# Impact of Unconventional Gas Technology in the *Annual Energy Outlook 2000*

by
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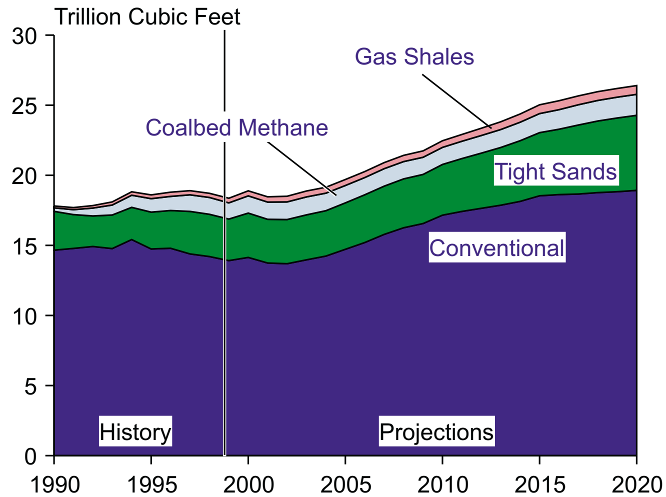
*U.S. natural gas demand is projected to exceed 30 trillion cubic feet per year within two decades. To meet this demand producers will increasingly rely on production from unconventional gas sources such as tight sands, coalbed methane, and gas shales. Because of the technical difficulties inherent in developing such resources, technology will necessarily play a vital role in their future exploitation. This paper describes the methodology used in the National Energy Modeling System (NEMS) to represent unconventional gas technologies and their impacts on projections in the* Annual Energy Outlook 2000 *(*AEO2000*).*

## Introduction

Technological progress, as represented in the National Energy Modeling System (NEMS),[1] affects the projections of unconventional natural gas production and wellhead prices in the *Annual Energy Outlook 2000* (*AEO2000*). "Unconventional gas" refers to natural gas extracted from coalbeds (coalbed methane) and from low-permeability sandstone and shale formations (respectively, tight sands and gas shales). Unconventional gas has become an increasingly important component of total U.S. domestic production over the past decade (Figure 1). From 18 percent (3.2 trillion cubic feet) of total gas production in 1990, the unconventional gas share grew to 24 percent (4.5 trillion cubic feet) by 1998.

Although unconventional gas resources are abundant (Figure 2), they are generally more costly to produce. Their exploitation was boosted in the late 1980s and early 1990s with the successful implementation of tax incentives designed to encourage their development. Since then, technologies developed and advanced in the pursuit of unconventional gas resources have contributed to continued growth in production even in the absence of the tax incentives (which generally are unavailable for production from wells drilled after December 31, 1992). Indeed, increasing production from unconventional gas resources has actually offset a decline in conventional gas production in recent years. Over the next two decades the role of unconventional gas in meeting the Nation's energy needs is projected to expand to 28 percent of total production, or about 7.5 trillion cubic feet per year. Behind these projections are important assumptions about future technological advancements and their effect on the industry.

**Figure 1. Natural Gas Production, 1990-2020**




Sources: **History:** Advanced Resources International, Inc. (ARI). **Projections:** Energy Information Administration, *Annual Energy Outlook 2000*, DOE/EIA-0383(2000) (Washington, DC, December 1999), reference case.

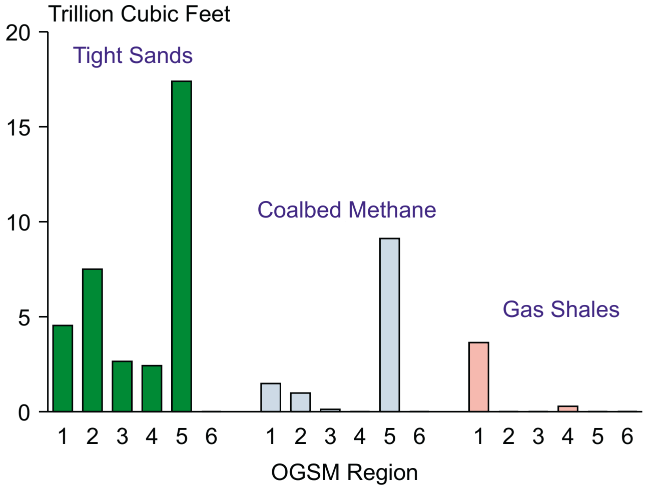
## Unconventional Gas Recovery Supply Submodule

### Methodology

The unconventional gas production projections in *AEO2000* were generated from the NEMS Unconventional Gas Recovery Supply Submodule (UGRSS) of the

[1]Energy Information Administration, *National Energy Modeling System: An Overview 2000*, DOE/EIA-0581(2000) (Washington, DC, March 2000), web site www.eia.doe.gov/oiaf/aeo.html.

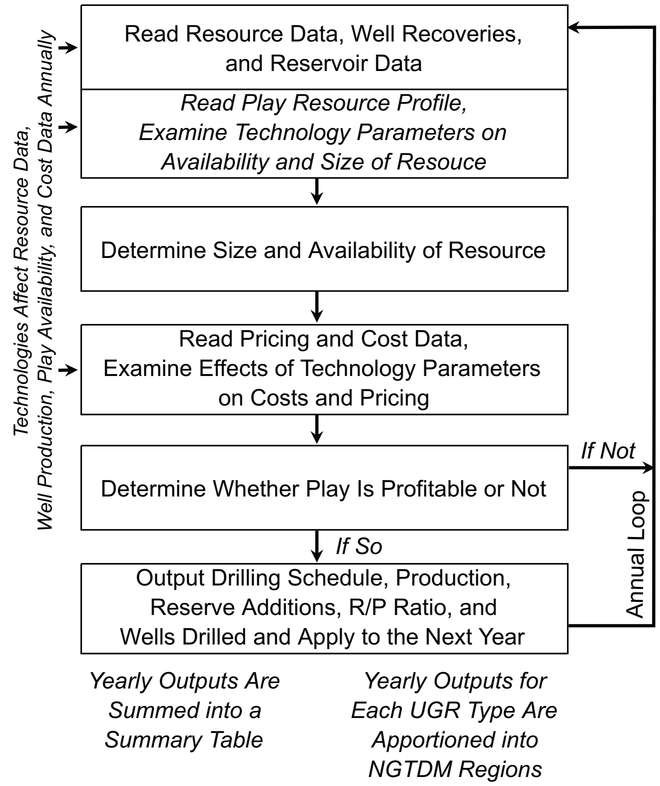
**Figure 2. Unconventional Gas: Historical Beginning-of-Year Proved Reserves by OGSM Region, 1998**




Note: OGSM Regions: 1 = Northeast, 2 = Gulf Coast, 3 = Midcontinent, 4 = Southwest, 5 = Rocky Mountain, 6 = West Coast (see Figure 4 for map).

Source: Advanced Resources International, Inc. (ARI), compilation of various privately and publicly held data sources.

**Figure 3. NEMS UGRSS General Process Flow Diagram**




Source: Office of Integrated Analysis and Forecasting.

Oil and Gas Supply Module (OGSM).[2] The UGRSS is a play-level model[3] that explicitly analyzes the three major unconventional resources—coalbed methane, tight gas sands, and gas shales. The UGRSS calculates the economic feasibility of individual plays based on region-specific wellhead gas prices and production costs, resource quantity and quality, and the compounded effects of technological progress on both resources and costs (Figure 3).

In each year an initial resource characterization determines the estimated ultimate recoveries (EURs)—the average amounts of undeveloped resources (Figure 2) that will be developed per well—for the wells drilled in a particular play. The EURs, or resource profiles, are then adjusted to reflect assumed technological impacts on the size, availability, and industry knowledge of the resources in the play.

After the resource profiles are established, prices received from the Natural Gas Transmission and Distribution Module (NGTDM)[4] and endogenous costs adjusted for the effects of technology are used to calculate the play's economic profitability (or lack thereof). If the play is profitable, drilling occurs according to an assumed schedule that is adjusted annually to account for technological improvements. Drilling results in reserve additions, which depend on the EURs and the success rates for the wells in the play. Based on these reserve additions, reserve levels and "expected" production for the following year are recalculated and sent to the NGTDM. The NGTDM then combines these values with similar values from other OGSM submodules (conventional onshore and shallow offshore; deep offshore) and determines, through market equilibration with the demand modules, the prices and realized production for the succeeding year.

## Resources

Technology in the UGRSS affects both the conversion of undeveloped resources into proved reserves and the production of those proved reserves. An awareness of the nature and extent of these two types of resources—undeveloped resources and proved reserves—is

[2]Energy Information Administration, *Documentation of the Oil and Gas Supply Module (OGSM)*, DOE/EIA-M063(2000) (Washington, DC, January 2000), web site www.eia.doe.gov/bookshelf/docs.html.

[3]A play is a set of known or postulated oil and/or gas accumulations sharing similar geologic, geographic, and temporal qualities, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type. See U.S. Geological Survey, National Oil and Gas Resource Assessment Team, "1995 National Assessment of United States Oil and Gas Resources," *U.S. Geological Survey Circular 1118* (1995), p. 6.

[4]Energy Information Administration, *Natural Gas Transmission and Distribution Model of the National Energy Modeling System*, DOE/EIA-M062(2000) (Washington, DC, January 2000), web site www.eia.doe.gov/bookshelf/docs.html.

essential to understanding the impact of technological progress on unconventional gas recovery in the UGRSS.

Proved reserves are those unconventional gas resources "which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions."[5] Reserves are considered proven if "economic producibility is supported by actual production or conclusive formation test (drill stem or wire line), or if economic producibility is supported by core analyses and/or electric or other log interpretations."[6]

Proved reserves are highest in the Rocky Mountain region for tight sands and coalbed methane and in the Northeast for gas shales. Approximately 51 percent (16.2 trillion cubic feet) of tight sands and 77 percent (8.1 trillion cubic feet) of coalbed methane proved reserves are located in the Rocky Mountain region. Proved reserves of gas shales are located almost entirely in the Northeast region (93 percent, 3.4 trillion cubic feet), with relatively small amounts in the Southwest (0.3 trillion cubic feet). Significant quantities of tight sands proved reserves exist in all the other regions, except the West Coast, but coalbed methane proved reserves are largely limited to two other regions: the Northeast (1.4 trillion cubic feet) and the Gulf Coast (0.9 trillion cubic feet). No significant volume of unconventional gas proved reserves exists in the West Coast region.

Undeveloped resources in the UGRSS are what the U.S. Geological Survey (USGS) classified as "Continuous-Type (Unconventional) Accumulations" in its 1995 Assessment.[7] The resource estimates in that assessment represent the volume of unproved resources that could yet be added to proved reserves under the technology and development practices existing at the time of the assessment (January 1994). Continuous-type resources are defined to include those "resources that exist as geographically extensive accumulations that generally lack well-defined oil/water or gas/water contacts."[8] This category encompasses "coal-bed gas, gas in many of the so-called 'tight sandstone' reservoirs, and auto-sourced oil- and gas-shale reservoirs."[9] The UGRSS incorporates all the USGS-designated continuous-type resources into the model structure and adds some resources in plays that were not quantitatively assessed by the USGS (Figure 4).

Undeveloped resources of unconventional gas are predominantly located in the same two regions that have the most unconventional gas reserves. The bulk of tight sands and coalbed methane (71 percent and 76 percent, respectively) are in the Rocky Mountain region. For gas shales, 87 percent of the undeveloped resources are in the Northeast region. Moderate quantities of tight sands and lesser amounts of gas shales or coalbed methane are contained in the other regions, except the West Coast region. In the West Coast region, only relatively small quantities of tight sands (2 trillion cubic feet) are estimated to exist.

## Technology Representation in the UGRSS

The UGRSS captures the effects of technological progress on the production of unconventional gas by classifying numerous research and technology initiatives into 11 specific "technology groups" that encompass the full spectrum of key disciplines—geology, engineering, operations, and the environment. The effects of these technology groups are represented in the UGRSS by time-specific adjustments to assumptions about costs, productivity, and resource size and availability.

Each of the technology groups tends to be closely associated with a particular stage of the upstream (exploration, development, and production) natural gas industrial process. On this basis, the 11 technology groups are combined into three categories: (1) exploration, (2) drilling and completion, and (3) production. The 11 technology groups, discussed in detail in subsequent sections, are as follows:

**Exploration technologies**

- Basin assessments
- Play-specific, extended reservoir characterizations
- Advanced exploration and natural fracture detection research and development (R&D)

[5]Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1998 Annual Report*, DOE/EIA-0216(98) (Washington, DC, December 1999), p. 154.

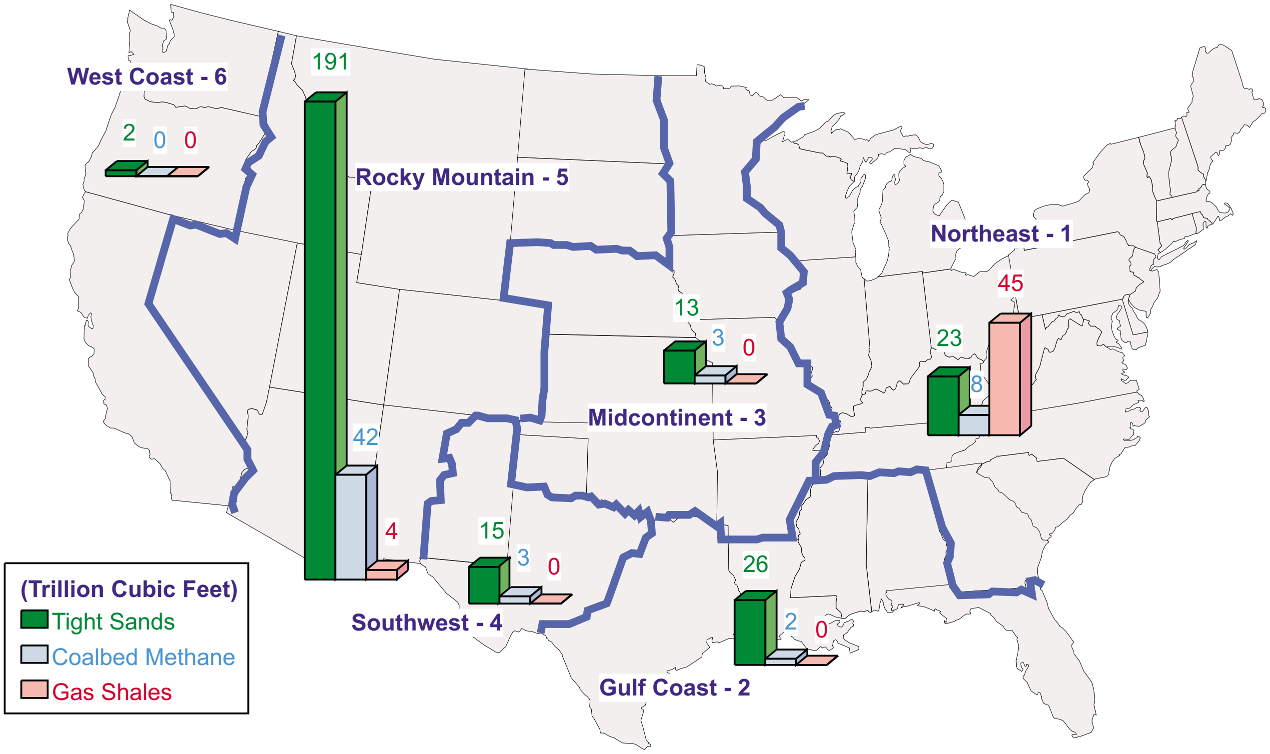
[6]Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1998 Annual Report*, DOE/EIA-0216(98) (Washington, DC, December 1999), p. 154.

[7]U.S. Geological Survey, National Oil and Gas Resource Assessment Team, "1995 National Assessment of United States Oil and Gas Resources," *U.S. Geological Survey Circular 1118* (1995).

[8]U.S. Geological Survey, National Oil and Gas Resource Assessment Team, "1995 National Assessment of United States Oil and Gas Resources," *U.S. Geological Survey Circular 1118* (1995), p. 4.

[9]U.S. Geological Survey, National Oil and Gas Resource Assessment Team, "1995 National Assessment of United States Oil and Gas Resources," *U.S. Geological Survey Circular 1118* (1995), p. 5.

**Figure 4. Unconventional Gas: Undeveloped Resources by OGSM Region as of January 1, 1998**




Sources: Resources as of January 1, 1996, from the U.S. Geological Survey and Advanced Resources International, Inc., by 1996-1997 model results from AEO2000 National Energy Modeling System, run BASIN.D060600A (June 2000).

**Drilling and completion technologies**

- Geology / technology modeling and matching
- More effective, lower damage well completion and stimulation technology
- Targeted drilling and hydraulic fracturing R&D
- Advanced well completion technologies such as cavitation, horizontal drilling, and multilateral wells

**Production technologies**

- Advanced well performance diagnostics and remediation
- New practices and technology for gas and water treatment
- Other unconventional gas technologies, such as enhanced coalbed methane and enhanced gas shales recovery using nitrogen or carbon dioxide injection
- Mitigation of environmental and other constraints on development.

The following section provides a detailed description of the technology groups, including their representation in the UGRSS and their projected effects on production and price.

# Technology Groups

## Exploration Technologies

In the UGRSS, exploration technologies are assumed to accelerate the discovery of hypothetical plays in unassessed areas, shorten the development time for emerging plays, and increase the success of development. Technological progress is not modeled individually by technology but in the aggregate by technology group. The technologies considered in setting the aggregate rates of technological progress for exploration technologies are briefly discussed below.

### *Increasing the Available (or Approachable) Resource Base with Improved Basin Assessments*

A substantial amount of unconventional gas resources, approximately 120 trillion cubic feet, is currently categorized by the USGS as hypothetical resources. Because insufficient information exists concerning these plays, producers have less ability to explore for or develop them within an expedient time frame. Many of the areas currently under development have benefited from basin assessments sponsored by the U.S. Department of Energy (DOE) and the Gas Research Institute (GRI) in the 1980s. Another round of assessments that included areas currently categorized as hypothetical would provide a new core of comprehensive data that would potentially shorten the development schedules for plays in those areas.[10] The USGS is currently conducting such an assessment, the final results of which will be available in about 3 years.[11]

In the UGRSS, hypothetical plays in currently unassessed areas are assumed to become available for development during the forecast time frame because of new basin assessments in the forecast period. Also, in the *AEO2000* rapid technology case,[12] the area subject to potential development within a given hypothetical play is assumed to increase gradually.[13] The latter effect reflects the impact that better information from improved assessments is expected to have in helping producers locate more of the productive area of a play during the projection period.

### Accelerating the Development of Emerging Unconventional Gas Plays via Better Play-Specific Reservoir Characterization

Emerging plays in such basins as the Powder River, Piceance, Raton, and Wind River contain a large share of the unconventional gas resource base. The reservoirs in these emerging plays are not yet adequately characterized to allow easy determination of the most efficient productive practices. Because of the lack of information, it is often difficult to match to a given reservoir within a particular gas play the technology that would allow for the most efficient development of that reservoir. As a result, industry attaches a higher risk to these emerging plays and tends therefore to proceed at a slower pace in their development. R&D activities that would help better define emerging gas plays for the industry include extended three-dimensional reservoir characterization studies.[14]

A recent example of advancement in this area is a set of three portfolios developed by Advanced Resources International, Inc. (ARI), and partners under the sponsorship of GRI, depicting emerging gas resources in key underdeveloped gas plays in the Rocky Mountains.[15] The authors assembled three reports containing geologic, reservoir, and production data on promising plays in the Greater Green River, Piceance, and Wind River basins. The purpose of developing the portfolios was to define the area's resource potential so that producers could more efficiently and economically develop the resources in these three geologically complex basins.

In the UGRSS, extended play-specific reservoir characterizations are assumed to accelerate the pace of development for emerging plays by decreasing the number of years required for full development.

### Improving Exploration Efficiency via Advanced Exploration and Natural Fracture Detection Technology

The USGS, in its 1995 National Assessment,[16] assumed that the development of unconventional gas or continuous-type basins would occur in a rather uniform pattern lacking an emphasis on finding the most productive areas first. However, a play may contain one or more discrete areas of higher productivity, called "fairways," that have a greater concentration of accessible gas and are commercially more desirable. It is a major challenge to find these areas of higher natural fracture intensity within a play; and the ability to find them often determines the commercial success of the play. The goal of R&D in this case is to develop a better methodology for finding these "sweet spots" in a given basin.[17]

A number of low-permeability gas reservoir R&D studies conducted by DOE's National Energy Technology Laboratory (DOE / NETL) have focused on natural fracture detection and improved exploration technology.

[10]Energy Information Administration, *Oil and Gas Supply Module (OGSM), Model Documentation 2000,* Appendix 4D (prepared by Advanced Resources International, Inc.), p. 4D-13.

[11]Robert A. Crovelli of the USGS spoke at a conference for the Institute for Operations Research and the Management Sciences (INFORMS) in Salt Lake City, Utah (May 9, 2000) about the new resource assessment method developed for this project.

[12]For two sensitivity cases in *AEO2000* the technology assumptions for both unconventional gas and conventional gas were adjusted to represent conditions of slow and rapid technological progress.

[13]Appendix C details the unconventional gas technology parameters for the *AEO2000* reference case, rapid technology case, and slow technology case.

[14]Energy Information Administration, *Oil and Gas Supply Module (OGSM), Model Documentation 2000,* Appendix 4D (prepared by Advanced Resources International, Inc.), p. 4D-18.

[15]M.J. Doelger and D.K. Morton, Portfolio of Emerging Natural Gas Resources: Rocky Mountain Basins. Section 1. Greater Green River Basin (Arlington, VA: Gas Research Institute, June 1999); V.A. Kuuskraa, D. Campagna, I. Drayton, J. Frank, G. Koperna, J. Kuuskraa, and M. Marquis, Portfolio of Emerging Natural Gas Resources: Rocky Mountain Basins. Section 2. Piceance Basin (Arlington, VA: Gas Research Institute, April 1999); and V.A. Kuuskraa, J. Kuuskraa, G. Koperna, I. Drayton, J. Frank, M. Marquis, A. Finley, T. McCutcheon, J. McCutcheon, and M. Doelger, Portfolio of Emerging Natural Gas Resources: Rocky Mountain Basins. Section 3. Wind River Basin (Arlington, VA: Gas Research Institute, April 1999).

[16]U.S. Geological Survey, National Oil and Gas Resource Assessment Team, "1995 National Assessment of United States Oil and Gas Resources," *U.S. Geological Survey Circular 1118* (1995), p. 5.

[17]Energy Information Administration, *Oil and Gas Supply Module (OGSM), Model Documentation 2000*, Appendix 4D (prepared by Advanced Resources International, Inc.), p. 4D-28.

The methodologies derived from these studies are intended to help operators better delineate a basin's "sweet spots" prior to drilling, resulting in higher initial productivities as wells are planned and strategically drilled into these optimal areas first.[18]

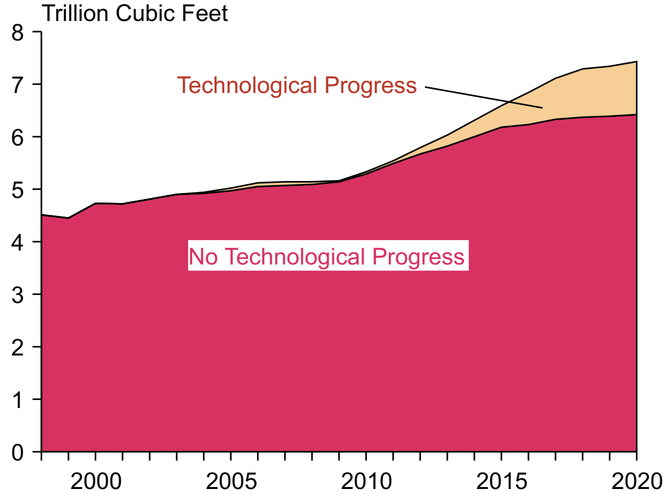
In the UGRSS, advanced exploration and natural fracture detection R&D is assumed to increase the success of development by (1) improving exploration/development drilling success rates for all plays and (2) improving the ability to find the most productive prospects/areas within a given play.

### *Effect of Exploration Technologies*

Two cases were developed to examine the effect of exploration technology. The *technological progress case* was run with all the unconventional gas technology features and accompanying assumptions as implemented in the UGRSS reference case for *AEO2000*.[19] The technological assumptions for this case reflect the status and trends in unconventional gas technologies during the development period of the UGRSS (1997-1998). The *no technological progress case* is represented by a model run in which the benefits of all the features installed in the UGRSS to simulate the effect of technological progress in exploration technology were removed. The same process was used to study the effects of the other technology categories.

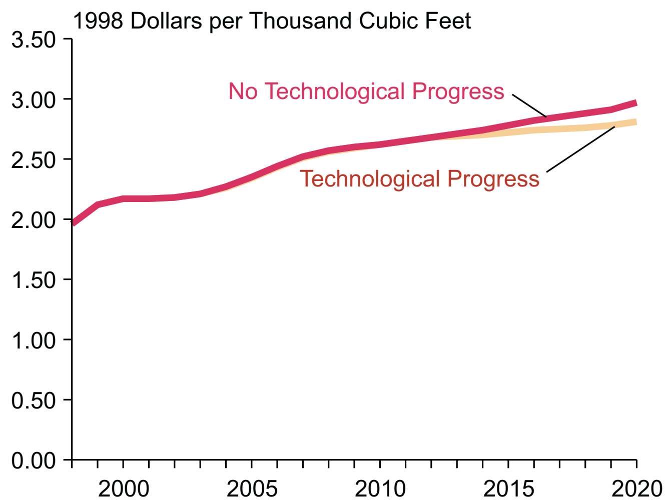
For exploration technologies, most of the effects on production and prices are realized later in the forecast period. Prior progress in exploration technologies has by this time is expected to allow emerging plays to attain greater maturity, more hypothetical plays to reach the development stage, and developers to be able to concentrate their efforts on the most profitable and productive parts of the basins. The projected difference in cumulative production between the technological progress case and the no technological progress case by 2020 is 5.7 trillion cubic feet, 88 percent of which occurs during the last 7 years of the forecast (Figure 5). The U.S. average wellhead price is projected to be 17 cents lower in 2020 in the technological progress case than in the no technological progress case (Figure 6).

**Figure 5. Projected Effect of Exploration Technologies on Unconventional Gas Production, 1998-2020**




Source: AEO2000 National Energy Modeling System, runs BASIN.D060600A and UGRTE02.D051600A.

**Figure 6. Projected Effect of Unconventional Gas Exploration Technologies on U.S. Lower 48 Gas Wellhead Prices, 1998-2020**




Source: AEO2000 National Energy Modeling System, runs BASIN.D060600A and UGRTE02.D051600A.

Production, end-use consumption, and wellhead prices are market-determined in all the cases examined in the model. These values result from an "integrated" NEMS solution that equilibrates the supplies that will be made available at specific prices with the amounts that consumers will demand at those prices. In the technological progress case, more gas can be supplied less expensively than in the no technological progress case, as a result of technology-induced efficiency gains in finding, developing, and producing unconventional gas. Consumption and production are projected to reach higher levels in the technological progress case as consumers respond

[18] V. Kuuskraa, D. Decker, S. Squires, and H. Lynn, *Naturally Fractured Tight Gas Reservoir Detection Optimization: Piceance Basin* (Pittsburgh, PA: National Energy Technology Laboratory, August 1996); J.C. Lorenz, N.R. Warpinski, and L.W. Teufel, *Natural Fracture Characteristics and Effects* (Pittsburgh, PA: National Energy Technology Laboratory, August 1996); and H.B. Lynn, K.M.Simon, C.R. Bates, and R. Van Dok, *Azimuthal Anisotropy in P-Wave 3-D (Multiazimuth) Data* (Pittsburgh, PA: National Energy Technology Laboratory, August 1996).

[19] The technological progress case is not exactly identical to the *AEO2000* reference case. It reflects a gas shales mapping change incorporated into the OGSM after the production of *AEO2000*. This change does not significantly affect aggregate results as published in *AEO2000*, but it was necessary to implement this change in order to properly assess model behavior at the play level.

to the lower supply prices with increased purchases of unconventional gas. The market convergence between supply and demand in this case also tends to occur at significantly lower projected prices than in the no technological progress cases. As a result, wellhead price projections are generally lower in the technological progress case.

## Drilling and Completion Technologies

Drilling and completion technologies are assumed in the UGRSS to increase the EUR per well and decrease drilling and stimulation costs over time. As with exploration technologies, this area of technological progress is modeled in the aggregate by technology group rather than individually by technology. The technologies considered in setting the aggregate rates of technological progress for drilling and completion technologies are briefly discussed below.

### *Increasing Effectiveness of Field Development via Geology/Technology Modeling and Matching*

It is often difficult to design optimal development plans for unconventional gas plays because of the generally complex, diverse, hard-to-measure reservoir properties of these plays. Selecting the "best available" technology and production practices is not usually an easy task. To facilitate the decisionmaking process, R&D should improve industry's ability to understand gas reservoir conditions and to appraise "best available" technology. Essential components of such research would include studies on multi-phase relative permeability, stress-sensitive formations, and natural fracture patterns. Another important part of this R&D would be the development of more effective reservoir simulations to help characterize the reservoir structures. The results of these research efforts will enhance industry's ability to choose optimal technologies and enable them to most effectively develop unconventional fields.[20]

An example of successful geology/technology modeling and matching can be found in the efforts of an exploration and production multidisciplinary reservoir management team that Amoco established to improve the economic performance of a field in the East Texas Cotton Valley trend.[21] The team implemented a data collection and critical evaluation which resulted in modification of the fracturing program, improving incremental production and eliminating ineffective fracturing costs. The production gain for one well was estimated to be 127 million cubic feet over a 2-year period as a result of changes in stimulation design. This represents an increase of nearly 24 percent. Nearly $200,000 per well was saved after mechanical properties logging and laboratory conductivity tests led to a decision to run Ottawa sand in the field instead of more expensive, synthetic proppants.[22]

In the UGRSS, geology/technology modeling and matching the "best available technology" to a given play are assumed to increase the EUR per well.

### *Improving Well Performance via Lower Damage, More Effective Well Completions and Stimulations*

Coalbed methane, gas shales, and tight sands formations can be damaged by use of inappropriate chemicals, gels, drilling muds, and heavy cement, resulting in reduced performance per well. A significant amount of damage could be avoided with improved well drilling, completion, and stimulation fluids and procedures, especially in multi-zone, vertically heterogeneous formations. Formation damage could be reduced and fracture length, placement, and conductivity enhanced by R&D on formation and fluid compatibility, low damage fluids such as carbon dioxide ($CO_2$) or nitrogen ($N_2$), improved rock mechanics and simulation models, underbalanced drilling, and improved proppant carrying fluids, especially for multi-zone reservoirs. Such improvement could result in increased reserves per well.[23]

An illustration of this technology group is the use of viscosity-controlled acid (VCA). VCA has been used successfully to control fluid loss, improve surface etching, provide more uniform damage zone removal, and improve acid placement. The gels in VCA break back to original viscosity in one day's time. These acids have proved useful in matrix-acidizing long horizontal and vertical well sections and in containing fluid loss during fracture acidizing to enable longer fractures and greater live-acid penetration. Gel formation and breaking are controlled by fluid acidity/alkalinity (pH) levels. The use of VCA has been responsible for a production increase of 2.5- to 6-fold in one operator's wells. The acids have improved production by 170 percent to 375 percent through their use in carbonate formation fracture-acidizing.[24]

[20]Energy Information Administration, *Oil and Gas Supply Module (OGSM), Model Documentation 2000*, Appendix 4D (prepared by Advanced Resources International, Inc.), p. 4D-30.

[21]G. Holly K. Krus, and L. Haley, "Strategic Alliance, Multidisciplinary Teamwork Enhance Field Development in Cotton Valley Trend," *Oil & Gas Journal* (March 31, 1997).

[22]Proppants are materials inserted into fractures to prop them open in order to facilitate the release of hydrocarbons.

[23]Energy Information Administration, *Oil and Gas Supply Module (OGSM), Model Documentation 2000*, Appendix 4D (prepared by Advanced Resources International, Inc.), p. 4D-32.

[24]V. Yeager and C. Shuchart, "*In situ* Gels Improve Formation Acidizing," *Oil & Gas Journal* (January 20, 1997).

Another example of this technology group is the use of $CO_2$/sand fracturing technology, a "dry" stimulation technique that is especially applicable to water-sensitive formations.[25] In the typical fracturing process, in which water-based fluids and proppant are pumped into the formation to create and maintain the fracture, unwanted side effects can occur that limit or eliminate production gains. Such detrimental side effects include solids plugging, water retention, and chemical reactions between the formation minerals and stimulation fluids that reduce permeability. With $CO_2$/sand fracturing technology, $CO_2$ is the carrier fluid that places the proppant at a created fracture, and no water or any additional treatment additive is required. Because the pay zone remains free of damaging fluids, the risk to water-sensitive formations is minimized. The use of $CO_2$/sand fracturing technology during a 5-month test in the Appalachian region increased production by two to five times. $CO_2$/sand stimulation was four times more effective than foam stimulation and twice as effective as nitrogen in increasing gas production. Another benefit from this method is a reduction in cleanup time and costs, because there are no water hauling and disposal costs. $CO_2$/sand stimulation has been tested successfully in the Appalachian, San Juan, Permian, and Williston basins.

In the UGRSS, more effective, lower damage well completion and stimulation technology is assumed to improve near-face permeability, fracture length, and conductivity, resulting in increased EUR per well.

### Lowering Well Drilling and Completion Costs via Unconventional-Gas-Specific Drilling and Hydraulic Fracturing R&D

Typically high economic hurdles to overcome in unconventional gas development are the drilling and stimulation costs. This is particularly true for deep, low-permeability unconventional plays. The costs could be lowered through R&D on advanced drilling and completion methods, such as the use of downhole motors or coiled tubing and modified stimulation practices that could lead to faster penetration rates and simpler fracturing fluids.[26]

An example of this group of technological advances is the Swift Energy Company's experience with the AWP Olmos Field in South Texas.[27] By implementing more effective well completion and stimulation technologies, Swift Energy quintupled its natural gas and oil production from the AWP Olmos Field in less than 2.5 years. Swift eliminated significant operating and repair costs and at the same time increased production by running coiled tubing velocity strings for artificial lift. Gross daily production rose from about 12 million cubic feet in 1994 to more than 67 million cubic feet in 1997. Swift also lowered fracture stimulation costs by 30 percent and used single-stage cementing and slim-hole drilling to lower drilling completion costs by 10 to 15 percent.

Another example of modification of stimulation practices is Mitchell Energy & Development's work in the Barnett Shale in the Fort Worth Basin in North Texas.[28] The use of lower cost "light sand" fracture stimulation enabled Mitchell to increase gas reserves in the Barnett by 25 percent, adding an additional 213 billion cubic feet to the company's total reserves. Mitchell saved approximately $140,000 per well in sand, chemicals, and gel by using "light sand" stimulation.

In the UGRSS, targeted drilling and hydraulic fracturing R&D are assumed to result in more efficient drilling and stimulation, which lowers well drilling and stimulation costs.

### Improving Recovery Efficiency via Advanced Well Drilling and Completion Technology

Under certain geological conditions the use of cavitation is a far more efficient and productive way of extracting methane than the use of traditional methods of drilling, casing, and hydraulically stimulating wells. A more accurate name for cavitation is dynamic open-hole completion, in that creation of a cavity is a byproduct of the process and not the primary objective. Wells using dynamic open-hole completion are cased only to the top of the coal. Large compressors pump air or foam into the well to pressurize the reservoir, which is then depressurized, allowing coal and other rock to collapse into the wellbore, and then cleaned out. This cycle is repeated several times. The result is an enlarged wellbore in the coal zones.

Dynamic open-hole completion is commonly called "cavitation" or "open-holed cavity completion," because measured diameters of enlarged wellbores have ranged from that of the bit diameter to 16 feet. The objective of a dynamic open-hole completion is to effectively link the wellbore with the natural fracture system of the reservoir without causing undue damage to the system. The potential benefits of this technique are that "damaged, near-wellbore coal and other rocks are removed, multidirectional, self-propped fractures are created that intersect pre-existing natural fractures, the near-wellbore aperture of pre-existing natural fractures may

[25] "$CO_2$/Sand Fracturing," *DOE Fossil Energy TECHLINE* (March 1999).

[26] Energy Information Administration, *Oil and Gas Supply Module (OGSM), Model Documentation 2000*, Appendix 4D (prepared by Advanced Resources International, Inc.), p. 4D-34.

[27] T.E. Swift and P. Mladenka, "Technology Tackles Low-Permeability Sand in South Texas," *Oil & Gas Journal* (September 29, 1997).

[28] G.A. Petzet, "Mitchell Hikes Barnett Shale Reserves, Fort Worth Basin Output in N. Texas," *Oil & Gas Journal* (September 27, 1999).

be increased and retained, and the enlarged wellbore may intersect natural fractures."[29]

There has not been significant investment in cavitation science, design, or operating procedures, and there is insufficient knowledge about what conditions allow for cavitation to be effectively employed. Accordingly, the only "cavity fairway" in the United States is the one established in the central San Juan Basin. DOE has sponsored R&D efforts through Small Business Innovative Research (SBIR). The object is to identify other formations that are favorable for cavitation. SBIR has also assisted in the development of CAVITYPC, the first publicly available model of cavitation. Additional investment in well cavitation R&D could result in the identification of more "cavity fairways" and increase understanding of the rock mechanics and flow equations that underlie the implementation of successful cavitation.[30]

For "blanket" tight sands, improved horizontal drilling technology could theoretically be important. More of the pay zone could be contacted by this drilling method, resulting in improved recovery efficiencies and reserves per well. Horizontal wells have not generally been successful in tight sands, however, with problems ranging from inappropriate reservoir settings, inefficient placement, and drilling damage. As one example of this lack of success, a horizontal well supported by DOE at the Multi-Well (MWX) site in the Corcoran Formation of the Southern Piceance Basin initially experienced high flow rates, but the output quickly turned to water. The well was abandoned shortly thereafter.[31]

Another DOE project in the Greater Green River Basin of Wyoming may help determine the appropriate geological setting for horizontal drilling in tight sands formations and increase knowledge of the drilling and stimulation technologies required for this type of drilling.[32] Sponsored by DOE/NETL, Union Pacific Resources Company (UPR) drilled a 17,000-foot-deep well with a 1,700-foot horizontal section using fracture imaging and advanced drilling technologies developed by DOE and GRI. In the first 6 months, 2.1 billion cubic feet of gas flowed from the well. The drilling of a successful horizontal well 3 miles deep in dense Wyoming sandstone has encouraged more drilling of this nature, which could dramatically increase the potential supply of unconventional gas in the Rocky Mountain region.

Horizontal drilling is not likely to be effective in gas shales because of the generally thick pay sections, multiple productive horizons, and low vertical permeability. For gas shales, the advanced drilling and completion technology of choice may be multiple laterals, which potentially allow a vertically thick, heterogeneous gas shale formation to be contacted and efficiently drained from a single vertical borehole. No use of this technology for gas shales has yet been reported, however. Because there has been no program to explore the possibilities of using this technology for gas shales, there is no allowance during the forecast period for the effects of its implementation.[33]

In the UGRSS, R&D in advanced well completion technologies such as cavitation, horizontal drilling, and multilateral wells is assumed to (1) help define applicable plays, thereby accelerating the date when such technologies are available and (2) introduce improved versions of the respective technologies, increasing the EUR per well.

### *Effect of Drilling and Completion Technologies*

Drilling and completion technologies have an increasingly significant impact throughout the forecast period as the most appropriate technologies for particular applications become more easily determined and are more consistently applied to basins in all stages of development. Cumulative production through 2020 is projected to be 11.4 trillion cubic feet higher in the technological progress case than in the no technological progress case (Figure 7), and the wellhead price in 2020 is projected to be 33 cents lower (Figure 8)—about twice the projected price effect of progress in exploration technologies.

## Production Technologies

Advances in production technologies are assumed in the UGRSS to increase the gas recovery factor, reduce certain production costs, increase EUR per well in plays susceptible to enhanced coalbed methane (ECBM) technologies, and increase the accessibility of gas-prone areas. As with the other technology categories, these effects are modeled in the aggregate by technology group rather than individually. The technologies considered in setting the aggregate rates of technological progress for production technologies are briefly discussed below.

[29]Gas Research Institute, *Final Report: Western Cretaceous Coal Seam Project*, Prepared by Resource Enterprises, Inc. (March 31, 1995), p. 113.

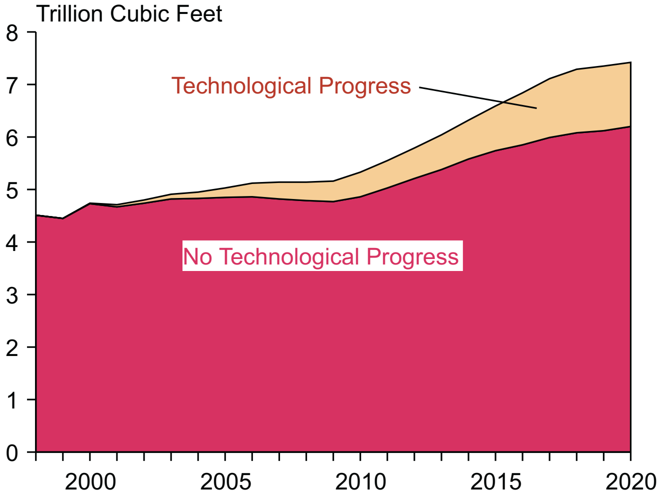
[30]Energy Information Administration, *Oil and Gas Supply Module (OGSM), Model Documentation 2000*, Appendix 4D (prepared by Advanced Resources International, Inc.), p. 4D-38.

[31]Energy Information Administration, *Oil and Gas Supply Module (OGSM), Model Documentation 2000*, Appendix 4D (prepared by Advanced Resources International, Inc.), p. 4D-43.

[32]"Success of Deep Horizontal Gas Well in Wyoming Stimulates Commercial Expansion of Drilling Activity," *DOE Fossil Energy TECHLINE* (December 20, 1999).

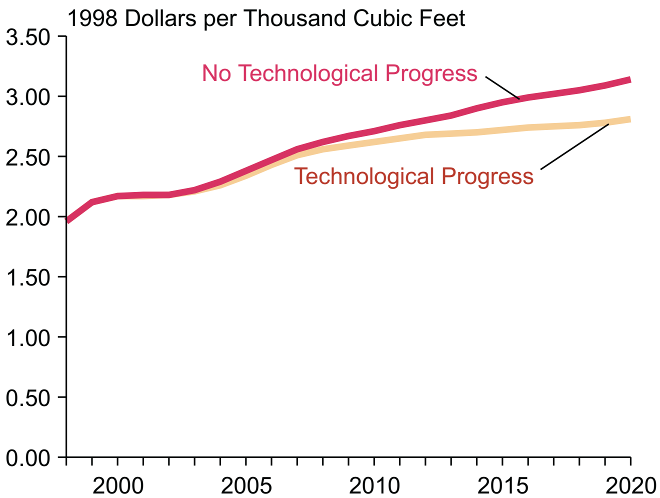
[33]Energy Information Administration, *Oil and Gas Supply Module (OGSM), Model Documentation 2000*, Appendix 4D (prepared by Advanced Resources International, Inc.), p. 4D-41.

**Figure 7. Projected Effect of Drilling and Completion Technologies on Unconventional Gas Production, 1998-2020**




Source: AEO2000 National Energy Modeling System, runs BASIN.D060600A and UGRTD02.D051600A.

**Figure 8. Projected Effect of Unconventional Gas Drilling and Completion Technologies on U.S. Lower 48 Natural Gas Wellhead Price, 1998-2020**




Source: AEO2000 National Energy Modeling System, runs BASIN.D060600A and UGRTD02.D051600A.

### *Extending Reserve Growth in Existing Unconventional Gas Fields via Advanced Well Performance Diagnostics and Remediation*

Historically, proved reserves in existing unconventional gas fields have grown ("appreciated") as a result of uphole well recompletions, restimulation, and more effective production practices. The rate of this non-drilling reserve expansion has been steadily declining, however, as it has often become increasingly difficult for operators to determine the reasons for the low recovery efficiencies they have encountered. An effective unconventional gas well diagnostic and remediation R&D program could produce techniques and applications for evaluating and targeting problem gas wells. Such a program could also serve as a blueprint for designing and choosing the most cost-effective well remediation technologies and, thereby, help support continued reserve growth.[34]

An example of this technology group is a DOE/NETL-sponsored remediation R&D program currently underway for gas stripper wells, many of which are in low-permeability formations.[35] DOE/NETL has selected ARI to develop a cost-effective method for analyzing stripper well performance. The project is intended to produce an efficient, low-cost methodology for categorizing the general well performance characteristics of a stripper gas field, identifying high-potential candidate wells for remediation, and diagnosing the specific reasons for well under-performance. Emphasis is to be placed on the discovery of new, economically viable remediation options that will be widely applicable to stripper gas wells of all types across the country. This program is in progress and not yet subject to evaluation.

In the UGRSS, advanced well performance diagnostics and remediation are assumed to expand the available resource base by increasing the rate of growth for existing reserves.

### *Lowering Water Disposal and Gas Treating Costs via New Practices and Technology for Gas and Water Treatment*

Two significant costs for unconventional gas operations are the disposal of produced water and the removal of $CO_2$ and $N_2$ (injected or naturally occurring) from the produced methane. The overall economics of unconventional plays, especially those with high water and $CO_2$ content, would be improved by a lowering of these costs. Some costs would be reduced by R&D on water treatment, such as the use of electrodialysis and reverse osmosis, and improved water disposal practices. Similarly, a reduction in the costs of $CO_2$ and $N_2$ removal would result from R&D on gas treatment, such as the use of advanced separation membranes.[36]

[34]Energy Information Administration, *Oil and Gas Supply Module (OGSM), Model Documentation 2000*, Appendix 4D (prepared by Advanced Resources International, Inc.), p. 4D-23.

[35]"DOE Selects Second Round of Projects To Boost Low-Cost Stripper Gas Production," *DOE Fossil Energy TECHLINE* (March 7, 2000).

[36]Energy Information Administration, *Oil and Gas Supply Module (OGSM), Model Documentation 2000*, Appendix 4D (prepared by Advanced Resources International, Inc.), p. 4D-36.

A DOE/NETL-sponsored project representative of this technology group is the field demonstration of Freeze–Thaw/Evaporation Process (FTE®), a technology with the potential to greatly reduce the volume of wastewater from oil and gas production.[37] Water purity levels achieved through the FTE® process are acceptable for livestock watering and agricultural irrigation. Deployment of an FTE® facility in the Jonah Field in the Green River Basin of Wyoming showed that the costs of produced-water disposal can be lowered to as little as $1 per barrel using this method. This compares to charges of up to $6 per barrel in commercial disposal facilities in southwestern Wyoming.

In the UGRSS, new practices and technology for gas and water treatment are assumed to result in more efficient gas separation and water disposal, which lowers water and gas treatment operation and maintenance costs.

### Improving and Accelerating Gas Production via Other Unconventional Gas Technologies such as Enhanced Coalbed Methane and Enhanced Gas Shales Recovery

Experimental injection of $CO_2$ and $N_2$ has been shown to be effective in enhancing the desorption[38] of methane from coal seams. Several issues remain to be resolved, however, such as the circulatory pattern of the injected gases within the reservoir, the effectiveness of the gases in contacting and displacing the methane adsorbed on the coal, and appropriate and cost-effective treatment of the produced methane/injected gas mixtures. An R&D program similar to those currently in place for enhanced oil recovery could provide industry with knowledge concerning the feasibility of, and appropriate settings for, ECBM production by conducting comprehensive geologic, laboratory, and field studies on the subject.[39]

Two projects exemplifying this type of technology have been conducted in New Mexico's San Juan Basin.[40] In one project, Burlington Resources, Inc., developed the first long-term production pilot for carbon dioxide-enhanced coalbed methane recovery ($CO_2$-ECBM).[41] In the other, BP Amoco tested nitrogen-flood ECBM, which operates through the creation of methane partial-pressure differentials in the reservoir. In theory, methane can be replaced by an equal volume of nitrogen. Full results from this field test have not been released.

In the UGRSS, enhanced coalbed methane technologies are assumed to introduce dramatically new recovery methods that (1) increase EUR per well and (2) become available at dates accelerated by increased R&D. To account for the extra costs associated with the additional gas production made possible by these technologies, operation and maintenance costs are increased, but only with respect to the incremental production. Neither gas shales nor tight sands are assumed to reflect the effects of any other unconventional gas recovery technology in the reference case. In the *AEO2000* rapid technology case, some other type of enhanced tight sands technology is assumed to increase the EUR per well near the end of the forecast.

### Increasing Accessible Area by Mitigation of Environmental and Other Constraints on Development

Environmental constraints, predominantly in the Rocky Mountain region, exist in the form of wilderness set-asides and regulations on air quality, water disposal, and land disturbance. These constraints may deny access to certain high-potential areas and slow the pace of development in those areas that are not totally restricted. Actions that could help overcome these constraints include in-depth environmental assessments that focus on the most significant constraints; the development of environmentally enhanced exploration and production technologies, such as low nitrogen oxide emission ($NO_x$) compressors; the creative use of more environmentally sensitive water treatment and disposal methods; and minimization of the "drilling footprint" through use of a single drilling pad with multiple, directional wells.[42]

Representative of this group of technologies is the Groundwater Research Program, sponsored by DOE/NETL and conducted by GRI.[43] This program was instituted to provide laboratory and field research on waste management to the gas industry. Information from the program is intended to contribute to the

[37] National Energy Technology Laboratory, "FETC SUCCESS: Treating Oil and Gas Produced Waters" (Pittsburgh, PA, March 1999), web site www.fetc.doe.gov/publications/success/fuel-10.pdf.

[38] Removal of the methane adsorbed (collected in condensed form on a surface) on the coals.

[39] Energy Information Administration, *Oil and Gas Supply Module (OGSM), Model Documentation 2000*, Appendix 4D (prepared by Advanced Resources International, Inc.), p. 4D-46.

[40] G. Moritis, "Emerging Technologies To Boost Hydrocarbon Production Efficiency," *Oil & Gas Journal* (December 13, 1999).

[41] S. Stevens, D. Spector, and P. Riemer, "Enhanced Coalbed Methane Recovery Using $CO_2$ Injection: Worldwide Resource and $CO_2$ Sequestration Potential," Society of Petroleum Engineers, 1998 SPE International Conference and Exhibition (Beijing, China, November, 2-6, 1998).

[42] Energy Information Administration, *Oil and Gas Supply Module (OGSM), Model Documentation 2000*, Appendix 4D (prepared by Advanced Resources International, Inc.), p. 4D-49.

[43] National Energy Technology Laboratory, "FETC SUCCESS: Groundwater Research Program" (Pittsburgh, PA, March 1999), web site www.fetc.doe.gov/publications/success/fuel-10.pdf.

management of gas industry-related wastes, improving the industry's ability to diagnose the presence of organic and inorganic constituents and to remediate soil and groundwater impacted by gas industry activities.

In the UGRSS, environmental mitigation is assumed to gradually remove development constraints in environmentally sensitive basins, resulting in an increase in the areas available for development.

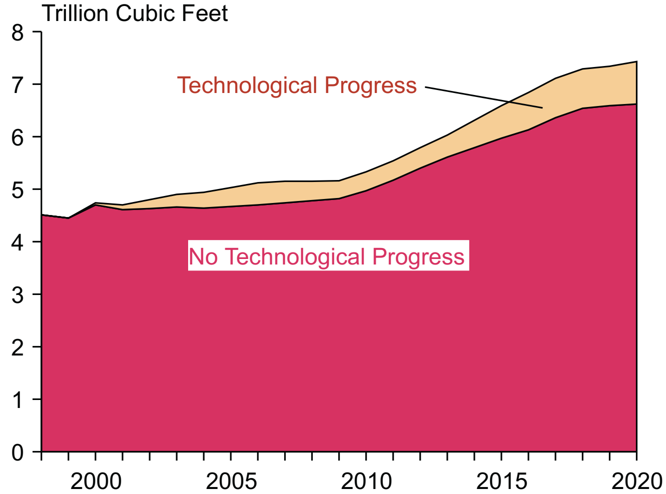
### *Effect of Production Technologies*

Production technologies are projected to have a noticeable impact early in the forecast period, primarily through the assumed success of remediation efforts that increase the productivity of developed areas. Cost-effective gains in water and gas treatment technology also are assumed to work to increase production throughout the forecast. Toward the end of the forecast, production is assumed to be boosted by advances in ECBM production technology and increases in accessible acreage due to environmental impact mitigation.

From 2000 to 2013 unconventional gas production in the technological progress case is projected to exceed production in the no technological progress case by a cumulative 4.2 trillion cubic feet (Figure 9). The difference in production between the two cases widens thereafter, with production in the technological progress case exceeding production in the no technological progress case by a cumulative 4.9 trillion cubic feet over the last 7 years of the projection period (2014-2020).

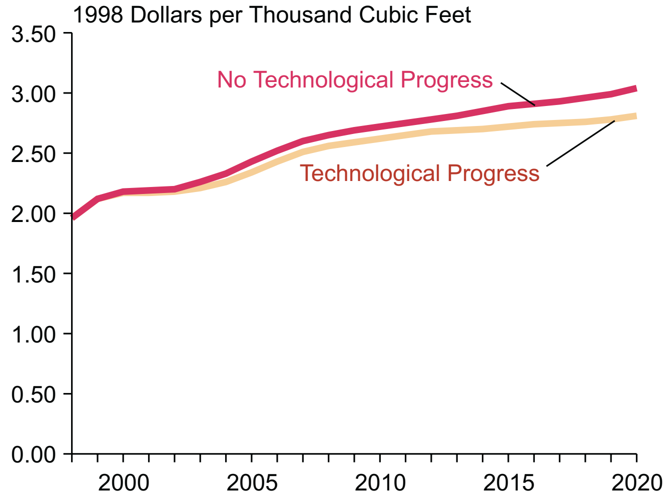
The projected price in the technological progress case is approximately 9 cents lower by 2005 than in the no technological progress case. The differential remains relatively constant for about 10 years and then begins to widen as technology-driven increases in production capacity act to hold down prices in the technological progress case. By 2020 the Lower 48 natural gas wellhead price in the technological progress case is projected to be 23 cents lower than in the no technological progress case (Figure 10).

**Figure 9. Projected Effect of Production Technologies on Unconventional Gas Production, 1998-2020**




Source: AEO2000 National Energy Modeling System, runs BASIN.D060600A and UGRTP01.D051600A.

**Figure 10. Projected Effect of Unconventional Gas Production Technologies on U.S. Lower 48 Natural Gas Wellhead Price, 1998-2020**




Source: AEO2000 National Energy Modeling System, runs BASIN.D060600A and UGRTP01.D051600A.

## Aggregate Effect of Unconventional Gas Recovery Technologies

### National Level

At the national level, the aggregate effects of the various unconventional gas recovery technologies (as represented in the UGRSS) on *AEO2000* projections of unconventional gas production (Figure 11) and U.S. natural gas wellhead prices (Figure 12) do not equal a summation of the results observed for the three major technology categories treated separately.[44] This is in part because of an overlap in impact on recovery among the individual technologies within the UGRSS. Some portion of the resource base can become economically recoverable with the introduction of any of several technology options. For that segment of the resource base, activation of the full set of technologies is redundant within the time frame of the outlook. In the no technological progress case, cumulative production is projected to be 24.7 trillion cubic feet lower and the

[44]Selected year-by-year results are presented in Appendix C.

wellhead price in 2020 is projected to be 78 cents higher than in the technological progress case. These differences in projected cumulative production and the price in 2020 are 1.6 trillion cubic feet lower and 5 cents higher, respectively, than would be indicated by the summed results of the three major technology categories treated separately.

## Regional Level

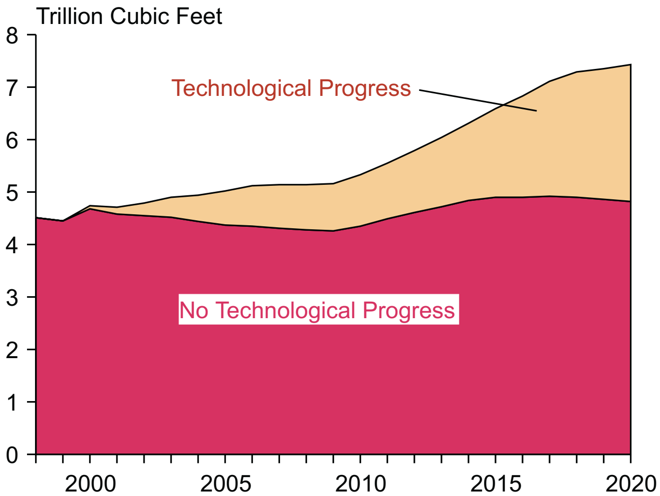
Most of the projected technology-driven increase in unconventional gas production is concentrated in the Rocky Mountain region (Figure 13). The Rocky Mountain region accounts for 78 percent and 83 percent, respectively, of the increase in tight sands production and coalbed methane production that is projected to result from technological progress.

Much of the incremental coalbed methane production, 2.5 trillion cubic feet (36 percent of the total increase), is projected to occur in the Fairway play of the San Juan Basin (see Appendix A), primarily as a result of higher reserves made possible by gains in remedial technology. Another 1.6 trillion cubic feet increase (23 percent of the total) is projected for the Ferron play in the Uinta Basin, due to progress in ECBM technology in the later years of the forecast period.

For tight sands, the greatest effects from technological progress are projected for the Greater Green River Basin, where the Shallow Mesaverde play is projected to account for 18 percent (2.8 trillion cubic feet) of the total technology-induced increase in U.S. tight sands production between cases. A cumulative increase of 2.3 trillion cubic feet is also projected for the Fox Hills / Lance play in the Greater Green River Basin.

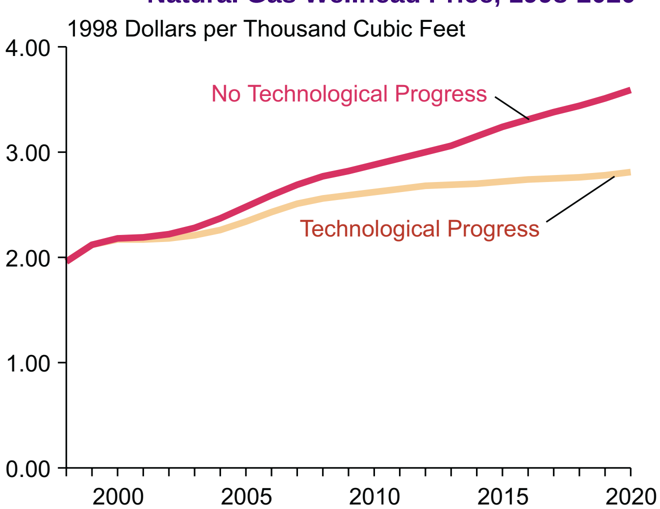
The technological benefits for gas shales are projected to occur almost entirely in the Northeast Region. Approximately 60 percent (1.4 trillion cubic feet) of the total cumulative increase in gas shale production is projected to come from the Appalachian Basin and another 30 percent from the Developing Area play of Michigan's Antrim Basin. The remaining 10 percent is projected to come from the Fort Worth Barnett Basin in Texas.

**Figure 11. Projected Effect of All Unconventional Gas Technologies on Unconventional Gas Production, 1998-2020**



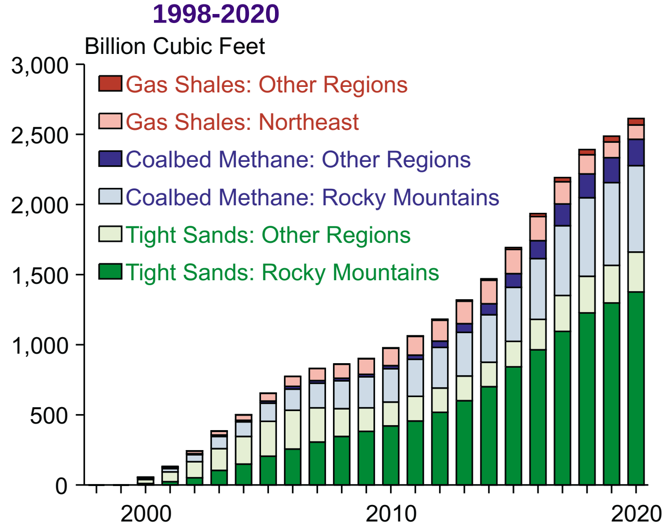

Source: AEO2000 National Energy Modeling System, runs BASIN.D060600A and UGRT04.D051600A.

**Figure 12. Projected Effect of All Unconventional Gas Technologies on U.S. Lower 48 Natural Gas Wellhead Price, 1998-2020**




Source: AEO2000 National Energy Modeling System, runs BASIN.D060600A and UGRT04.D051600A.

**Figure 13. Projected Effect of All Unconventional Gas Technologies on Regional Unconventional Gas Production: Incremental Production in the Technological Progress Case, 1998-2020**



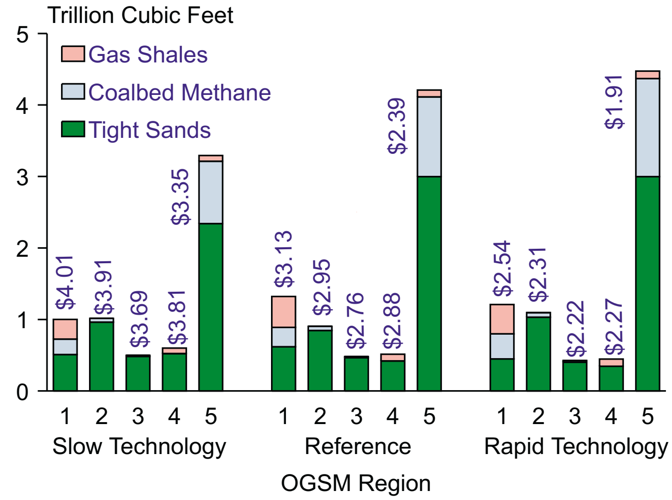

Source: AEO2000 National Energy Modeling System, runs BASIN.D060600A and UGRT04.D051600A.

## Unconventional Gas in the *AEO2000* Technology Cases

A comparison of three *AEO2000* cases (Figure 14) further illustrates the role of technology with respect to the unconventional gas projections. For two sensitivity cases in *AEO2000*, the technology assumptions for both unconventional gas and conventional gas were adjusted to represent conditions of slow and rapid technological progress.[45] There are generally only moderate differences in projected production among the cases but rather large differences in projected market prices. This reflects limited variation in end-use consumption among the cases. In the model, producers are able to meet these similar demands only at dramatically different prices when the beneficial impacts of technology are allowed to vary substantially among cases.

Because projected consumption levels do not change substantially, the projected production levels in each case depend primarily on the ability of unconventional gas producers to compete for market share with other sources of natural gas supply. Under conditions of rapid technological progress they are able to increase their efficiency and retain enough of the market for production to rise slightly over the reference case projections. The highest projected increase in production in the rapid technology case occurs for coalbed methane in the Rocky Mountain region. This sector could be expected to benefit most from an increase in the rate of technological progress. Projected unconventional gas production in the slow technology case falls below the reference case production, by a greater margin. This implies a significant shift out of unconventional gas under a diminished technological outlook. The shift is projected to come mostly from tight sands in the Rocky Mountain region, but also significantly from gas shales in the Appalachian region. This suggests a greater downside sensitivity in these sectors to the state of technology.

**Figure 14. Projected Regional Unconventional Gas Production and Natural Gas Wellhead Prices by Technology Case, 2020**




Notes: Regional average wellhead prices are shown in 1998 dollars per thousand cubic feet. OGSM Regions: 1 = Northeast, 2 = Gulf Coast, 3 = Midcontinent, 4 = Southwest, 5 = Rocky Mountain (see Figure 4 for map).

Source: AEO2000 National Energy Modeling System, runs AEO2K.D100199A, OGHTEC.D100799C, and OGLTEC. D100799A.

## Summary

In the UGRSS, 11 groups of technologies are represented by time-specific adjustments to assumptions concerning costs, productivity, and resource availability. These 11 groups can be combined into three basic categories: (1) exploration, (2) drilling and completion, and (3) production. Exploration technologies, as represented in the UGRSS, affect the *AEO2000* projections primarily near the end of the forecast as emerging plays mature, hypothetical plays reach the development stage, and developers are able to concentrate their efforts on the best parts of the plays. Drilling and completion technologies have the greatest projected impact, as better geology/technology matching, lower damage completions, improved hydraulic fracturing, and advanced completion methods combine to increase projected cumulative unconventional gas production by 11.4 trillion cubic feet and lower the 2020 projected average wellhead price by 33 cents. Production technologies are projected to have a substantial impact in the early years of the forecast due to improvements in remediation technology and cost-effective gains in water and gas treatment. They are expected to have an even greater impact in later years as a result of increased acreage from environmental mitigation and the successful development of enhanced coalbed methane technologies. Regionally, most of the benefits from technological progress are projected to occur in the Rocky Mountain region for tight sands and coalbed methane and in the Northeast region for gas shales.

[45]The specific assumptions and parameter values of the three *AEO2000* technology cases are provided in Energy Information Administration, *Assumptions to the Annual Energy Outlook 2000*, web site www.eia.doe.gov/oiaf/aeo.html.

# Appendix A

# Representation of Unconventional Gas Technology Groups: Adjustments and Parameters

| Technology Group | Item | Type of Deposit | Technology Case | | |
|---|---|---|---|---|---|
| | | | Slow | Reference | Rapid |
| 1. Basin assessments | Year Hypothetical Plays Become Available | Coalbed Methane and Gas Shales | NA | 2016 | 2013 |
| | | Gas Shales | NA | NA | 2018 |
| | Proportionate Increase in Share of Hypothetical Play Area Assessed to be Productive (per year) | All Types | NA | NA | 0.5% |
| 2. Play specific, extended reservoir characterizations | Decrease in Extended Portion of Development Schedule for Emerging Plays (per year) | Coalbed Methane and Gas Shales | NA | 5.0% | 7.5% |
| | | Tight Sands | NA | 6.3% | 8.2% |
| 3. Advanced exploration and natural fracture detection research and development (R&D) | Increase in Percentage of Wells Drilled Successfully (per year) | Coalbed Methane and Gas Shales | 0.1% | 0.3% | 0.6% |
| | | Tight Sands | 0.1% | 0.3% | 0.8% |
| | Year that Best 30 Percent of Basin is Fully Identified | Coalbed Methane | 2017 | 2017 | 2012 |
| | | Tight Sands | NA | 2017 | 2012 |
| | | Gas Shales | NA | 2017 | 2017 |
| 4. Geology technology modeling and matching | Increase in EUR per Well (per year) | Coalbed Methane and Gas Shales | NA | 0.1% | 0.3% |
| | | Tight Sands | NA | 0.3% | 0.4% |
| 5. More effective, lower damage well completion and stimulation technology | Increase in EUR per Well (per year) | Coalbed Methane and Gas Shales | 0.3% | 0.4% | 0.6% |
| | | Tight Sands | 0.4% | 0.5% | 0.6% |
| 6. Targeted drilling and hydraulic fracturing R&D | Decrease in Drilling and Stimulation Costs per Well (per year) | Coalbed Methane and Gas Shales | 0.3% | 0.5% | 0.8% |
| | | Tight Sands | 0.3% | 0.5% | 0.5% |
| 7. Advanced well completion technologies such as cavitation, horizontal drilling and multilateral wells | Year Advanced Well Completion Technologies Become Available | Coalbed Methane | 2018 | 2011 | 2008 |
| | | Tight Sands | 2016 | 2011 | 2011 |
| | | Gas Shales | NA | NA | 2016 |
| | Increase in EUR per well (total increase) | Coalbed Methane | 10.0% | 20.0% | 25.0% |
| | | Tight Sands | 5.0% | 10.0% | 12.5% |
| | | Gas Shales | NA | NA | 5.0% |
| 8. Advanced well performance diagnostics and remediation | Expansion of Existing Reserves (per year, declining by 0.1% per year) | Coalbed Methane and Gas Shales | 2.0% | 3.0% | 3.5% |
| | | Tight Sands | 1.0% | 2.0% | 2.5% |
| 9. New Practices and Technology for gas and water treatment | Decrease in Water and Gas Treatment O&M Costs per Well (per year) | All Types | 0.6% | 1.0% | 1.3% |
| 10. Other unconventional gas technologies, such as enhanced coalbed methane and enhanced gas shales recovery | Year Advanced Recovery Technologies Become Available | Coalbed Methane | 2018 | 2010 | 2010 |
| | | Tight Sands | NA | NA | 2018 |
| | | Gas Shales | NA | NA | NA |
| | Increase in EUR per well (total increase) | Coalbed Methane | 10.0% | 25.0% | 27.5% |
| | | Tight Sands | NA | NA | 10% |
| | | Gas Shales | NA | NA | NA |
| | Increase in Costs ($1998/Mcf) for Incremental CBM production | Coalbed Methane | 1.54 | 1.03 | 0.91 |
| | | Tight Sands and Gas Shales | NA | NA | NA |
| 11. Mitigation of environmental and other constraints on development | Proportion of Areas Currently Restricted that Become Available for Development (per year) | Coalbed Methane | 0.3% | 1.0% | 1.3% |
| | | Tight Sands | NA | 1.0% | 1.3% |
| | | Gas Shales | 0.5% | 1.0% | 1.3% |

NA = not applicable.
Source: Office of Integrated Analysis and Forecasting.

# Appendix B

## Projected Effect of Technology on Unconventional Gas Production and Natural Gas Wellhead Price by Region and Major Plays

| Region/Major Plays | 1998 Production (Billion Cubic Feet) | Cumulative Production, 1998-2020 (Billion Cubic Feet) | | Regional Wellhead Price, 2020 (1998 Dollars per Thousand Cubic Feet) | |
|---|---|---|---|---|---|
| | | No UGR Technology Adjustments | *AEO2000* Reference Technology | No UGR Technology Adjustments | *AEO2000* Reference Technology |
| **Tight Sands** | | | | | |
| **Region 1: Northeast** | 407.7 | 7,299 | 8,891 | 3.86 | 3.17 |
| Clinton-Medina High | 106.2 | 2,971 | 3,691 | | |
| Upper Devonian High | 301.5 | 4,328 | 5,152 | | |
| **Region 2: Gulf Coast** | 975.0 | 20,028 | 21,651 | 3.76 | 2.94 |
| LA/MS Salt-Cotton Valley | 396.4 | 13,159 | 13,785 | | |
| Texas Gulf: Wilcox/Lobo | 461.2 | 5,902 | 6,284 | | |
| **Region 3: Midcontinent** | 273.3 | 5,786 | 6,898 | 3.48 | 2.75 |
| Anadarko: Cleveland | 46.8 | 2,199 | 2,195 | | |
| Anadarko: Cherokee/Redfork | 139.2 | 2,735 | 3,298 | | |
| **Region 4: Southwest** | 280.0 | 8,295 | 7,841 | 3.62 | 2.85 |
| Permian Canyon | 221.3 | 7,622 | 6,890 | | |
| **Region 5: Rocky Mountain** | 1,175.1 | 31,713 | 43,119 | 3.44 | 2.43 |
| Greater Green River: Fox Hills/Lance | 16.0 | 2,114 | 4,459 | | |
| G. G. River Frontier (Moxa Arch) | 275.5 | 4,990 | 5,346 | | |
| G. G. River Shallow Mesaverde | 169.7 | 4,075 | 6,900 | | |
| Piceance: South Basin Williams Fork/Mesaverde | 35.0 | 1,809 | 2,613 | | |
| Piceance: Iles/Mesaverde | 10.2 | 122 | 801 | | |
| San Juan Basin: Central Basin/Mesaverde | 262.2 | 7,528 | 8,593 | | |
| N. Great Plains: High Potential | 23.1 | 756 | 1,444 | | |
| **Coalbed Methane** | | | | | |
| **Region 1: Northeast** | 49.0 | 2,431 | 3,029 | 3.86 | 3.17 |
| Central Appalachian B.-Central B. | 49.0 | 2,431 | 2,971 | | |
| **Region 2: Gulf Coast** | 122.0 | 969 | 1,496 | 3.76 | 2.94 |
| Black Warrior: Shallow | 122.0 | 969 | 1,442 | | |
| **Region 3: Midcontinent** | 5.0 | 104 | 186 | 3.48 | 2.75 |
| MC: Cherokee & Arkoma | 5.0 | 104 | 186 | | |
| **Region 5: Rocky Mountain** | 1,033.0 | 19,397 | 25,143 | 3.44 | 2.43 |
| Uinta Basin: Ferron | 26.0 | 2,193 | 3,783 | | |
| Raton Basin: North Raton Basin | 3.0 | 289 | 513 | | |
| Raton Basin: Purgatoire River | 15.0 | 565 | 775 | | |
| Piceance Basin: Shallow | 0.0 | 0 | 165 | | |
| Northern San Juan Basin: CO | 93.0 | 2,681 | 3,299 | | |
| Fairway SJB: NM & CO | 808.0 | 9,404 | 11,880 | | |
| Western SJB: NM | 43.0 | 1,211 | 1,137 | | |
| **Gas Shales** | | | | | |
| **Region 1: Northeast** | 310.0 | 8,654 | 10,781 | 3.86 | 3.17 |
| Appalachia: Big Sandy Central | 88.2 | 3,869 | 4,735 | | |
| Appalachia: Big Sandy Extension | 17.6 | 520 | 1,075 | | |
| Mich. Antrim: Developing Area | 204.0 | 4,265 | 4,971 | | |
| **Region 4: Southwest** | 36.0 | 1,095 | 1,342 | 3.62 | 2.85 |
| Fort Worth Barnett: Main Area | 36.0 | 1,095 | 1,342 | | |

# Appendix C
# Year-by-Year Results

## Unconventional Gas Production and Production Shares

The projected unconventional gas share of total gas production and the projected quantity of unconventional gas production change significantly between cases (Tables C1 and C2). The projected unconventional gas share of total production is more than 10 percent smaller (as compared with the reference case with all technological advances included) in the later years for two out of three cases where there is a partial removal of the effect of technological advances. In the case where all the effects of technological advances are removed, the projected unconventional gas share of total production is more than 15 percent lower in the last 12 years and 28 percent lower by the end of the forecast period. The relative differences are greater with respect to projected production levels. By 2020, unconventional gas production in the case with no advances in unconventional gas technology is projected to be 35 percent lower than production in the reference case.

**Table C1. Unconventional Gas Share of Total Gas Production**

| | Reference | No Exploration Technological Advances | | No Drilling and Completion Technological Advances | | No Production Technological Advances | | No Technological Advances | |
|---|---|---|---|---|---|---|---|---|---|
| Year | UG Production Share | UG Production Share | % Change from Reference | UG Production Share | % Change from Reference | UG Production Share | % Change from Reference | UG Production Share | % Change from Reference |
| 1998. . . . . | 0.24 | 0.24 | 0.00% | 0.24 | 0.00% | 0.24 | 0.00% | 0.24 | 0.00% |
| 1999. . . . . | 0.24 | 0.24 | 0.00% | 0.24 | 0.00% | 0.24 | 0.00% | 0.24 | 0.00% |
| 2000. . . . . | 0.25 | 0.25 | -0.09% | 0.25 | -0.19% | 0.25 | -0.83% | 0.25 | -1.11% |
| 2001. . . . . | 0.26 | 0.26 | 0.22% | 0.25 | -0.67% | 0.25 | -1.84% | 0.25 | -2.59% |
| 2002. . . . . | 0.26 | 0.26 | 0.19% | 0.26 | -1.10% | 0.25 | -3.20% | 0.25 | -4.65% |
| 2003. . . . . | 0.26 | 0.26 | -0.07% | 0.26 | -1.54% | 0.25 | -4.36% | 0.24 | -7.02% |
| 2004. . . . . | 0.26 | 0.26 | -0.52% | 0.25 | -2.10% | 0.24 | -5.28% | 0.24 | -8.89% |
| 2005. . . . . | 0.26 | 0.25 | -0.98% | 0.25 | -3.07% | 0.24 | -6.08% | 0.23 | -11.37% |
| 2006. . . . . | 0.25 | 0.25 | -1.20% | 0.24 | -4.82% | 0.23 | -7.02% | 0.22 | -13.32% |
| 2007. . . . . | 0.25 | 0.24 | -1.23% | 0.23 | -5.65% | 0.23 | -6.67% | 0.21 | -14.11% |
| 2008. . . . . | 0.24 | 0.24 | -0.91% | 0.23 | -6.13% | 0.23 | -5.99% | 0.20 | -14.63% |
| 2009. . . . . | 0.24 | 0.23 | -0.51% | 0.22 | -6.82% | 0.22 | -5.48% | 0.20 | -15.14% |
| 2010. . . . . | 0.24 | 0.24 | -0.23% | 0.22 | -7.32% | 0.22 | -5.12% | 0.20 | -15.58% |
| 2011. . . . . | 0.24 | 0.24 | -0.84% | 0.22 | -7.90% | 0.23 | -5.13% | 0.20 | -15.93% |
| 2012. . . . . | 0.25 | 0.24 | -1.80% | 0.23 | -8.34% | 0.23 | -5.04% | 0.21 | -16.85% |
| 2013. . . . . | 0.25 | 0.24 | -3.22% | 0.23 | -8.97% | 0.24 | -5.43% | 0.21 | -17.94% |
| 2014. . . . . | 0.26 | 0.25 | -4.42% | 0.23 | -9.61% | 0.24 | -6.41% | 0.21 | -19.00% |
| 2015. . . . . | 0.26 | 0.25 | -5.75% | 0.24 | -10.52% | 0.24 | -7.49% | 0.21 | -21.02% |
| 2016. . . . . | 0.27 | 0.25 | -8.33% | 0.24 | -11.79% | 0.25 | -8.34% | 0.21 | -23.34% |
| 2017. . . . . | 0.28 | 0.25 | -10.24% | 0.24 | -13.04% | 0.25 | -8.51% | 0.21 | -25.73% |
| 2018. . . . . | 0.28 | 0.25 | -11.82% | 0.24 | -13.66% | 0.26 | -8.13% | 0.20 | -27.18% |
| 2019. . . . . | 0.28 | 0.25 | -11.88% | 0.24 | -13.42% | 0.26 | -7.72% | 0.20 | -27.68% |
| 2020. . . . . | 0.28 | 0.25 | -12.17% | 0.25 | -12.66% | 0.26 | -8.02% | 0.20 | -28.21% |

## Table C2. Unconventional Gas Production
(Trillion Cubic Feet)

| Year | Reference | No Exploration Technological Advances | | No Drilling and Completion Technological Advances | | No Production Technological Advances | | No Technological Advances | |
|---|---|---|---|---|---|---|---|---|---|
| | Production | Production | % Change from Reference | Production | % Change from Reference | Production | % Change from Reference | Production | % Change from Reference |
| 1997. . . . . | 4.51 | 4.51 | 0.00% | 4.51 | 0.00% | 4.51 | 0.00% | 4.51 | 0.00% |
| 1998. . . . . | 4.51 | 4.51 | 0.00% | 4.51 | 0.00% | 4.51 | 0.00% | 4.51 | 0.00% |
| 1999. . . . . | 4.45 | 4.45 | 0.00% | 4.45 | 0.00% | 4.45 | 0.00% | 4.45 | 0.00% |
| 2000. . . . . | 4.74 | 4.73 | -0.08% | 4.73 | -0.21% | 4.70 | -0.88% | 4.68 | -1.19% |
| 2001. . . . . | 4.71 | 4.72 | 0.19% | 4.67 | -0.76% | 4.61 | -2.01% | 4.58 | -2.82% |
| 2002. . . . . | 4.80 | 4.81 | 0.22% | 4.74 | -1.18% | 4.63 | -3.54% | 4.55 | -5.07% |
| 2003. . . . . | 4.90 | 4.90 | -0.09% | 4.82 | -1.74% | 4.66 | -4.89% | 4.52 | -7.85% |
| 2004. . . . . | 4.94 | 4.92 | -0.50% | 4.83 | -2.34% | 4.64 | -6.09% | 4.44 | -10.12% |
| 2005. . . . . | 5.03 | 4.97 | -1.03% | 4.85 | -3.51% | 4.67 | -7.16% | 4.37 | -13.02% |
| 2006. . . . . | 5.12 | 5.05 | -1.29% | 4.86 | -5.15% | 4.70 | -8.21% | 4.35 | -15.10% |
| 2007. . . . . | 5.15 | 5.07 | -1.40% | 4.82 | -6.25% | 4.74 | -7.98% | 4.31 | -16.16% |
| 2008. . . . . | 5.14 | 5.09 | -0.97% | 4.79 | -6.84% | 4.78 | -7.18% | 4.28 | -16.75% |
| 2009. . . . . | 5.16 | 5.14 | -0.36% | 4.77 | -7.62% | 4.82 | -6.50% | 4.26 | -17.49% |
| 2010. . . . . | 5.33 | 5.29 | -0.75% | 4.86 | -8.81% | 4.97 | -6.83% | 4.35 | -18.32% |
| 2011. . . . . | 5.55 | 5.49 | -0.97% | 5.03 | -9.34% | 5.17 | -6.75% | 4.49 | -19.15% |
| 2012. . . . . | 5.79 | 5.67 | -2.04% | 5.21 | -10.00% | 5.40 | -6.66% | 4.61 | -20.39% |
| 2013. . . . . | 6.04 | 5.82 | -3.55% | 5.38 | -10.88% | 5.61 | -7.01% | 4.72 | -21.87% |
| 2014. . . . . | 6.31 | 6.00 | -4.90% | 5.58 | -11.68% | 5.79 | -8.30% | 4.84 | -23.28% |
| 2015. . . . . | 6.59 | 6.18 | -6.21% | 5.74 | -12.91% | 5.97 | -9.45% | 4.90 | -25.68% |
| 2016. . . . . | 6.84 | 6.23 | -8.90% | 5.85 | -14.42% | 6.13 | -10.33% | 4.90 | -28.30% |
| 2017. . . . . | 7.11 | 6.33 | -10.95% | 5.99 | -15.79% | 6.36 | -10.60% | 4.92 | -30.83% |
| 2018. . . . . | 7.29 | 6.37 | -12.67% | 6.08 | -16.62% | 6.54 | -10.30% | 4.90 | -32.80% |
| 2019. . . . . | 7.35 | 6.39 | -12.97% | 6.12 | -16.76% | 6.59 | -10.26% | 4.86 | -33.86% |
| 2020. . . . . | 7.43 | 6.42 | -13.53% | 6.20 | -16.48% | 6.62 | -10.94% | 4.82 | -35.17% |

## Unconventional Gas Revenue

Firms involved primarily in unconventional gas activities would generally be increasing their revenues by engaging in R&D. The total revenue for producers of unconventional gas is projected to be lower throughout the forecast in two of the three cases in which the effect of technological advances is partially removed (Table C3). Total revenue is projected to be slightly higher (less than 1 percent) in the early years of the forecast with the removal of technological advances in exploration technology. In this instance, wellhead prices in two regions are expected to be driven up by decreased production in the other regions. In these two regions, the Midcontinent and the Southwest, the negative effects on production from the absence of exploratory technological advances are quite small in the early years. Accordingly, production is higher there in response to higher prices, despite the lack of advances in exploration technology. The revenues for these two regions are also projected to be higher than in the reference case in those years, high enough to offset lower revenues in other regions. In the later years, when the absence of the benefits of advances in exploration technologies is felt the most, total revenue is lower than in the reference case. Lower projected revenues in several regions, particularly the Rocky Mountain, offset any higher projected revenues elsewhere. In the case where all the effects of technological advances on unconventional gas recovery are removed, total revenue from unconventional gas is lower throughout and by more than 10 percent in the last 4 years of the projection period.

**Table C3. Unconventional Gas Revenue**
(Billion 1998 Dollars)

| | Reference | No Exploration Technological Advances | | No Drilling and Completion Technological Advances | | No Production Technological Advances | | No Technological Advances | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Revenue | Revenue | % Change from Reference | Revenue | % Change from Reference | Revenue | % Change from Reference | Revenue | % Change from Reference |
| 1998 | 8.27 | 8.27 | 0.00% | 8.27 | 0.00% | 8.27 | 0.00% | 8.27 | 0.00% |
| 1999 | 8.83 | 8.83 | 0.00% | 8.83 | 0.00% | 8.83 | 0.00% | 8.83 | 0.00% |
| 2000 | 9.76 | 9.76 | 0.03% | 9.74 | -0.14% | 9.71 | -0.45% | 9.69 | -0.67% |
| 2001 | 9.79 | 9.83 | 0.43% | 9.74 | -0.55% | 9.71 | -0.88% | 9.65 | -1.47% |
| 2002 | 10.10 | 10.17 | 0.64% | 10.02 | -0.81% | 9.97 | -1.30% | 9.90 | -2.05% |
| 2003 | 10.61 | 10.68 | 0.61% | 10.50 | -1.05% | 10.46 | -1.39% | 10.29 | -3.02% |
| 2004 | 11.08 | 11.14 | 0.52% | 10.95 | -1.17% | 10.91 | -1.60% | 10.68 | -3.65% |
| 2005 | 11.74 | 11.75 | 0.10% | 11.54 | -1.72% | 11.48 | -2.24% | 11.11 | -5.38% |
| 2006 | 12.45 | 12.44 | -0.06% | 12.11 | -2.71% | 12.01 | -3.49% | 11.62 | -6.66% |
| 2007 | 12.99 | 12.96 | -0.21% | 12.55 | -3.35% | 12.50 | -3.70% | 12.06 | -7.14% |
| 2008 | 13.29 | 13.31 | 0.21% | 12.84 | -3.39% | 12.85 | -3.27% | 12.36 | -6.98% |
| 2009 | 13.45 | 13.56 | 0.85% | 12.95 | -3.70% | 13.12 | -2.40% | 12.49 | -7.14% |
| 2010 | 13.99 | 14.03 | 0.27% | 13.34 | -4.67% | 13.60 | -2.78% | 12.96 | -7.39% |
| 2011 | 14.63 | 14.69 | 0.46% | 13.96 | -4.57% | 14.27 | -2.42% | 13.58 | -7.18% |
| 2012 | 15.27 | 15.32 | 0.31% | 14.59 | -4.47% | 15.00 | -1.79% | 14.19 | -7.05% |
| 2013 | 15.83 | 15.82 | -0.04% | 15.13 | -4.39% | 15.66 | -1.04% | 14.79 | -6.55% |
| 2014 | 16.49 | 16.44 | -0.31% | 15.82 | -4.04% | 16.21 | -1.67% | 15.56 | -5.64% |
| 2015 | 17.16 | 17.08 | -0.45% | 16.42 | -4.32% | 16.73 | -2.49% | 16.07 | -6.35% |
| 2016 | 17.84 | 17.32 | -2.88% | 16.81 | -5.76% | 17.17 | -3.75% | 16.35 | -8.32% |
| 2017 | 18.57 | 17.78 | -4.24% | 17.35 | -6.59% | 17.89 | -3.68% | 16.68 | -10.16% |
| 2018 | 19.17 | 18.08 | -5.72% | 17.86 | -6.84% | 18.65 | -2.71% | 16.94 | -11.66% |
| 2019 | 19.47 | 18.42 | -5.39% | 18.14 | -6.80% | 19.07 | -2.03% | 17.15 | -11.92% |
| 2020 | 19.93 | 18.87 | -5.33% | 18.68 | -6.28% | 19.45 | -2.44% | 17.36 | -11.92% |

Note: Revenue values were calculated by multiplying regional production projections times regional wellhead price projections.

## Wellhead Prices and Price Differentials

For most of the forecast period the sum of the price differentials (from the reference case) for the three cases with partial removal of the effect of technological progress on unconventional gas is projected to be less than the price for the case where all of the effects are removed (Tables C4 and C5). For 15 of 23 years this difference is less than 12 percent. The percentage difference is as high as 28 percent in the middle years, but by the last year of the forecast it is down to 6 percent: 73 cents for the summation versus 78 cents for the price in the case with no advances in any technology. The projected differences are partly due to an overlap in the effect of the technologies represented in the three respective major categories. Once the technologies in one category render a play economic, the technologies in another category that would also have made the play economic just make it more profitable. When this occurs, the effects (increased production and decreased price) of the two different technology options are not strictly additive.

**Table C4. Wellhead Price Differentials: Partial No Technological Advances and No Technological Advances**
(1998 Dollars per Thousand Cubic Feet)

| Year | Reference Wellhead Price | (A) No Exploration Technological Advances vs. Reference | (B) No Drilling and Completion Technological Advances vs. Reference | (C) No Production Technological Advances vs. Reference | (A)+(B)+(C) | (D) No Technological Advances vs. Reference | (A)+(B)+(C) vs. (D) |
|---|---|---|---|---|---|---|---|
| 1998 | 1.96 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% |
| 1999 | 2.12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00% |
| 2000 | 2.17 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 5.23% |
| 2001 | 2.17 | 0.00 | 0.00 | 0.01 | 0.02 | 0.02 | -3.56% |
| 2002 | 2.18 | 0.00 | 0.01 | 0.03 | 0.04 | 0.04 | -9.87% |
| 2003 | 2.21 | 0.00 | 0.01 | 0.05 | 0.06 | 0.07 | -10.38% |
| 2004 | 2.26 | 0.01 | 0.02 | 0.07 | 0.10 | 0.11 | -7.57% |
| 2005 | 2.34 | 0.01 | 0.03 | 0.09 | 0.13 | 0.14 | -8.15% |
| 2006 | 2.43 | 0.01 | 0.04 | 0.09 | 0.14 | 0.16 | -10.65% |
| 2007 | 2.51 | 0.01 | 0.05 | 0.09 | 0.15 | 0.18 | -16.21% |
| 2008 | 2.56 | 0.01 | 0.06 | 0.09 | 0.16 | 0.21 | -21.68% |
| 2009 | 2.59 | 0.01 | 0.08 | 0.10 | 0.18 | 0.23 | -20.28% |
| 2010 | 2.62 | 0.00 | 0.09 | 0.10 | 0.18 | 0.26 | -28.62% |
| 2011 | 2.65 | 0.00 | 0.11 | 0.10 | 0.21 | 0.29 | -27.89% |
| 2012 | 2.68 | 0.01 | 0.13 | 0.11 | 0.24 | 0.32 | -25.47% |
| 2013 | 2.69 | 0.02 | 0.15 | 0.12 | 0.30 | 0.37 | -20.57% |
| 2014 | 2.70 | 0.04 | 0.19 | 0.14 | 0.38 | 0.45 | -15.55% |
| 2015 | 2.72 | 0.06 | 0.23 | 0.17 | 0.46 | 0.52 | -11.44% |
| 2016 | 2.74 | 0.08 | 0.25 | 0.18 | 0.51 | 0.58 | -11.20% |
| 2017 | 2.75 | 0.10 | 0.27 | 0.19 | 0.55 | 0.63 | -11.89% |
| 2018 | 2.76 | 0.12 | 0.29 | 0.20 | 0.60 | 0.68 | -10.75% |
| 2019 | 2.78 | 0.14 | 0.31 | 0.21 | 0.67 | 0.73 | -8.85% |
| 2020 | 2.81 | 0.17 | 0.33 | 0.23 | 0.73 | 0.78 | -6.58% |

**Table C5. U.S. Average Wellhead Natural Gas Price**
(1998 Dollars per Thousand Cubic Feet)

| Year | Reference | No Exploration Technological Advances | | No Drilling and Completion Technological Advances | | No Production Technological Advances | | No Technological Advances | |
|---|---|---|---|---|---|---|---|---|---|
| | Price | Price | % Change from Reference | Price | % Change from Reference | Price | % Change from Reference | Price | % Change from Reference |
| **1997** | 2.39 | 2.39 | 0.00% | 2.39 | 0.00% | 2.39 | 0.00% | 2.39 | 0.00% |
| **1998** | 1.96 | 1.96 | 0.00% | 1.96 | 0.00% | 1.96 | 0.00% | 1.96 | 0.00% |
| **1999** | 2.12 | 2.12 | 0.00% | 2.12 | 0.00% | 2.12 | 0.00% | 2.12 | 0.00% |
| **2000** | 2.17 | 2.17 | -0.04% | 2.17 | -0.04% | 2.18 | -0.22% | 2.18 | -0.28% |
| **2001** | 2.17 | 2.17 | 0.00% | 2.18 | -0.16% | 2.19 | -0.65% | 2.19 | -0.83% |
| **2002** | 2.18 | 2.18 | -0.03% | 2.18 | -0.31% | 2.20 | -1.26% | 2.22 | -1.76% |
| **2003** | 2.21 | 2.21 | -0.11% | 2.22 | -0.56% | 2.26 | -2.12% | 2.28 | -3.07% |
| **2004** | 2.26 | 2.27 | -0.28% | 2.29 | -1.00% | 2.33 | -2.99% | 2.37 | -4.52% |
| **2005** | 2.34 | 2.35 | -0.30% | 2.38 | -1.38% | 2.43 | -3.52% | 2.48 | -5.50% |
| **2006** | 2.43 | 2.44 | -0.37% | 2.47 | -1.71% | 2.52 | -3.59% | 2.59 | -6.12% |
| **2007** | 2.51 | 2.52 | -0.37% | 2.56 | -1.98% | 2.60 | -3.47% | 2.69 | -6.67% |
| **2008** | 2.56 | 2.57 | -0.36% | 2.62 | -2.37% | 2.65 | -3.38% | 2.77 | -7.43% |
| **2009** | 2.59 | 2.60 | -0.37% | 2.67 | -2.91% | 2.69 | -3.60% | 2.82 | -8.17% |
| **2010** | 2.62 | 2.62 | 0.00% | 2.71 | -3.23% | 2.72 | -3.53% | 2.88 | -8.92% |
| **2011** | 2.65 | 2.65 | 0.00% | 2.76 | -3.85% | 2.75 | -3.63% | 2.94 | -9.72% |
| **2012** | 2.68 | 2.68 | -0.21% | 2.80 | -4.50% | 2.78 | -3.85% | 3.00 | -10.69% |
| **2013** | 2.69 | 2.71 | -0.75% | 2.84 | -5.31% | 2.81 | -4.42% | 3.06 | -12.16% |
| **2014** | 2.70 | 2.74 | -1.46% | 2.90 | -6.70% | 2.85 | -5.07% | 3.15 | -14.22% |
| **2015** | 2.72 | 2.78 | -2.25% | 2.95 | -7.88% | 2.89 | -5.76% | 3.24 | -16.08% |
| **2016** | 2.74 | 2.82 | -2.83% | 2.99 | -8.51% | 2.91 | -6.11% | 3.31 | -17.41% |
| **2017** | 2.75 | 2.85 | -3.46% | 3.02 | -8.95% | 2.93 | -6.34% | 3.38 | -18.64% |
| **2018** | 2.76 | 2.88 | -4.02% | 3.05 | -9.50% | 2.96 | -6.73% | 3.44 | -19.71% |
| **2019** | 2.78 | 2.91 | -4.70% | 3.09 | -10.15% | 2.99 | -7.16% | 3.51 | -20.81% |
| **2020** | 2.81 | 2.97 | -5.56% | 3.14 | -10.65% | 3.04 | -7.50% | 3.59 | -21.71% |