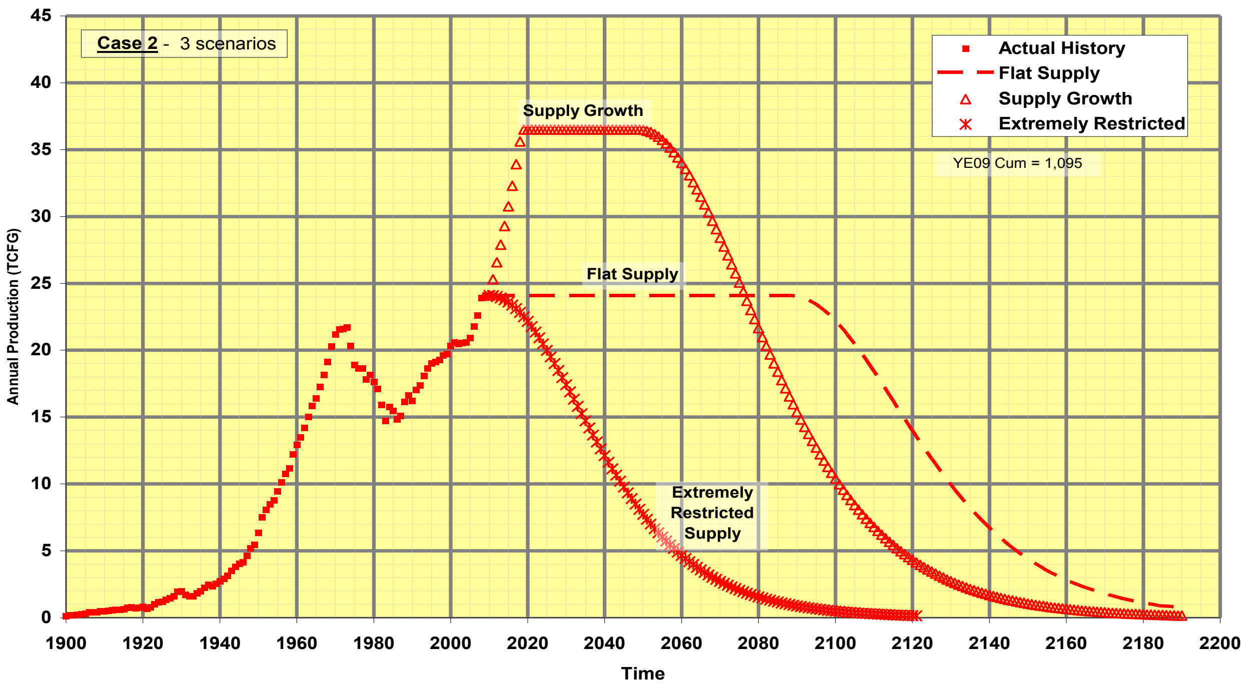


Figure 25: North America Onshore (Non-Arctic) Supply Plateau Summary Under Flat, Growth and Extremely Restricted Scenarios

Figure 25 provides a summary of Flat Supply, Supply Growth, and Extremely Restricted Scenarios; representing the wide envelope of natural gas supply possibilities as a result of demand and regulatory impacts for Case 2. Further details and discussion of all scenarios are presented in Appendix B.

Sourcing Inputs - Indicative Estimates ("How do we get there?")

Approach

A methodology to estimate the magnitude of fundamental requirements to enable the above described gas resource was developed to ascertain the reasonableness of the asserted resource. That methodology is briefly described here and this section presents the indicative requirements of rigs, industry personnel, tubular (steel) tonnage, proppant and fracture stimulation water usage required to support both the Flat Supply and Supply Growth scenarios. The well count and gas production estimates developed in this section are for the sole purpose of estimating indicative input requirements and *should not be treated as a rigorous production forecast*.

A Front End Model is employed to estimate the rough number of wells that might be required to support the applicable supply profile. Characteristics of wells from seven type regions are hypothesized as adequate proxies to represent the span of North American non-arctic onshore gas production:

- Marcellus Shale
- Haynesville Shale
- Barnett/Woodford/Eagle Ford Shale (remaining U.S. Shale proxy)
- Montney (Canadian Shale proxy)
- Jonah/Pinedale (Tight Gas proxy)
- Powder River/Raton Basin (CBM proxy)
- Non-fracture stimulate South Texas (Conventional proxy)

For simplification, well counts from the front end model are assigned to the best applicable type region.

A Back End Model is employed to estimate low and high fundamental requirements for each type region by multiplying the respective low and high regional well parameter by the number of regional wells of that type in a particular year. The seven type region subtotals are then summed for the yearly non-arctic onshore gas total requirements. Four time slices, namely: (1) the recent industry peak in 2008; (2) current 2010 requirements; (3) a medium term outlook for 2030; and (4) a longer term outlook for 2050 are discussed.

<u>Front End Model</u>

To represent the possible range of natural gas wells that might need to be drilled to develop the onshore natural gas resources described above, an analysis was undertaken that estimated the initial amount of production contributed by individual wells and the rate that this production would decline over the operational lifetime of the wells. By summing the output from these representative wells and continually adding additional wells as required to maintain the indicated production levels in the U.S. and Canada, an estimate of well requirements was obtained. The estimate was improved by dividing the total resource by region and major play type (conventional, CBM, tight gas and shale gas) and applying an average of the production performance over recent years of actual wells drilled in each of these groupings.

To reflect the general progression from higher producing wells to lower producing wells over the lifetime of a gas field, it was assumed that the starting production rate of a new well would be one percent lower than the wells that were drilled in the preceding year. While technological advances are likely to occasionally interrupt this progression, and potentially reverse it for certain periods, the one percent reduction in initial productivity each year was adopted as a conservative outlook that would likely err to indicating a higher number of wells than might eventually be required.

An expectation of the relative economics of the major natural gas types led to an assumption that increases in drilling would primarily target shale gas, and to a lesser extent at tight gas. Conventional gas and CBM drilling were assumed to remain essentially flat at around current levels over the period to 2050. To avoid a disproportionate draw on any particular resource type, the potential amount of natural gas that would be produced over the lifetime of the wells drilled between 2010 and 2050 was checked against public estimates of recoverable resources by type to avoid a disproportionate draw on a particular resource category.

The estimated production by resource type and pace of onshore natural gas drilling to maintain combined U.S. and Canadian production at current levels of roughly 66 Bcfd for the Flat Supply Scenario is indicated in Figures 26 and 27.

Increasing output of shale gas rises to about 60 percent of the total and is able to offset declines in conventional and CBM production to maintain production. As shale gas wells produce at higher rates than many of the conventional, CBM and tight gas wells that were relied on previously, the absolute number of new onshore gas wells required to maintain current production remains less than 60 percent of the peak 2006 level.

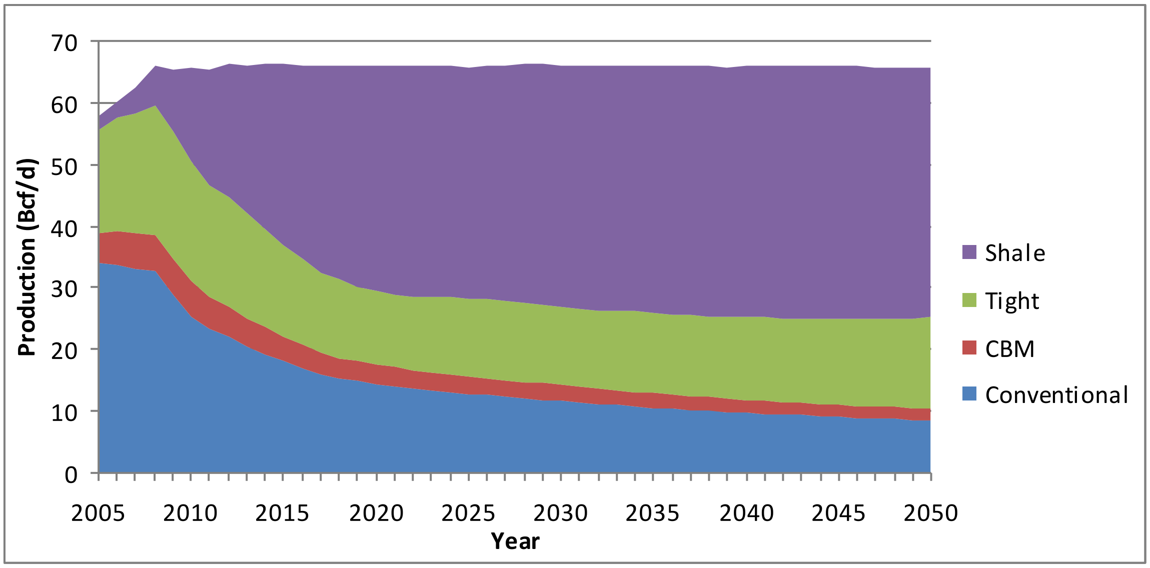


Figure 26: Estimated Resource Supply Production (Flat Supply Scenario)

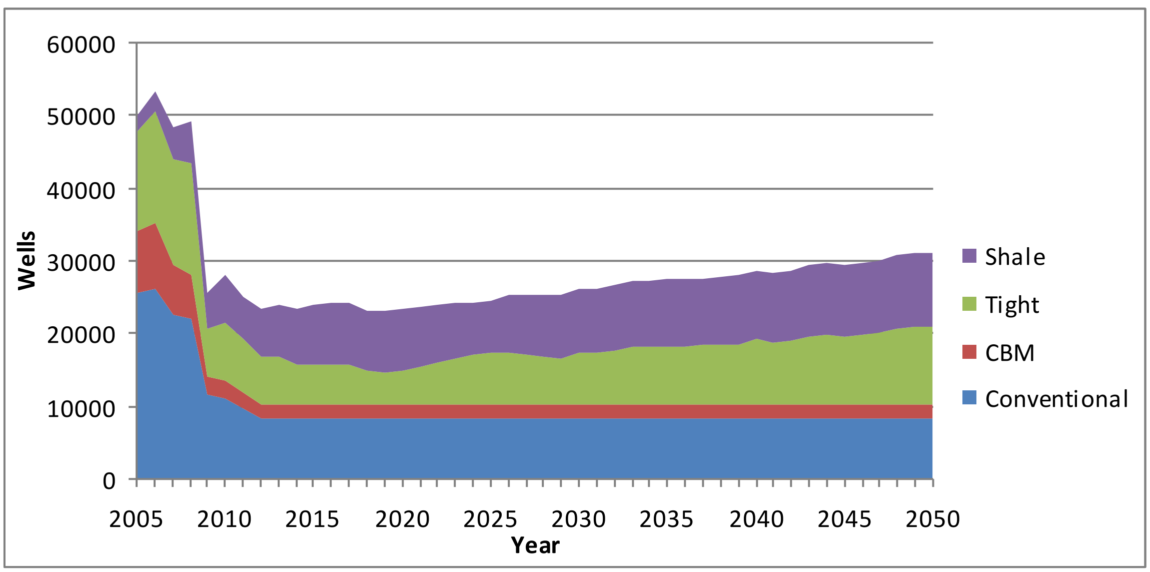


Figure 27: Projected Required Wells from Front End Model (Flat Supply Scenario)

To achieve significant increases in combined U.S. and Canadian production to roughly 100 Bcfd by 2020 and maintain that level thereafter would involve higher levels of drilling. As indicated in Figures 28 and 29, shale gas again is projected to account for about 60 percent of the production from 2020 onward. By 2050, the requirement for new onshore natural gas wells is projected to reach over 80 percent of the 2006 peak.

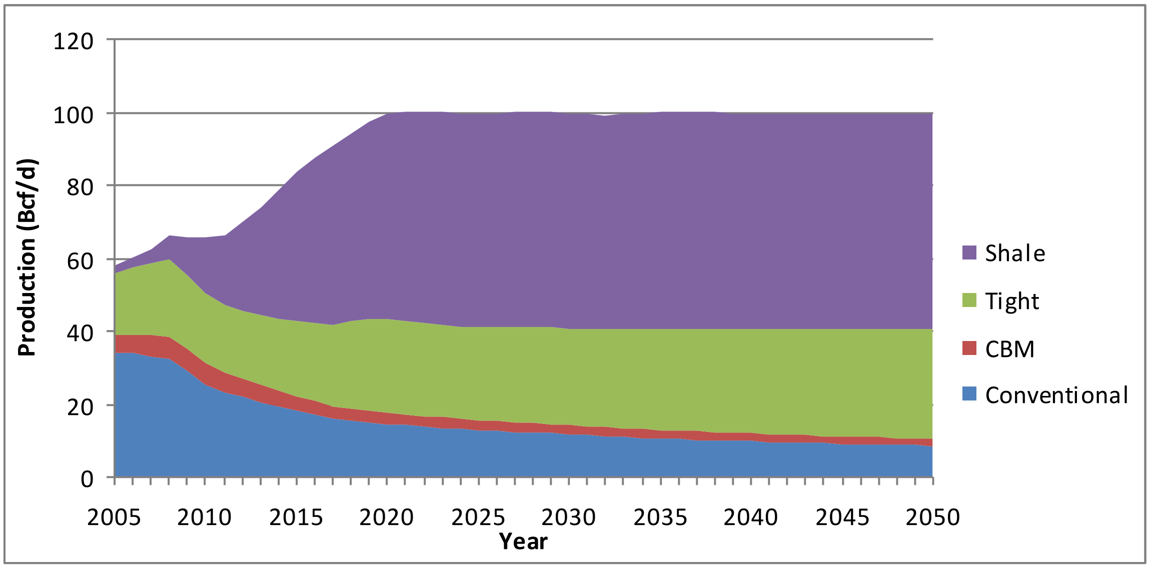


Figure 28: Estimated Resource Supply Production (Supply Growth Scenario)

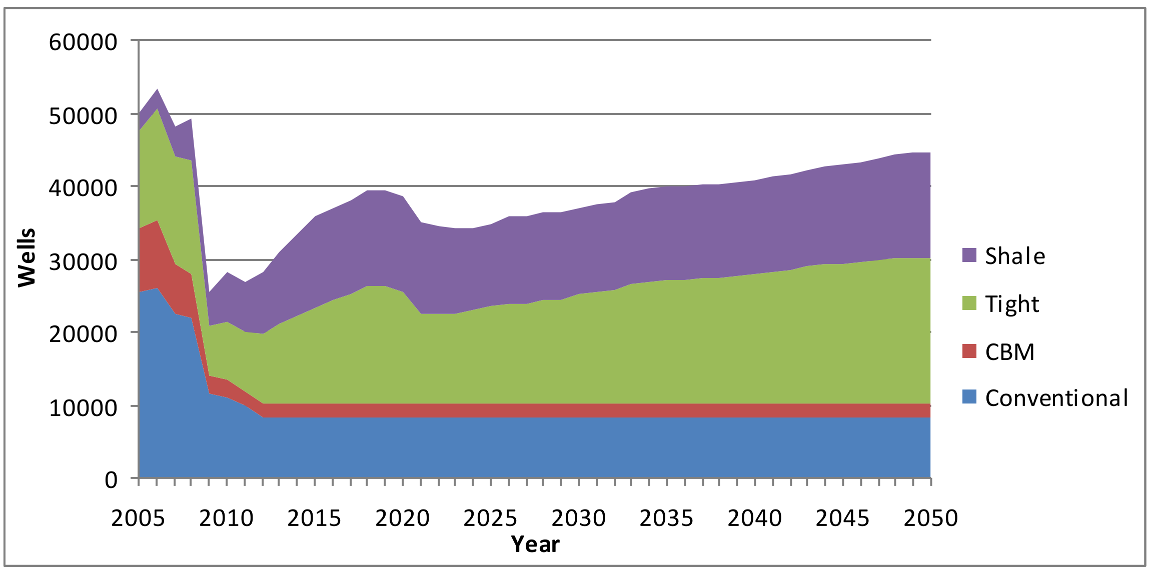


Figure 29: Projected Required Wells from Front End Model (Supply Growth Scenario)

While the absolute number of new onshore natural gas wells remains below previous peaks, the numbers are not strictly comparable since shale gas wells tend to require greater amounts of labor, equipment and materials to drill and complete than earlier generations of onshore natural gas wells. A second analysis was performed to address this issue of increased requirements per well.

Back End Model

The Back End Model includes the calculation of a range of input or industry requirements that would be necessary to achieve the onshore natural gas well counts from the Front End Model. The foundation of the model is a set of parameters for each of the seven type regions used as proxies for the North American non-arctic onshore gas play types as described in Table 3.

Parameter	Description
Rig Count	Drilling rigs servicing the natural gas industry
Well Costs	Capital expenditure for drilling & completion (2010 or current dollars)
Frac Stages	Number of frac stages per well (for stimulated wells)
Proppant Volume	Lbs of proppant per frac stage
Water Volume	Gallons of water required per frac stage (does not include flowback)
Steel Tonnage	OCTG only - tonnes of steel based on vertical depth and lateral length
People	Directly employed labor force

Table 3: Back End Model Parameters

For each of these parameters a low to high range was assumed based on an informal aggregation process of public records, consultant research reports, company presentations, and industry contacts. Since this type of data is not readily available via any industry or government publication process, it will not be comprehensive. More specifically in any given play there might be examples of wells with characteristics that fall outside the range, particularly when looking back over the lifecycle of the play as the industry moves up the learning curve trying to identify an optimal well configuration and/or location.

The objective here was to describe an expected or average well within the identified play type so that estimates of input requirements on a go-forward basis could be made. Then using the ranges of each parameter and the number of wells by play type, the model simply multiplies through to arrive at the input requirements. In other words, we estimate how much the industry would have to ramp up to meet the expected drilling requirements of the supply scenario under consideration. It is important to note that this model does not take into consideration any improvements or degradation of the well parameters over time as the play matures, new technology is implemented, or industry practices change. These dynamics were considered too complex to be addressed as the uncertainty is very difficult, if not impossible, to quantify. Table 4 illustrates the assumed high and low characteristics of a well within each of the seven type regions.

The final step in the model is the calculation of the number of industry personnel to support the drilling activity for a given supply scenario. In order to establish a relationship between the level of industry activity and employment, monthly employment data from the U.S Department of Labor's

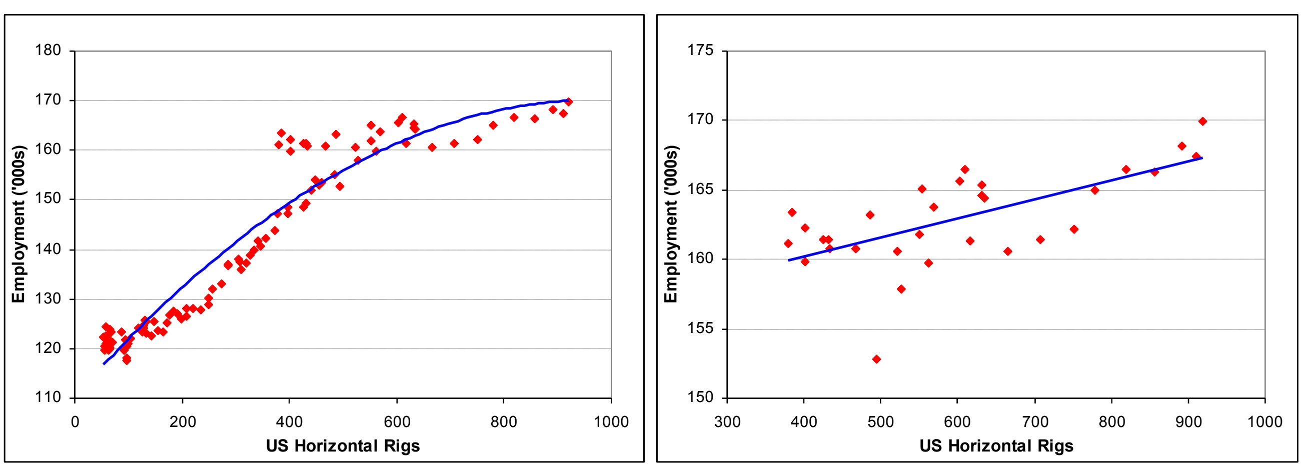


Figure 30: Rig-Manpower Correlation

Data sources: U.S. BLS, Baker Hughes

Plays	**Play Type**	**Shale 1**		**Shale 2**		**Shale 3 (generic)**		**Shale 4**	
	Analog	**Marcellus**		**Haynesville**		**Eagle Ford/Barnett/Woodford**		**Canada - Montney**	
	Profile	A (Low)	B (High)	A (Low)	B (High)	A (Low)	B (High)	A (Low)	B (High)
Well Characteristics	**Drill time (days)**	**17**	**30**	**30**	**60**			**15**	**30**
	Calculated days (central tendency)	18.8	24.7	36.0	47.3	20.4	26.8	18.0	23.6
	Well Costs ($, 2010)	**3,500,000**	**4,600,000**	**6,800,000**	**12,000,000**	**4,500,000**	**9,000,000**	**5,000,000**	**9,000,000**
	Calculated Costs (central tendency)	3,240,000	4,252,500	7,520,000	9,870,000	5,400,000	7,087,500	5,600,000	7,350,000
	Frac stages	**8**	**15**	**7**	**16**	**9**	**17**	**6**	**12**
	Calculated Stages (central tendency)	9.2	12.1	9.2	12.1	10.3	13.5	7.2	9.5
	Proppant volume/stage (lbs)	**300,000**	**500,000**	**300,000**	**400,000**	**420,000**	**730,000**	**300,000**	**400,000**
	Calculated vol/stage (central tendency)	320,000	420,000	280,000	367,500	460,000	603,750	280,000	367,500
	Water Used (gallons per stage)	**350,000**	**550,000**	**400,000**	**600,000**	**350,000**	**800,000**	**100,000**	**500,000**
	Calculated gal/stage (central tendency)	360,000	472,500	400,000	525,000	460,000	603,750	240,000	315,000
	Vertical Well Depth (ft)	**5,000**	**9,000**	**10,000**	**14,000**	**6,333**	**10,833**	**7,000**	**10,214**
	Lateral Length (ft)	**3,000**	**5,000**	**3,500**	**5,500**	**3,300**	**7,667**	**3,000**	**6,500**
	Estimated Steel (tonnes)	111	177	308	433	124	246	112	283
	Override Steel (input)								
	High HP Rig % (2010/2030/2050)	0		90 / 90 / 100		25 / 30 /35		20 / 33 / 40	

Plays	**Play Type**	**Tight Gas**		**CBM**		**Conventional**	
	Analog	**Jonah / Pinedale**		**Powder River / Raton**		**S. TX not frac'ed**	
	Profile	A (Low)	B (High)	A (Low)	B (High)	A (Low)	B (High)
Well Characteristics	**Drill time (days)**	**11**	**30**	**1**	**3**	**20**	**45**
	Calculated days (central tendency)	16.4	21.5	1.6	2.1	26.0	34.1
	Well Costs ($, 2010)	**4,000,000**	**6,000,000**	**375,000**	**465,000**	**1,500,000**	**3,500,000**
	Calculated Costs (central tendency)	4,000,000	5,250,000	336,000	441,000	2,000,000	2,625,000
	Frac stages	**12**	**21**	**0**	**0**	**0**	**0**
	Calculated Stages (central tendency)	13.2	17.3	0.0	0.0	0.0	0.0
	Proppant volume/stage (lbs)	**150,000**	**400,000**	-	-	-	-
	Calculated vol/stage (central tendency)	220,000	288,750	-	-	-	-
	Water Used (gallons per stage)	**37,500**	**67,000**	-	-	-	-
	Calculated gal/stage (central tendency)	41,800	54,863	-	-	-	-
	Vertical Well Depth (ft)	**9,000**	**15,000**	**1,000**	**3,600**	**9,000**	**17,000**
	Lateral Length (ft)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
	Estimated Steel (tonnes)	105	161	17	38	158	390
	Override Steel (input)						
	High HP Rig % (2010/2030/2050)	0		0		0	

Table 4: Back End Model Regional Well Characteristics
Data source: El Paso, Encana

Bureau of Labor Statistics (BLS) for industry classification: Oil and Gas Extraction (Series ID: CEU1021100001) was compared to rig counts from Baker Hughes for the time period of January 2002 thru October 2010. The chart on the left in Figure 30 shows U.S. employment in thousands versus total U.S. horizontal rigs, while the chart on the right shows the same employment data versus the horizontal rig count with correlation on an expanded scale covering the range of expected future activity.

Indeed, a recent analysis[8] by Timothy Considine, senior professor of economics and director of the center for energy economics, public policy and finance at the University of Wyoming enumerated the employment benefits on state and county economics attributed to unconventional gas development as:

- Shale gas development is continuous, more akin to a manufacturing process than (formerly viewed) one-off gas well drilling, and can last decades;
- The gas shale development areas are large and expansive; and
- Many local jobs are induced directly or indirectly.

Generally, states with shale development have lower unemployment than the U.S. national average

State	Shale Play	Rate (%)
Arkansas	Fayetteville	7.7
Louisiana	Haynesville	7.8
North Dakota	Bakken	3.7
Texas	Barnett / Eagle Ford	8.1
Pennsylvania	Marcellus	9.0
U.S. Average		9.6

able 5: Unemployment Rates (seasonally adjusted) y U.S. State)
ata source: University of Wyoming

(see Table 5).
The indicative requirements for both the Flat Supply (red bars) and Supply Growth (green bars) scenarios are shown in Figure 31a and Figure 31b respectively. Gas rig count was history matched to historical 2008 and 2010 year-to-date estimates. The height of the bars at 2030 and 2050 reflects the estimated range of input requirement for that scenario.

Figure 31a illustrates the activity related input requirements for U.S. Lower 48 and non-arctic Canada onshore gas supply; namely rigs (total and high horsepower), direct employment, well capital and OCTG steel for well tubulars. This level of activity is generally consistent within historical levels. Employment would increase. High horsepower rigs (1500 HP or more) are estimated at approximately 25 to 33% of total gas rig count.

Figure 31b illustrates the fracture stimulation activity related input requirements for U.S. Lower 48 and non-arctic Canada onshore gas supply; namely fracture stimulation stages, fracture proppant and initial water (without differentiation between primary and re-used water) required for fracture stimulation. The Flat Supply scenario is expected to require historically similar overall numbers of fracture stimulation stages and proppant compared to recent levels. Clearly regional and particularly local requirements would be expected to change.

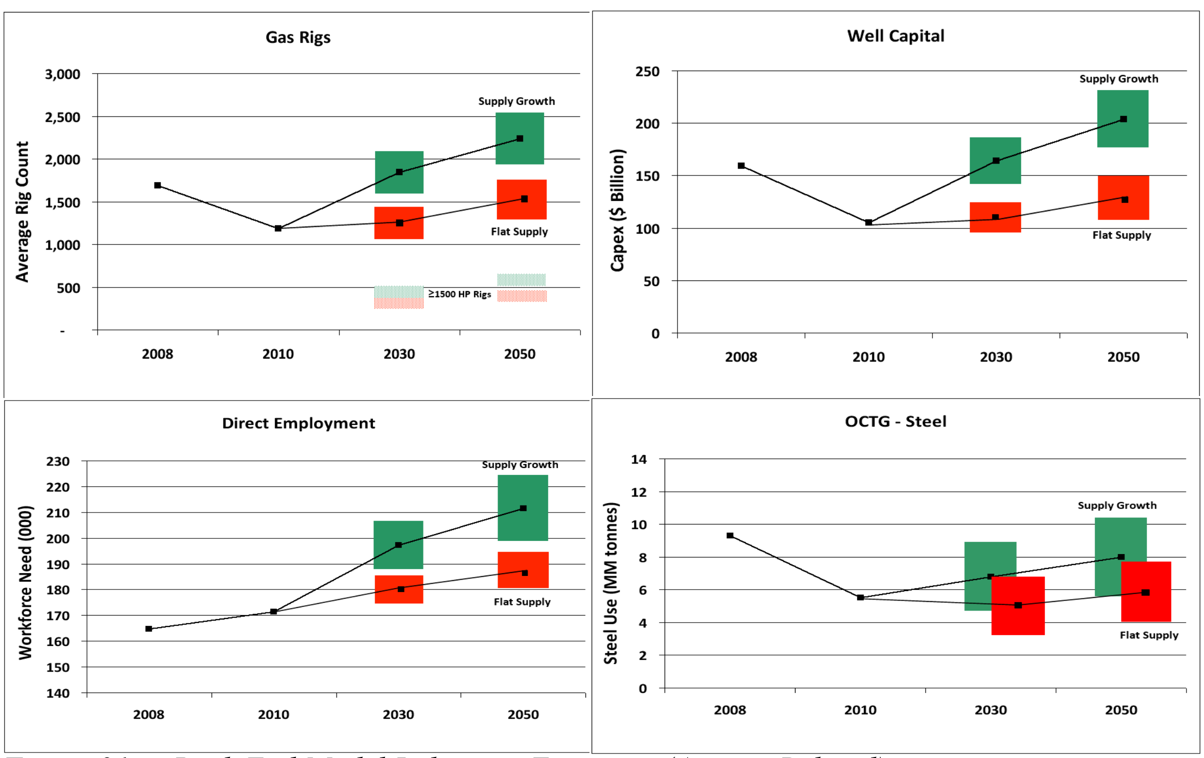


Figure 31a: Back End Model Indicative Estimates (Activity Related)

The Supply Growth scenario would require approximately 50% greater fracture stimulations overall by 2050 than recent history. Water (primary and re-use) for fracture stimulations would increase, depending upon scenario, by approximately 50 to 125% overall by 2050 over recent levels. Local increases in water use could be greater. Nonetheless, even in the Supply Growth scenario in 2050, estimated total annual water used for fracture stimulations at 2.5 Bbbl is still less than 0.2% of the U.S. daily consumption in 2000 (excluding hydroelectric utilization) of 213 B gallon per day (1.85 Tbbl)[1]. Advances by the industry to re-use stimulation water and utilize non-potable water will likely substantially reduce the actual use on primary water below this estimate.

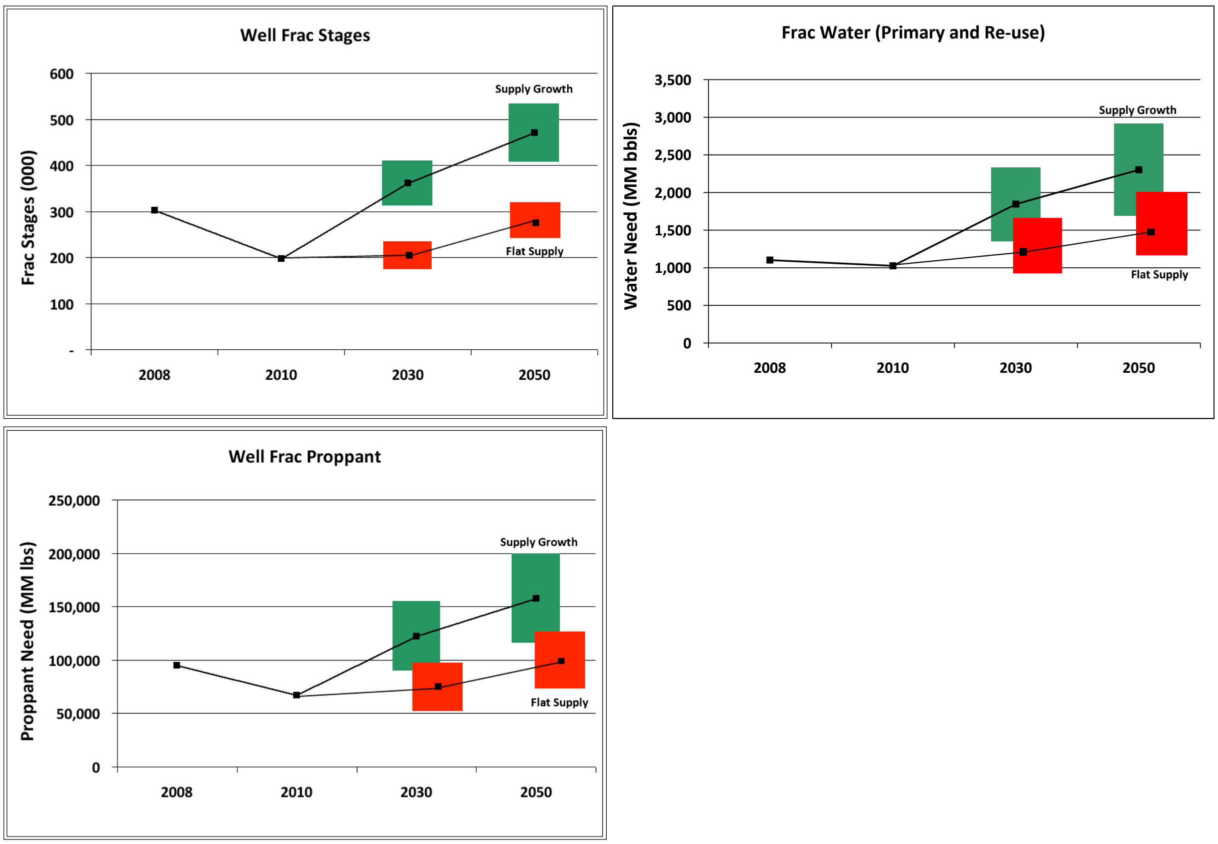


Figure 31b: Back End Model Indicative Estimates (Stimulation Related)

Conclusions

Natural gas can continue to be a significant contributor to the continent's energy supply and security. There is ample natural gas available in North America to supply current consumption levels or traditional use for decades and support significant growth into other sectors as well. New techniques, namely cost-effective multiple-stage fracture stimulation in horizontal wellbores, have recently and rapidly been enabling vast resources never before considered economic at any reasonable price. Input resource requirements (rigs, people, fracture stimulation proppant and water etc.) are significant yet manageable, and achieving these levels of supply is within industry means. Extreme restrictions on critical inputs (particularly fracture stimulation, water disposal, and land access) on a national level will cause natural gas supply rate to decline. Local effects could be more pronounced.

References

[1] Hutson, Sisan S., Barber, Nancy L., Kenny, Joan F., Linsey, Kristin S., Lumia, Deborah S., Maupin, Molly A. (2004, revised April, 2004, May, 2004 and February , 2005). *Estimated Use of Water in the United States in 2000.* U.S. Geological Survey Circular 1268, 15 figures, 14 tables.

[2] USGS/MMS/EIA. (1997).

[3] USGS/MMS/EIA. (2009).

[4] National Petroleum Council. (Dec. 1999). *Meeting the Challenges of the Nation's Growing Natural Gas Demand*

[5] National Petroleum Council. (Sept. 2003). *Balancing Natural Gas Policy- Fueling the Demands of a Growing Economy.*

[6] Raymond, Lee R. (2007). *HARDTRUTHS- Facing the Hard Truths about Energy*, National Petroleum Council

[7] Potential Gas Committee, 2001. Potential Supply of Natural Gas in the United States (Report of the Potential Gas Committee, December 31, 2000) Golden, Colorado, Colorado School of Mines, Potential Gas Agency.

[8] Potential Gas Committee, 2007. Potential Supply of Natural Gas in the United States (Report of the Potential Gas Committee, December 31, 2006) – Advanced Summary: Golden, Colorado, Colorado School of Mines, Potential Gas Agency.

[9] Potential Gas Committee, 2009, Potential Supply of Natural Gas in the United States (Report of the Potential Gas Committee, December 31, 2008) – Advanced Summary: Golden, Colorado, Colorado School of Mines, Potential Gas Agency.

[10] ICF, 2009

[11] Vidas, Harry and Hugman, Bob. (2008). *Availability, Economics, and Production Potential of North American Unconventional Natural Gas Supplies*. The INGAA Foundation, Inc.

[12] National Energy Board. (2009). *2009 Reference Case Scenario: Canadian Energy Demand and Supply to 2020.*

[13] CSUG, 2010

[14] Monez, Ernest J.; Jacoby, Henry D.; Meggs, Anthony J.M. et al; MIT Energy Initiative. (2010). "*The Future of Natural Gas, Interim Report*" ISBN 978-0-9828008-0-5. Retrieved from http://web.mit.edu/mitei/research/studies/report-natural-gas.pdf.

[15] ANGA, Q1, 2010

[16] GTI Current, 2010

[17] NPC Survey Results, (2010-11).

[18] Meggs, Anthony J.M.; 2010 emails on supply and cost information

[19] Hugman, Bob. 2010 emails on ICF International; further details of supply and cost information

[20] BP. (June 2010). BP Statistical Review of World Energy, Statistical Review of World Energy 2010.

[21] International Coiled Tubing Association (2005). *An Introduction to Coiled Tubing History, Applications and Benefits*. Retrieved from http://www.icota.com.

[22] Economides, M.J. and Nolte, K.G. (2000). *Reservoir Stimulation*, third edition. West Sussex: Wiley. pp. 367.

[23] Economides et al. (1994). *Petroleum Production Systems*. New Jersey: Prentice Hall. pp. 600.

[24] Holditch, S.A., and Tschirhart, N.R. (2005). *Optimal Stimulation Treatments in Tight Gas Sands*. SPE Paper 96104 for SPE Annual Technical Conference and Exhibition, Dallas, TX.

[25] Tiemann, Mary, Congressional Research Service, June 2, 2010)., *Safe Drinking Water Act (SDWA): Selected Regulatory and Legislative Issues*. pp. 22.

[26] Ammer, James. (2002). *Tight Gas Technologies for the Rocky Mountains.* GasTIPS. pp. 18-23.

[27] RPSEA. (Nov. 2005) *Technology Needs for Unconventional Gas Development, Final DOE Report*, Contract DE-RP26-04NT41817 TSK41817.211.01.05.

[28] Coal Bed Methane Association of Alabama. (Oct. 2010). *History of Coalbed Methane in Alabama*. Retrieved from http://www.coalbed.com.

[29] Young, G.B.C., Paul, G.W., & McElhiney, J.E. (Oct. 4-7, 1992). Advanced Resources Intl. Inc., McBane, R.A., Gas Research Inst. *A Parametric Analysis of Fruitland Coalbed Methane Reservoir Producibility*, SPE Annual Technical Conference and Exhibition. Washington, D.C.

[30] BLS (2010). *Oil and Gas Extraction: NAICS 211*. Retrieved from http://www.bls.gov/iag/tgs/iag211.htm#workforce.

[31] Shelkholesiami et al. (July. 1991). *Drilling and Production Aspects of Horizontal Wells in the Austin Chalk*. JPT. pp. 773-779.

[32] Flores, C.P. (Dec. 2008). *Technology and Economics Affecting Unconventional Reservoir Development*. Master's Thesis, Texas A&M University.

[33] Joshi, S.D. (2003). *Cost/Benefits of Horizontal Wells.* SPE paper 83621 for SPE Western Regional/AAPG Pacific Section Joint Meeting, Long Beach, CA.

[34] EIA. (Apr. 1993). *Drilling Sideways – A Review of Horizontal Well Technology and Its Domestic Application.* Contract No. DOE/EIA-TR-0565, US DOE, Washington, DC.

[35] EIA. (2010a). *Annual Energy Outlook 2010 with Projections to 2035.* US DOE, Washington, DC. and EIA. (2010b). *Natural Gas U.S. Data*. Retrieved from http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/natural_gas.html

[36] Hubbert, M. K. (Mar. 1956). *Nuclear Energy and the Fossil Fuels.* Presented at the spring meeting of the Southern District, San Antonio, TX.

[37] Laherrere, J.H. (Feb. 2000). *The Hubbert Curve: Its Strengths and Weaknesses*. Oil and Gas Journal.

[38] Rutledge, David. (2007). *Hubbert's Peak, The Coal Questions and Climate Change.*

[39] Bardi, Ugo. (Aug. 2008). *The Oil Drum: Europe*.

[40] Old, S., Holditch, S.A., SPE, Ayers, W.B., McVay, D.A., Texas A&M University. (2008). *PRISE: Petroleum Resource Investigation Summary and Evaluation*. Society of Petroleum

Engineers. SPE 117703.

Appendix A - Technology Discussion

Natural gas is a significant source of low carbon energy, supplying a significant part of the current fuel needs in North America (27% of the demand in 2009)[1] and has the potential to supply a much larger share in the future. Given that that the World's thirst for energy has not shown any sign of abatement (Figure A1) and is increasing at a rapid rate, it is apparent that all sources of energy, including natural gas, will play a vital role in the future not only for North America, but also for the World. Although it is not the purpose of this paper to address these implications, it is interesting to observe the rate of energy consumption in the world is growing at a much higher rate than that of North America. Obviously, any research and resulting technology that may be developed that would enable North American (N.A) supply will also have global implications. Thus, taking a myopic view of the role of technology with only N.A. in mind is short-sighted.

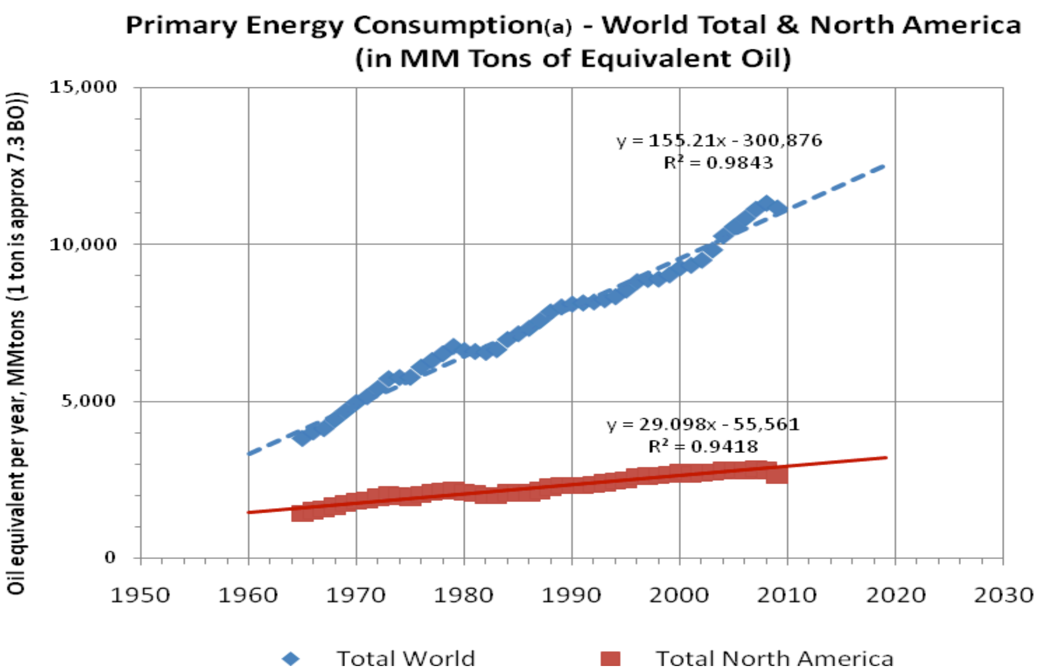


Figure A1: Primary Energy Consumption History - This plot includes equivalent amounts of oil, natural gas, coal, nuclear, and hydro-electric, but excludes energy generated from wind, solar, geothermal, wood, peat and animal wastes.
Data source: *Data from BP, 2010*

This appendix discusses how technology has enabled natural gas to become a significant, low carbon fuel for North America. Specific milestones discussed in the paper demonstrate the importance of technology and the incremental effect it has had on supply, and what future opportunities await the market for opening up additional supply. Finally, a brief discussion on a couple of key obstacles – the lack of R&D and manpower constraints will be mentioned.

Supply Fundamentals

Before discussing the technological milestones and their impact on supply, it is useful to mention a key concept associated with all naturally occurring mineral resources. For practical purposes, natural resource accumulations are distributed in a log-normal fashion. As S.A. Holditch has stated, and many others in the geosciences community have observed: "*If you are prospecting for gold, silver, iron, zinc, oil, natural gas, or any resource, you will find that the best or highest grade deposits are small in size and, once found, are easy to extract. The hard part is finding these **high quality** pure veins of gold or high-permeability gas fields. Once you find the high-grade deposit, producing the resource is rather easy and straightforward*"[2].

The following excerpt[2] graphically depicts an important relationship of how natural deposits are distributed. Figure A2 illustrates the principle of the resource triangle.

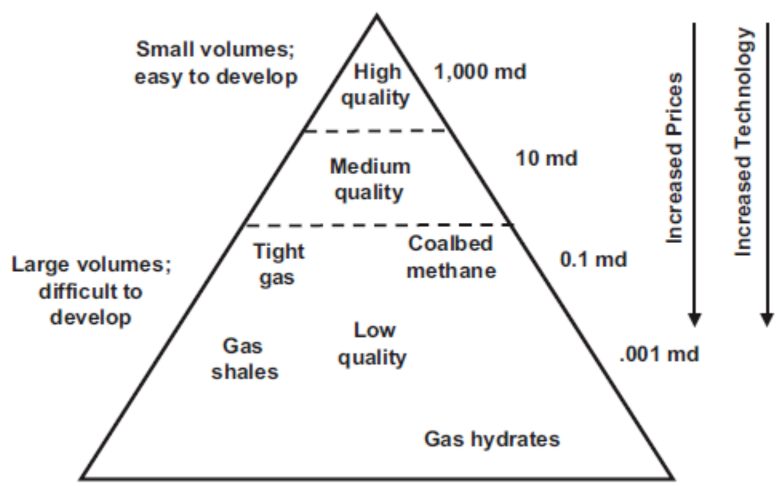


Figure A2: Resource triangle for natural gas - As you go deeper into the gas-resource triangle, the reservoirs are lower grade, which usually means the reservoir permeability **quality** is decreasing **thus, extraction costs are increasing**. These low permeability reservoirs, however, are much larger in size than the higher-quality reservoirs. The common theme is that low-quality deposits of natural gas require improved technology and adequate gas prices before they can be developed and produced economically.
Data source: *Holditch, 2006*

McKelvey described the relationship between prices and technology as they relate to reserves. He noted that "*the quantity of usable resources is not fixed, but changes with progress in science, technology, and exploration and with shifts in economic conditions*" (1972).

At the time of publication, improvements in copper mining had exemplified this behavior. It was observed that technology increased the potential supply of resources by orders of magnitude. McKelvey also noted that "*the cutoff grade for copper has been reduced progressively not just by a factor of two or three but by a factor of ten since the turn of the century (1900), and by a factor of 250 over the history of mining*" (1972). Although McKelvey glossed over the impact that technology would have on natural gas, he did acknowledge that a similar relationship would exist for natural gas as a resource.

It is likely that many of McKelvey's contemporaries would not have envisioned commercializing ultra low permeability (nano-darcy) shale rock as is done routinely today. However, as history has shown we continually discount the role of technology and its relationship to any meaningful reserve estimation, as evidenced by Figure A3.

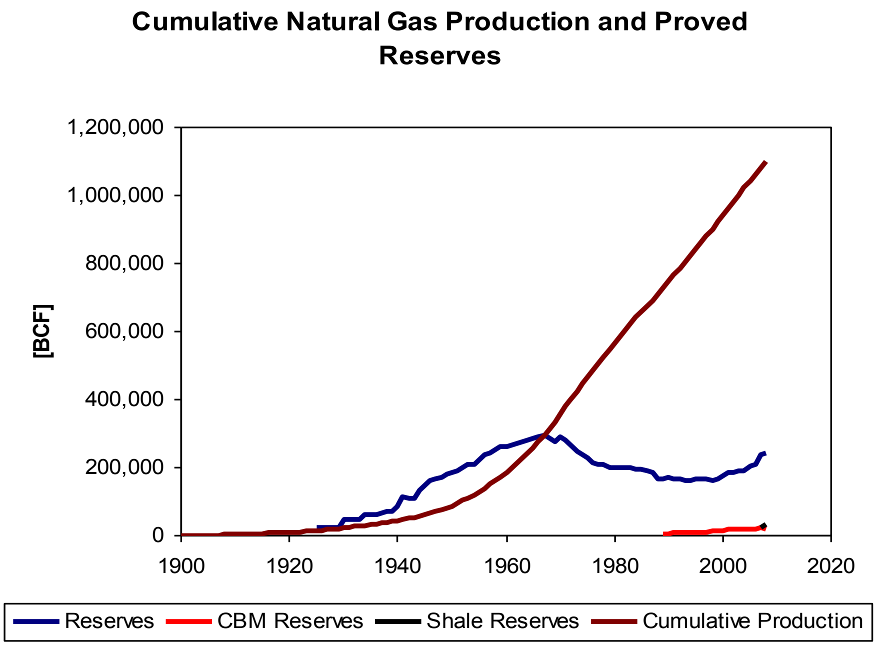


Figure A3: Natural Gas Reserves and Cumulative Production
Data source: U.S. EIA, 2010

In addition, a relationship is beginning to emerge between the total recoverable resource in-place for any given basin (a basis for potential ultimate reserves) and that which is considered conventional resources (easy to recover). Although it is a work in progress, Olds et al examined ten basins in N.A. and found that from 6% to 20% of the resource in a given basin appears to be from easy to produce reservoirs (conventional fields), as seen in Figure A4. This work supports the resource triangle, and suggests that current recovery is a small fraction of what will ultimately be extracted. Thus, taking a view of reserves (function of today's pricing) without regard for technological enablers (which can reduce supply cost) is at best, short-sighted.

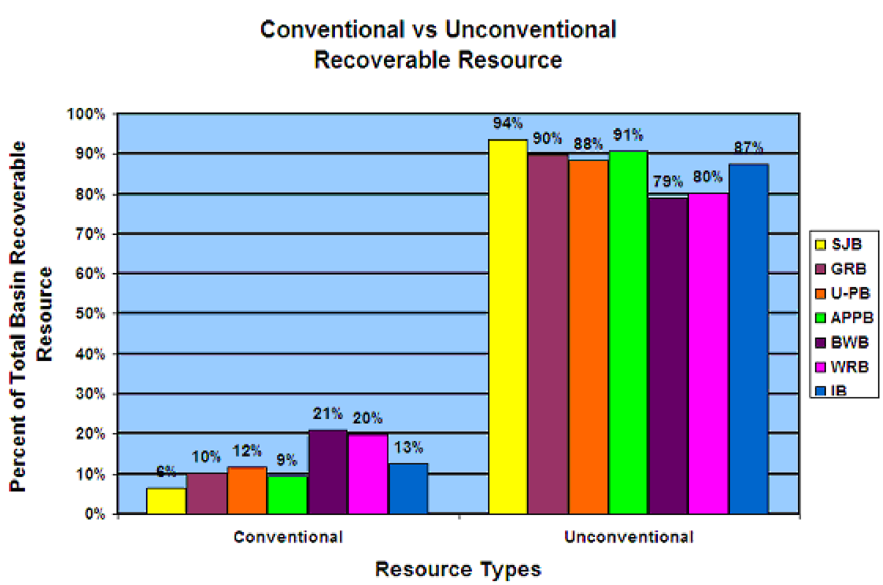


Figure A4: Conventional vs. Unconventional Recoverable Resource
SJB - San Juan Basin
GRB - Green River Basin
U-PB - Uinta-Piceance Basin
APPB - Appalachian Basin
BWB - Black Warrior Basin
WRB - Wind River Basin
IB - Illinois Basin

Source: Old, Holditch, Ayers, and McVay, 2008 (SPE 117703)

In summary, as the industry has gained experience, the limitations of exploration have been continually challenged. One of the most competitive advantages we have in North America is our collective innovative spirit, which has resulted in creative new technologies which, in-turn have allowed us to enable new energy sources.

What follows are a few examples of what the oil and natural gas industry has been able to accomplish thus far, and also the opportunities that exist for enabling environmentally, cost-effective, new resources.

Case Studies

These selected case histories demonstrate how technology has impacted natural gas and enabled additional N.A. resources.

By definition, tight formations are those classified as having 0.1 mD permeability or less and require some form of stimulation treatment in order to produce. That is, prior to the invention of hydraulic fracturing stimulation, these formations were uneconomic and, for all intents and purposes, impermeable.

Case Study – Cotton Valley

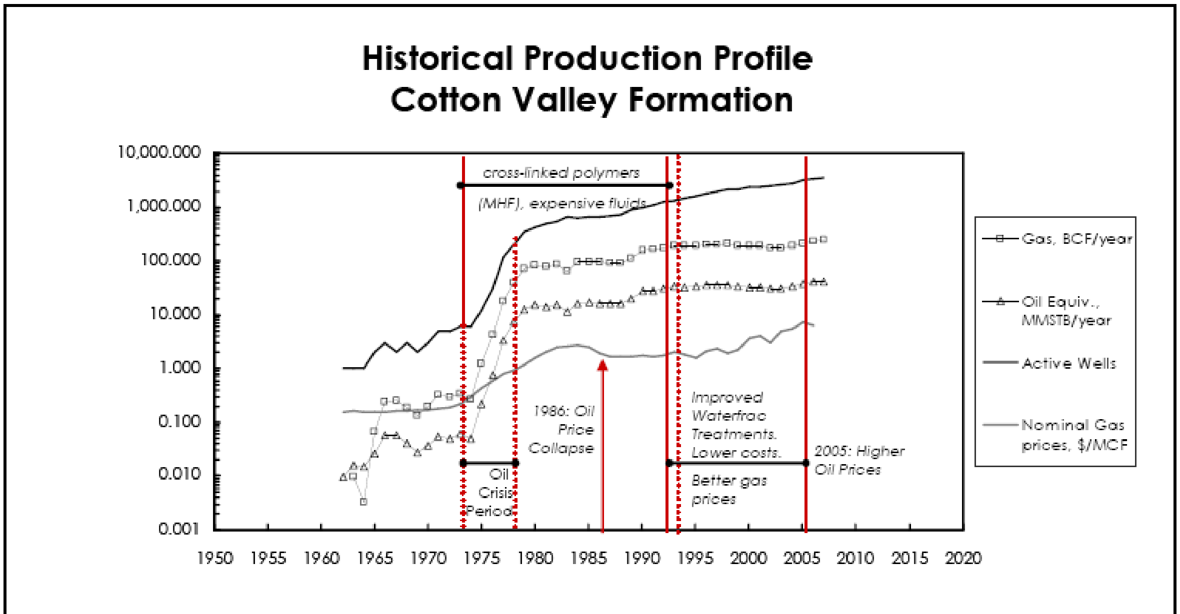
In the Cotton Valley sand formation (Figure A5), vertical well gas flow rates prior to stimulation average just 50 MCF/day, while post-stimulation flow rates typically range 500-2,500 MCF/day, at least an order of magnitude improvement[3].

Although the production from the Cotton Valley formation continues to grow, production has had local peaks in 1967, 1982, and 1992. Production associated with the peak in 1982 was directly associated with the widespread implementation of massive hydraulic fracture stimulations in vertical wells. The local peak in 1992 may be associated with improvements in fracturing modeling and resultant improvements in staged hydraulic fracturing treatments, as well as higher associated liquids prices, which led to additional experience and learning(s) that resulted in a reduction in formation damage and an increase in well productivity[4]. Furthermore, natural gas production was spurred on by the creation of the Section 29 tax credit in 1980. Despite the low price environment, natural gas production continually grew during the late 1980s and early 1990s as a direct result of this tax incentive.

In 2010, natural gas production from the Cotton Valley formation continues to increase as the technology utilized in shale gas exploration becomes standard practice in all tight gas sands. It can be readily seen (Figure 14) that natural gas exploration has historically been driven by technology with each subsequent generation of technology allowing access to new resources.

The Hubbert trend line in Figure 13 from 1976 through 1987 covers the period of development where well spacing in the Cotton Valley was halved from 640 acres down to 320 acres, resulting in greater expected production from the formation. Down-spacing to 160 acres and again to 80 acres occurred between 1988 and 2003, resulting in a bump in production and an anticipated field recovery of 26 TCFG. Further down-spacing to 40 acres per well resulted in another bump in production.

This flat decline presents difficulty in extrapolating ultimate field-wide recovery. The resulting decline in 2009 is the competition for rigs that are drilling Haynesville Shale wells, but is not representative of the true field-wide decline. For the purposes of this paper, the slope of the decline from the period 1988 through 2003 is kept constant, resulting in a likely conservative estimate of 40 TCFG ultimate recovery for the Cotton Valley formation.



1960s: Gas prices were very low and gas production from low-permeability sandstones to the south in Louisiana and to the west in northwestern Louisiana and eastern Texas flowed gas at rates less than 1,000 MCFD was considered not commercial.

1970s: Gas prices increased after the oil crisis events. Advances in stimulation techniques such as massive hydraulic fracturing (MHF) helped to develop the play. At Carthage field in eastern Texas production increased from 2.2 BCF of gas in 1976 to 70.9 BCF of gas in 1980.

1980s: Officially classified as low-permeability reservoir, the Cotton Valley sandstones qualified for additional price incentives. For example at Carthage field, production increased from 2.2 BCF of gas in 1976 to 70.9 BCF of gas in 1980.

1990s: Operators went back to water fracture stimulation treatments (waterfrac or slickwater). Similar results in gas production made operators prefer low cost waterfrac treatments over expensive cross-linked gelled treatments (Jennings, A.R., Westerman, C.W., Tadlock, D.W., Westerman, R. and Anderson, M., 2005). Full Wellhead Decontrol in 1993 resulted in better gas prices.

Figure A5: Cotton Valley Sand Production History - The Cotton Valley formation was developed in phases. These phases coincide with improvements in hydraulic fracturing followed by a period of tax incentives. The Cotton Valley group of sands demonstrates the influence tax policy can have on commercial exploitation of resources. Government tax incentives were put in place beginning in 1980 and ultimately phased out in 2002. During this time, drilling activity in tight gas sands earned a government tax credit and resulted in an effective cost-reduction for the producer. **This demonstrates that government tax incentives can increase the amount of recoverable resources**.

Source: Flores, 2008

The following Cotton Valley Well Spacing Timeline is pertinent:

- 1977: 640 acre field rule
- 1981: 320 acre field rule
- 1988: 160 acre field rule
- 1992: 80 acre field rule
- 2004: 40 acre field rule

<u>Case Study – Barnett Shale</u>

The next example is taken from the Barnett Shale. As can be seen by Figures A6-A8, the Barnett took nearly twenty years to perfect. Pioneers, such as George Mitchell of Mitchell Energy, experimented with completion techniques to find the right combination of technology to commercialize this resource. Many of the techniques learned in the Barnett by Mitchell and other operators have blossomed into a revolution, enabling production from ultra tight (nano-Darcy) shales on a scale never seen before; this revolution may be seen by the rapid increase in marketed gas production (Figure A9) from emerging shale plays such as the Fayetteville, Haynesville, Marcellus, and Eagle Ford.

Using the technique of Hubbert Linearization in order to assess total recoverable resources over time (see Figure 15), it may be seen that step-changes in development, such as the transition from vertical wells to horizontal wells coupled with better completion techniques resulted in substantial increases in recoverable resources in the Barnett Shale. Figure A7 demonstrates how single well EURs grew as completion technology matured e.g., slick-water verticals, horizontal wells, and multi-stage fracture stimulations. As can be seen, these technologies have added at least 20 TCFG to the field and very likely much more.

The Barnett field-wide decline profile demonstrates changes in technology and completions that substantially enhanced the ultimate recovery. Prior to 1999, Barnett wells were completed with fracturing treatments making use of gelled fluids. These gels lead to substantial formation damage and as a result, the ultimate economic field-wide recovery was anticipated at less than 1 TCFG.. During the period from 1999-2003, slickwater fracturing treatments became commercial. These

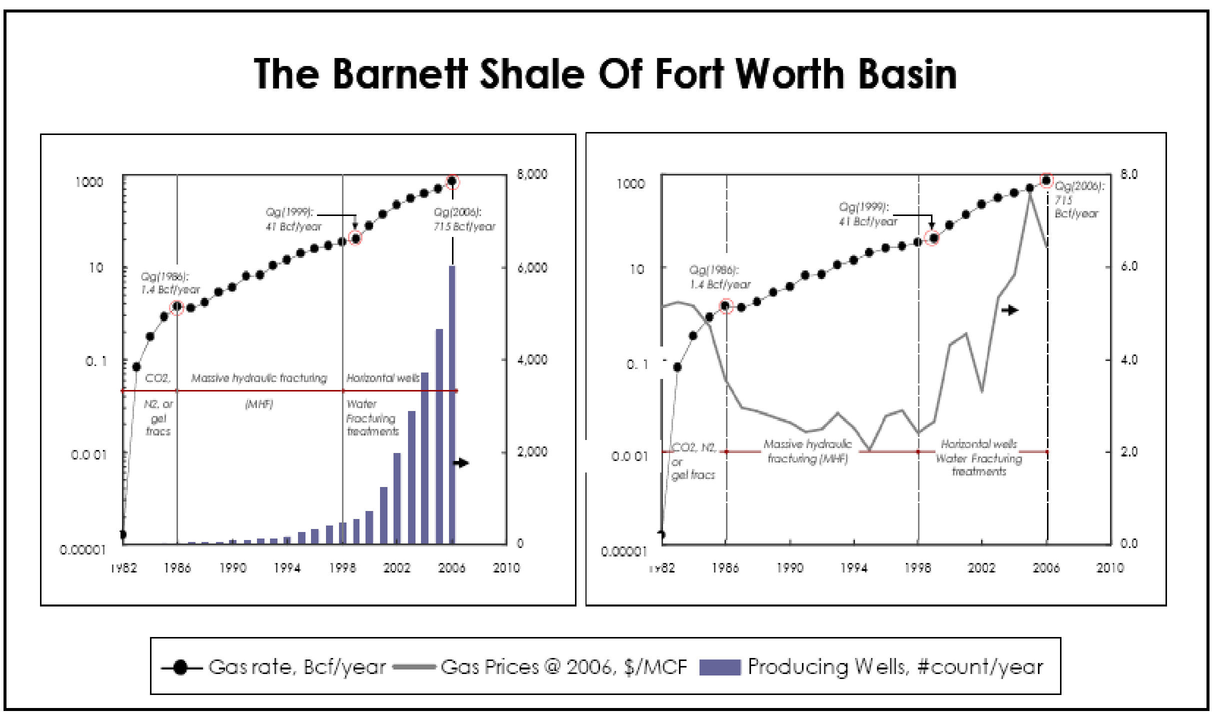


Figure A6: Barnett Shale Production History
Source: Flores, 2008

fracturing treatments resulted in substantially increased fracture lengths with increased productivity. Ultimate economic field-wide recovery would have been estimated at 2 TCFG. Finally, from 2004 to 2010, as horizontal drilling coupled with slickwater fracturing treatments became standard, the Barnett ultimate recovery may be estimated at 23 TCFG. Based on the known geographic extent of this play, and the known number of drillable locations, the ultimate Barnett recovery is very likely in excess of 50 TCFG. Just as all other fields have shown increased ultimate recovery over time, it is expected that the Barnett will continue to grow.

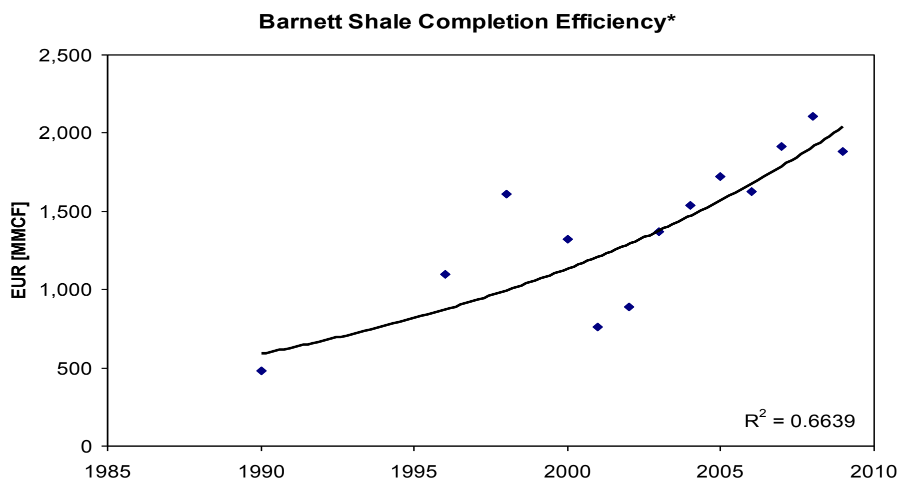


Figure A7 Barnett Shale Completion Efficiency
Data source: Devon, 2010

Figure A8 shows a learning curve for one operator in the Barnett Shale that is typical for exploration and production companies experimenting with drilling in any new play. As can be seen, many wells were drilled before the optimization of rigs, bits, and workflows was perfected. The techniques and technology that were developed in the Barnett are now applied in other shales with much faster results, significantly shortening the time from discovery until first production, as shown in Figure A9.

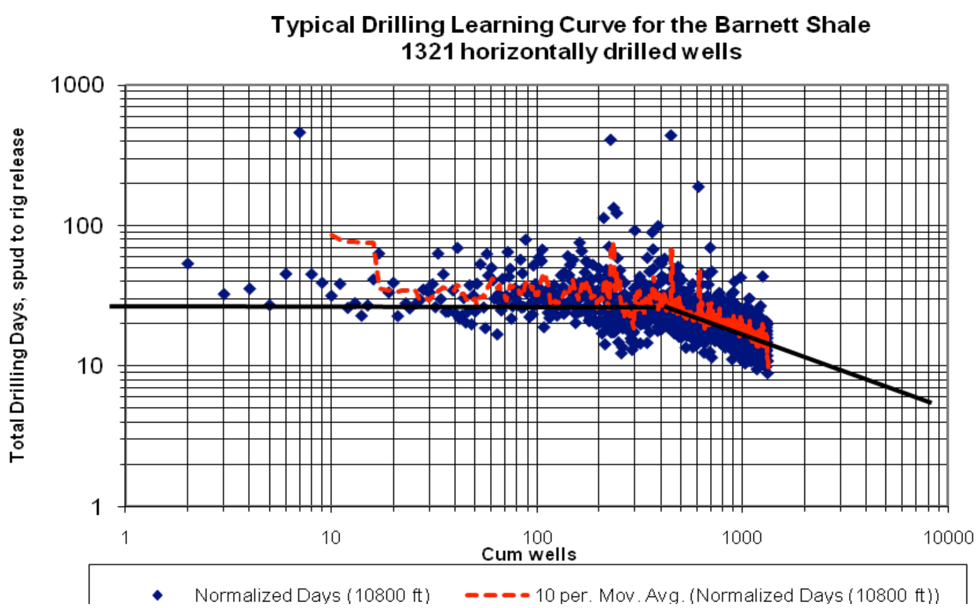


Figure A8: Barnett Shale Drilling Learning Curve
Data source: CERA IHS, 2010

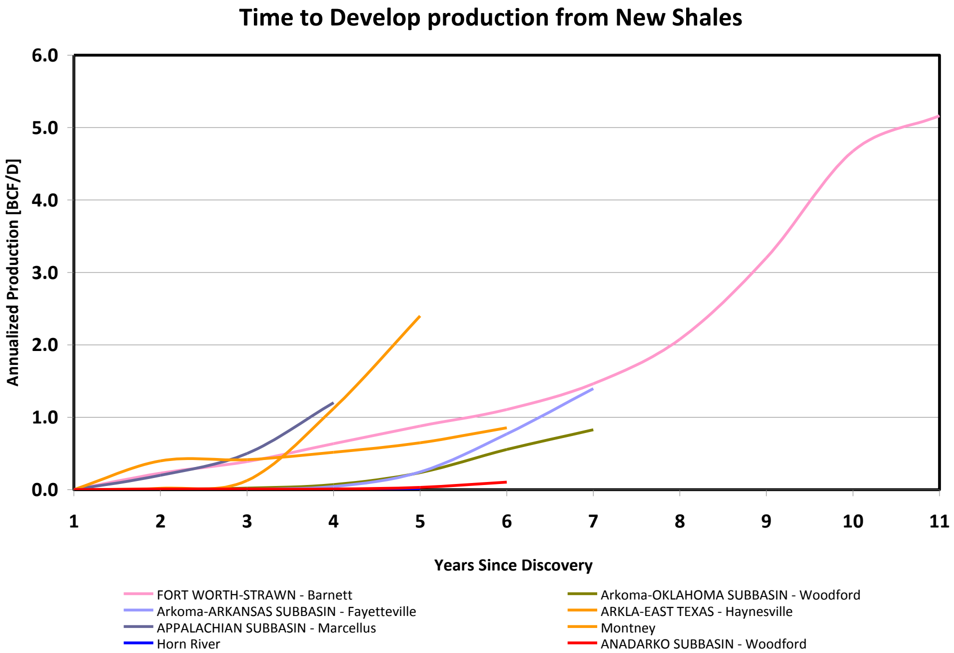


Figure A9: Time to Develop Production from New Shale Plays
Data source: CERA IHS

Case Study - Mesaverde

Figure A10 shows the progression of the Mesaverde, another tight gas sand located in the Rocky Mountains. It may be seen that despite the formation having a local peak in 1980, production peaks again after 2000 because of access to superior technology.

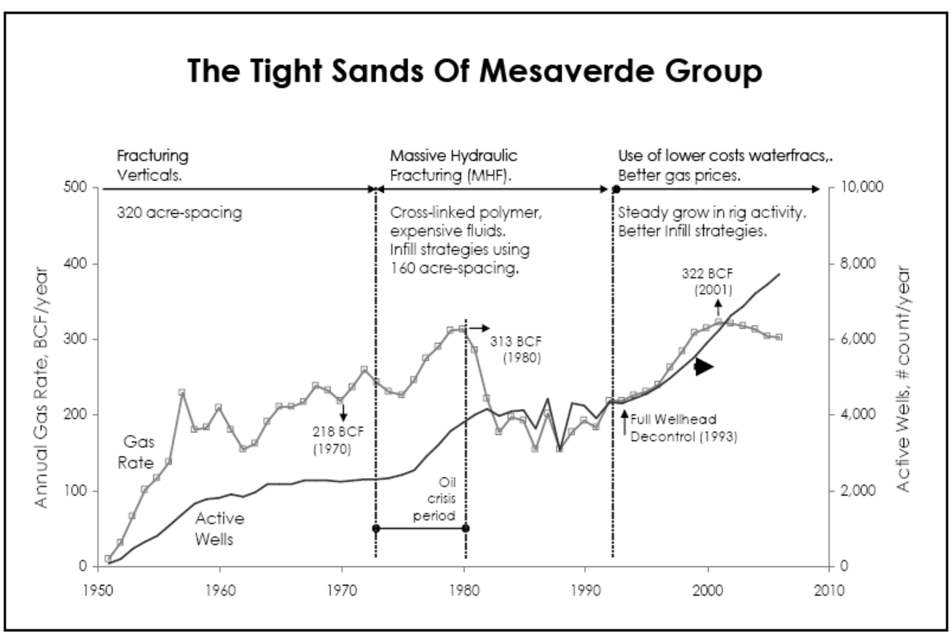


Figure A10: Mesaverde Group Tight Gas Sands Production History

Data source: Flores, 2008

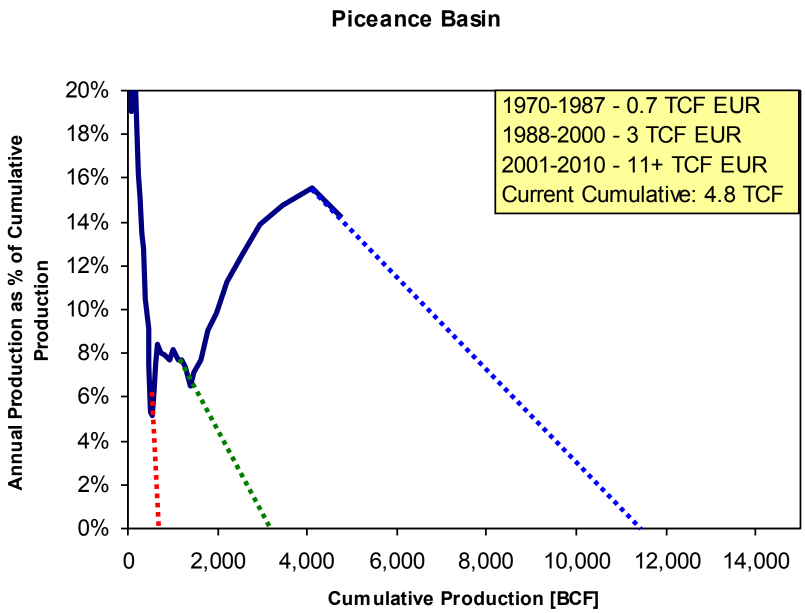


Figure A11 shows the approximate incremental reserves from just one of the fields of the Mesaverde, the Piceance. As noted, a combination of prices and fracture stimulation technology (multi-stage water fracs), enabled this resource to contribute at least 11 TCFG to the N.A. supply base despite the fact that earlier estimates would have placed total recoverable resources at less than one TCFG.

Figure A11: Piceance Basin Hubbert Linearization
Data source: IHS CERA

Case Study - Austin Chalk Formation

The Austin Chalk is an excellent example of a reservoir that was exploited in phases that coincide with advances in technology. The work done by C. Flores shows how the Austin Chalk field development may be broken up into distinct phases[4].

Beginning in 1933, thirty wells were drilled; however, the field was largely uneconomic until the second phase of exploration in the 1950s. As oil price increased, 99 wells were drilled between 1948 and 1956. As oil prices again increased in the 1970s additional vertical wells were drilled. Reservoir characterization improvements allowed for the superior understanding and mapping of regional faulting. These wells were able to be placed in the best locations.

As hydraulic fracturing became standard practice by 1980 and as oil prices climbed over $30/bbl, another phase of development occurred. These wells were completed vertically and with hydraulic fractures.

Due to lower oil prices in the mid to late 1980s, newer technologies were necessitated to continue to develop reserves. Horizontal drilling was attempted and developed during this time period and eventually became standard practice. By 1988 horizontal drilling had progressed to a mature enough level that it was able to be commercially deployed. By 1989, continued price declines resulted in the dwindling number of wells drilled in the Austin Chalk. However, improvements in rotary drilling continued to occur – so much so that by 1991, the number of wells surged to more than 1,000 as horizontal completion effectiveness improved and costs decreased. Horizontal drilling and hydraulic stimulation again made the play economic.

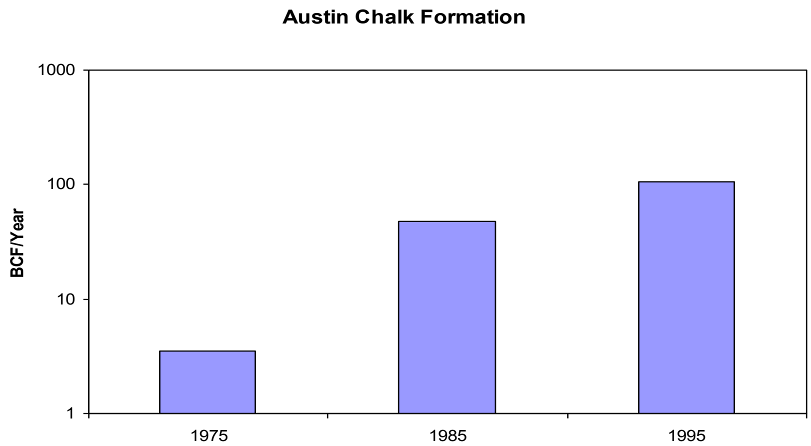
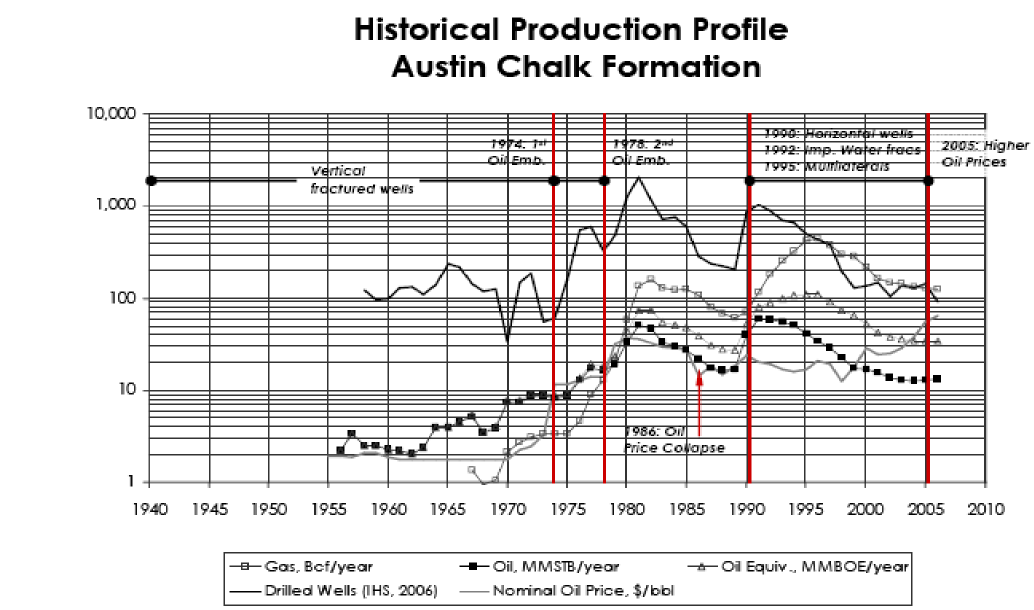


Figure A12– Austin Chalk Natural Gas Production
Source: Based on Flores, 2008

Although the Austin Chalk was predominantly exploited as an oil reservoir, natural gas production associated with each phase of exploration may be used as a metric for the overall state of the play. Figure A12 illustrates how the introduction of step-changes in technology led to orders of magnitude improvements in production as predicted by the resource pyramid.



1948-1956: Second period of development. 99 wells were drilled. Oil prices from $1.50 to $2.44 per barrel (nominal) (Rose, Austin and Pike, 1992).

1974: Third period of development. More than 500 wells drilled at the end of 1976. Oil prices moved toward $10.0 per barrel (nominal) (Rose, Austin and Pike, 1992).

1980s: Four period of development. Oil prices were over $30.0 per barrel (nominal).

Late 1908s: Fifth period of development. First horizontal wells drilled in Pearsall field (Kyte and Meehan, 1996). In 1988, Horizontal drilling activity began in the Giddings field. Production in 1990 increased in Giddings field to 26.4 MBO/D, extreme active drilling increased production in June 1993 to 81 MBO/D and 365 MMCF/D (Meehan, 1995). In 1986, water fracturing began in Giddings.

1992: 427 horizontal wells were producing in Giddings (Meehan, 1995).

1993: As of September 1993; there were 2,834 producing wells in Giddings field. Horizontal wells constitute 29% of this total with 816 wells contributing with more than 70% of field production (Meehan, 1995).

Figure A13 – Austin Chalk Production History
Data source: Flores, 2008

The Austin Chalk formation reached peak production twice, once in 1981, and again in 1995. In 1981, the formation reached its initial peak of 74 MM BOE/y as a result of the hydraulic fracturing stimulation treatments that were induced in vertical wells. Later, the formation reached a higher peak of 110 MM BOE/y, this time as a result of horizontal drilling coupled with improved fracture stimulation treatments. The influence of both technology as well as commodity prices are shown on Figure A13[4].

The Austin Chalk formation is representative of many different hydrocarbon bearing formations. That is, depending on price pressures and technological improvements, the hydrocarbon resources present may be upgraded to the reserves category when conditions are appropriate.

Present Technology

There are a number of areas of ongoing research associated with natural gas production that will result in improved recoveries and operational efficiencies in the near-term. Some of these projects are discussed below.

Fracturing Technology

Although hydraulic fracturing technology has matured since its inception, there are many challenges to optimizing fracture stimulation. Listed below are some of the challenges that researchers are actively improving[5].

- Proppant settling into the bottom of the fracture and not being evenly distributed
- Fracture growth outside of the productive interval
- Proppant crushing
- Proppant embedding into the formation
- Reservoir formation damage caused by fracture fluids
- Water reuse, disposal, and optimization

Encompassing all of the above, and arguably the most important arena for fracture research is in increasing the effective half-length induced by fracture stimulation treatment. By making use of cleaner fluids there is less damage posed to the reservoir following flowback. One other area of concern is in immovable water being introduced into the formation following water fracture stimulation treatments. By making use of a CO_2 miscible fluid or surfactants, relative permeability issues may be reduced. In the case of reduced permeability, methane bypasses the water and leaves it stranded in the fractures, thereby decreasing the effective half-lengths of the induced fracture[6].

Surface Disturbance Minimization

Over time the optimal well spacing has continually decreased as a result of improvements in recovery factors caused by superior technology[7]. The improvements in land management can best be illustrated by Figure A14, which shows the progression to date of the shrinking surface footprint.

Historically, before advancements in directional drilling, a single well was drilled from one surface location. Each of these locations would often require construction of a road, a drilling fluid pit and some surface production equipment. Today, with directional drilling techniques perfected with advanced electronics, new workflows, and modern drilling rigs, surface disturbances have been continuously decreasing. Location footprints (surface disturbances) that once were ten to twenty acres in size have been reduced to a fraction of the original size. Furthermore, these smaller surface locations also provide access to much more sub-surface area than was initially envisioned (Figure A14). The use of high angle drilling and horizontal wells has also allowed more of the production equipment to be placed out of sight as the former need for multiple vertical well locations may be replaced by the drilling of one lateral well instead.

These improvements in drilling technology have resulted in fewer surface locations having to be constructed, directly resulting in less total environmental disturbance.

There are a number of emerging technologies that specifically aim at reducing the surface disturbances associated with natural gas exploration. Three of these are discussed below.

Super-Pad Drilling

The concept behind super-pad drilling is to consolidate multiple horizontal wells onto one prepared surface location. Rather than preparing multiple drilling locations, each with its own frac pond and surface equipment, these operations may be combined. This represents an example of a win-win for both industry and land-owners. Land-owners have much less of their land modified to accommodate

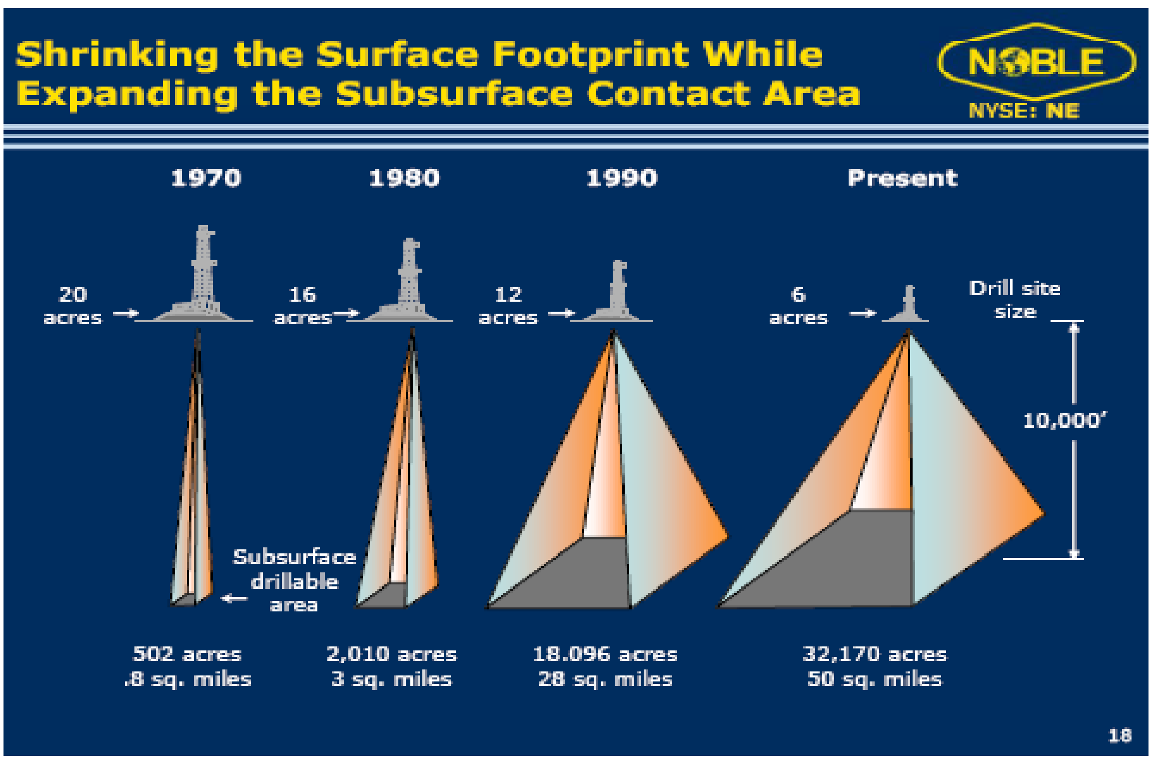


Figure A14: Reducing Surface Impact
Data source: Noble Drilling

drilling operations while there are simultaneous operational cost savings by consolidating equipment and optimizing the scheduling of fracture stimulations and wireline perforation activities. Figure A15 details one possible configuration of horizontal wells that would allow six laterals to be drilled from one surface location. Through the persistent pursuit of efficiencies in well drilling and field operations, the unconventional gas industry has been able to economically develop unconventional resources[8] and will continue to do so as new technologies emerge.

Slim-Hole Completions

Drilling cost reductions allow for previously uneconomic reservoirs to be produced economically. One current area of research is in the use of slim-hole and micro-hole technology[6]. By decreasing the required drill-bit size, it is possible to penetrate the formation in less time and further reduce costs by using less materials such as drilling mud, cement, and metal for tubulars and casing, which, represents a cost-savings.

Fit-for-Purpose Coiled Tubing Drilling

Another technology on the cusp of commerciality is the use of coiled tubing for drilling. One company, Xtreme Drilling, has developed a complete coiled tubing drilling package that can significantly reduce the rig up and rig down time (what about less pipe connections and thereby less tripping), thereby resulting in cost savings of up to 35 percent in certain instances[9].

Multilateral Wells

Current technology allows for drilling multiple horizontal laterals out of a single vertical wellbore. By making use of a single vertical penetration in order to place multiple horizontal laterals, surface disturbance and costs may be minimized.

Multilaterals hold great promise for effectively increasing recovery in “depleted” fields[10]. Tight gas sands have been associated with most conventional hydrocarbon bearing reservoirs[11]. These undeveloped tight gas sands represent production that has been historically ignored because it had been uneconomic. Evaluation of unconventional resources not only involves the discovery of whole new fields but also the rediscovery of presently uneconomic fields[12].

At present, existing fracturing technology does not allow for the effective stimulation of multiple fractures within each of the multilaterals but would represent an improvement in efficiencies from super-pad drilling. Soon, multilaterals with multiple fracture stimulation treatments will become standard[13].

As was discussed in regard to the resource pyramid, hydrocarbons are deposited in basin-wide events. Thus, it should not be a surprise that where there once existed high-quality, and easy to exploit deposits, there are additional lower quality hydrocarbons present as well. Recovery of additional resources is a function of technology and prices. As can be seen in Figure A2, as availability of high-quality hydrocarbon decreases, harder to access and unconventional hydrocarbons become exploited.

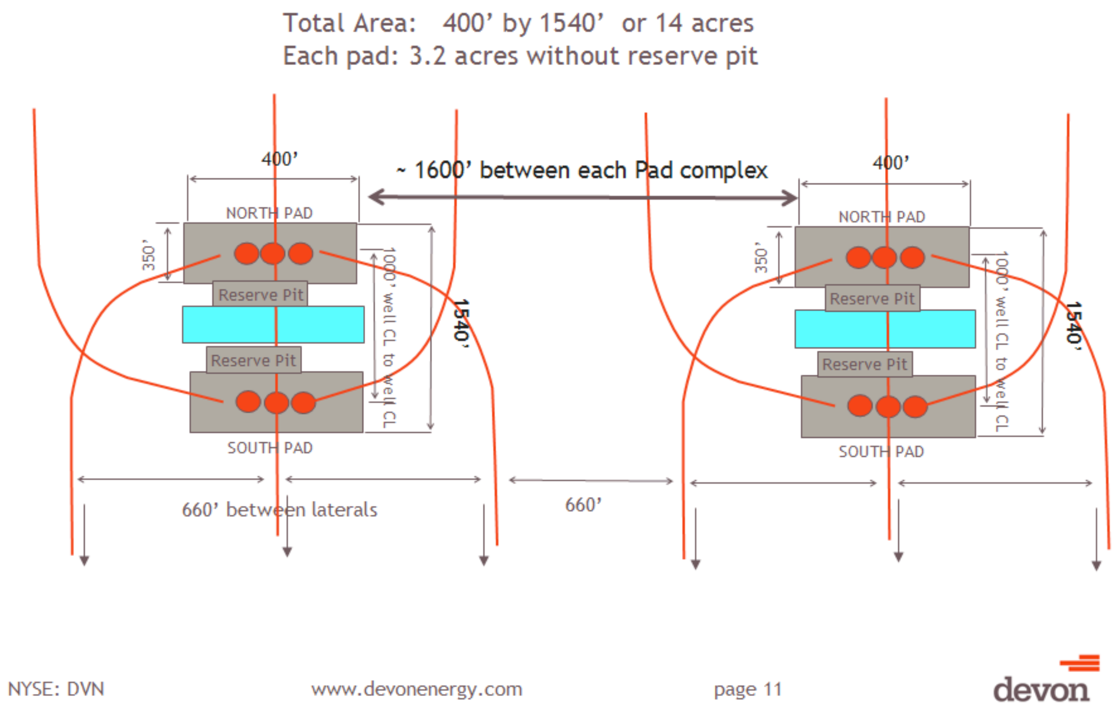


Figure A15: Super-Pad Drilling Schematic
Data source: Devon Energy

Future Technology

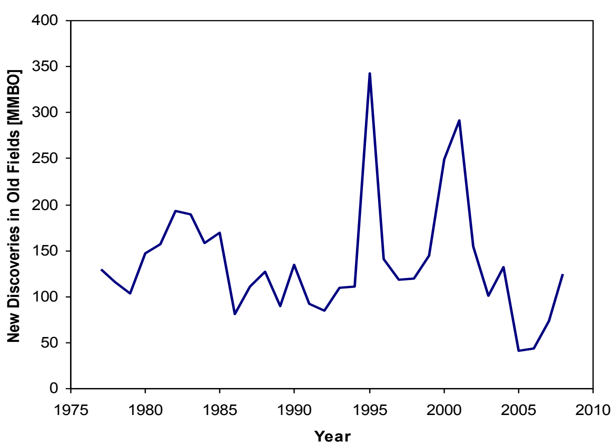


Figure A16: New Discoveries in Old Fields by Year
Data source: U.S. EIA

Of the natural gas production in the U.S. in 2008, it has been estimated that approximately 40% of the wells required hydraulic fracturing stimulation to produce at economic rates[14]. By the year 2030, it is estimated that 75% of wells will require stimulation[15]. Without both hydraulic fracturing and horizontal drilling, the base forecasts could not be met and any reservoir termed "unconventional" would be uneconomic. The EIA has modeled natural gas price increases for a scenario with no additional tight gas production. In this scenario, natural gas production from onshore North America had fallen by 39%. From these estimates it can be seen that the future of natural gas supply in North America will rely upon fracturing tight-gas formations.

It has been observed that it generally takes approximately 16 years for a new technology to mature from concept to a commercial project[16]. This problem has been exacerbated with an ever declining investment in research related funds as the majors have focused their efforts in the hunt for oil in international plays. Much of, if not all, the current R&D for natural gas resource plays is undertaken by service companies, academia, large independents, and an underfunded DOE/RPSEA/NETL contingent.

The following is a brief review of some of the projects that RPSEA/NETL and others are working on that offer promise.

RPSEA (Research Partnership to Secure Energy for America)

The RPSEA organization partners with the DOE in order to appropriate funds for research. RPSEA projects fall under three broad categories: Ultra-Deepwater, Unconventional Resources, and the Small Producer Program. Within these categories, approved research projects aim to improve safety, minimize environmental impacts, increase efficiency, and reduce the cost of domestic hydrocarbon resources[17]. The projects selected are chosen because of their ability to show incremental success over the life of the project. Early results can be immediately applied in the oil and gas industry and existing projects are able to run their course until incremental improvements are no longer present.

One of the stated goals of RPSEA is to convert technical resource into increased economic gas production. This will ultimately lead directly to lower gas prices and energy security. However, there are challenges in fund appropriations. A project to fund a pipeline to carry waste CO_2 to oil fields in North Louisiana and North Texas where carbon dioxide could be used for enhanced oil recovery was passed over by government authorities. The pipeline project was considered as being outside the scope of the purpose of RPSEA, despite the fact that it would lead to a pilot program to reduce emissions while simultaneously enhancing domestic fuel supplies. Challenges such as this exemplify the need for a concerted technology policy.

RPSEA categorizes the unconventional program projects according to the following designations:

- Resource Assessment
- Geosciences
- Basin Analysis and Resource Exploitation
- Drilling
- Stimulation and Completion
- Water Management
- Reservoir Description and Management
- Reservoir Engineering
- Environmental

Because of the diversity of project areas, the number of projects selected by RPSEA to receive funding is constrained by its budget. If the budget of RPSEA were to be increased, there are a number of on-the-shelf projects that could immediately be deployed and could quickly manifest research dividends[18].

In order to give a flavor for the type of work RPSEA is involved in, below is a non-exhaustive list of the "Unconventional Resources" projects selected for funding for 2010.

- Marcellus Gas Shale Project

- Prediction of Fault Reactivation in Hydraulic Fracturing of Horizontal Wells in Shale Gas Reservoirs
- Characterizing Stimulation Domains for Improved Well Completions in Gas Shales
- Simulation of Shale Gas Reservoirs Incorporating Appropriate Pore Geometry and the Correct Physics of Capillarity and Fluid Transport
- Improved Drilling and Fracturing Fluids for Shale Gas Reservoirs
- Using Single-Molecule Imaging System Combined with Nano-Fluidic Chips to Understand Fluid Flow in Tight and Shale Gas Formation

Nano-Technology

The emerging research in nano-technology holds great promise for energy related successes in the near future. Nano-technology holds promise for natural gas production in a number of ways.

Proppants

One of the areas of focus with respect to nano-materials is in creating ultra-light, high-strength proppant materials with improved sphericity. Such a proppant would be able to be transported farther into the fracture for a given pump rate. That means that an equivalent fracture treatment could potentially be pumped with less volume and with less rate, thereby decreasing costs and simultaneously increasing the effective fracture half-length. New proppant materials may lead to improved recovery factors and possibly less capital investment in wells if fewer wells are needed to produce the same volume of resources by making use of more effective fracture stimulations.

Downhole Sensors

Another area of focus that nano-technology may impact is downhole sensing. Nano-particles may be introduced into a fracture stimulation treatment and monitored with downhole sensors in order to determine their rate of dispersion. By customizing the particles introduced into the formation, the particles may be preferentially placed into a particular phase. For instance, by placing the nano-particles into the water phase or into the hydrocarbon phase, the fracture permeability or the formation permeability may be measured respectively. While it is currently possible to measure permeability, the measurement is imprecise and orders of magnitude measurements are possible, at best. However, nano-particles and sensors could potentially increase measured resolution by two or even three orders of magnitude[19]. Nano-particles could even find application with sour gas cleanup. Particles could potentially be introduced into a water flood and preferentially bind to H_2S in-situ, creating immobile sulfur and eliminating the need for expensive surface treatment equipment, while simultaneously increasing the safety of gas production operations.

Water Purification

A major focus for the unconventional resource industry is water disposal or clean-up and reuse following flowback of fracturing treatments. From an energy standpoint, membrane separations are often the most efficient. However, in order to purify water to the levels required, these membranes must have very small pore sizes and correspondingly very small flow rates. In order to treat large volumes of water these membranes must be scaled larger and may become prohibitively expensive. However, ceramic membrane separation, which has larger pores, may be treated with a special nano-material that is extremely hydrophilic. In this way, the water is literally sucked through the membrane because of the coating, while leaving the impurities behind. Such technologies will soon provide on-site, cost-effective water purification, leading to more effective use of water resources[19].

Logging Tools

Logging tools for coal bed methane as well as shale formations are in development. These new tools will allow for the identification of total organic content (TOC), an important indicator of shale productivity, as well as adsorbed gas content[20]. Logging tools will also help differentiate between gas and water within coal bed methane and shale reservoirs. One other important area of focus for logging research is in the application of re-logging old wells. In this case, tools are necessary that have deep resolution so as to reveal bypassed zones containing hydrocarbon that is now sealed off behind cement and one or more strings of casing. Another area of research focuses specifically on logging applications for hydrate formations.

Multi-Stage Multi-Laterals

Current completion techniques for horizontal shale wells involve inducing hydraulic fractures along the length of each lateral. Drilling has advanced to the point that multiple laterals may be connected with one vertical riser; however, operational challenges still exist that prevent the same multi-stage fracturing procedure in each of these laterals. Just as fracturing technology has advanced and allowed horizontal wells to be fractured and stimulated multiple times, research will soon allow multi-laterals to have multi-stage fracs as well. Ultimately, as this goal comes to fruition, large natural gas resource deposits could be more economically exploited while simultaneously reducing the land disturbance caused by drilling operations.

Laser Cutting Technology

Current drilling technology relies on the use of a rotating drill bit that is powered by surface equipment circulating a drilling fluid. Research is being directed toward novel rock cutting technologies[21]. Lasers are being researched for applications such as preparing core samples, perforating, as well as drilling. One primary advantage of laser rock cutting is the operational cost savings. A laser bit would have a longer life cycle, resulting in fewer days of rig-time and therefore cost savings. Mechanical systems, that is, those involving moving parts, are more prone to failure so perforating and coring systems implementing lasers would be more robust. Ultimately, laser cutting technology would allow superior reservoir completions for less cost.

Real-Time Communications

By analyzing real-time data, drilling, completing, and stimulating wells can be improved while each activity is still in progress. Areas of research involve rugged high-strength sensors capable of withstanding the extremely high pressures and temperatures experienced down-hole. As one improvement example, by having access to this data while in the field, fracture treatments could be modified depending on the observed response to surface flowrates and bottomhole pressures[22].

Fracture Mapping

Seismic processing may soon allow for distinguishing fractured zones from nearby un-fractured zones as well as predicting the orientation of these fractures[23]. Natural fractures are associated with increased productivity in many unconventional resource plays. Development of technology to map these fracture "sweet spots" is an area of intense focus for R&D. Research is being directed toward evaluation of localized fracturing on a per-well basis and on a per-reservoir basis[6].

Hydrates

Commercial production of methane hydrates is not expected over the next twenty years. The massive potential of the hydrate resource will continue to make it the focus of ongoing research. Core-samples of hydrate bearing formations and seismic tools with resolution tailored toward hydrate formations are on-going areas of long-term research[24]. Improvements in well-logging tools will allow for resolution of gas hydrate phase relationships as well as thermal conductivity[25], thereby paving the way for resource assessment and eventual exploitation. In-situ production is an example of a technology being researched that could have future applications. Thermal or chemical dissociation of gas[26] would allow for natural gas to be produced from hydrate formations similarly to how steam assisted gravity drainage (SAGD) has allowed for the commercial exploitation of bitumen deposits in Canada. Although the promise of hydrate producing technology is far from reality, given the enormous potential prize to be had, any incremental success could pay off for many future generations.

Obstacles to the Advancement of Technology

As has been shown, there is little question that the creation and application of technology is vital to energy supply not only in North America, but also for the World. There should also be little question that after examination of the supply study that there are sufficient resources to meet the energy needs well into this century and very possibly beyond. That said, there are however, potential obstacles to technology that must be addressed to enable future resource supply. Obstacles to resource supply include research and development funding, and a lack of engineering and science professionals in the workforce.

Research and Development (after NPC, 2008)

Since the beginning of the modern age of oil and natural gas, technology has played a fundamental role in supporting the efficient production of hydrocarbons. Oil and natural gas technologies are often destined for hostile, hard-to-reach environments such as deep offshore waters or in the high temperatures and pressures encountered at the bottoms of wells. Full-scale tests must be completed before a technology can be proven and accepted by the market. As a result, commercializing technology in oil and natural gas markets is both costly and time-intensive; as was mentioned, some studies indicate an average of 16 years from concept to commercialization. The Technology Development Topic Report examines both lessons from history and current trends in oil and natural gas technology development and deployment to make predictions for the coming years.

The sources of technology destined for the oil and natural gas markets have changed over time. Starting in the early 1980s, major oil and natural gas companies began to decrease their R&D spending, driven in large part by a decision to "buy versus build" new technology. Historically, independent oil and natural gas companies have spent little on R&D. Service companies have stepped in to partially fill this gap by increasing their R&D spending. There is little doubt that in the coming years, new technologies will be invented and applied around the globe to maximize production from oil and natural gas reservoirs. As oil prices have increased over the past few years, so have R&D budgets, with the exception of U.S. government spending.

The global industry will spend more than $6 billion on R&D, much of it in areas outside the United States. The major oil and natural gas companies follow the best investment opportunities, including R&D, which are increasingly found overseas. This pursuit leaves U.S. onshore production largely in the hands of independent oil and natural gas companies. In a global marketplace, the service companies continue to respond to the needs of their worldwide customer base. Being one of the most mature oil and natural gas producing countries, the United States has specific technology requirements when compared with much of the rest of the world. More than 390,000 U.S. oil wells produce less than 10 barrels a day (of these, the average national production is 2.2 barrels per day)[27]. Marginal gas wells are defined as those producing less than 60 MCF/day of natural gas. About 260,000 marginal natural gas wells are operated in the United States with an average of just over 15 MCF/day per well. Although the individual flow rates per well are very modest, collectively they represent a substantial portion of domestic production. That is, in 2003, 29% of the oil and 11% of natural gas produced onshore in the United States comes from these marginal wells.

Research is the key to the survival of these marginal wells. Unfortunately, the small, independent producers who operate these wells rarely have the ability to conduct research, though research might keep them producing for many more years and ultimately improve their bottom lines. As a result, unless the technology requirement of the U.S. oil and natural gas business aligns with the needs of the rest of the world, there is a danger that U.S. interests may not be addressed adequately. Figure A17 shows U.S. government R&D funding has declined in recent years.

Research undertaken by national laboratories and universities usually leads to fundamental understanding and basic technologies. These technologies are typically applied by other entities such as oil and natural gas, service, or start-up companies. However, the U.S. government proposal for fiscal year 2007 to terminate the oil and natural gas program within the Department of Energy leaves only $50 million in royalty receipts that were set aside in the Energy Policy Act of 2005. The bulk of the funds ($35 million) are set aside for ultra-deepwater and unconventional-hydrocarbon research programs as part of the Research Partnership for a Secure Energy America (RPSEA). The remainder ($15 million) is set aside for an internal National Energy Technology Laboratory program and administrative funds.

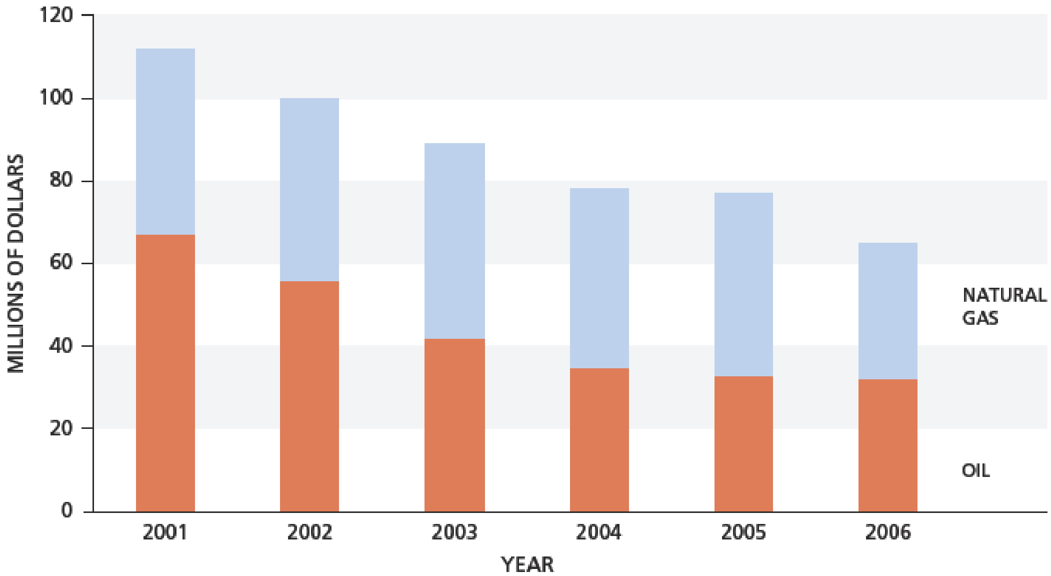


Figure A17: Oil and Natural Gas R&D Funds Provided by the U.S. Government
Data source: NPC, 2008

Many successful research programs have featured accountability as a key attribute. Examples show that it is possible to leverage funding, such as the Ansari X prize for privately funded manned space flight, the Orteig prize to Lindbergh for his solo flight across the Atlantic, and the Board of Longitude prize for the 18th century invention of the precision marine chronograph that enabled navigators to determine longitude at sea.

Vello A. Kuuskraa and James Ammer gave an excellent example in an article they wrote a few years ago regarding the importance of R&D and the role the DOE played in tight gas sand resource development. The following is an excerpt from that article describing the role the DOE/NETL had in aiding commercial exploitation of the Mesaverde tight gas sand resource[28]:

> *The DOE/NETL sponsored three major research and development (R&D) activities in the Piceance Basin during the 1980s that helped establish a foundation for Intensive Research Development (IRD) technology. First was a series of resource assessments for the Piceance, Greater Green River and Wind River basins completed during a 15-year period (1980 to 1995). These assessments drew attention to large, high-concentration, Cretaceous-age unconventional gas accumulations and established the need for their thorough characterization.*
>
> *Second was the Multiwell Experiment (MWX) in the southern Piceance Basin. This R&D project produced a comprehensive, well-documented description of the geologic controls on gas productivity in the Williams Fork and Iles Formations of the Mesaverde Group.*
>
> *The third effort was an initial field test and demonstration of geomechanical-based natural fracture prediction technology in the Rulison field of the southern Piceance Basin. This test drew on prior work at the MWX site to develop technology for locating the higher productivity areas within tight gas sand accumulations.*

As was noted by authors Kuusskraa and Ammer[28]…

> *The MWX project is a good example of the DOE-sponsored research providing the basic data and analytical foundation for interpretations the industry would not otherwise make the investment to acquire (2004).*

The work carried out by government scientists working alongside private interests opened a resource that is, unquestionably, now very important to the North American gas supply.

Workforce (NPC, 2008)

The current and projected demographics of trained personnel in the broad U.S. energy industry indicate a shortage that is expected to worsen due to retirements in the next decade and beyond. The shortage affects both the E&P part of the business (upstream) and the refining part (downstream), construction, and other sectors, including the transportation industry. It ranges from skilled craftspeople to PhDs. Fewer academic departments are training students in the petro-technical areas now than in the 1980s. However, the problem is wider, with shortages of students in science, engineering, and mathematics. A similar situation exists for craft labor. Although the industry has recently been in a boom cycle after a protracted bust that lasted approximately twenty years, enrollment in U.S. universities is approximately 25% of the level seen at its peak in 1982.

The cyclic nature of the business, the public's negative image of the industry, fierce competition with other industries for limited technical personnel, plus an aging workforce create a situation that has been described by the US Department of Labor as being on a "demographic cliff". Although the industry has become much more efficient in recent years, as evidenced by Figures B7 and B8, resources are becoming more technically challenging and requiring more R&D and technology to extract. These challenges, though daunting, can be addressed, and should provide ample, future employment opportunities for many decades to come.

Conclusions

Technology drives the present understanding of formations and allows gas to be produced at a lower cost. Technology allows probable reserves to be pushed into the proved category. It has been demonstrated that this is occurring with respect to shale formations today[29].

It is possible to assess the impact of technology on ultimate natural gas recovery through the use of the technique of Hubbert Linearization. By extending a best-fit line through natural gas production data, the ultimate natural gas recovery can be estimated (Figure 19). It has been shown that changes in the slope of the data coincide with the introduction of step-changes in technology. The ultimate projection of recoverable gas in North America from 1900 to 1970 indicated that apx. 1,000 TCFG would be recovered. Improvements in technology have allowed less permeable formations and CBM to be commercially exploited. The commercialization of these resources was caused by the introduction of low-cost hydraulic fracturing, which produces a demonstrable slope change on the curve. Extrapolation of the Hubbert Linearization curve including these resources increases ultimate natural gas recovery to apx. 2,100 TCFG. The introduction of inexpensive horizontal completions with multiple hydraulic fractures leads to another, even more substantial, slope change. Although the trajectory of the ultimate recovery is somewhat uncertain, it can be seen that there has been continual improvement through time. Past natural gas supply projections had assumed an exponential increase in liquefied natural gas (LNG) imports in order to keep pace with growth in domestic demand for natural gas. Recent growth from shale gas has contributed to decreased utilization of LNG terminals, which may continue for decades. Recent improvements in shale gas technology have indicated the potential for higher sustained U.S. gas production than was shown in previous projections[30].

Natural gas remains an important and environmentally friendly energy source for domestic demand[31]. Because of the efficiency of natural gas combustion in terms of energy produced per molecule of carbon dioxide produced there is an inherent value to producing electricity with natural gas. As less permeable reservoirs are made commercial, the volume of resource that becomes available increases dramatically as a result of the resource pyramid. Referring to Figures 18 - 21, it can be seen that technology advances have enabled 3,500 TCFG (Case 3) of natural gas resource between 1979 and today. It can be expected that 21st century technology will continue to realize new opportunities for the natural gas industry and result in upward revisions to the ultimate recovery curve. This of course presupposes that the aforementioned workforce and R&D challenges are addressed.

References

[1] BP. (Jun. 2010). BP Statistical Review of World Energy, Statistical Review of World Energy 2010.

[2] Holditch, S.A. (2006). *Tight Gas Sands.* SPE Paper 103356, Distinguished Author Series.

[3] Bartberger et al. (2002). *Is there any Basin-Centered Gas Accumulation in Cotton Valley Group Sandstones, Gulf Coast Basin*. Final Report, Contract No. DE-AT26-98FT40031 and DE-AT26-98FT40032, US DOE.

[4] Flores, C.P. (Dec. 2008). *Technology and Economics Affecting Unconventional Reservoir Development*, Master's Thesis, Texas A&M University.

[5] Holditch, S.A. (2009). *Stimulation of Tight Gas Reservoirs Worldwide*, OTC 20267-PP. Texas A&M University. pp. 8.

[6] Canadian Society for Unconventional Gas. (2006). *Filling the Gap Unconventional Gas Technology Roadmap. Petroleum Technology Alliance Canada*.

[7] Research Partnership to Secure Energy for America (RPSEA). (Apr. 2007). *Draft Annual Plan – April 2007*. pp. 51.

[8] Kuuskraa et al. (2007). Outlook for Unconventional Gas: The Next Decade. *OGJ Unconventional Gas Article #6.* Advanced Resources International, Arlington, VA.

[9] Xtreme Drilling. (2010). *Corporate Update September 2010.* Retrieved from http://www.xtremecoildrilling.com/ir/corpPresent/100914_XDC_corp_pres.pdf.

[10] Charlez. Ph.A. and P. Breant. (1999). *The Multiple Role of Unconventional Drilling Technologies. From Well Design to Well Productivity.* SPE Paper 56405 for SPE European Formation Damage Conference, The Hague, Netherlands.

[11] Center for Energy. (2008). *How is Gas from Tight Sands Produced?.* Retrieved from http://www.centerforenergy.com.

[12] Engler, T. (Summer 2005). Capturing Missed Reserves in Existing Wells. *GasTIPS.*

[13] Baker Hughes. (2010). *Frac-HOOK Multilateral System Fractures Saved Nearly 50% in Stimulation Costs.* Retrieved from http://www.bakerhughes.com/news-and-media/resources/case-histories/frac-hook-case-history

[14] EIA. (2010a). *Annual Energy Outlook 2010 With Projections to 2035.* US DOE, Washington, DC.

[15] EIA. (2008). *Annual Energy Outlook 2008.* US DOE, Washington, DC.

[16] Raymond, Lee R. (2007). *HARDTRUTHS- Facing the Hard Truths about Energy*, National Petroleum Council.

[17] RPSEA. (2010). *RPSEA Selects Projects to Award $16.5 Million for the Unconventional Resources and Small Producers Programs.* Retrieved from http://www.rpsea.org/en/art/275.

[18] Pappas, James. (Aug. 11, 2010). RPSEA. Personal interview.

[19] Barron, A. Rice. (Aug. 20, 2010). University, Department of Chemistry. Personal interview.

[20] Krivak, K. (May. 2004). *Alberta Research Council- Reservoir Characterization Using MRI Techniques.* Presented at Canadian Society for Unconventional Gas Technical Forums. Calgary, Alberta.

[21] Gahan, B. (Spring 2002). Laser Drilling: Understanding Laser/Rock Interaction Fundamentals. *GasTIPS*.

[22] Nickle's. (2005). Cracking Coal. *Nickle's New Technology Magazine. Vol. 11, No. 8.*

[23] Ammer, James. (2002). Tight Gas Technologies for the Rocky Mountains. *GasTIPS.* pp. 18-23.

[24] Hyndman, R., and Dallimore, S. (2001). Natural Gas Hydrate Studies in Canada. *The Recorder.* Canadian Society of Exploration Geophysicists. Vol. 26.

[25] Dallimore, S., and T. Collett. (2005). *Bulletin 585 – Scientific Results from the Mallik 2002 Gas Hydrates Production Research Well Program.* Geological Survey of Canada.

[26] Dallimore, S. (Jan. 2003). *The Potential of Canadian Gas Hydrates.* Unconventional Gas Symposium, Calgary, Alberta.

[27] DOE. (2005). *Marginal Wells: Contributions to Future Supply.* Retrieved from http://www.netl.doe.gov/publications/factsheets/policy/Policy077.pdf.

[28] Kuuskraa, V.A., and Ammer, J. (Winter 2004) Tight Gas Sands Development – How to Dramatically Improve Recovery Efficiency. *Gas Tips.*

[29] Aspen Environmental Group. (2010). *Implications of Greater Reliance on Natural Gas for Electricity Generation.* Prepared for American Public Power Association.

[30] NPC. (2008). *2008 Update to the National Petroleum Council Report Hard Truths: A Comprehensive View to 2030 of Global Oil and Natural Gas Topic Paper on Energy Supply.*

[31] Congressional Research Service. (2008). *Natural Gas Markets: Overview and Policy Issues.* Washington, DC.

Appendix B - Resource Supply Discussion

This Appendix provides supplemental details and analysis discussion of the U.S. Lower 48 and non-arctic Canada onshore sections on six supply scenarios: Flat Supply, Supply Growth and four on Restricted Supply. As a reminder, the described scenarios and cases are not a forecast of onshore gas production but rather an indication of supply implications under the stated assumptions.

Yearly historical gas production volumes were taken from various sources including US Energy Information Administration, Canadian Association of Petroleum Producers, and National Energy Board of Canada. These volumes were broken into three components (conventional, old tech unconventional, new tech unconventional) based on information gathered from PI Dwights, Interstate Natural Gas Association of America, ICF International, and Wood Mackenzie.

The future resource volumes for these three components were derived from a Hubbert extrapolation of each component based on the current shape of its plot in rate-time space. The values for conventional and old tech unconventional were kept constant for all three cases, allowing the new tech unconventional resource to be the variable in reaching the total value.

The remaining resource base for each component was gathered from the MITei Interim Study. The assumption was made that the conventional component is comprised of the growth, new field, and miscellaneous categories. The old tech unconventional is assumed to be comprised of the tight and coalbed categories while shale comprises the new tech unconventional.

The supply cost stack for each case was determined by plotting the wellhead price in $/mmBTU against its associated gas resource after terminal decline. Also, supply cost stacks for shale and non-shale gas were created in the same manner.

Flat Supply Scenario – supply is assumed available at a constant 24.1 TCFG/yr until onset of supply terminal decline.

- ***Case One*** – MITei/ICF Mean Resource Base, Current (2007) Technology; Remaining Recoverable Resource 1,901 TCFG, Estimated Ultimate Recoverable Resource 2,996 TCFG. *The consensus view of the sub-group is that this case is quite conservative and it is highly probable that it will be surpassed.*

- ***Case Two*** – MITei/ICF Mean Resource Base, Advanced Technology, Remaining Recoverable Resource 2,890 TCFG, Estimated Ultimate Recoverable Resource 3,985 TCFG. *The consensus view of the sub-group is that this case is rather conservative and it is probable that it will be surpassed.*

- ***Case Three*** – MITei/ICF High Resource Base, Advanced Technology, Remaining Recoverable Resource 3,561 TCFG, Estimated Ultimate Recoverable Resource 4,656 TCFG. *The consensus view of the sub-group is that this case is reasonable today and could readily be surpassed.*

Table B1: Flat Supply Scenario Details

Supply is available at constant rate of 24.1 TCFG/year

	Case 1	**Case 2**	**Case 3**
Resource Base	**Mean**	**Mean**	**High**
Technology	**Current**	**Advanced**	**Advanced**
Supply Stack based	(TCFG)	(TCFG)	(TCFG)
@ $20/mmBTU Supply Cost			
Ultimate Recoverable Resource	**2,996**	**3,985**	**4,656**
Cum Production as of YE09	1,095	1,095	1,095
YE09 Remaining Recoverable Resource	**1,901**	**2,890**	**3,561**
Years of Flat Production	54 yrs	78 yrs	90 yrs
Flat Production Volume	1,301	1,890	2,161
Assumed Terminal Decline Volume	600	1,000	1,400
YE09 Remaining Recoverable Resource	**1,901**	**2,890**	**3,561**
Non-Shale Resource	870	1,171	1,451
Shale Resource	1,031	1,719	2,110
YE09 Remaining Recoverable Resource	**1,901**	**2,890**	**3,561**
Conventional	189	189	189
Old Tech Unconventional	753	753	753
New Tech Unconventional	959	1,948	2,619
2010 Yearly Enabled Production	**24.1**	**24.1**	**24.1**
Proved	6.2	4.1	3.2
Conventional	1.9	1.8	2.0
Old Tech Unconventional	0.2	0.6	1.0
New Tech Unconventional	15.8	17.7	17.9
2030 Yearly Enabled Production	**24.1**	**24.1**	**24.1**
Proved	4.8	3.3	2.5
Conventional	2.3	2.2	2.3
Old Tech Unconventional	0.5	1.5	1.8
New Tech Unconventional	16.5	17.1	17.4
2030 Supply Cost ($/mmBTU)	< $6	< $5	< $5
2050 Yearly Enabled Production	**24.1**	**24.1**	**24.1**
Proved	4.0	2.7	2.1
Conventional	3.9	2.4	2.7
Old Tech Unconventional	1.9	2.4	2.5
New Tech Unconventional	14.3	16.6	16.9
2050 Supply Cost ($/mmBTU)	< $11	< $7	< $7

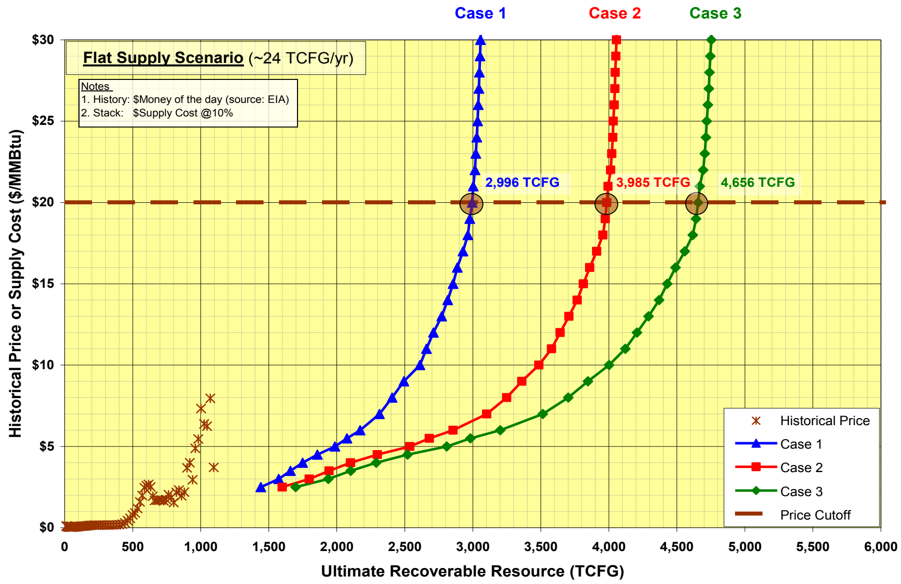
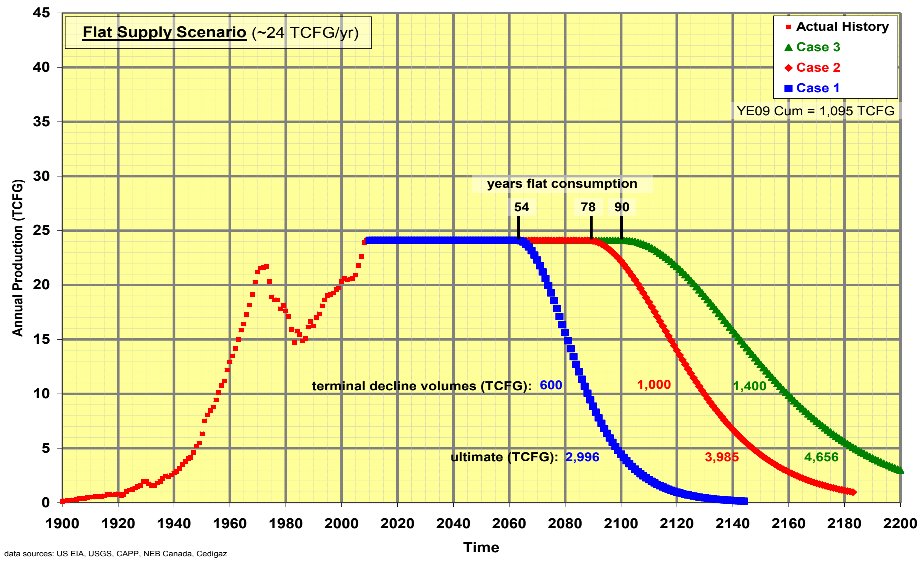


Figure B1: Cost Supply Stack for Remaining Resource Range (Flat Supply Scenario, Cases 1-3)



data sources: US EIA, USGS, CAPP, NEB Canada, Cedigaz

Figure B2: Supply Plateau Range under Flat Supply Scenario, Cases 1-3

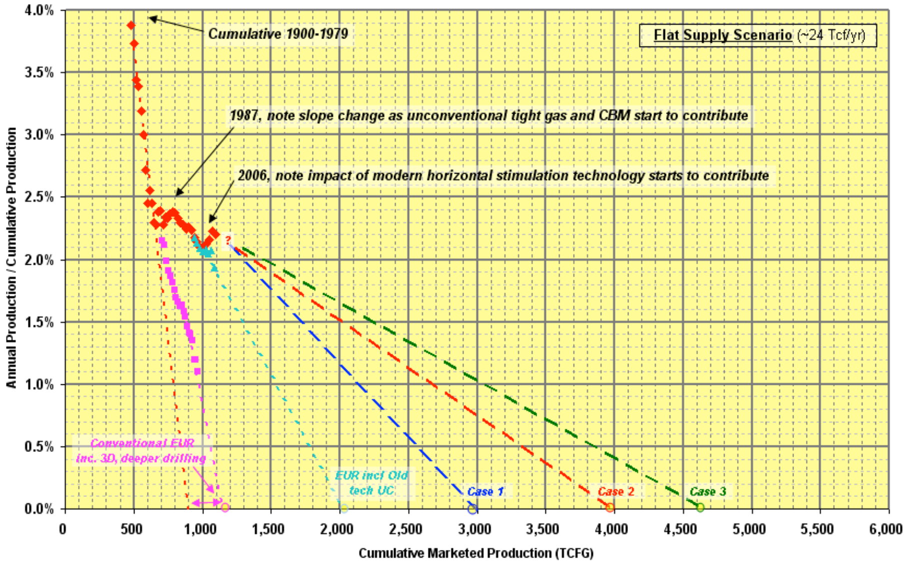


Figure B3: Hubbert Linearization Analysis Range under Flat Supply Scenario, Cases 1-3

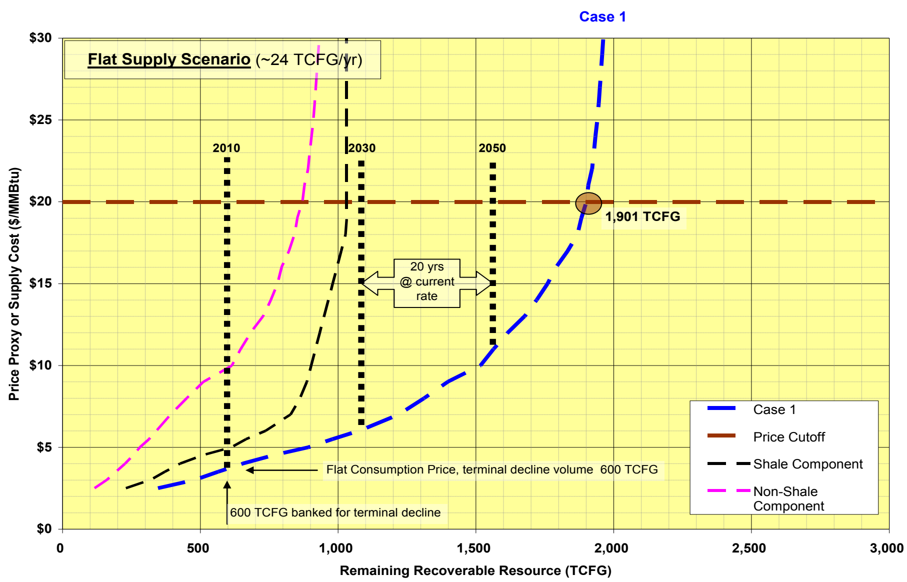


Figure B4: Cost Supply Stack for Remaining Resource and Shale/Non-Shale Breakout (Flat Supply Scenario, Case 1)

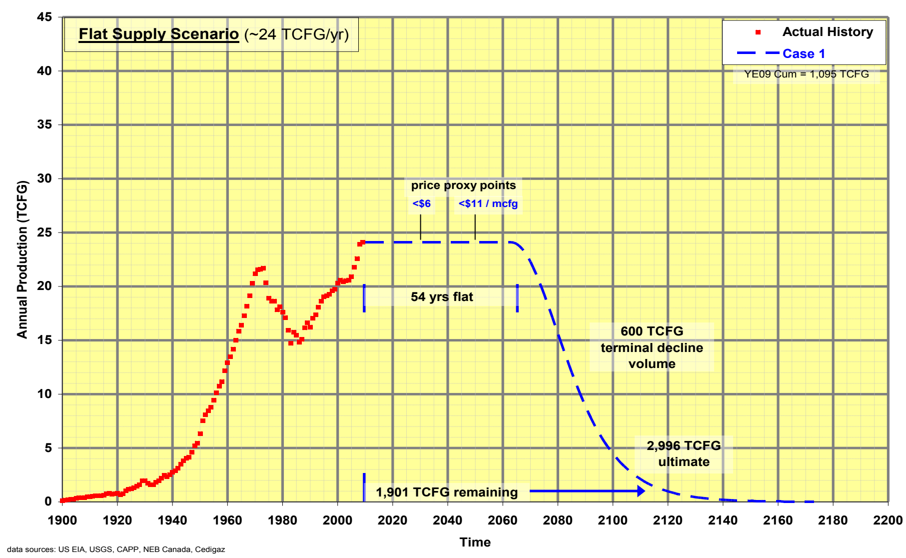


Figure B5: Supply Plateau under Flat Supply Scenario, Case 1

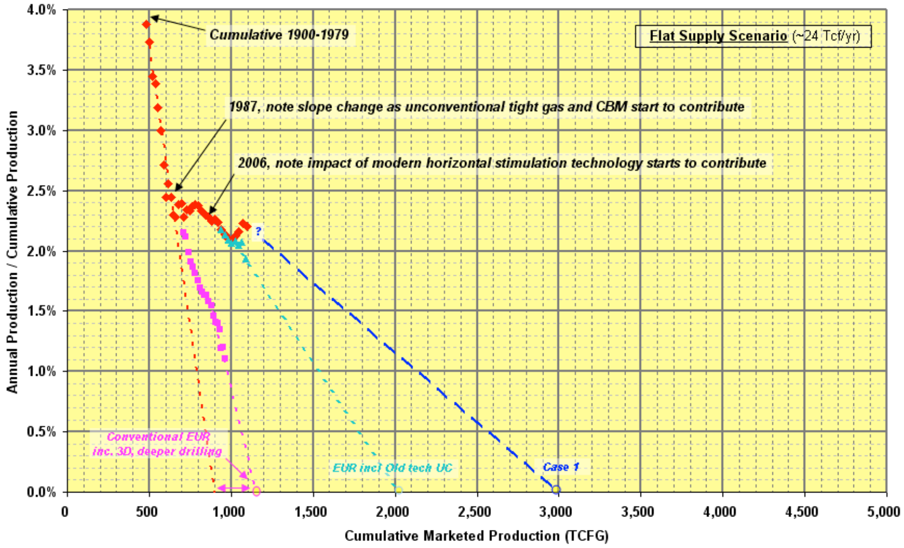


Figure B6: Hubbert Linearization Analysis under Flat Supply Scenario, Case 1

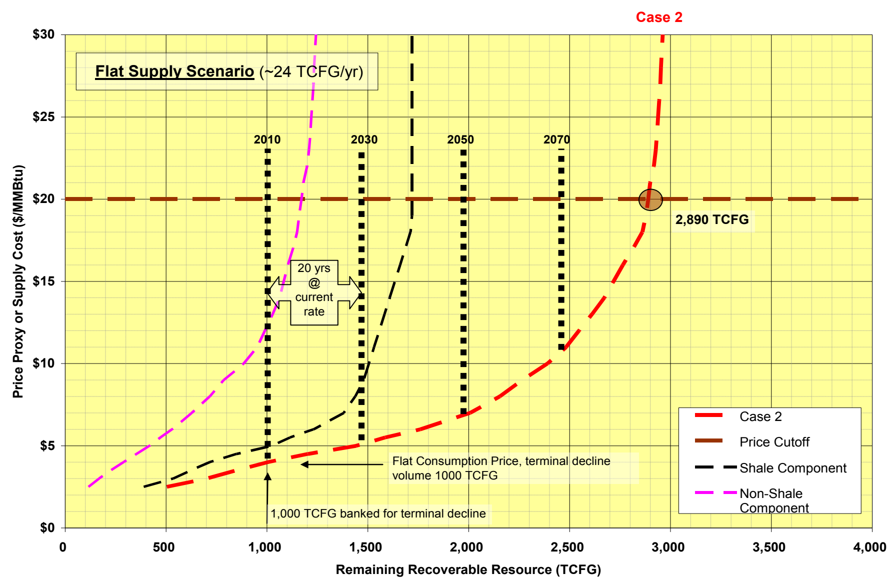


Figure B7: Cost Supply Stack for Remaining Resource and Shale/Non-Shale Breakout (Flat Supply Scenario, Case 2)

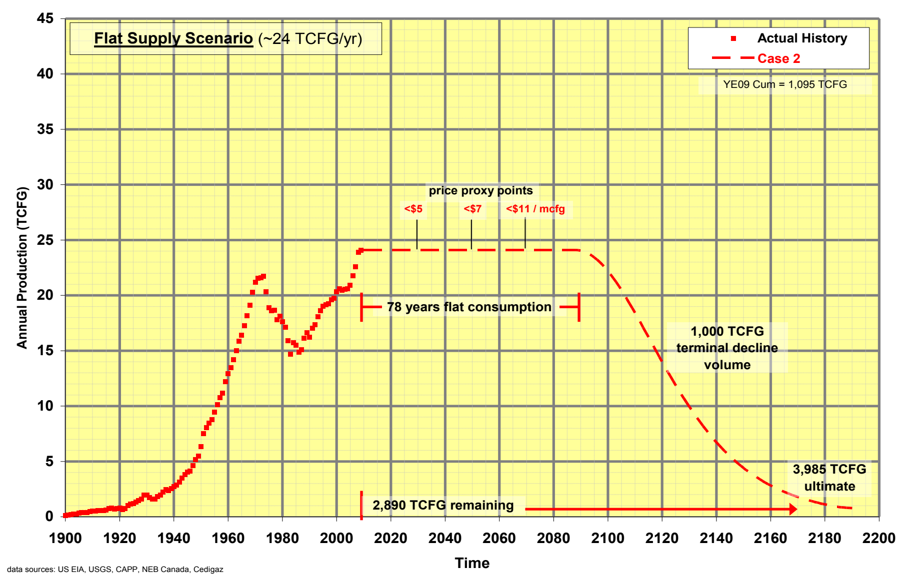


Figure B8: Supply Plateau under Flat Supply Scenario, Case 2

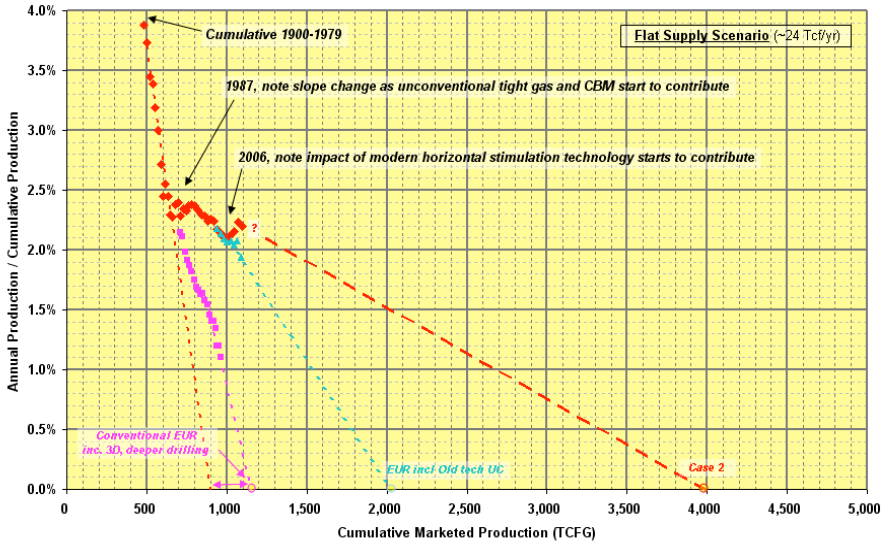


Figure B9: Hubbert Linearization Analysis under Flat Supply Scenario, Case 2

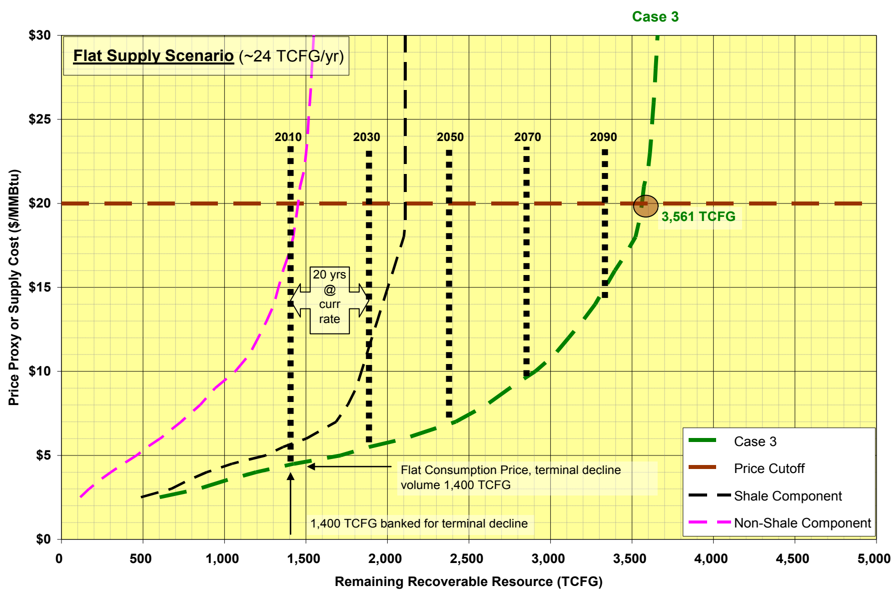


Figure B10: Cost Supply Stack for Remaining Resource and Shale/Non-Shale Breakout (Flat Supply Scenario, Case 3)

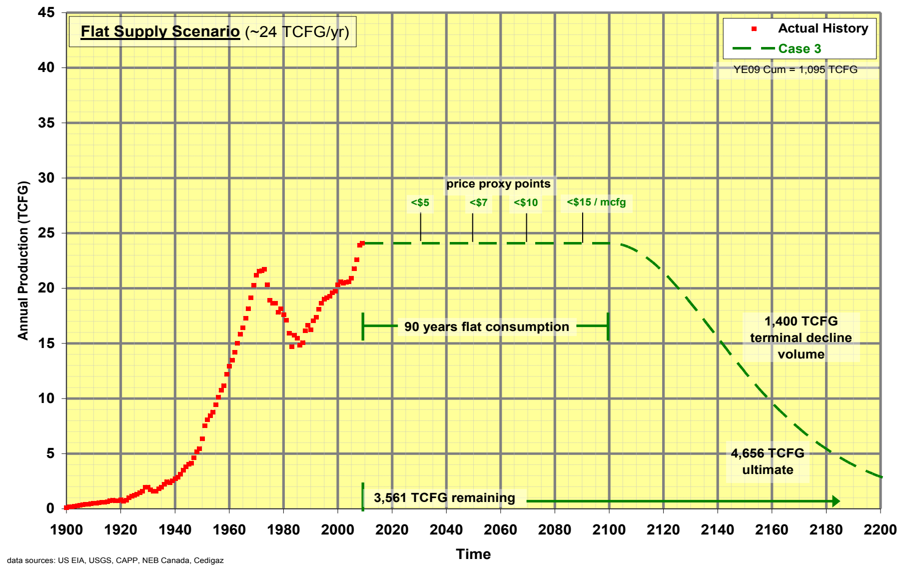


Figure B11: Supply Plateau under Flat Supply Scenario, Case 3

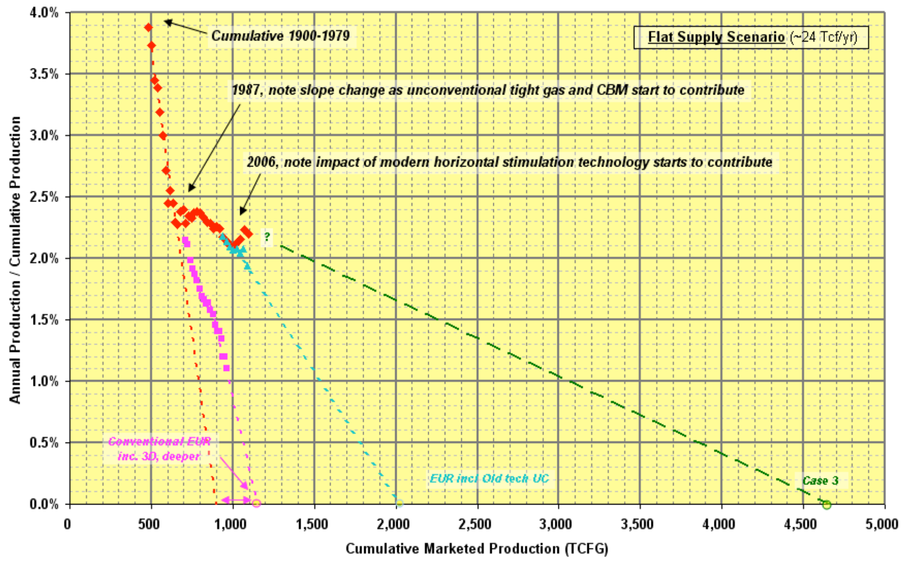


Figure B12: Hubbert Linearization Analysis under Flat Supply Scenario, Case 3

Supply Growth Scenario – supply in flat scenario is increased, such as may occur with increased utilization. Assumption: gas supply is increased by approximately 5% per year to a constant 36.5 TCFG/yr until onset of supply terminal decline.

- ***Case One*** – MITei/ICF Mean Resource Base, Current (2007) Technology; Remaining Recoverable Resource 1,901 TCFG, Estimated Ultimate Recoverable Resource 2,996 TCFG. *The consensus view of the sub-group is that this case is quite conservative and it is highly probable that it will be surpassed.*

- ***Case Two*** – MITei/ICF Mean Resource Base, Advanced Technology, Remaining Recoverable Resource 2,890 TCFG, Estimated Ultimate Recoverable Resource 3,985 TCFG. *The consensus view of the sub-group is that this case is rather conservative and it is probable that it will be surpassed.*

- ***Case Three*** – MITei/ICF High Resource Base, Advanced Technology, Remaining Recoverable Resource 3,561 TCFG, Estimated Ultimate Recoverable Resource 4,656 TCFG. *The consensus view of the sub-group is that this case is reasonable today and could readily be surpassed.*

As this scenario only assumes a higher rate of production, ultimate recoverable volumes are the same as the Flat Supply Scenario.

Table B2: Supply Growth Scenario Details
5% growth per year to +50% consumption rate of 36.5 TCFG/year

	Case 1	**Case 2**	**Case 3**
Resource Base	**Mean**	**Mean**	**High**
Technology	**Current**	**Advanced**	**Advanced**
Supply Stack based	(TCFG)	(TCFG)	(TCFG)
@ $20/mmBTU Supply Cost			
Ultimate Recoverable Resource	**2,996**	**3,985**	**4,656**
Cum Production as of YE09	1,095	1,095	1,095
YE09 Remaining Recoverable Resource	**1,901**	**2,890**	**3,561**
Years to Reach Flat Production	9 yrs	9 yrs	9 yrs
Years of Flat Production	20 yrs	31 yrs	33 yrs
Flat Production Volume	735	1,124	1,195
Assumed Terminal Decline Volume	900	1,500	2,100
YE09 Remaining Recoverable Resource	**1,901**	**2,890**	**3,561**
Non-Shale Resource	870	1,171	1,451
Shale Resource	1,031	1,719	2,110
YE09 Remaining Recoverable Resource	**1,901**	**2,890**	**3,561**
Conventional	189	189	189
Old Tech Unconventional	753	753	753
New Tech Unconventional	959	1,948	2,619
2010 Yearly Enabled Production	**24.1**	**24.1**	**24.1**
Proved	6.2	4.1	3.2
Conventional	1.9	1.8	2.0
Old Tech Unconventional	0.2	0.6	1.0
New Tech Unconventional	15.8	17.7	17.9
2030 Yearly Enabled Production	**36.5**	**36.5**	**36.5**
Proved	6.5	3.8	3.0
Conventional	4.6	4.7	5.4
Old Tech Unconventional	1.5	4.1	4.3
New Tech Unconventional	23.9	23.9	23.8
2030 Supply Cost ($/mmBTU)	< $11	< $8	< $9

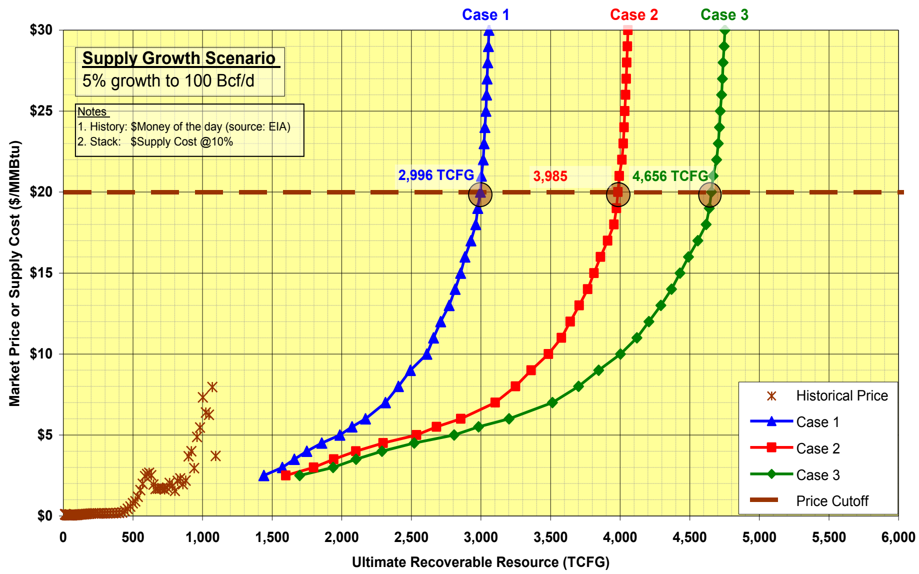


Figure B13: Cost Supply Stack for Remaining Resource range (Supply Growth Scenario, Cases 1-3)

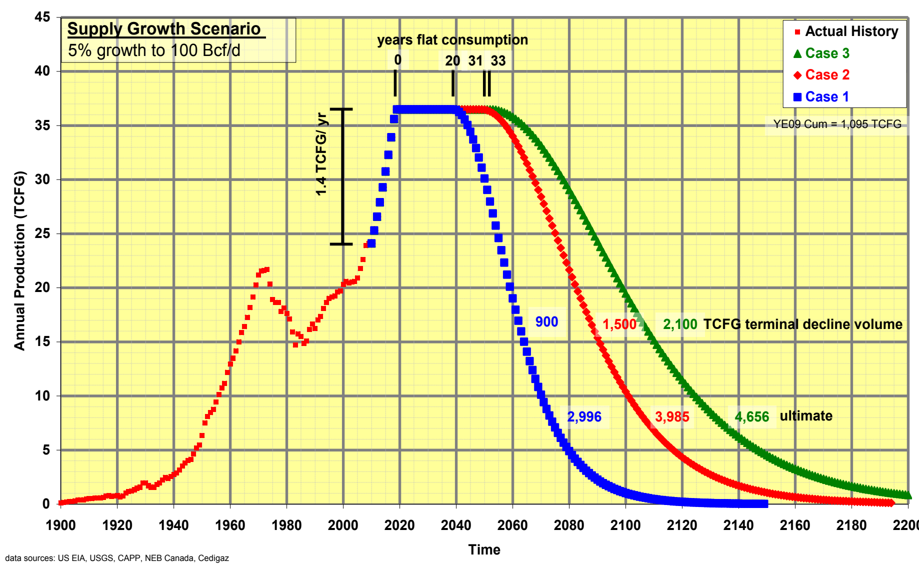


Figure B14: Supply Plateau Range under Supply Growth Scenario, Cases 1-3

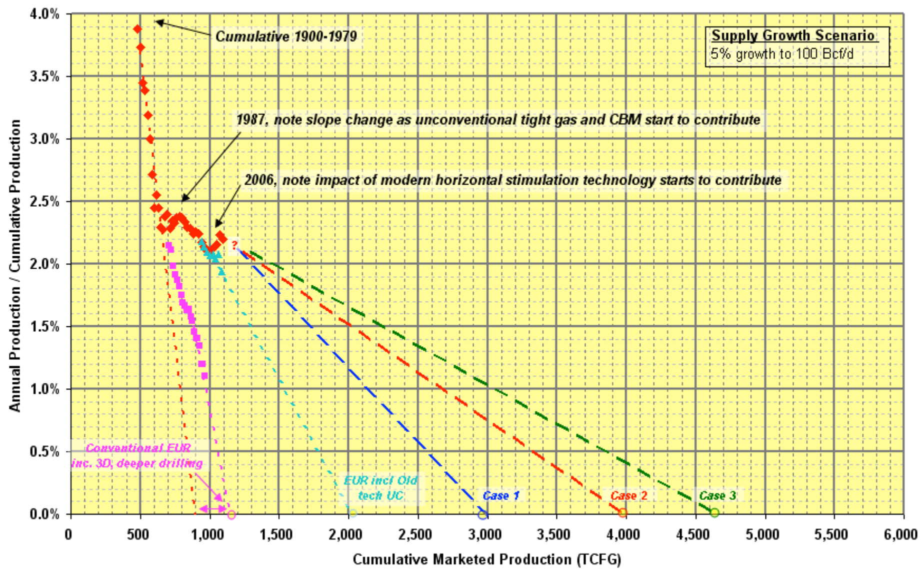


Figure B15: Hubbert Linearization Analysis Range under Supply Growth Scenario, Cases 1-3

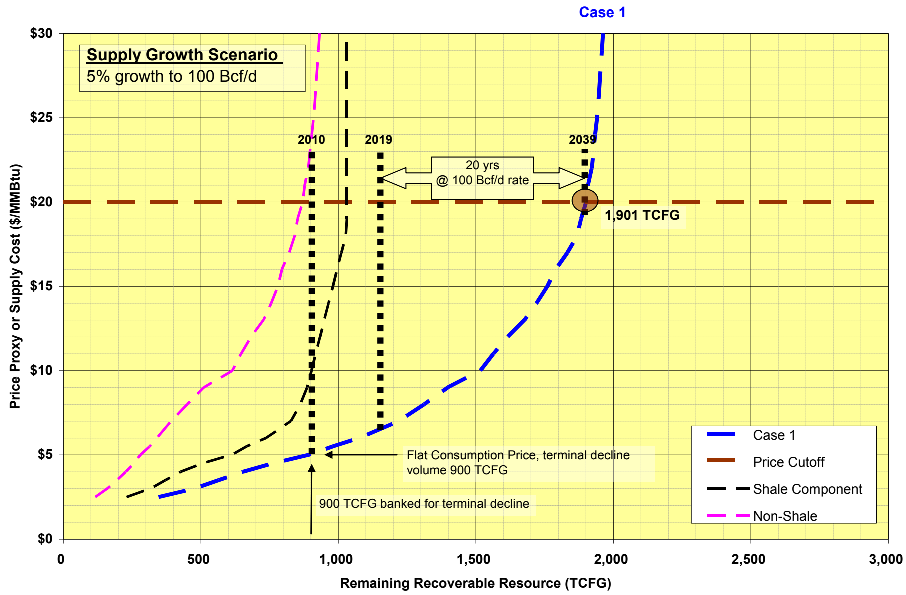


Figure B16: Cost Supply Stack for Remaining Resource and Shale/Non-Shale Breakout (Supply Growth Scenario, Case 1

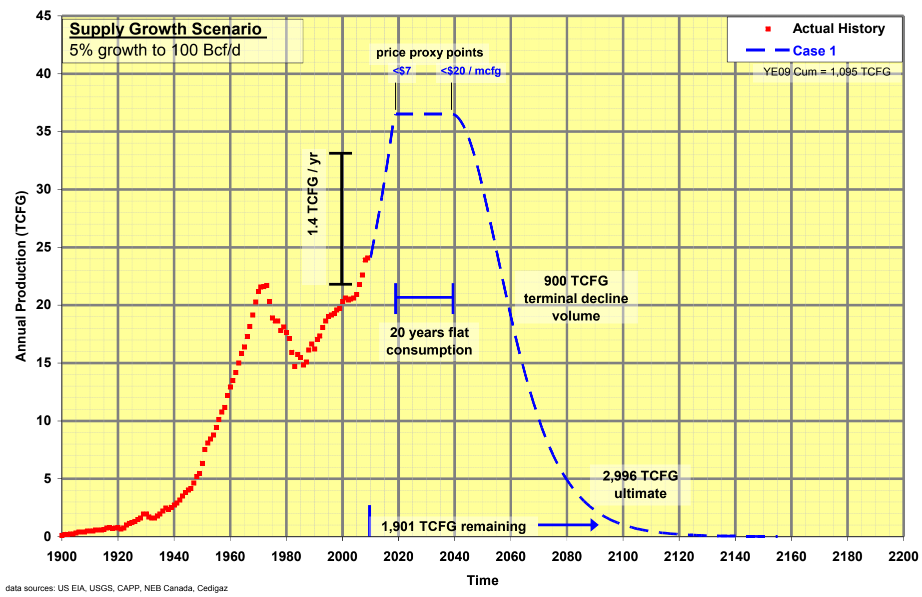


Figure B17: Supply Plateau under Supply Growth Scenario, Case 1

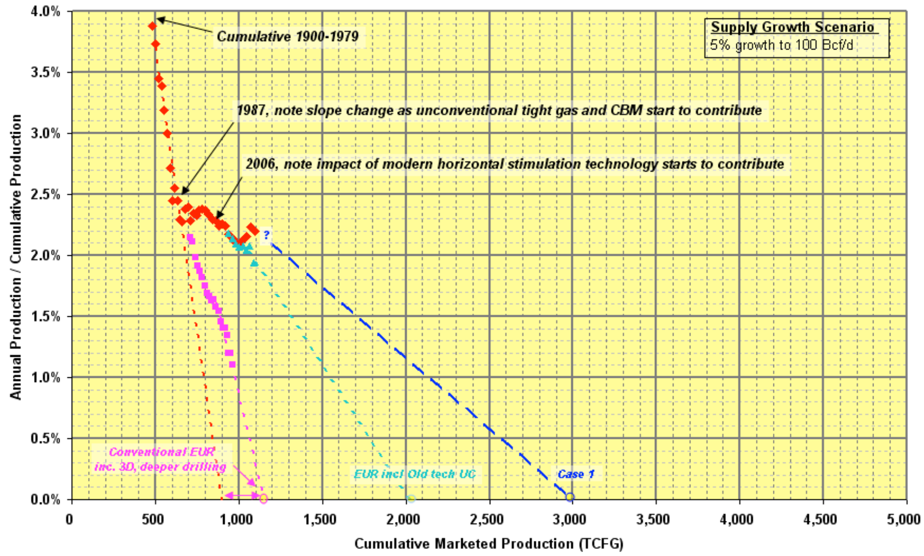


Figure B18: Hubbert Linearization Analysis under Supply Growth Scenario, Case 1

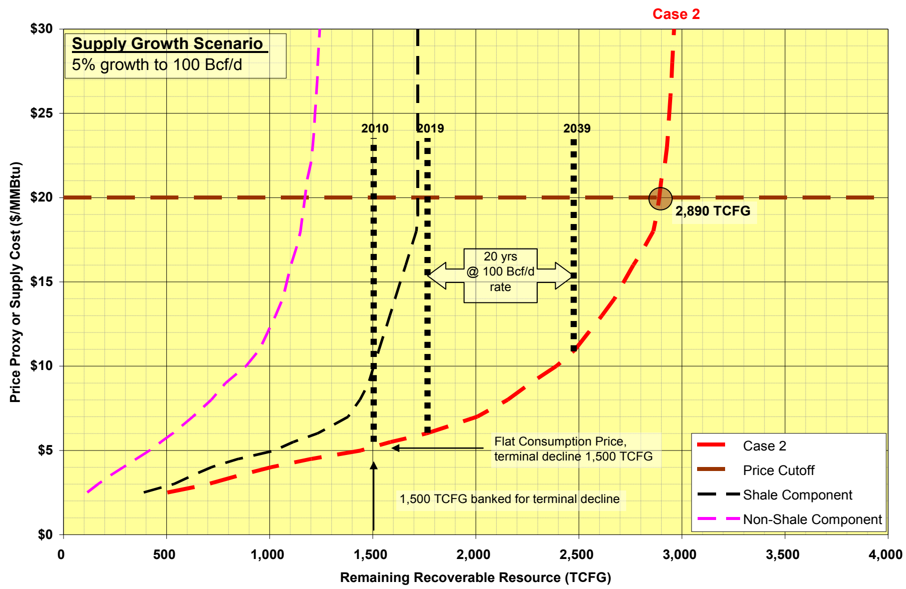


Figure B19: Cost Supply Stack for Remaining Resource and Shale/Non-Shale Breakout (Supply Growth Scenario, Case 2)

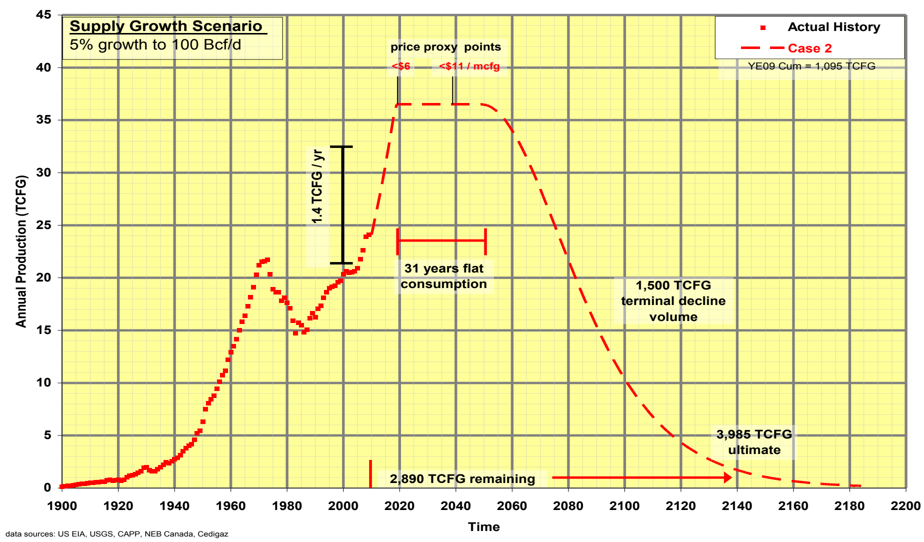
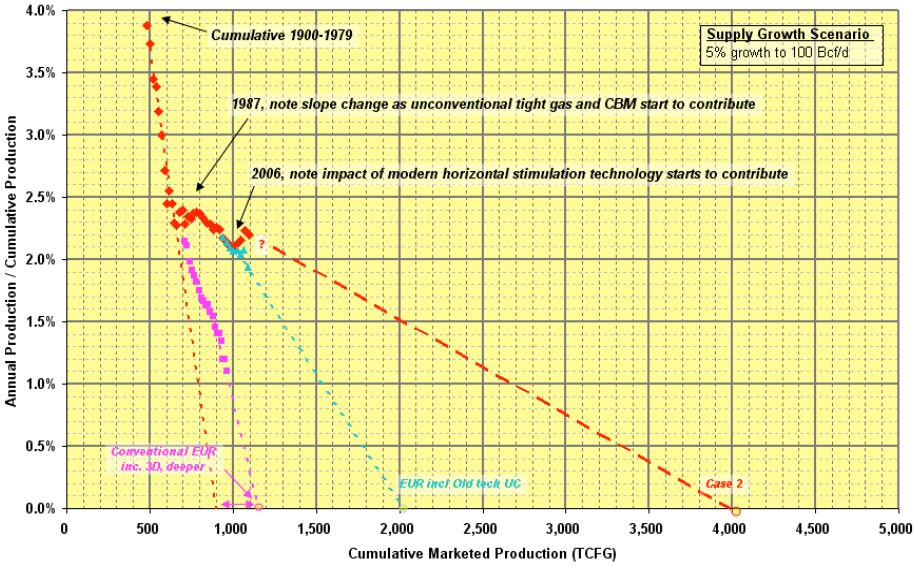


Figure B20: Supply Plateau under Supply Growth Scenario, Case 2

Figure B21: Hubbert Linearization Analysis under Supply Growth Scenario, Case 2



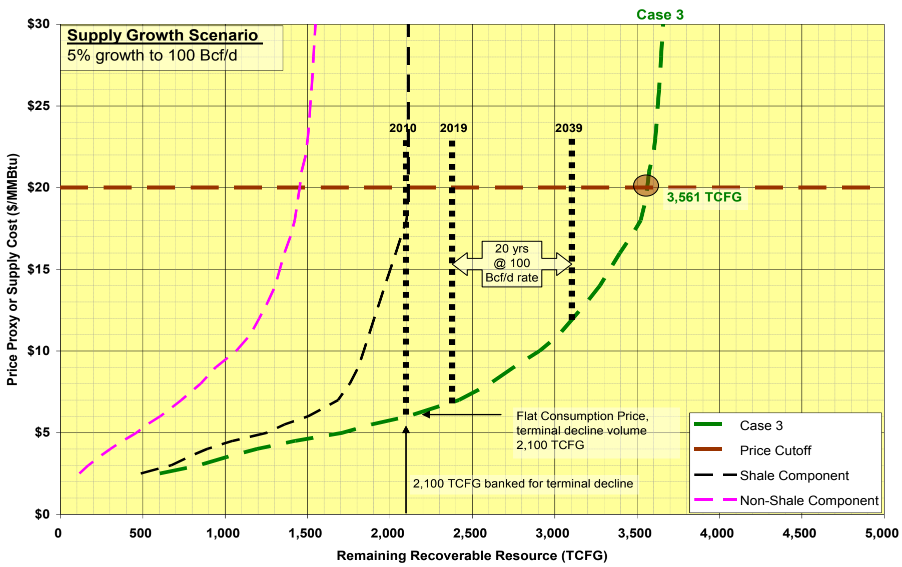


Figure B22: Cost Supply Stack for Remaining Resource and Shale/Non-Shale Breakout (Supply Growth Scenario, Case 3)

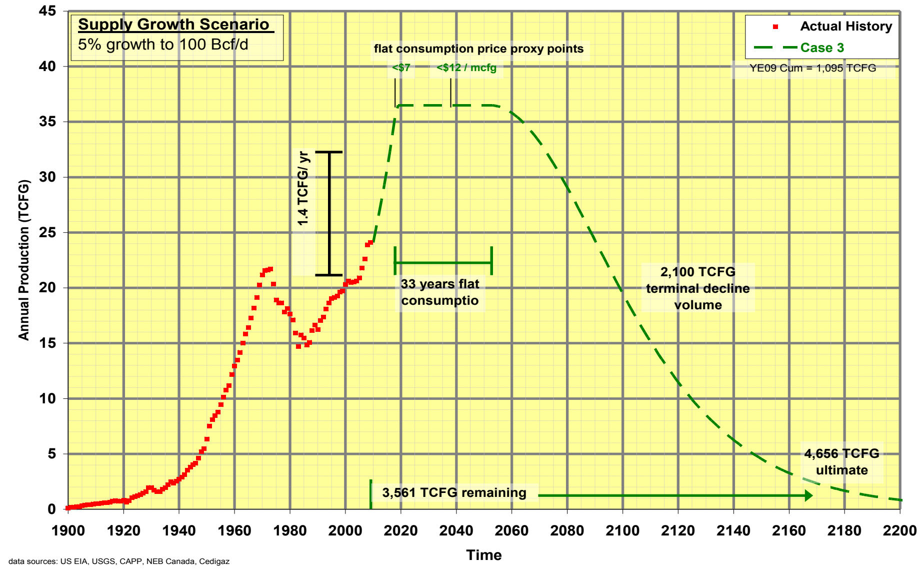


Figure B23: Supply Plateau under Supply Growth Scenario, Case 3

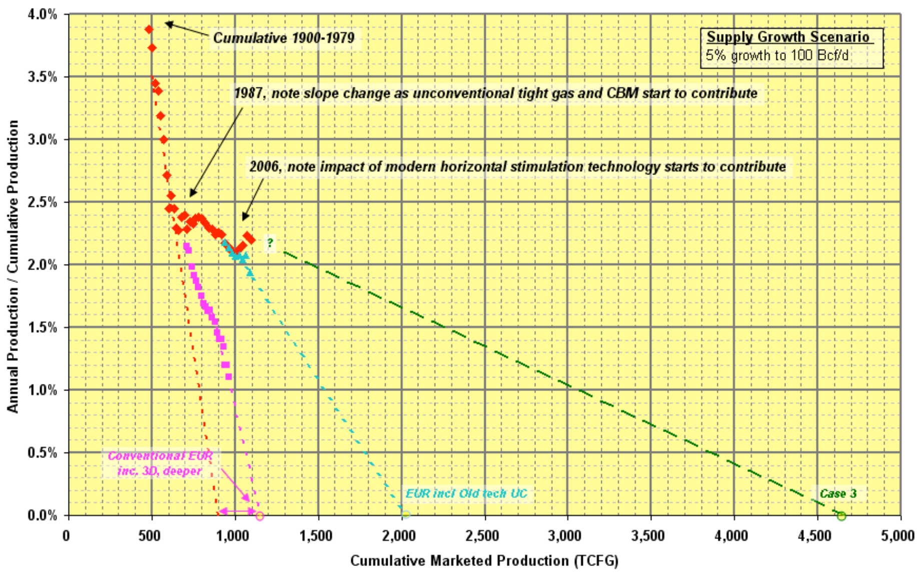


Figure B24: Hubbert Linearization Analysis under Supply Growth Scenario, Case 3

Restricted Supply Scenarios:

Extreme – supply is reduced such as may occur with a moratorium on fracture stimulation. Assumption: 100% of shale gas supply and 85% of tight gas/CBM supply is eliminated.

Severe – supply is reduced such as may occur with severe restrictions on fracture stimulation. Assumption: 67% of shale gas/tight gas/CBM supply is eliminated.

Moderate – supply is reduced such as may occur with moderate restrictions on fracture stimulation. Assumption: 33% of shale gas/tight gas/CBM supply is eliminated.

Restricted Supply Scenario – Increased Cost – supply is reduced such as may occur with additional costs on fracture stimulation. Assumption: cost to supply shale gas/ tight gas/CBM increased by $2/mmBTU.

- ***Case One*** – MITei/ICF Mean Resource Base, Current (2007) Technology; Remaining Recoverable Resource 1,901 TCFG, Estimated Ultimate Recoverable Resource 2,996 TCFG ***truncated to each unique assumption***.

- ***Case Two*** – MITei/ICF Mean Resource Base, Advanced Technology, Remaining Recoverable Resource 2,890 TCFG, Estimated Ultimate Recoverable Resource 3,985 TCFG ***truncated to each unique assumption***.

- ***Case Three*** – MITei/ICF High Resource Base, Advanced Technology, Remaining Recoverable Resource 3,561 TCFG, Estimated Ultimate Recoverable Resource 4,656 TCFG ***truncated to each unique assumption***.

Table B3: Extremely Restricted Scenario Details
100% of shale gas supply and 85% of tight gas/CBM supply is eliminated

	Case 1	Case 2	Case 3
Resource Base	**Mean**	**Mean**	**High**
Technology	**Current**	**Advanced**	**Advanced**
Supply Stack based	(TCFG)	(TCFG)	(TCFG)
@ $20/mmBTU Supply Cost			
Ultimate Recoverable Resource	**1,787**	**1,919**	**2,108**
Cum Production as of YE09	1,095	1,095	1,095
YE09 Remaining Recoverable Resource	**692**	**824**	**1,013**
Years of Flat Production	4 yrs	0 yrs	0 yrs
Flat Production Volume	92	0	0
Assumed Terminal Decline Volume	600	824	1,013
YE09 Remaining Recoverable Resource	**692**	**824**	**1,013**
Non-Shale Resource	692	824	1,013
Shale Resource	0	0	0
YE09 Remaining Recoverable Resource	**692**	**824**	**1,013**
Conventional	366	366	366
Old Tech Unconventional	296	296	296
New Tech Unconventional	30	162	351
2010 Yearly Enabled Production	**24.1**	**24.1**	**24.1**
Proved	11.1	8.3	6.3
Conventional	12.1	14.0	15.9
Old Tech Unconventional	0.9	1.9	1.9
New Tech Unconventional	0.0	0.0	0.0

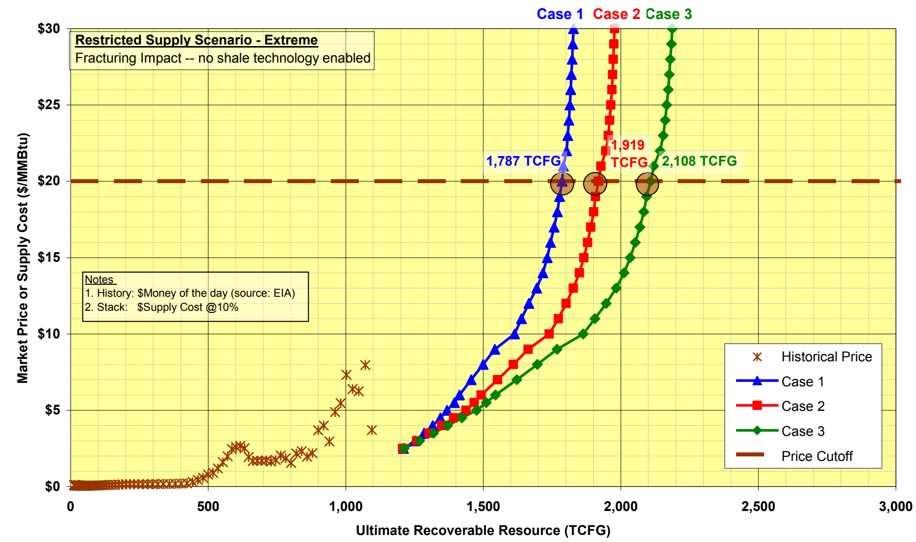


Figure B25: Cost Supply Stack for Remaining Resource range (Restricted Supply Scenario - Extreme, Cases 1-3)

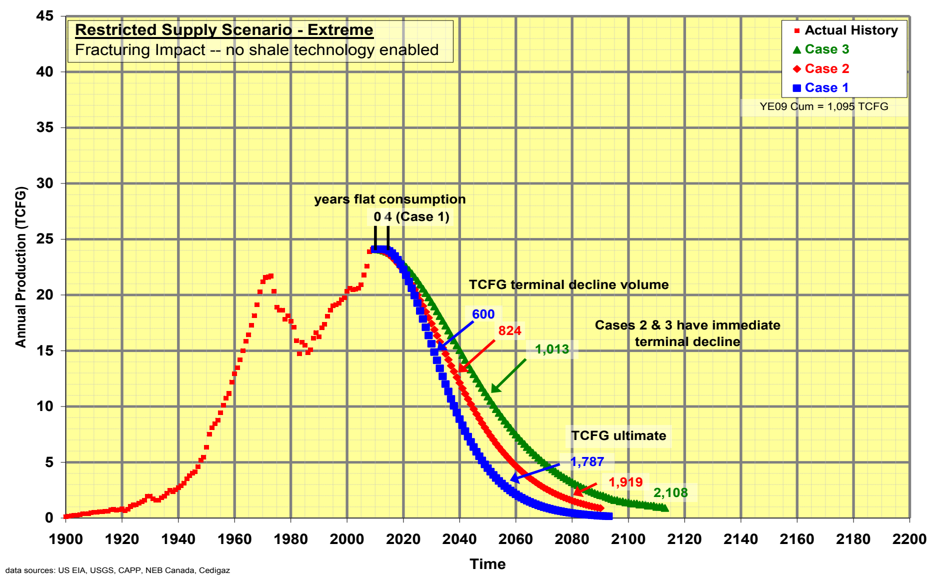
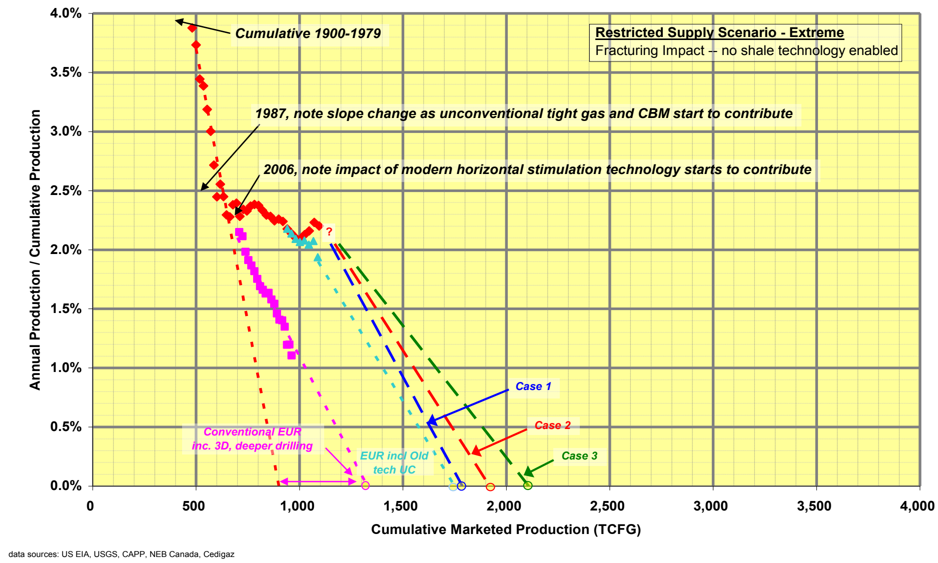


Figure B26: Supply Plateau Range under Restricted Supply Scenario - Extreme, Cases 1-3

Figure B27: Hubbert Linearization Analysis Range under Restricted Supply Scenario - Extreme, Cases 1-3



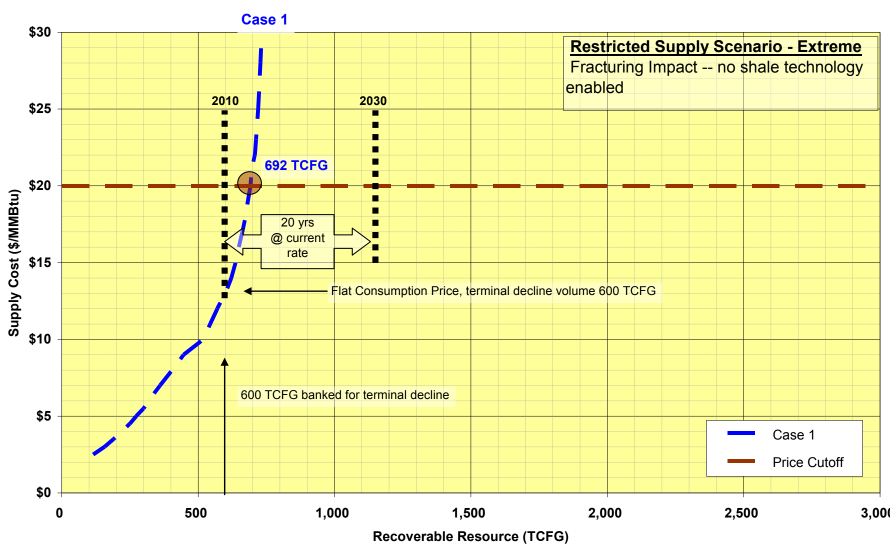


Figure B28: Cost Supply Stack for Remaining Resource and Shale/Non-Shale Breakout (Restricted Supply Scenario - Extreme, Case 1)

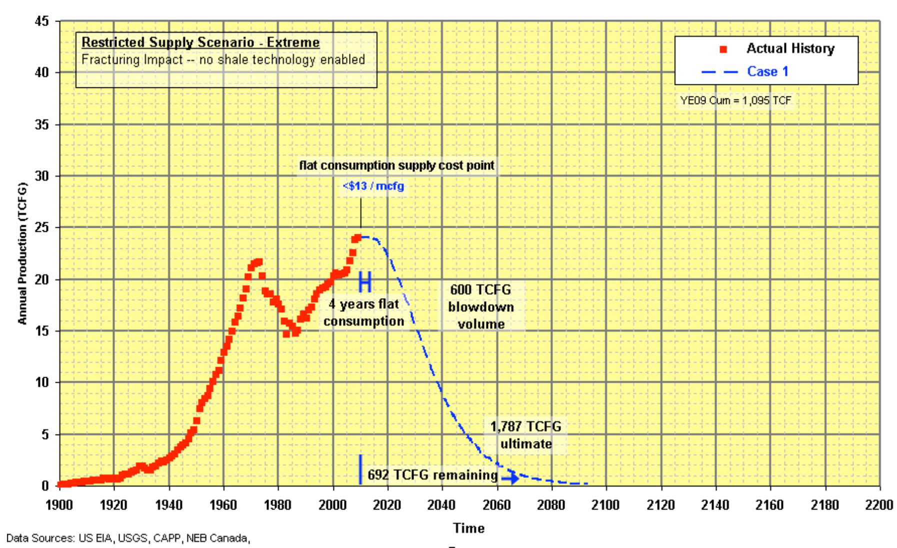


Figure B29: Supply Plateau under Restricted Supply Scenario - Extreme, Case 1

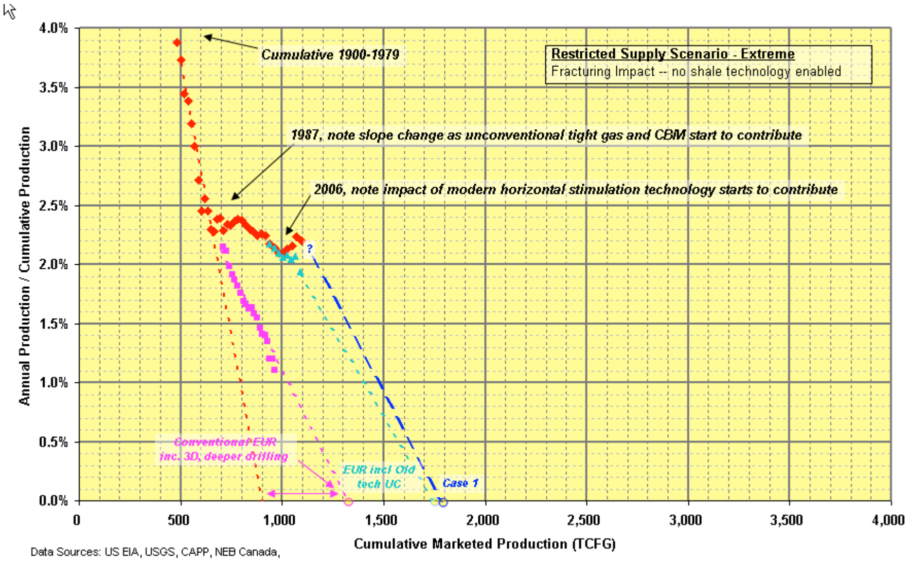


Figure B30: Hubbert Linearization Analysis under Restricted Supply Scenario - Extreme, Case 1

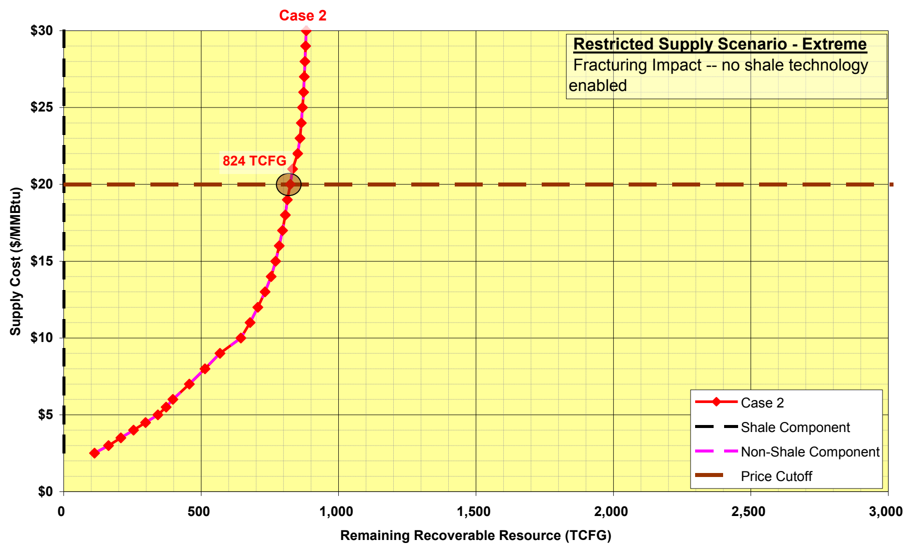


Figure B31: Cost Supply Stack for Remaining Resource and Shale/Non-Shale Breakout (Restricted Supply Scenario - Extreme, Case 2)

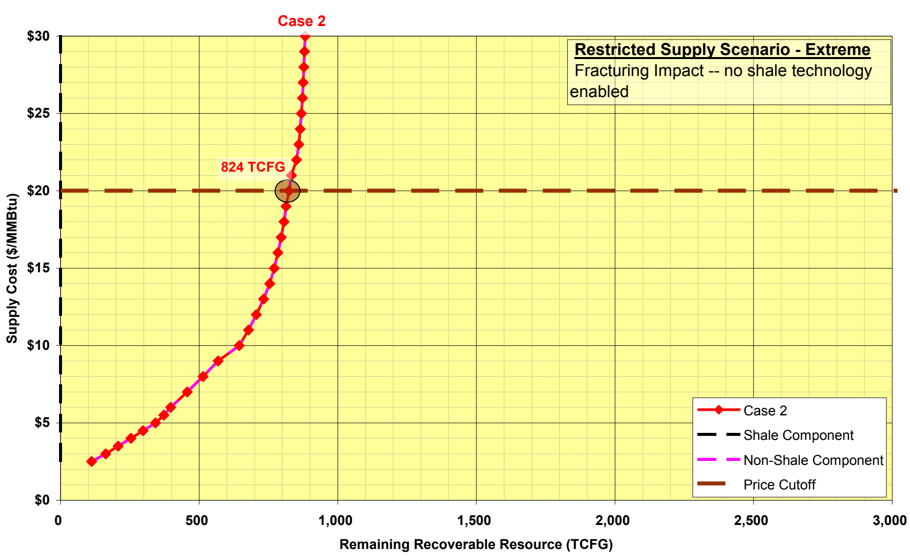
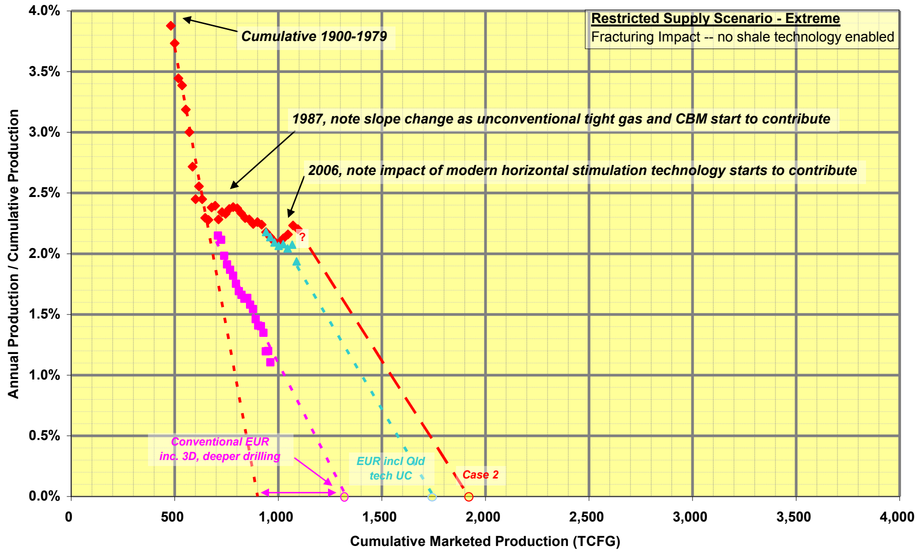


Figure B32: Supply Plateau under Restricted Supply Scenario - Extreme, Case 2

Figure B33: Hubbert Linearization Analysis



data sources: US EIA, USGS, CAPP, NEB Canada, Cedigaz

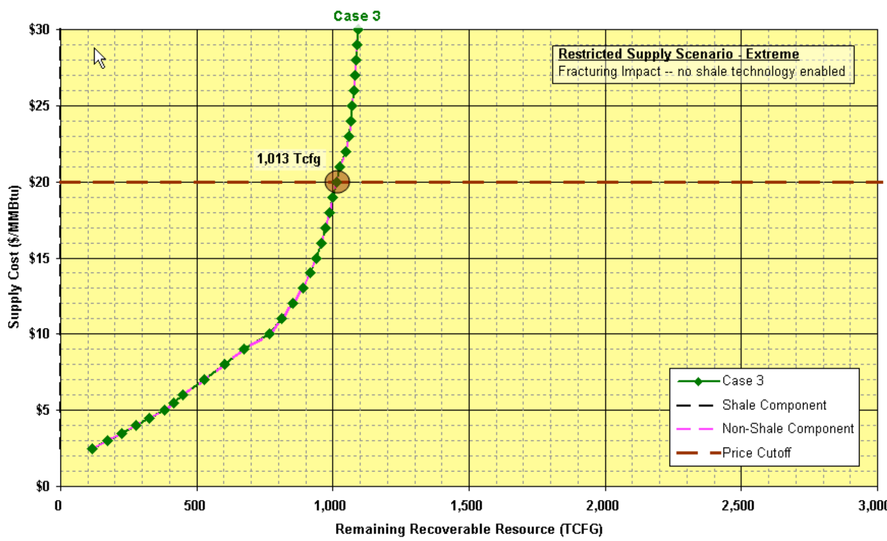
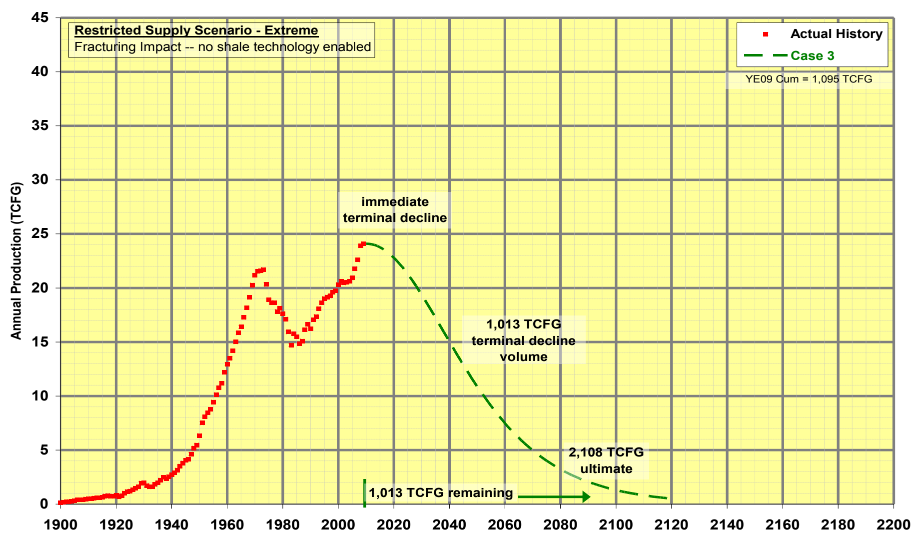


Figure B34: Cost Supply Stack for Remaining Resource and Shale/Non-Shale Breakout (Restricted Supply Scenario - Extreme, Case 3)



data sources: US EIA, USGS, CAPP, NEB Canada, Cedigaz

Figure B35: Supply Plateau under Restricted Supply Scenario - Extreme, Case 3

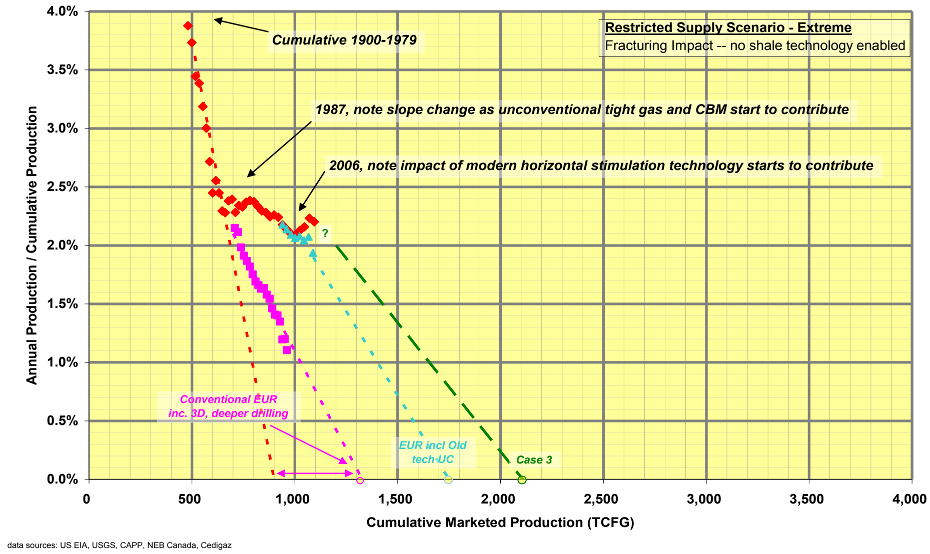


Figure B36: Hubbert Linearization Analysis under Restricted Supply Scenario - Extreme, Case 3

Table B4: Severely Restricted Scenario Details
67% of shale gas/tight gas/CBM supply is eliminated

	Case 1	Case 2	Case 3
Resource Base	**Mean**	**Mean**	**High**
Technology	**Current**	**Advanced**	**Advanced**
Supply Stack based	(TCFG)	(TCFG)	(TCFG)
@ $20/mmBTU Supply Cost			
Ultimate Recoverable Resource	**2,165**	**2,560**	**2,896**
Cum Production as of YE09	1,095	1,095	1,095
YE09 Remaining Recoverable Resource	**1,070**	**1,465**	**1,801**
Years of Flat Production	20 yrs	19 yrs	17 yrs
Flat Production Volume	470	465	401
Assumed Terminal Decline Volume	600	1,000	1,400
YE09 Remaining Recoverable Resource	**1,070**	**1,465**	**1,801**
Non-Shale Resource	730	898	1,105
Shale Resource	340	567	696
YE09 Remaining Recoverable Resource	**1,070**	**1,465**	**1,801**
Conventional	366	366	366
Old Tech Unconventional	393	393	393
New Tech Unconventional	312	706	1,042
2010 Yearly Enabled Production	**24.1**	**24.1**	**24.1**
Proved	9.1	5.7	4.1
Conventional	4.3	5.2	7.1
Old Tech Unconventional	0.3	1.7	1.9
New Tech Unconventional	10.3	11.6	11.0
2030 Yearly Enabled Production	**24.1**	**24.1**	**24.1**
Proved	6.1	4.5	3.3
Conventional	8.7	8.0	9.4
Old Tech Unconventional	1.6	2.3	2.3
New Tech Unconventional	7.7	9.4	9.1
2030 Supply Cost ($/mmBTU)	< $20	N/A	N/A

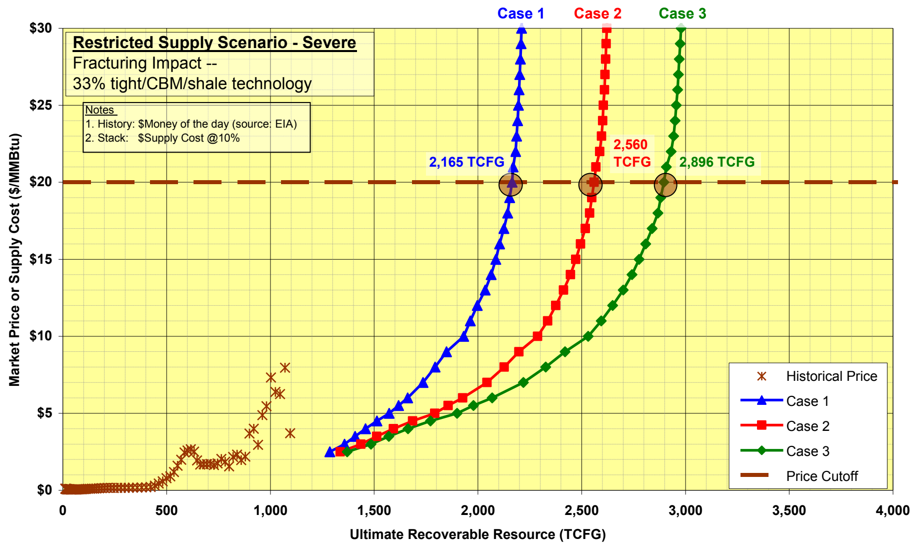


Figure B37: Cost Supply Stack for Remaining Resource range (Restricted Supply Scenario - Severe, Cases 1-3)

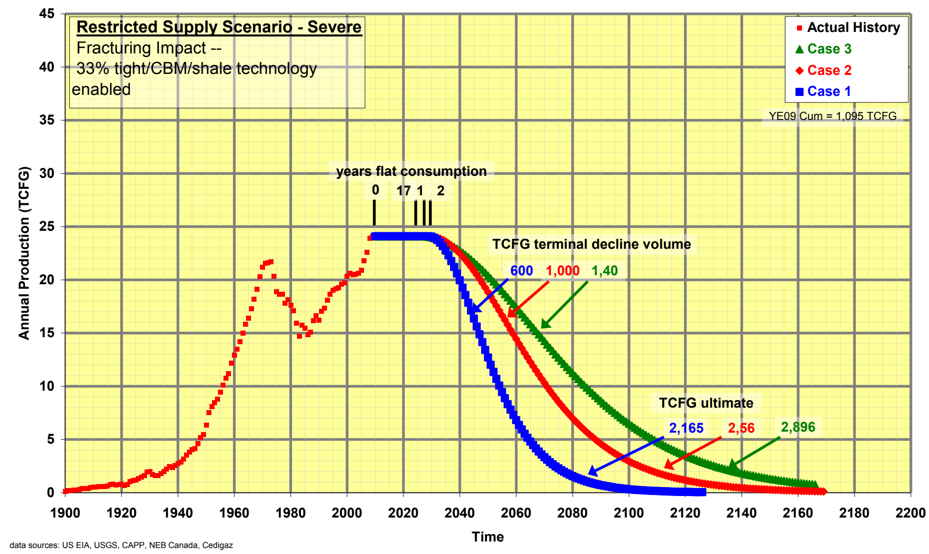


Figure B38: Supply Plateau Range under Restricted Supply Scenario – Severe, Cases 1-3

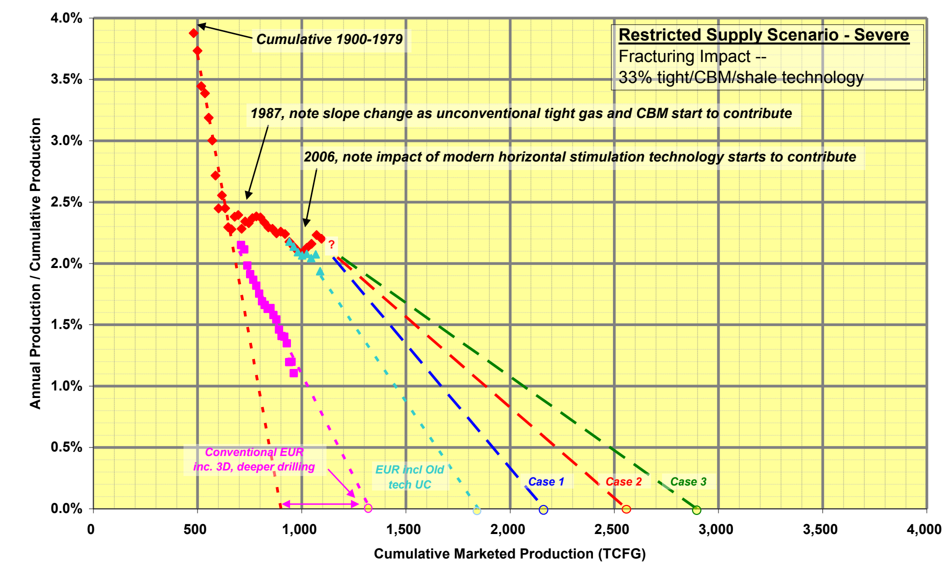


Figure B39: Hubbert Linearization Analysis Range under Restricted Supply Scenario – Severe, Cases 1-3

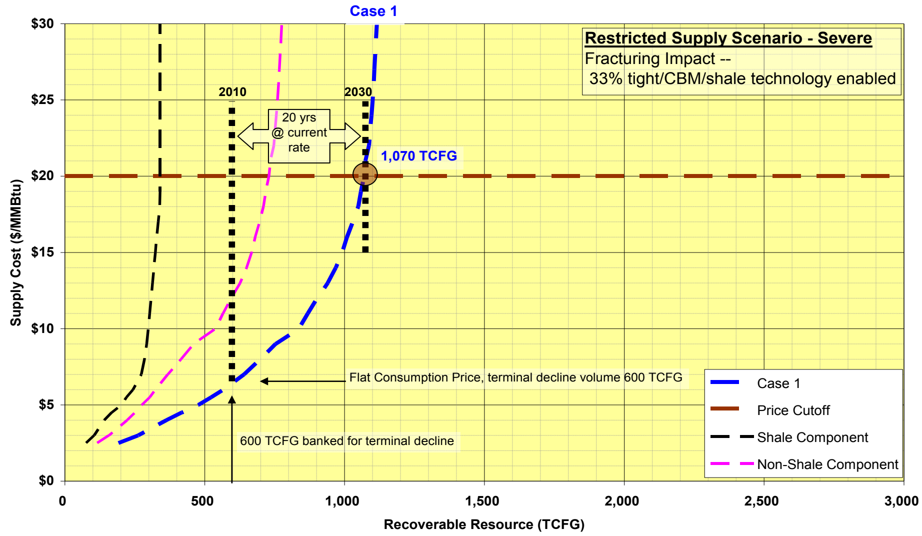


Figure B40: Cost Supply Stack for Remaining Resource and Shale/Non-Shale Breakout (Restricted Supply Scenario - Severe, Case 1)

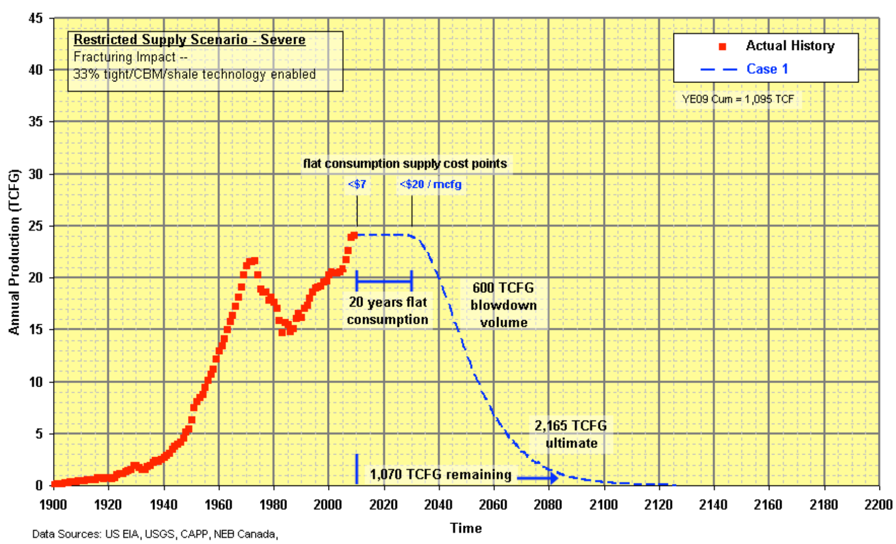


Figure B41: Supply Plateau under Restricted Supply Scenario - Severe, Case 1

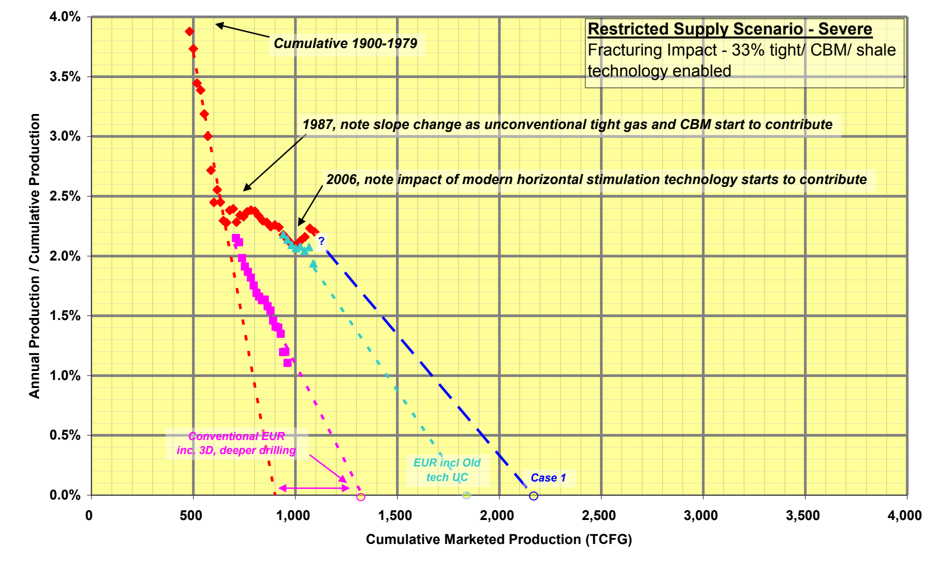


Figure B42: Hubbert Linearization Analysis under Restricted Supply Scenario – Severe, Case 1

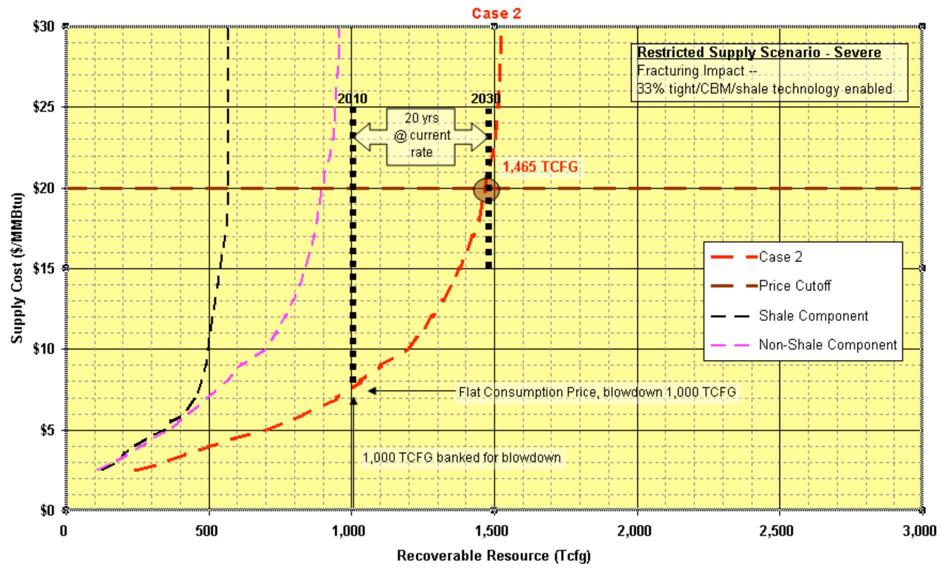


Figure B43: Cost Supply Stack for Remaining Resource and Shale/Non-Shale Breakout (Restricted Supply Scenario - Severe, Case 2)

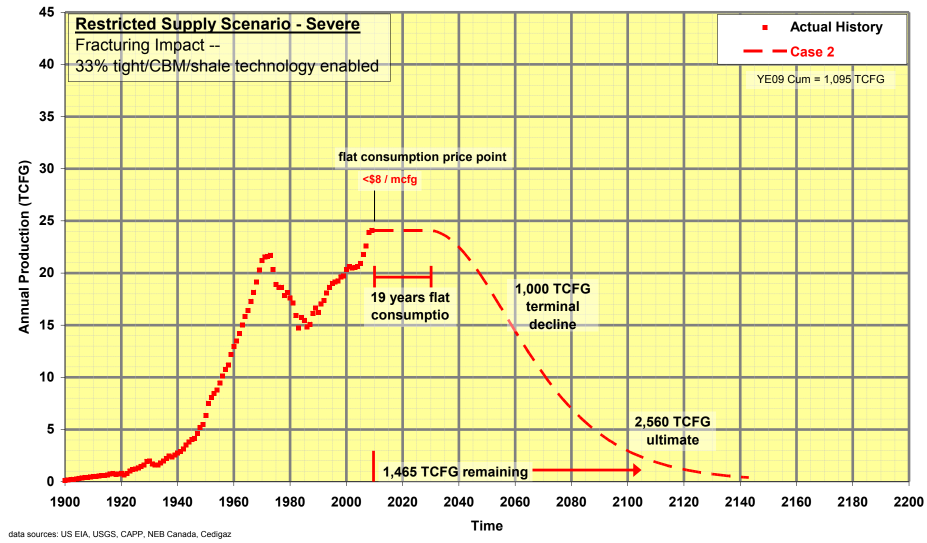


Figure B44: Supply Plateau under Restricted Supply Scenario - Severe, Case 2

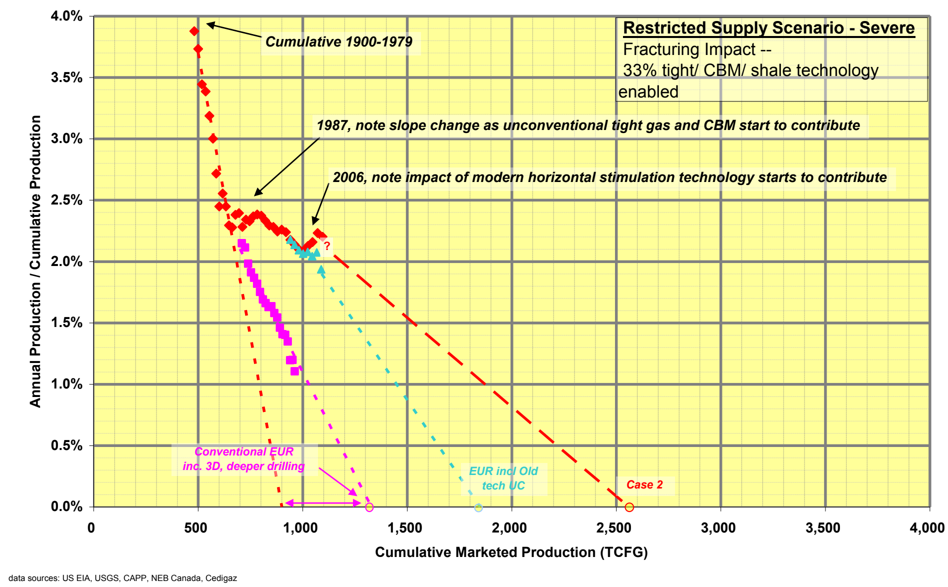


Figure B45: Hubbert Linearization Analysis under Restricted Supply Scenario - Severe, Case 2

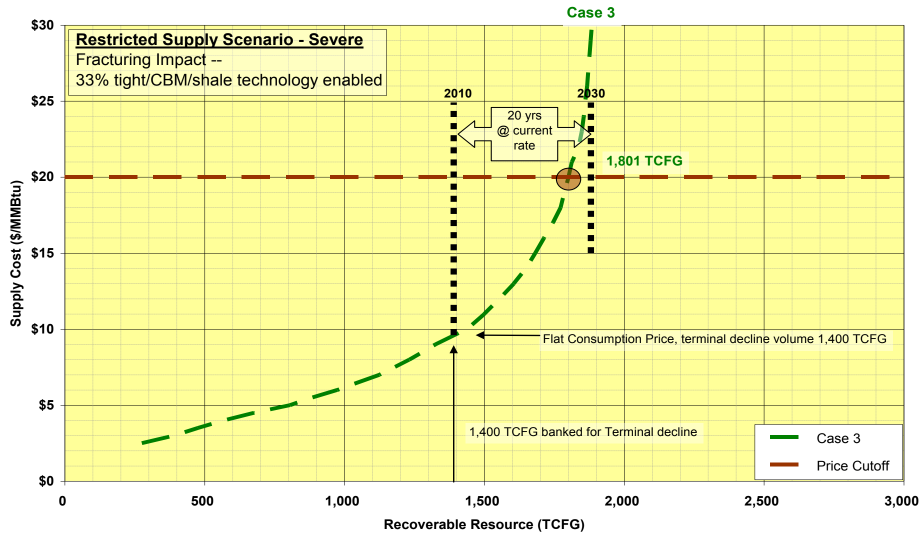


Figure B46: Cost Supply Stack for Remaining Resource and Shale/Non-Shale Breakout (Restricted Supply Scenario - Severe, Case 3)

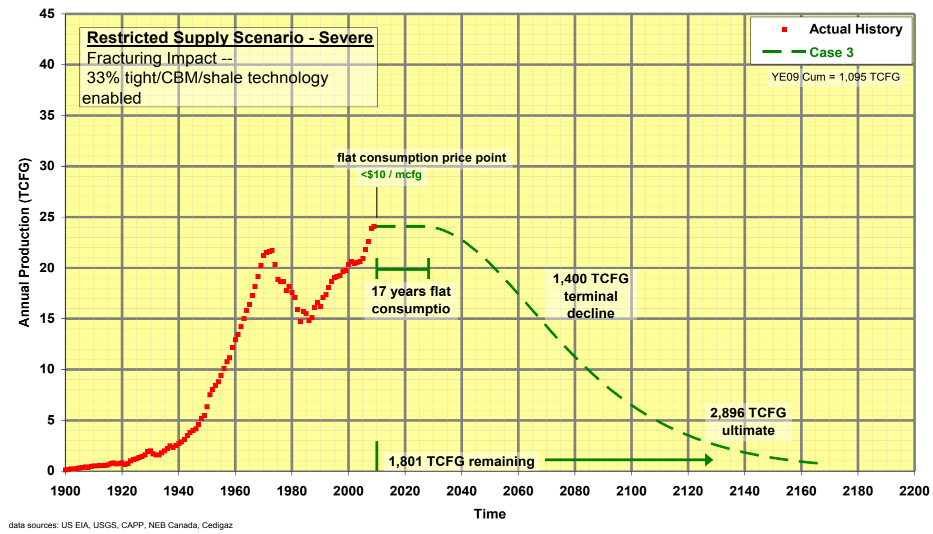


Figure B47: Supply Plateau under Restricted Supply Scenario - Severe, Case 3

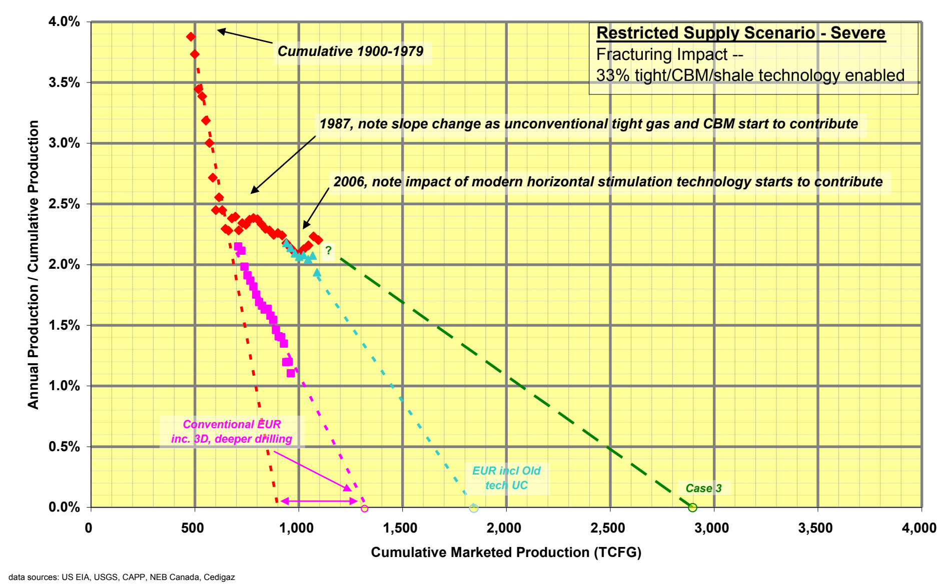


Figure B48: Hubbert Linearization Analysis under Restricted Supply Scenario - Severe, Case 3

Table B5: Moderately Restricted Scenario Details
33% of shale gas/tight gas/CBM supply is eliminated

	Case 1	Case 2	Case 3
Resource Base	**Mean**	**Mean**	**High**
Technology	**Current**	**Advanced**	**Advanced**
Supply Stack based	(TCFG)	(TCFG)	(TCFG)
@ $20/mmBTU Supply Cost			
Ultimate Recoverable Resource	**2,587**	**3,283**	**3,789**
Cum Production as of YE09	1,095	1,095	1,095
YE09 Remaining Recoverable Resource	**1,492**	**2,188**	**2,694**
Years of Flat Production	37 yrs	49 yrs	54 yrs
Flat Production Volume	892	1,188	1,294
Assumed Terminal Decline Volume	600	1,000	1,400
YE09 Remaining Recoverable Resource	**1,492**	**2,188**	**2,694**
Non-Shale Resource	801	1,036	1,281
Shale Resource	691	1,152	1,413
YE09 Remaining Recoverable Resource	**1,492**	**2,188**	**2,694**
Conventional	366	366	366
Old Tech Unconventional	575	575	575
New Tech Unconventional	551	1,247	1,753
<u>2010</u> Yearly Enabled Production	**24.1**	**24.1**	**24.1**
Proved	7.5	4.9	3.4
Conventional	2.6	2.8	3.1
Old Tech Unconventional	0.2	1.2	1.7
New Tech Unconventional	13.8	15.2	15.9
<u>2030</u> Yearly Enabled Production	**24.1**	**24.1**	**24.1**
Proved	5.3	3.6	2.7
Conventional	4.4	3.3	4.1
Old Tech Unconventional	1.1	2.2	2.5
New Tech Unconventional	13.2	15.0	14.8
2030 Supply Cost ($/mmBTU)	< $9	< $7	< $8
<u>2050</u> Yearly Enabled Production		**24.1**	**24.1**
Proved		3.3	2.5
Conventional		4.9	5.3
Old Tech Unconventional		2.9	2.9
New Tech Unconventional		13.1	13.3
2050 Supply Cost ($/mmBTU)		< $13	< $12

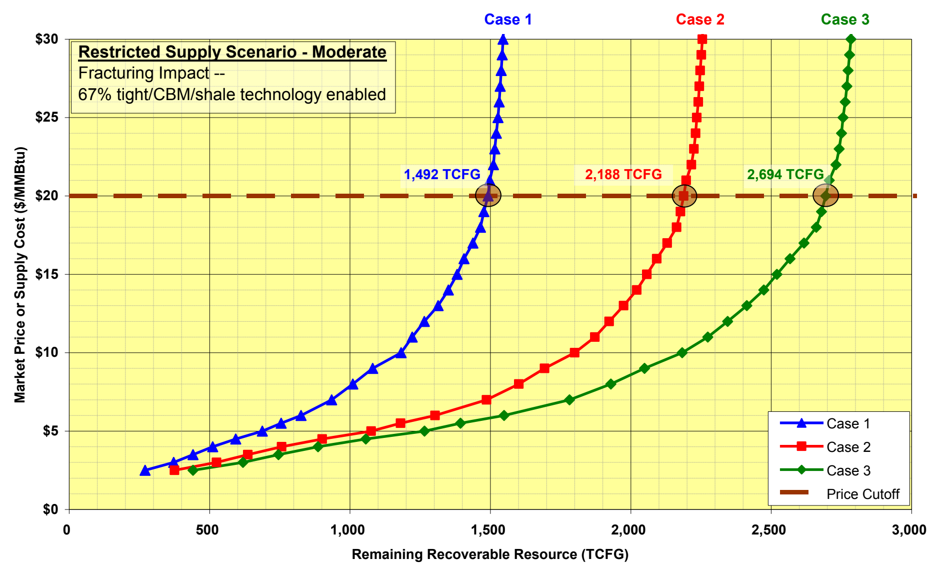


Figure B49: Cost Supply Stack for Remaining Resource range (Restricted Supply Scenario - Moderate, Cases 1-3)

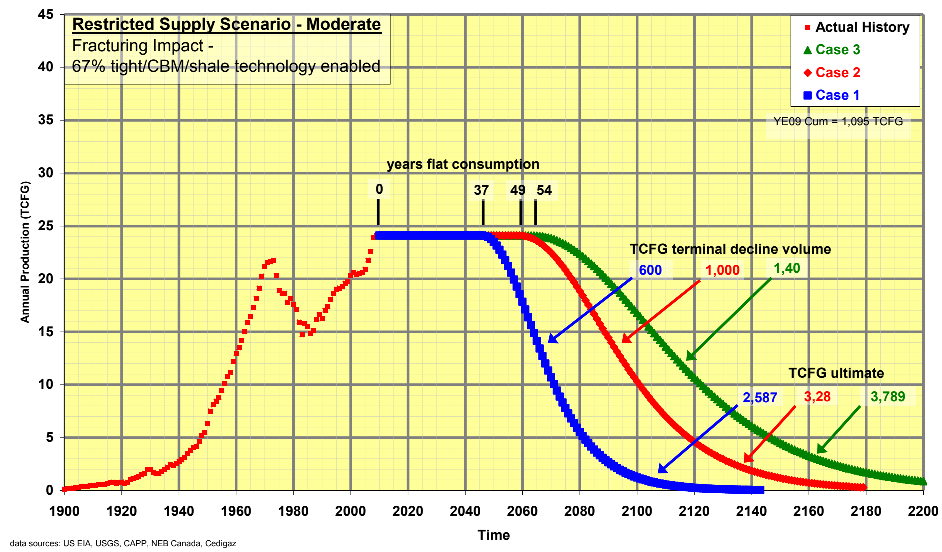


Figure B50: Supply Plateau Range under Restricted Supply Scenario – Moderate, Cases 1-3

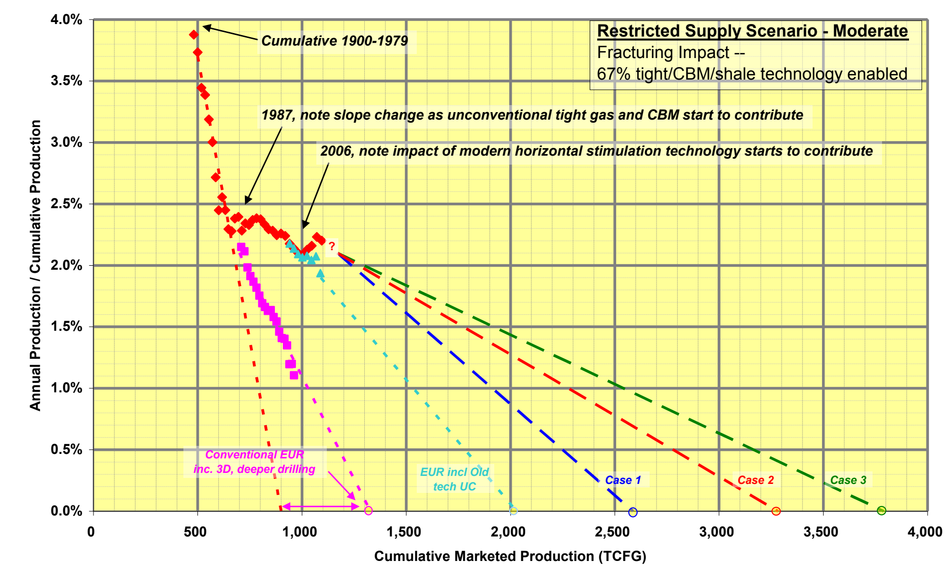


Figure B51: Hubbert Linearization Analysis Range under Restricted Supply Scenario – Moderate, Cases 1-3

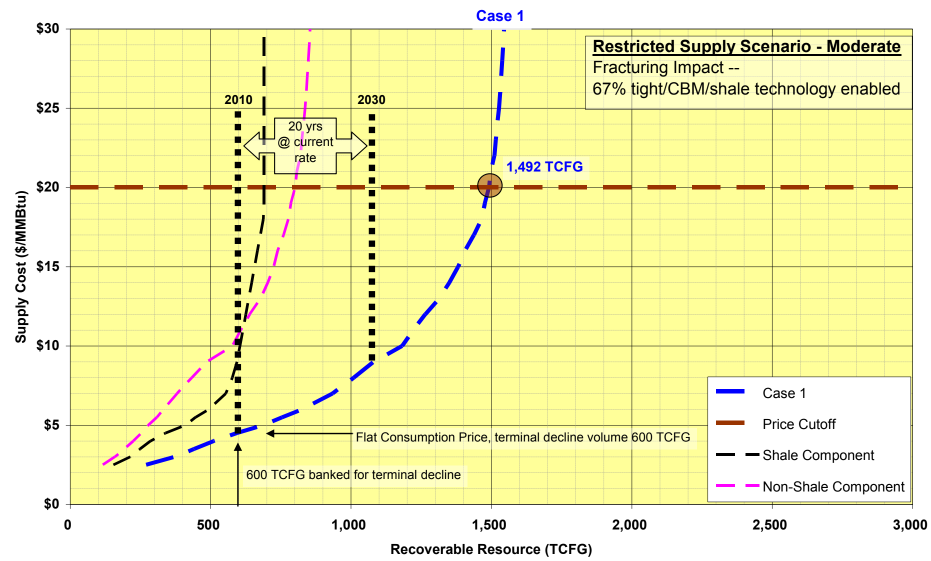


Figure B52: Cost Supply Stack for Remaining Resource and Shale/Non-Shale Breakout (Restricted Supply Scenario - Moderate, Case 1)

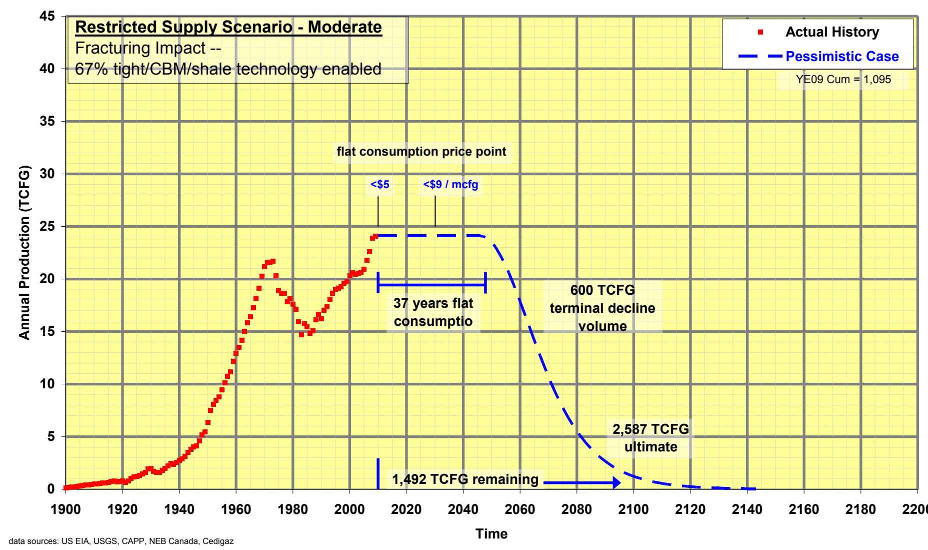


Figure B53: Supply Plateau under Restricted Supply Scenario - Moderate, Case 1

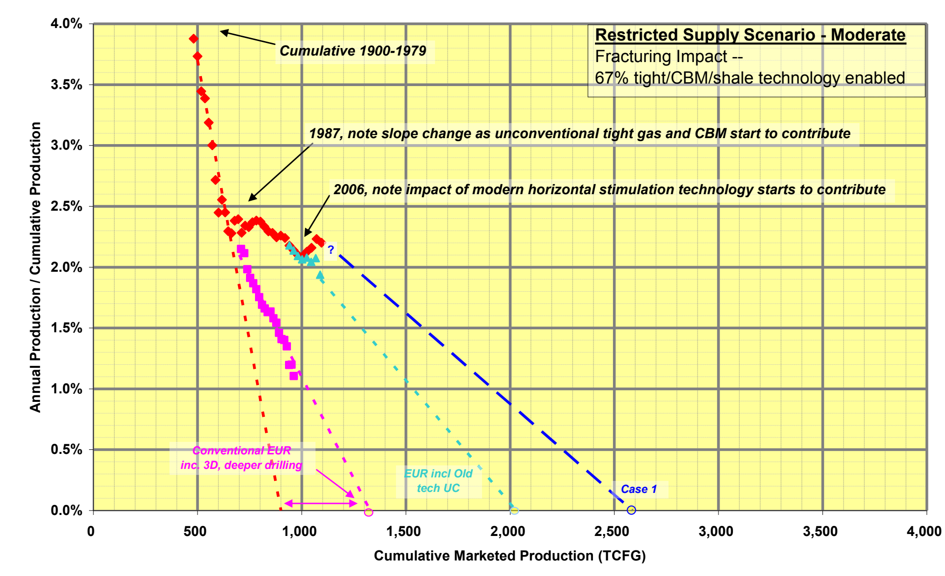


Figure B54: Hubbert Linearization Analysis under Restricted Supply Scenario - Moderate, Case 1

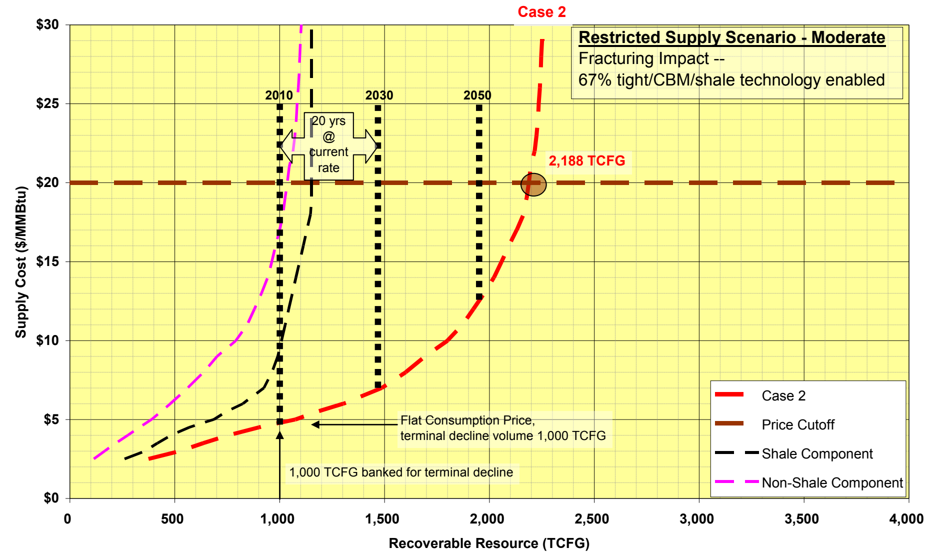


Figure B55: Cost Supply Stack for Remaining Resource and Shale/Non-Shale Breakout (Restricted Supply Scenario - Moderate, Case 2)

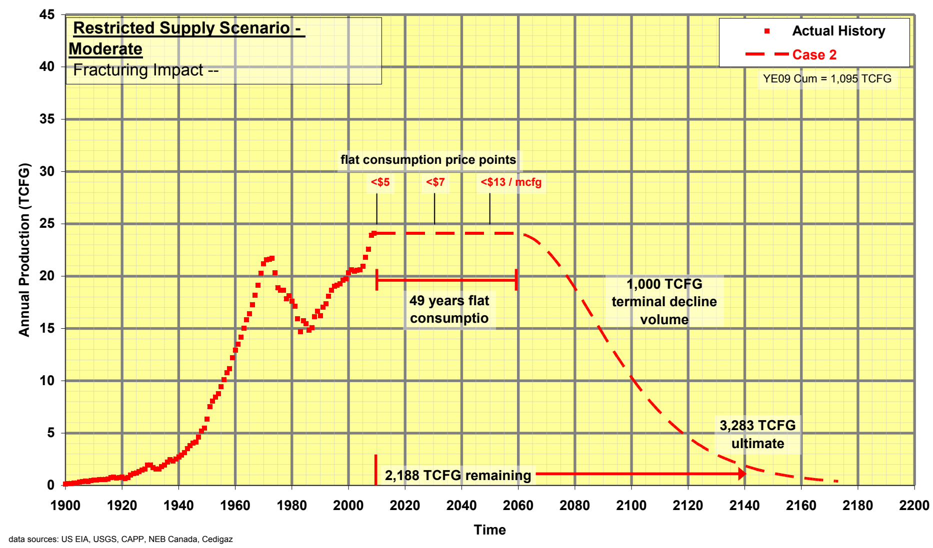


Figure B56: Supply Plateau under Restricted Supply Scenario - Moderate, Case 2

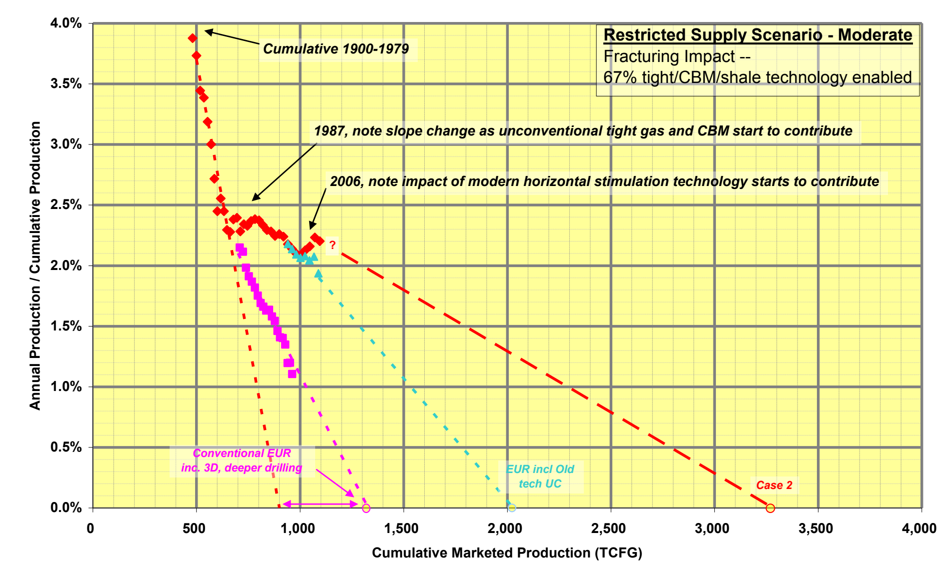


Figure B57: Hubbert Linearization Analysis under Restricted Supply Scenario - Moderate, Case 2

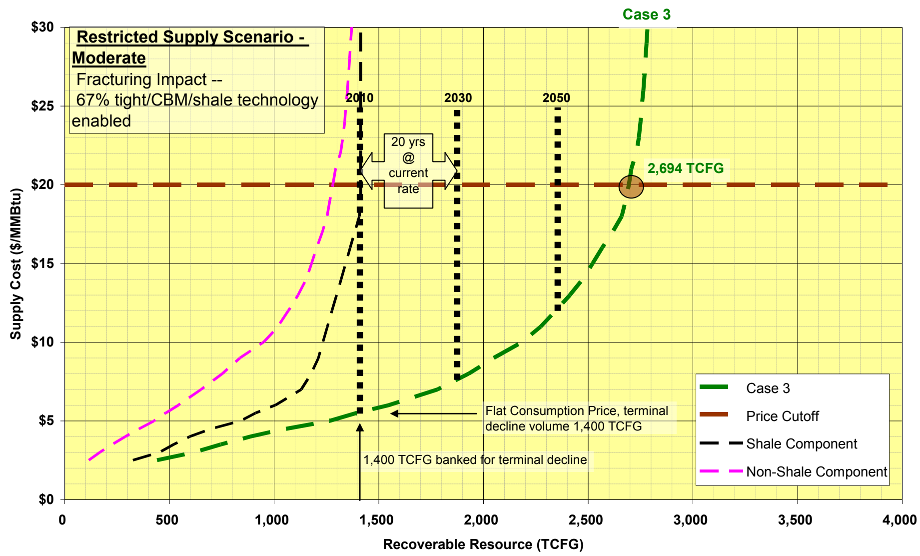


Figure B58: Cost Supply Stack for Remaining Resource and Shale/Non-Shale Breakout (Restricted Supply Scenario - Moderate, Case 3)

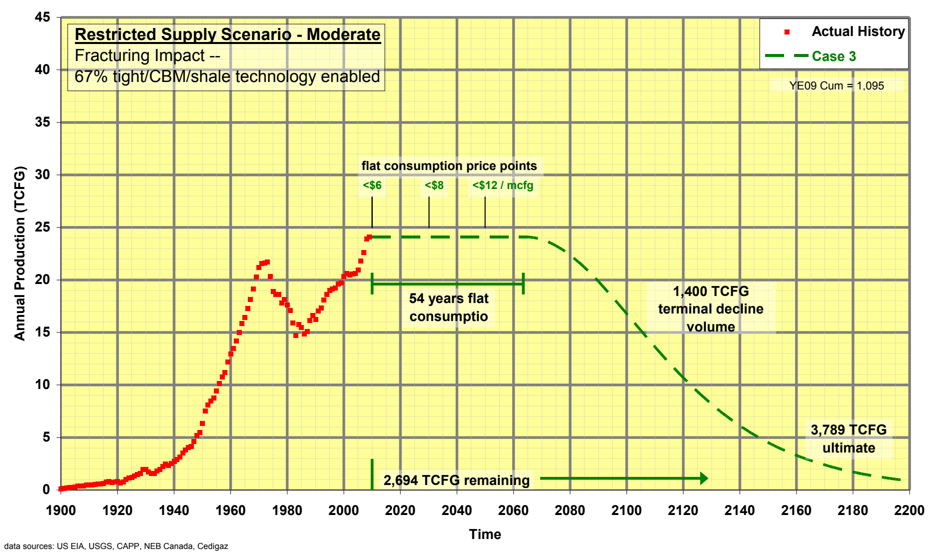


Figure B59: Supply Plateau under Restricted Supply Scenario - Moderate, Case 3

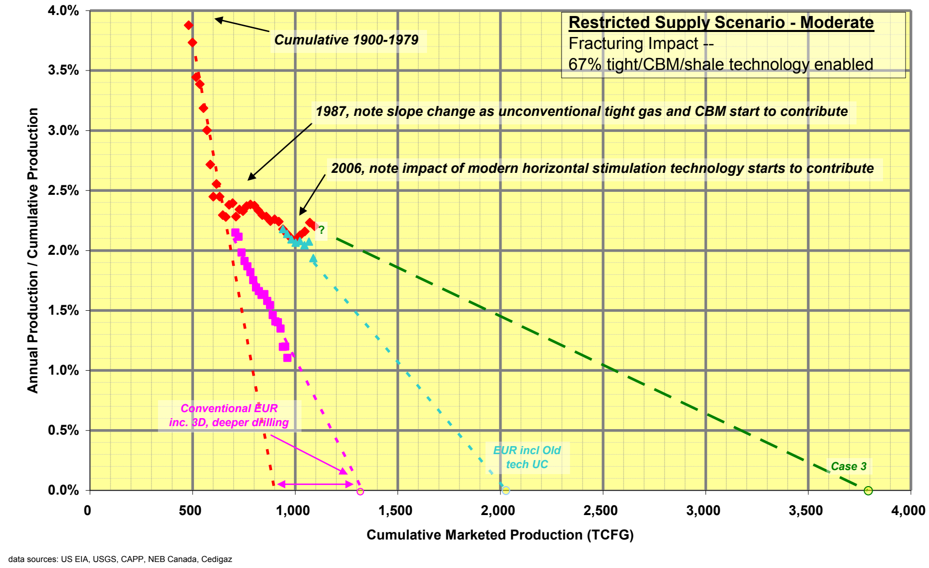


Figure B60: Hubbert Linearization Analysis under Restricted Supply Scenario - Moderate, Case 3

Table B6: Restricted Scenario (Increased Cost) Details
Cost to supply shale gas/tight gas/CBM increased by $2/mmBTU

	Case 1	Case 2	Case 3
Resource Base	**Mean**	**Mean**	**High**
Technology	**Current**	**Advanced**	**Advanced**
Supply Stack based	(TCFG)	(TCFG)	(TCFG)
@ $20/mmBTU Supply Cost			
Ultimate Recoverable Resource	**2,979**	**3,973**	**4,640**
Cum Production as of YE09	1,095	1,095	1,095
YE09 Remaining Recoverable Resource	**1,884**	**2,878**	**3,546**
Years of Flat Production	53 yrs	78 yrs	89 yrs
Flat Production Volume	1,284	1,878	2,146
Assumed Terminal Decline Volume	600	1,000	1,400
YE09 Remaining Recoverable Resource	**1,884**	**2,878**	**3,546**
Non-Shale Resource	857	1,166	1,445
Shale Resource	1,027	1,712	2,101
YE09 Remaining Recoverable Resource	**1,884**	**2,878**	**3,546**
Conventional	189	189	189
Old Tech Unconventional	753	753	753
New Tech Unconventional	942	1,936	2,603
2010 Yearly Enabled Production	**24.1**	**24.1**	**24.1**
Proved	8.0	5.1	3.6
Conventional	3.1	3.5	3.7
Old Tech Unconventional	0.1	0.5	0.9
New Tech Unconventional	12.9	15.0	15.9
2030 Yearly Enabled Production	**24.1**	**24.1**	**24.1**
Proved	5.1	3.5	2.7
Conventional	3.4	3.2	3.5
Old Tech Unconventional	0.4	1.4	1.5
New Tech Unconventional	15.2	16.0	16.4
2030 Supply Cost ($/mmBTU)	< $8	< $7	< $7
2050 Yearly Enabled Production	**24.1**	**24.1**	**24.1**
Proved	4.0	2.9	2.2
Conventional	4.2	3.2	3.6
Old Tech Unconventional	1.8	2.1	2.2
New Tech Unconventional	14.1	15.9	16.1
2050 Supply Cost ($/mmBTU)	< $12	< $8	< $8

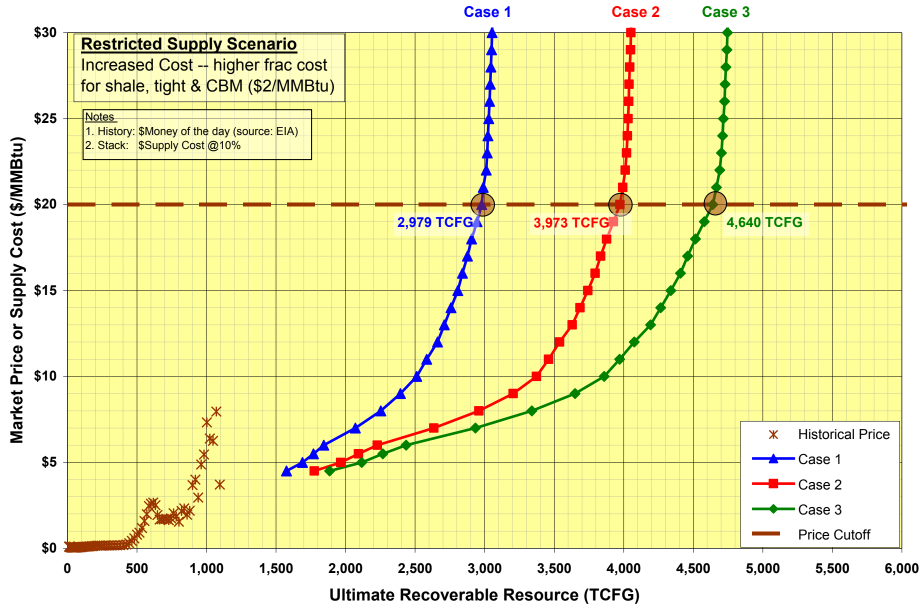


Figure B61: Cost Supply Stack for Remaining Resource range (Restricted Supply Scenario – Increased Cost, Cases 1-3)

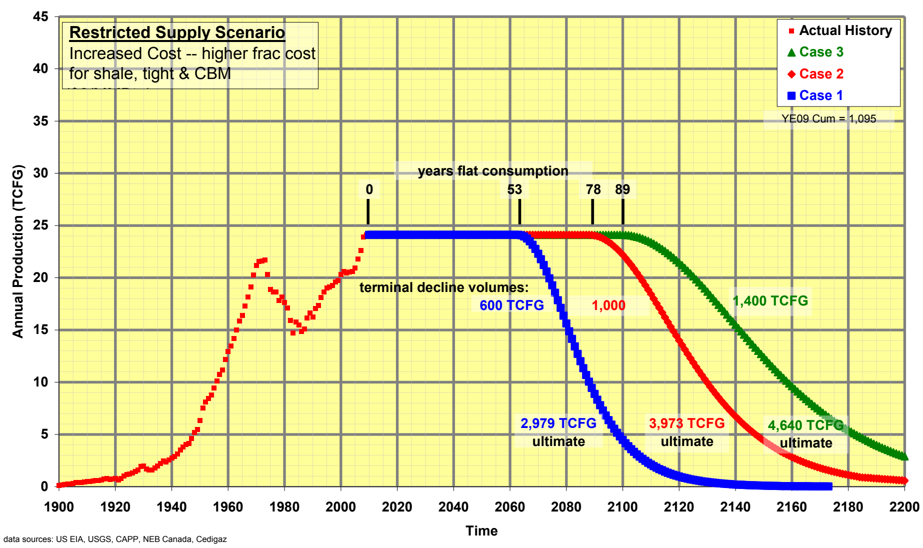


Figure B62: Supply Plateau Range under Restricted Supply Scenario – Increased Cost, Cases 1-3

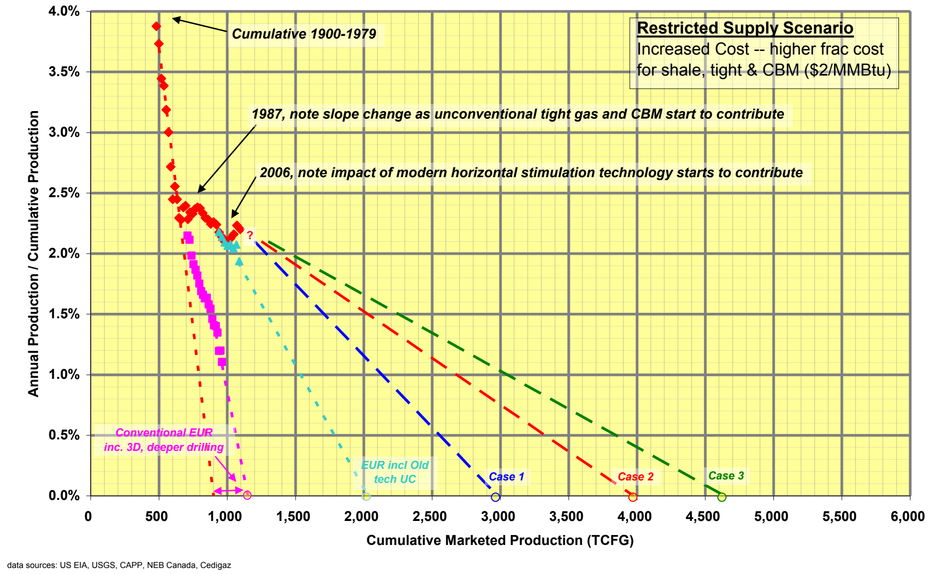


Figure B63: Hubbert Linearization Analysis Range under Restricted Supply Scenario – Increased Cost, Cases 1-3

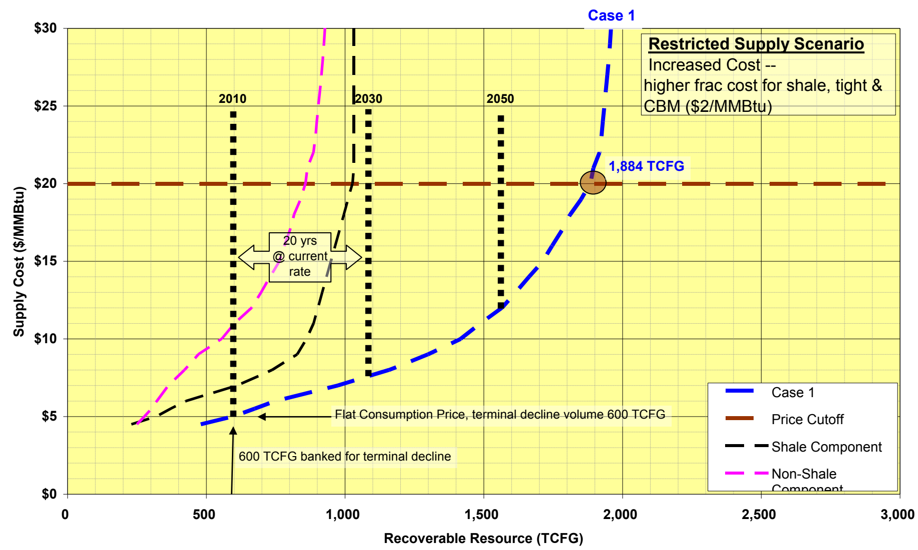


Figure B64: Cost Supply Stack for Remaining Resource and Shale/Non-Shale Breakout (Restricted Supply Scenario – Increased Cost, Case 1)

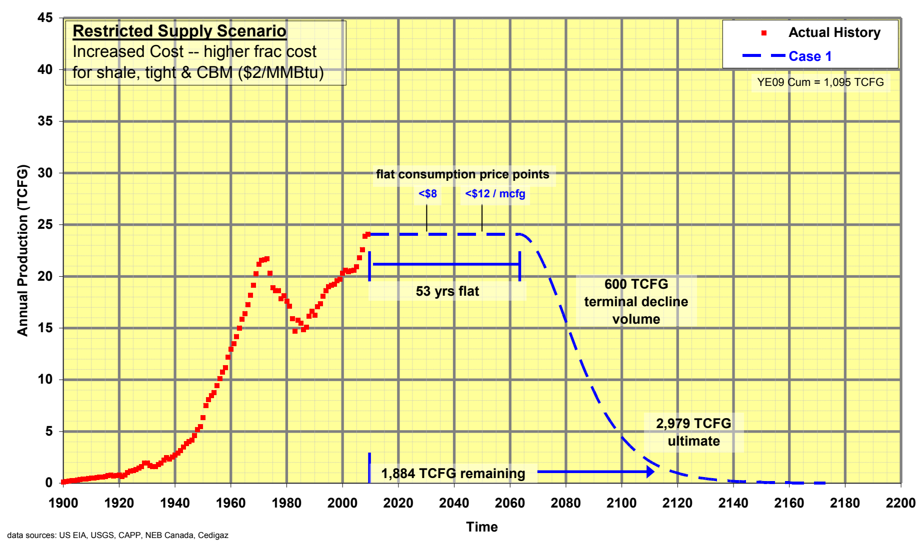


Figure B65: Supply Plateau under Restricted Supply Scenario – Increased Cost, Case 1

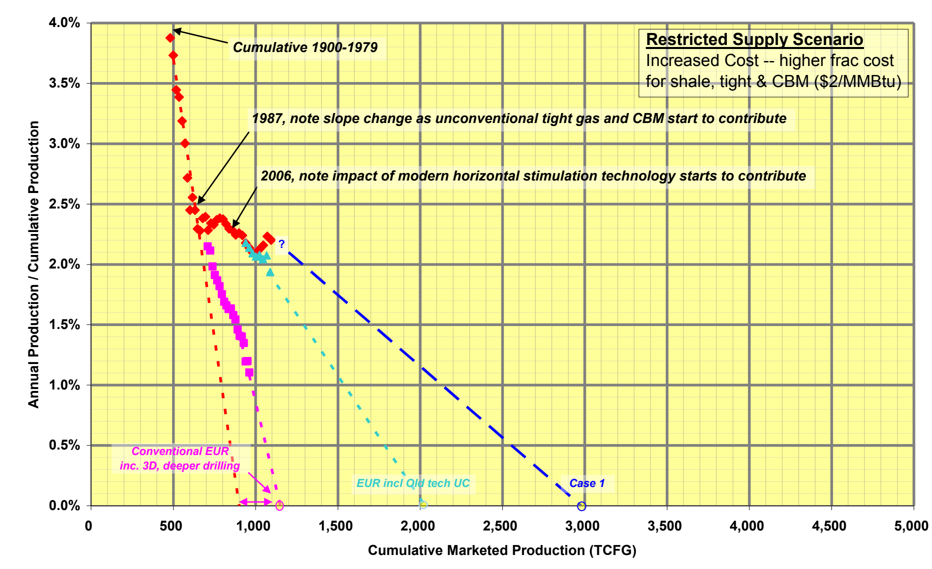


Figure B66: Hubbert Linearization Analysis under Restricted Supply Scenario – Increased Cost, Case 1

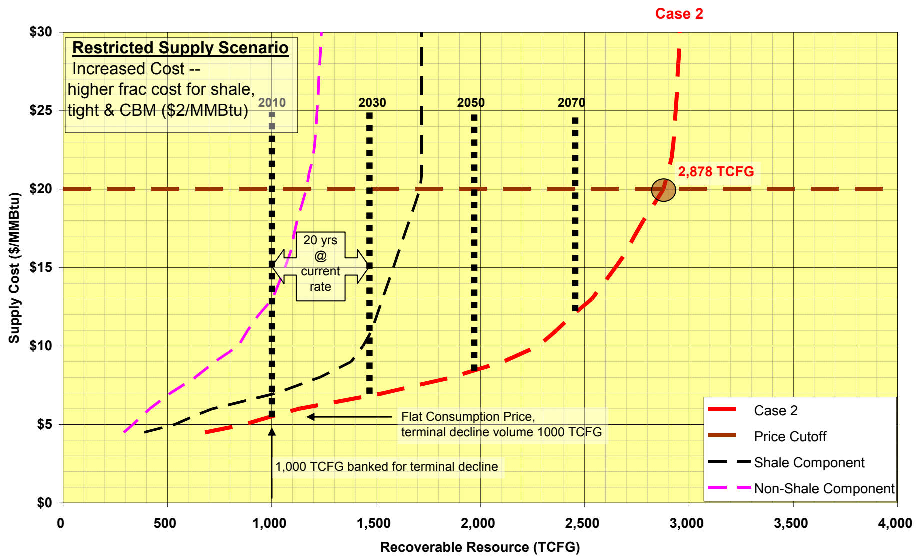


Figure B67: Cost Supply Stack for Remaining Resource and Shale/Non-Shale Breakout (Restricted Supply Scenario – Increased Cost, Case 2)

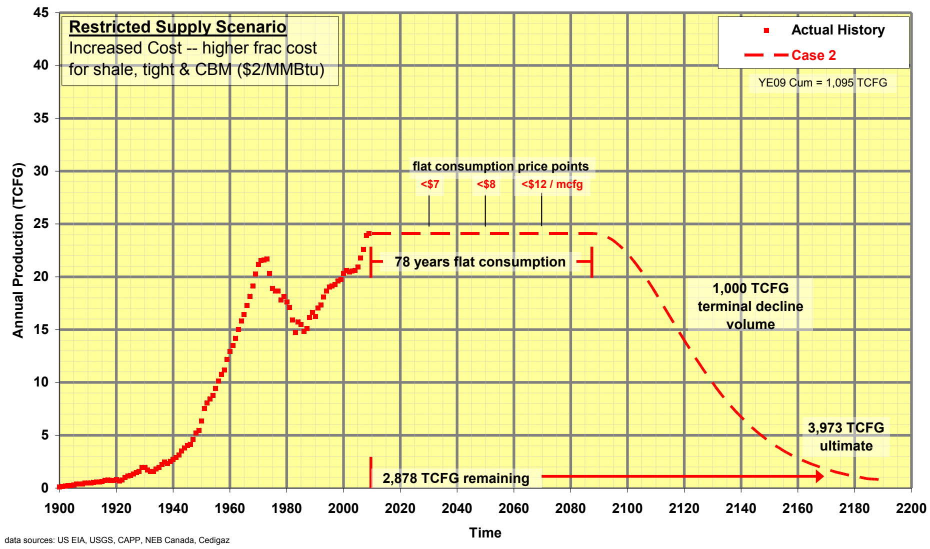


Figure B68: Supply Plateau under Restricted Supply Scenario – Increased Cost, Case 2

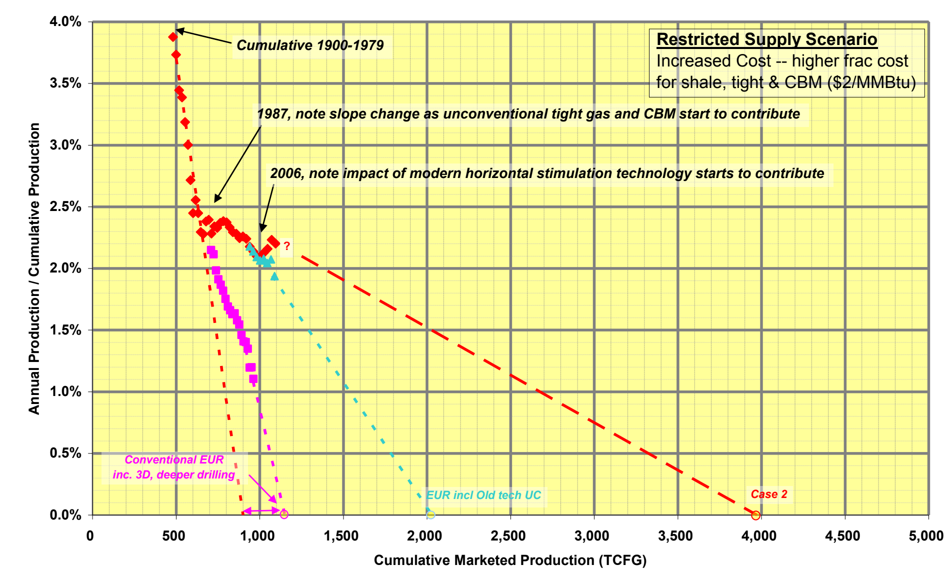


Figure B69: Hubbert Linearization Analysis under Restricted Supply Scenario – Increased Cost, Case 2

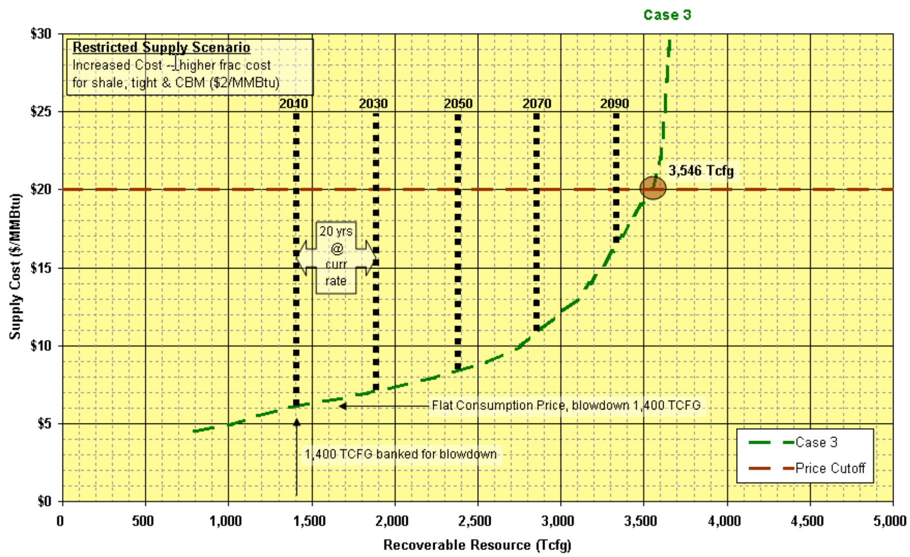


Figure B70: Cost Supply Stack for Remaining Resource and Shale/Non-Shale Breakout (Restricted Supply Scenario – Increased Cost, Case 3)

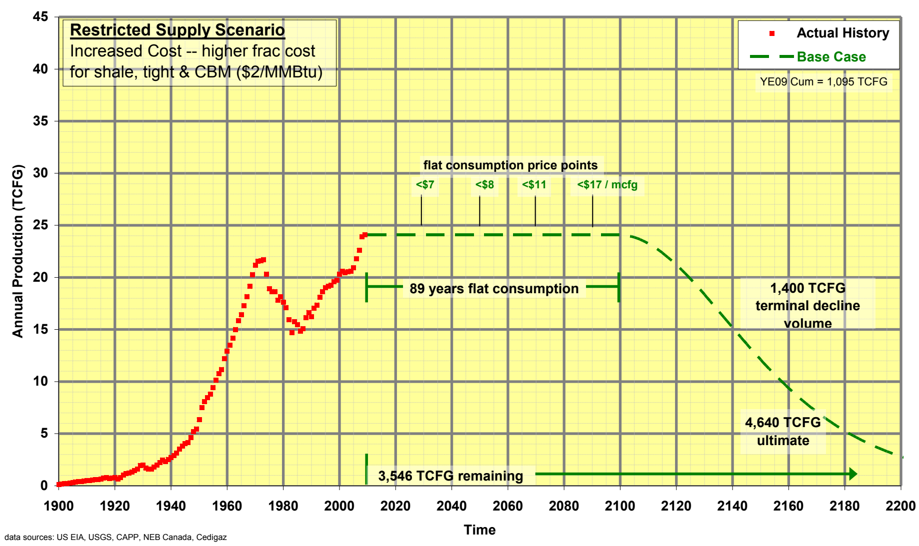


Figure B71: Supply Plateau under Restricted Supply Scenario – Increased Cost, Case 3

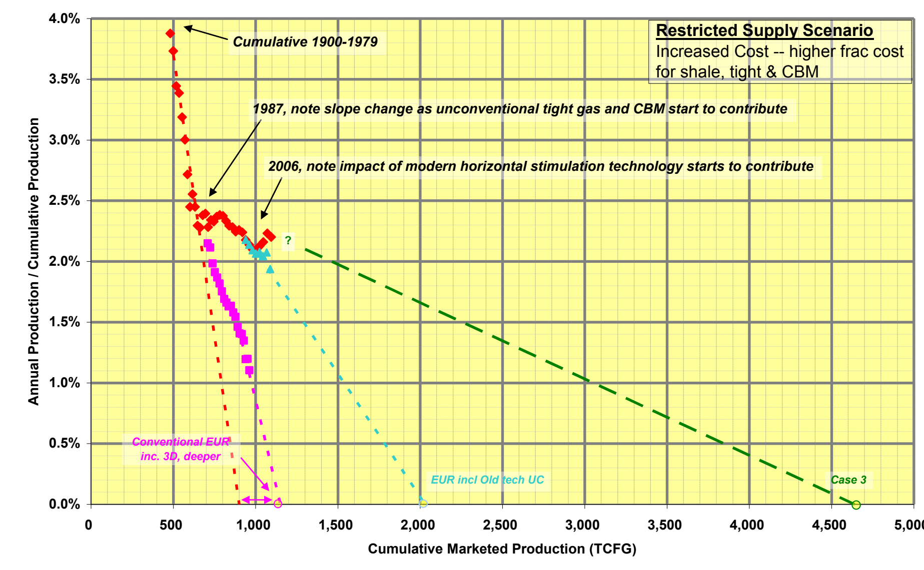


Figure B72: Hubbert Linearization Analysis under Restricted Supply Scenario – Increased Cost, Case 3

Appendix C – Data Discussion

Supplemental MITei Data

Gas supply curves were generated utilizing the North America model developed by ICF[1]. The data was modified to obtain the onshore, non-arctic gas resource for both the U.S. Lower 48 and Canada. Six views are shown for the high-medium-low resource bases using both current and advanced technology. The gas supply curves contain both proved and unproved resources at various wellhead prices from all gas types.

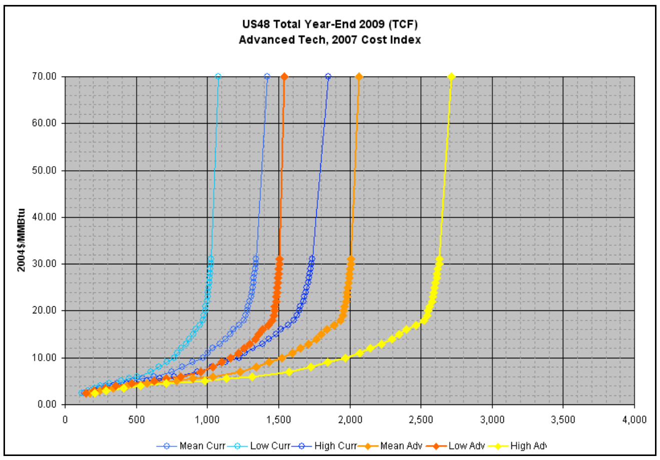


Figure C1 – U.S. Onshore (Non-Arctic) Gas Supply Cost Curves
Data source: MITei/ICF

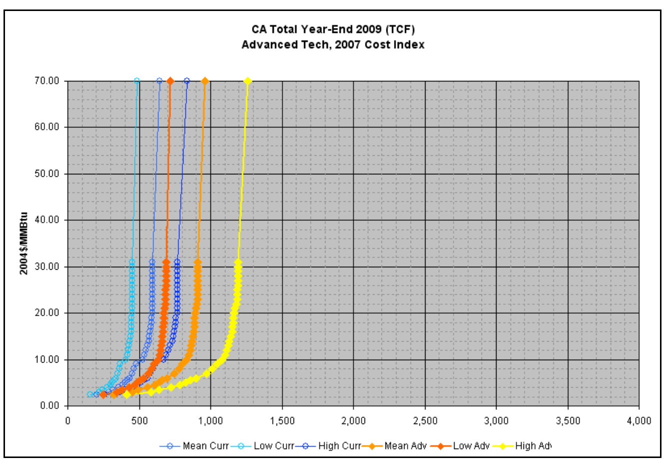


Figure C2 - Canada Onshore (Non-Arctic) Gas Supply Cost Curves
Data source: MITei/ICF

Combining MITei Raw Data

Statistically speaking, one may not add other than mean sample values together and attain the combined mean – this simple addition is flawed in trying to adding P10 or P90 values together for example. Figure C1 illustrates the (statistically correct) manner in which we incorporated the MITei provided data for Canada and the U.S. to achieve the combined dataset.

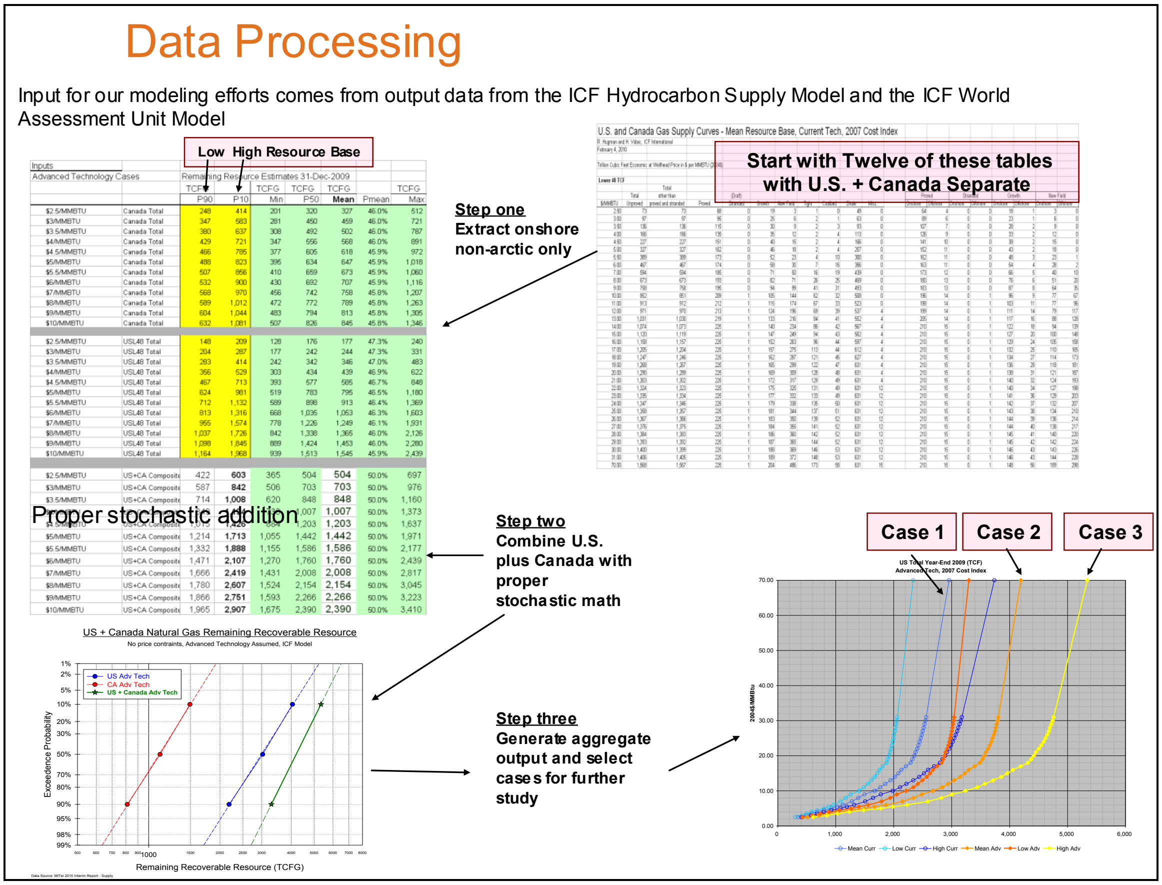


Figure C3 – Data Combination Workflow

Hubbert Linearization

In 1956, Hubbert presented a paper[2] that postulated that because of the rate of growth of both population and oil demand that the peak in crude oil production would be reached within his lifetime. The oil production and decline, he said, would follow a bell-shaped curve. He refined his technique and provided the means of estimating total recoverable resources by assuming that the cumulative recovery curve would be an S-shaped logistic function. By plotting the ratio of annual production to cumulative production on the y-axis against cumulative production on the x-axis, it may be estimated where the S-shaped curve maxes out[3] and corresponds to the ultimate recovery of a resource. By applying the technique referred to as "Hubbert Linearization" to natural gas production over different time intervals, an idea of the incremental recoverable gas from technology may be ascertained.

There are a number of reasons that Hubbert Linearization may underestimate total resource. For one, each trend projected from the data is inherently tied to a specific price for natural gas that exists during that time. As was noted for the Barnett, although there appears to be at least 20 TCFG of natural gas enabled ($4 to $5 per MCF), a modest price increase will enable additional resource.

Secondly, the oil commodity market has demonstrated inelastic demand. That is, every barrel that is brought to market will find a buyer and not meaningfully impact the price. Thus, oil production will follow a bell-shaped curve as the oil is rushed to market to find a global buyer. However, natural gas still remains a regional commodity. Large discoveries of natural gas rushed to market result in a decrease in price and a slow-down in drilling activity. Natural gas ultimate recovery forecasts will therefore systematically underestimate the resource because natural gas exploration is constrained by price rather than by supply.

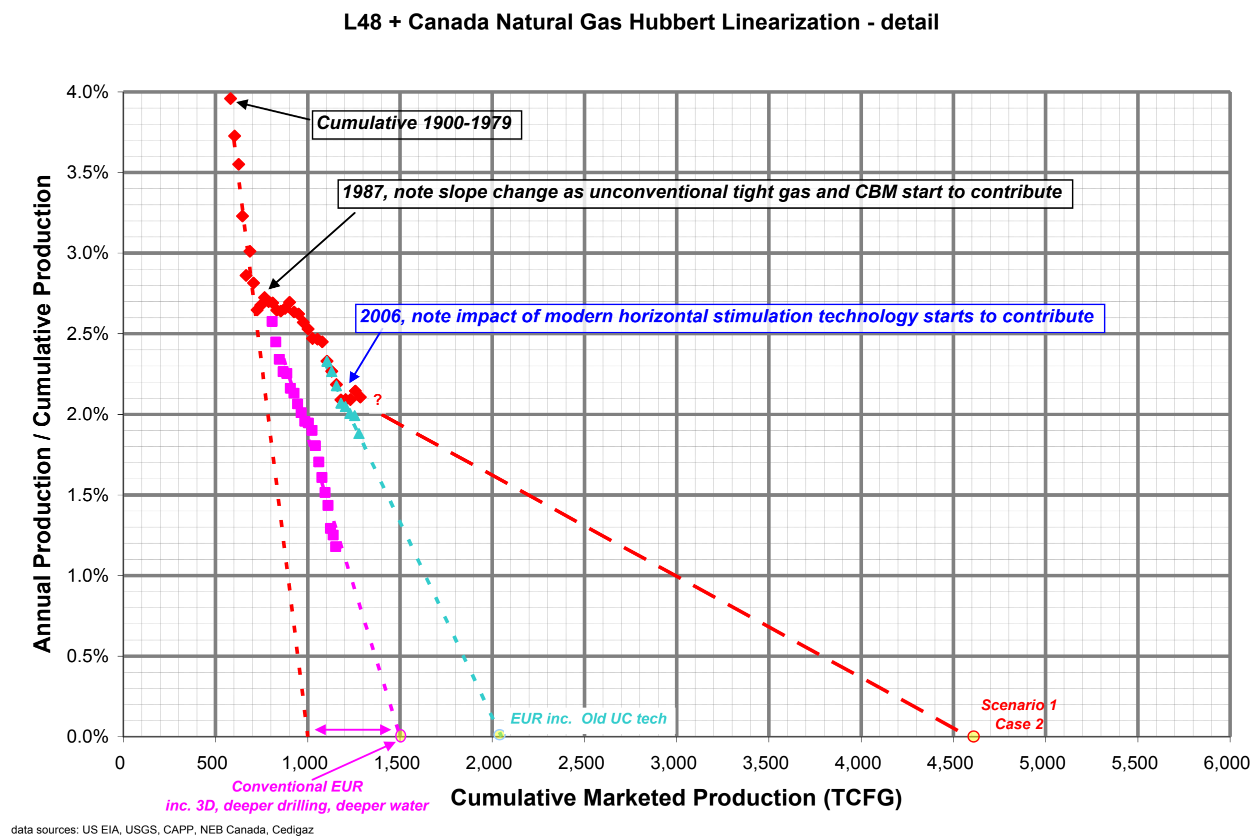


Figure C4 - Hubbert Linearization of North American Natural Gas Production

For all of the previously discussed reasons, the Hubbert Linearization plots should be thought of as demonstrating the lower-limit of the eventual ultimate recoverable resource. As was previously noted, and may be seen by Figures 14, 15, 16 and 21, upward revisions of resource estimates are the norm.

Development of Terminal Decline Volume

Idealized Hubbert curve constructions were utilized to estimate the volume of gas produced after any plateau period. It should be reasonable to assume directionally that higher resource estimates (and higher supply levels) would support, if not mandate, higher terminal decline volumes. The terminal decline volume is represented in Figure C5 below and increases in the Flat Supply scenario from 600 TCFG through 1000 TCFG to 1400 TCFG for Case 1 through Case 2 to Case 3 respectively. For the

Supply Growth scenario terminal decline volumes were increased 50% from this, commensurate with the increased rate of production (24.1 TCFG/yr versus 36.5 TCFG/yr).

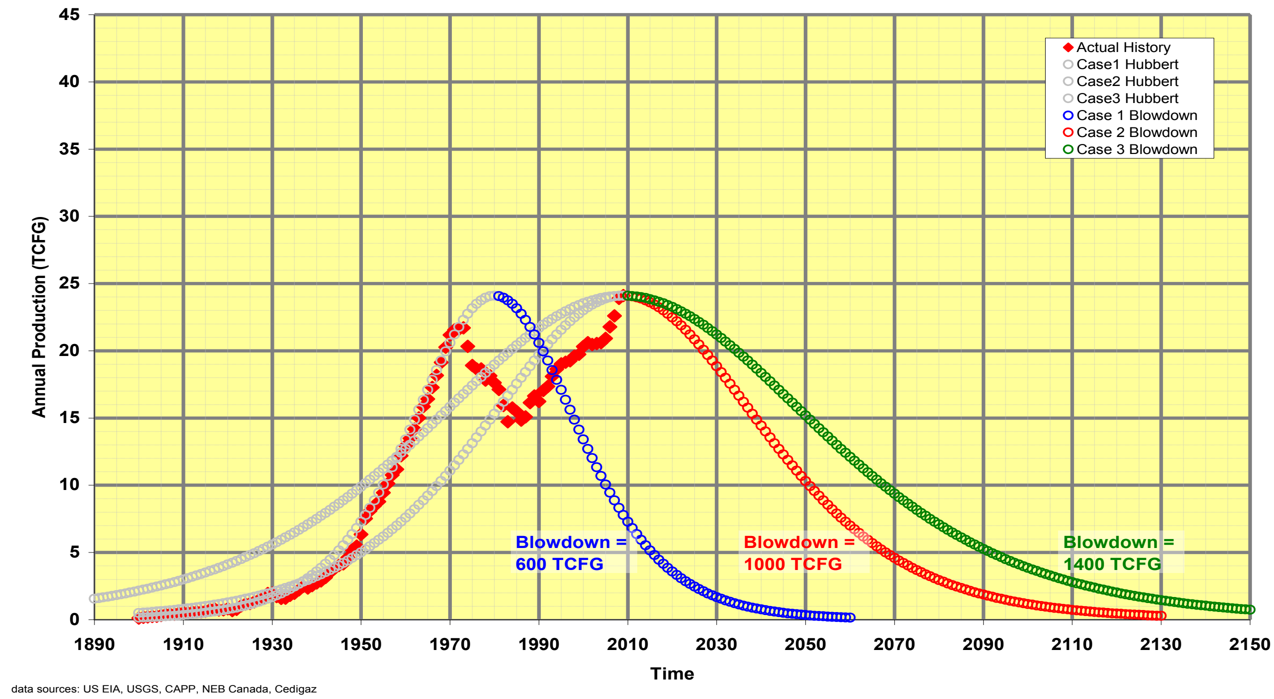


Figure C5: Idealized Hubbert Curves for Terminal Decline Periods, the Colored (declining) Half is Assumed

Supplemental Front End Model (FEM) Details

Although the purpose of the FEM is to provide the basis for the regional well counts to supply the BEM for indicative input parameter estimate - **and as such are not specific regional forecasts** – the FEM U.S. L48 and Canada onshore gas production and wells split are shown by gas category for the Flat Supply and Supply Growth Scenarios in Figures C4 and C5 respectively for completeness.

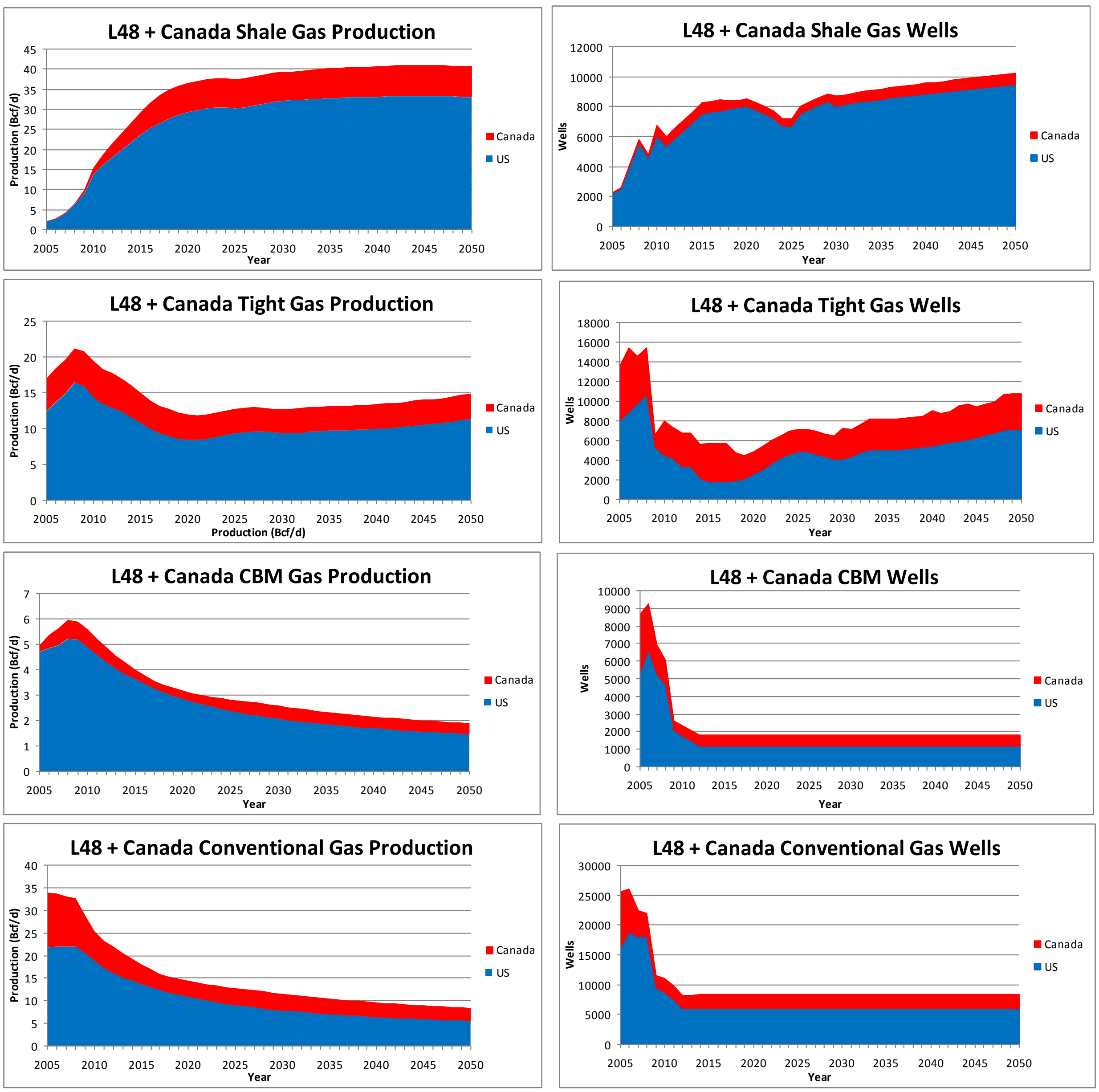


Figure C6: Front End Model Projected Regional Wells (Flat Supply Scenario)

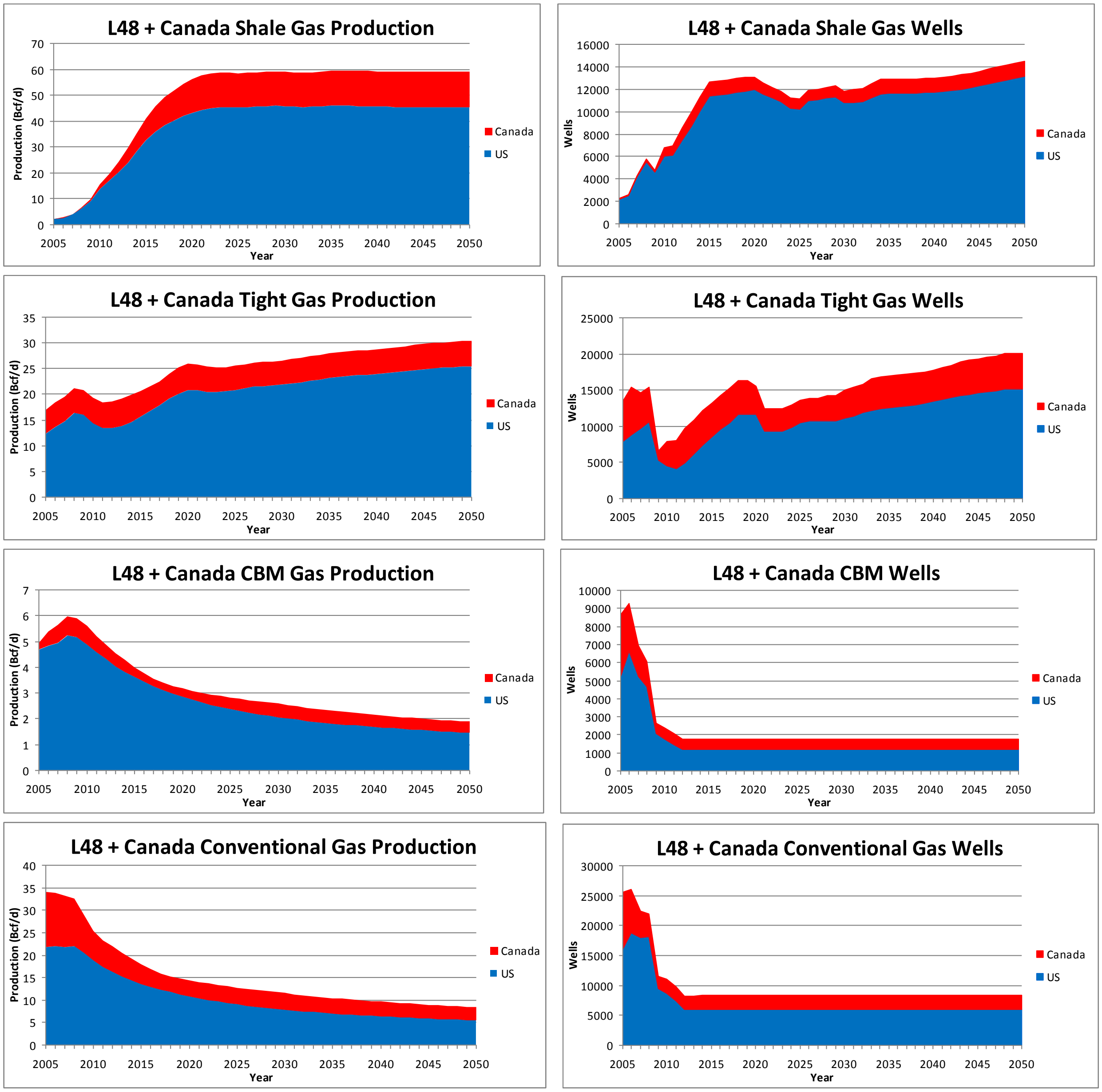


Figure C7: Front End Model Projected Regional Wells (Supply Growth Scenario)

Supplemental Back End Model (BEM) Details

Analog	2008	2010	2030	2050
Marcellus	729	928	1,182	1,357
Haynesville	141	694	1,355	1,412
Generic (Barnett, Woodford, Eagle Ford)	4,684	3,186	5,489	6,724
Canadian (Montney)	255	700	700	756
Generic (Jonah/Pinedale)	15,423	5,764	7,274	10,764
Generic (Powder River / Raton)	6,079	1,426	1,785	1,785
South Texas (not frac'ed)	21,934	6,478	8,294	8,297

Table C1: Back End Model Projected Regional Wells (Flat Supply Scenario)

Analog	2008	2010	2030	2050
Marcellus	729	928	1,627	1,881
Haynesville	141	694	1,866	1,915
Generic (Barnett, Woodford, Eagle Ford)	4,684	3,186	7,341	9,386
Canadian (Montney)	255	700	1,008	1,344
Generic (Jonah/Pinedale)	15,423	5,764	14,999	20,124
Generic (Powder River / Raton)	6,079	1,426	1,785	1,785
South Texas (not frac'ed)	21,934	6,478	8,294	8,301

Table C2: Back End Model Projected Regional Wells (Supply Growth Scenario)

Parameter	***A (Low) or B (High)***
Rigs	=((wells * Lower Central tendency(median(A & B days to drill)))/Drilling efficiency days
Capex	= wells * Lower Central Tendency(median A &B d&c estimates)
Frac Stages	= wells * Lower Central Tendecy(median A & B fracs)
Proppant	= Frac Stages * (Lower Central Tendency(median A & B lbs per stage))
Water	= Frac Stages * (Lower Central Tendency(median (A & B gallons per stage))
Pipe	= wells * Estimate from Steel Worksheet
Drilling Efficiency	340 days
People	=154.82+ 0.01361*rigs

Table C3: Back End Model Calculation Equations (A: Lower Tendency = 80% of Median shown, B: Upper Tendency = 105% of Median)

Shale 1								
Marcellus (Low)	**Vert Depth (ft)**	**Lat Length (ft)**	**Footage**	**Size (in)**	**Grade**	**Weight (lb/ft)**	**String Weight (lb)**	**Total Steel Weight (lb)**
Surface casing	5,000	3,000	1,500	9.625	J-55	36	54,000	243,250
Intermediate casing			0	7	L-80	26	0	
Production casing			8,000	5.5	P-110	20	160,000	
Tubing			4,500	2.875	L-80	6.5	29,250	
Marcellus (High)								
Surface casing	9,000	5,000	1,500	9.625	J-55	36	54,000	389,250
Intermediate casing			0	7	L-80	26	0	
Production casing			14,000	5.5	P-110	20	280,000	
Tubing			8,500	2.875	L-80	6.5	55,250	
							Average	**316,250** lbs
								144 tonnes

Shale 2								
Haynesville (Low)	**Vert Depth (ft)**	**Lat Length (ft)**	**Footage**	**Size (in)**	**Grade**	**Weight (lb/ft)**	**String Weight (lb)**	**Total Steel Weight (lb)**
Surface casing	10,000	3,500	2,100	10.75	J-55	40.5	85,050	677,800
Intermediate casing			8,000	7.625	P-110	29.7	237,600	
Production casing			13,500	5.5	P-110	23	310,500	
Tubing			9,500	2.375	L-80	4.7	44,650	
Haynesville (High)								
Surface casing	14,000	5,500	2,100	10.75	J-55	40.5	85,050	953,400
Intermediate casing			12,000	7.625	P-110	29.7	356,400	
Production casing			19,500	5.5	P-110	23	448,500	
Tubing			13,500	2.375	L-80	4.7	63,450	
							Average	**815,600** lbs
								371 tonnes

Shale 3 (generic)								
Eagle Ford Dry Gas (Low)	**Vert Depth (ft)**	**Lat Length (ft)**	**Footage**	**Size (in)**	**Grade**	**Weight (lb/ft)**	**String Weight (lb)**	**Total Steel Weight (lb)**
Surface casing	9,000	4,500	3,000	9.625	P-110	47	141,000	448,700
Production casing			9,000	5.5	P-110	23	207,000	
Production casing			4,500	4.5	P-110	13.5	60,750	
Tubing			8,500	2.375	L-80	4.7	39,950	
Eagle Ford Dry Gas (High)								
Surface casing	14,000	5,500	3,000	9.625	P-110	47	141,000	598,350
Production casing			14,000	5.5	P-110	23	322,000	
Production casing			5,500	4.5	P-110	13.5	74,250	
Tubing			13,000	2.375	L-80	4.7	61,100	
							Average	**523,525** lbs
								238 tonnes

Shale 3 (generic)								
Barnett (Low)	**Vert Depth (ft)**	**Lat Length (ft)**	**Footage**	**Size (in)**	**Grade**	**Weight (lb/ft)**	**String Weight (lb)**	**Total Steel Weight (lb)**
Surface casing	5,000	1,400	1,000	9.625	J-55	36	36,000	137,970
Intermediate casing			0	7.625	P-110	29.7	0	
Production casing			6,400	4.5	P-110	11.6	74,240	
Tubing			5,900	2.375	L-80	4.7	27,730	
Barnett (High)								
Surface casing	8,500	7,500	1,000	9.625	J-55	36	36,000	380,850
Intermediate casing			0	7.625	P-110	29.7	0	
Production casing			16,000	5.5	P-110	17	272,000	
Tubing			15,500	2.375	L-80	4.7	72,850	
							Average	**259,410** lbs
								118 tonnes

Shale 3 (generic)								
Woodford (Low)	**Vert Depth (ft)**	**Lat Length (ft)**	**Footage**	**Size (in)**	**Grade**	**Weight (lb/ft)**	**String Weight (lb)**	**Total Steel Weight (lb)**
Surface casing	5,000	4,000	1,500	9.625	J-55	36	54,000	229,560
Intermediate casing			0	7.625	P-110	29.7	0	
Production casing			9,000	5.5	P-110	17	153,000	
Tubing			4,800	2.375	L-80	4.7	22,560	
Woodford (High)								
Surface casing	10,000	10,000	1,500	13.375	J-55	54.5	81,750	646,400
Intermediate casing			5,000	9.625	J-55	36	180,000	
Production casing			20,000	5.5	P-110	17	340,000	
Tubing			9,500	2.375	L-80	4.7	44,650	
							Average	**437,980** lbs
								199 tonnes

Shale 4

Canada - Montney (Low)	Vert Depth (ft)	Lat Length (ft)	Footage	Size (in)	Grade	Weight (lb/ft)	String Weight (lb)	Total Steel Weight (lb)	
Surface casing	7,000	3,000	1,968	9.625	J-55	36	70,848	246,964	
Intermediate casing			0	7	L-80	26	0		
Production casing			10,000	4.5	P-110	15.1	151,000		
Tubing			6,900	2	QT-1000	3.64	25,116		
Canada - Montney (High)									
Surface casing	10,214	6,500	1,968	9.625	J-55	36	70,848	623,373	
Intermediate casing			10,214	7	L-80	26	265,564		
Production casing			16,714	4.5	P-110	15.1	252,381		
Tubing			9,500	2	QT-1000	3.64	34,580		
							Average	**435,169**	**lbs**
								198	**tonnes**

Tight Gas

Jonah (Low)	Vert Depth (ft)	Lat Length (ft)	Footage	Size (in)	Grade	Weight (lb/ft)	String Weight (lb)	Total Steel Weight (lb)	
Surface casing	9,000	0	2,500	9.625	J-55	36	90,000	232,000	
Intermediate casing			0	7.625	P-110	29.7	0		
Production casing			9,000	4.5	P-110	11.6	104,400		
Tubing			8,000	2.375	L-80	4.7	37,600		
Jonah (High)									
Surface casing	15,000	0	2,500	9.625	J-55	36	90,000	353,600	
Intermediate casing			0	7.625	P-110	29.7	0		
Production casing			15,000	4.5	P-110	13.5	202,500		
Tubing			13,000	2.375	L-80	4.7	61,100		
							Average	**292,800**	**lbs**
								133	**tonnes**

CBM

Powder River CBM (Low)	Vert Depth (ft)	Lat Length (ft)	Footage	Size (in)	Grade	Weight (lb/ft)	String Weight (lb)	Total Steel Weight (lb)	
Surface casing	1,000	0	200	9.625	J-55	36	7,200	36,960	
Intermediate casing			0	7.625	P-110	29.7	0		
Production casing			1,000	7	L-80	26	26,000		
Tubing			800	2.375	L-80	4.7	3,760		
Powder River CBM (High)									
Surface casing	2,500	0	200	9.625	J-55	36	7,200	82,540	
Intermediate casing			0	7.625	P-110	29.7	0		
Production casing			2,500	7	L-80	26	65,000		
Tubing			2,200	2.375	L-80	4.7	10,340		
							Average	**59,750**	**lbs**
								27	**tonnes**

CBM

San Juan CBM (Low)	Vert Depth (ft)	Lat Length (ft)	Footage	Size (in)	Grade	Weight (lb/ft)	String Weight (lb)	Total Steel Weight (lb)	
Surface casing	1,500	0	500	8.625	J-55	32	16,000	58,950	
Intermediate casing			0	7.625	P-110	29.7	0		
Production casing			1,500	5.5	P-110	23	34,500		
Tubing			1,300	2.875	L-80	6.5	8,450		
San Juan CBM (High)									
Surface casing	4,000	0	500	8.625	J-55	32	16,000	132,050	
Intermediate casing			0	7.625	P-110	29.7	0		
Production casing			4,000	5.5	P-110	23	92,000		
Tubing			3,700	2.875	L-80	6.5	24,050		
							Average	**95,500**	**lbs**
								43	**tonnes**

Conventional

South Texas (Low)	Vert Depth (ft)	Lat Length (ft)	Footage	Size (in)	Grade	Weight (lb/ft)	String Weight (lb)	Total Steel Weight (lb)	
Surface casing	9,000	0	2,000	8.625	P-110	49	98,000	346,750	
Intermediate casing			0	7.625	P-110	33.7	0		
Production casing			9,000	5	C-95	23.2	208,800		
Tubing			8,500	2.375	L-80	4.7	39,950		
South Texas (High)									
Surface casing	17,000	0	2,000	9.625	P-110	53.5	107,000	858,150	
Intermediate casing			7,500	7.625	P-110	33.7	252,750		
Production casing			17,000	5	C-95	23.2	394,400		
Tubing			16,000	2.875	L-80	6.5	104,000		
							Average	**602,450**	**lbs**
								274	**tonnes**

Table C4: Back End Model Regional Well OCTG Estimates

Data source: Encana

References

[1] ICF, 2009

[2] Hubbert, M. K. (Mar. 1956). *Nuclear Energy and the Fossil Fuels.* Presented at the spring meeting of the Southern District, San Antonio, TX.

[3] Hubbert, M. K. (1982). *Techniques of Prediction as Applied to the Production of Oil and Gas.* S.I Gass, ed., *Oil and Gas Supply Modeling.* National Bureau of Standards Special Publication 631. pp. 16-141.