Marcellus Shale Gas Play: Production and Price Dynamics

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January 4, 2012

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Abstract

While the U.S. has abundant natural gas resources, there is wide variation in the quality of the resource base in terms of well production rates and costs. Natural gas production progresses from the highest quality areas to the ever lower quality areas with a corresponding increase in wellhead gas prices. This analysis assesses development of the Marcellus shale gas resource base with the objective of identifying the year when Marcellus shale gas wellhead price reach $10/Mcf, which translates to a delivered natural gas price of about $11.5/Mcf for electricity generators and industrial customers. This benchmark natural gas price represents a doubling of 2011 prices. The Marcellus shale gas technically recoverable resource estimate is 410 Tcf, which is INTEK's estimate for the EIA's *Annual Energy Outlook 2011*. The findings indicate that if annual Marcellus shale gas production is increased to 6 Tcf by 2022 and held constant at 6.7 Tcf/year from 2025 through 2035, then well saturation of the areas of the Marcellus play that are able to maintain wellhead prices under $10/Mcf will occur in 2035. This finding suggests the need for careful attention to the scale-up of Marcellus shale gas production, particularly in regards to proposals to expand the use of natural gas as a transportation fuel, for added electricity generation, and for export to foreign countries. This conclusion is based on the importance of natural gas for residential, commercial, and industrial space and water heating purposes, which account for over 60% of total U.S. natural gas consumption.

1. Introduction

The U.S. has abundant natural gas resources since advances in drilling technologies have made possible commercial production of shale gas resources. The Energy Information Agency's (EIA) Annual Energy Outlook (AEO) 2011 estimate of the U.S. shale gas resource is 972 Tcf, which includes the USGS 2011 update. The EIA shale gas resource estimates are presented in Table 1.

The Marcellus shale gas play is the largest U.S. shale gas play. Shale gas resource estimates for the major U.S. shale gas plays are presented in Table 2. The Marcellus shale gas play contains 410 Tcf of technically recoverable resources according to the EIA's AEO 2011 report, which is 58% of the total U.S. shale gas resource base [1, 2]. The Marcellus shale gas technically recoverable resource (TRR) endowment is more than a factor of four greater than that of the next largest U.S. shale gas play, the Haynesville.

The purpose of this research is to gain insight into Marcellus well development, well production, and wellhead price dynamics. The analysis uses the EIA AEO 2011 shale gas resource data and conventional pro forma horizontal well production profiles. The distribution of the Marcellus shale gas resource is presented in Table 3. Analysis of the Marcellus play is important because its development will strongly influence long-term U.S. natural gas supply and prices.

Table 1. EIA U.S. and Marcellus Shale Gas Resource Estimates.

	U.S. (EIA, AEO 2011)	Marcellus (Revised)	U.S. (Revised)
Proved Reserves	35	4	61
Unproved Technically Recoverable Resources (TRR)	771	473	771
Undiscovered Resources (USGS)	56	84	140
Total Resources (Proved and Unproved)	862	561	972

Notes:

a. The revised totals include 26 Tcf the EIA added to proved reserves in December 2010 and 84 Tcf the USGS added to Marcellus undiscovered resources in August 2011.

Table 2. Major U.S. Shale Gas Plays – Shale Gas Resource Estimates (EIA/INTEK).

(trillion cubic feet – Tcf)	Total TRR	Active TRR	Inactive TRR	Proved Reserves	Total Resource
Marcellus (PA, NY, WV, OH, MD)	410	178	232	5	415
Haynesville (LA, TX)	73	53	19	11	83
Barnett (TX)	43	24	20	27	70
Fayetteville (AR)	32	27	5	9	41
Barnett-Woodford (TX)	32	32			
Woodford (OK)	22	19	3		
Antrim (MI)	20	20			
Lewis Shale (CO, NM)	12	12			
New Albany (IL, IN)	11	11			
Total	655	376	279		

The data in Table 3 is a summary of the 2011 EIA shale gas technically recoverable resource (TRR) estimates and were prepared by an independent contractor, INTEK. The EIA has made available a thorough and transparent description of the methodology INTEK used to generate their estimates [2]. Of the 410 Tcf TRR shale gas resource base, 178 Tcf are located in active areas of the Marcellus play and 232 Tcf are located in inactive areas. Active areas are the areas of the shale gas play that exploration and production (E&P) companies hold lease rights.

Table 3. EIA/INTEK Marcellus Shale Gas Data (Well EUR = Estimated Ultimate Recovery).

	Area (sq. mi.)	TRR (Tcf)	Average (Bcf/Well)	Top 10% (Bcf/Well)	Next 20% (Bcf/Well)	Next 30% (Bcf/Well)	Next 40% (Bcf/Well)
Developed	10,622	178	3.50	7.00	5.25	3.50	1.75
Undeveloped	83,627	232	1.15	2.30	1.73	1.15	0.58

Developed Area – Average Well EUR's (% Total Area)

	Area	Top 10%	Next 20%	Next 30%	Next 40%
Best Area	30%	9.31 (3%)	6.98 (6%)	4.66 (9%)	2.33 (12%)
Average Area	30%	7.00 (3%)	5.25 (6%)	3.50 (9%)	1.75 (12%)
Below Average	40%	5.25 (4%)	3.94 (8%)	2.63 (12%)	1.31 (16%)

Undeveloped Area – Avg. Well EUR's (% Total Area)

	Area	Top 10%	Next 20%	Next 30%	Next 40%
Best Area	30%	3.06 (3%)	2.30 (6%)	1.53 (9%)	0.77 (12%)
Average Area	30%	2.30 (3%)	1.73 (6%)	1.15 (9%)	0.58 (12%)
Bellow Average	40%	1.73 (4%)	1.30 (8%)	0.86 (12%)	0.44 (16%)

A central issue of this analysis is the large variation in well production rates within shale gas plays as shown in Table 3. The objective of E&P companies is to identify and secure lease rights to the highest quality acreage of a shale gas play, which have the best odds for high average well production rates. The highest quality areas of a shale gas play, which corresponds to the area with greatest well concentration, is often referred to as the core area, and the lower quality areas with less well concentration is the non-core area. For example, average horizontal well production rates for the Pennsylvania portion of the Marcellus play are presented in Fig. 1.

The average monthly well production rate for the first year of well production of horizontal shale gas wells in the Pennsylvania Marcellus play approximates a 5.25 Bcf EUR well production profile, which is the black dashed line in Fig. 1. The well production profiles for the core and non-core areas approximate 7.0 Bcf EUR and 3.5 Bcf EUR well production profiles respectively. These well production rates are consistent with the estimates presented in Table 3. Additional details of Pennsylvania horizontal well production are presented in the Appendix, A.2.

Wellhead natural gas prices are a function of well production rates since well costs are recovered with revenues from gas sales. Wellhead price estimates for a range of average well production profiles are presented in Table 4, and the average well production profiles are presented in Fig. 2. The wellhead gas price estimates are derived from the net present value cash flow method, and the underlying financial assumptions are presented in the Appendix, A.1, Table A-1.

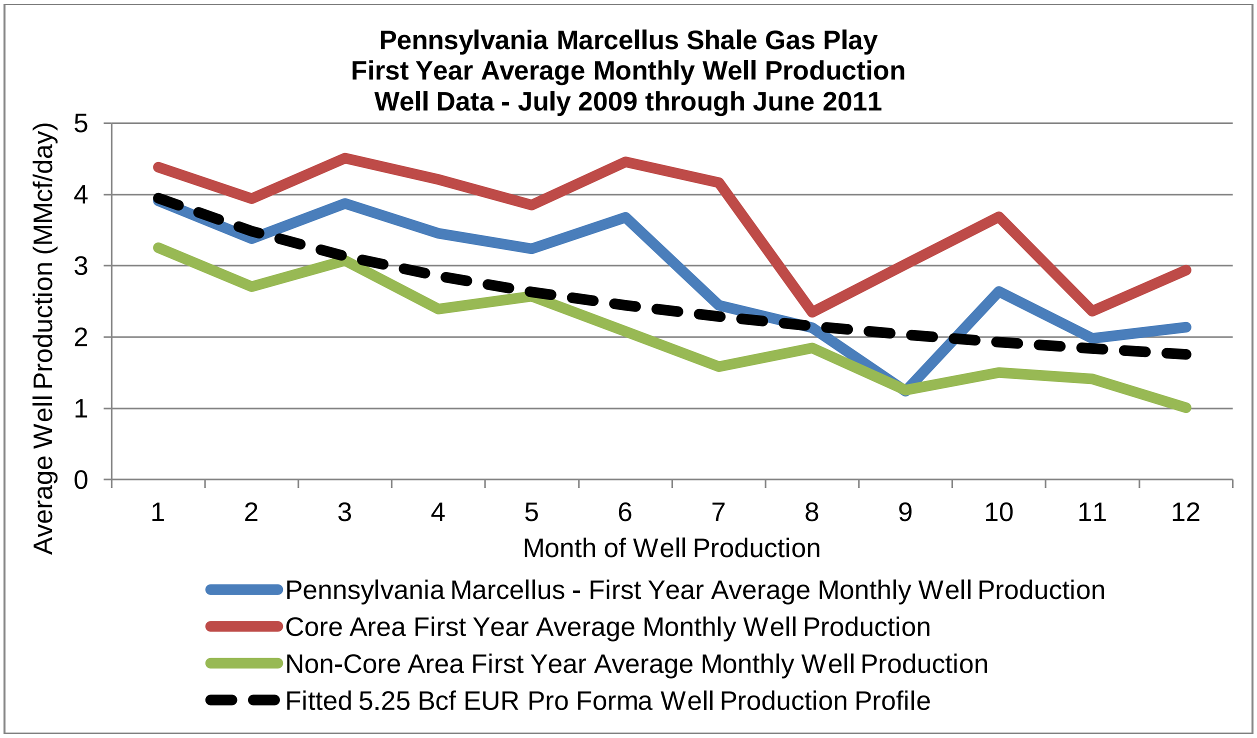

Figure 1. First year average monthly well production for horizontal wells in the Pennsylvania Marcellus shale gas play. Core area counties are Bradford, Tioga, Susquehanna, Wyoming, Lycoming, Clinton, and Sullivan; non-core is all other counties. The data source is PA DEP [3].

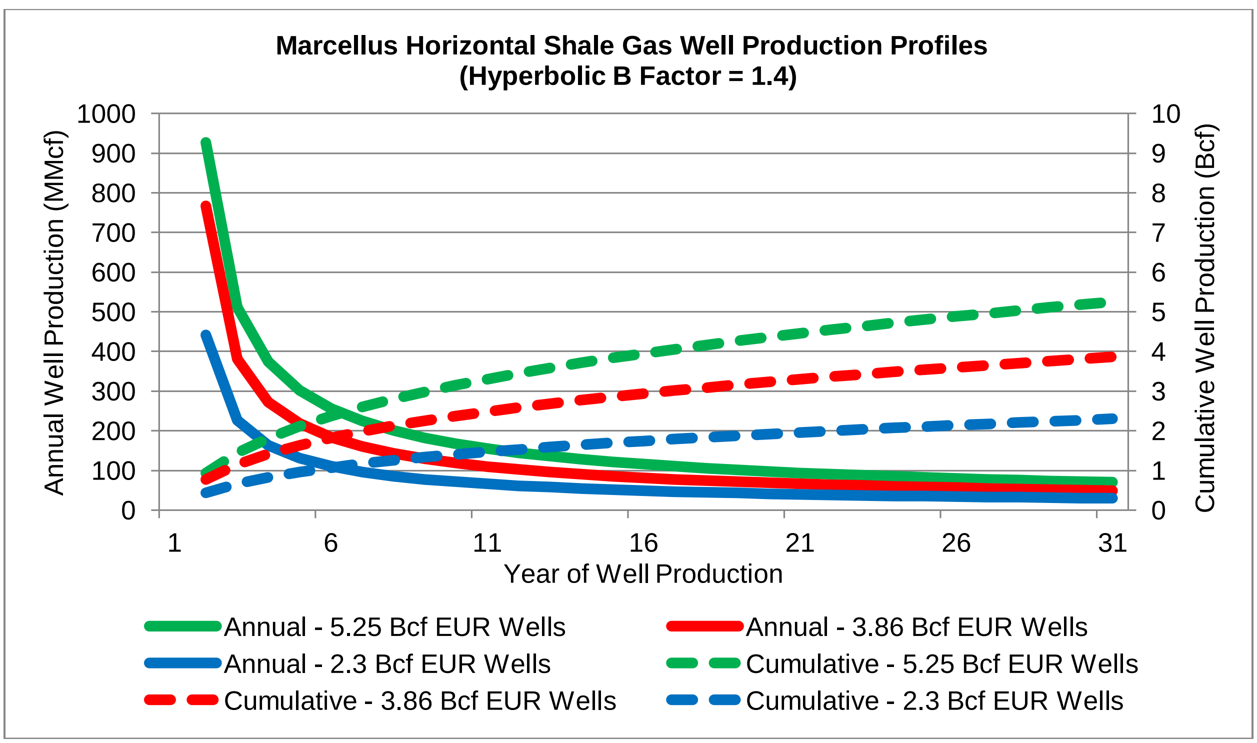

Figure 2. Marcellus horizontal well production profiles. Through the first five years, the decline in monthly well production is 87%, and cumulative production is 47% of the well's EUR.

Table 4. Simulated Wellhead Shale Gas Price Estimates ($/Mcf).

	Marcellus Average Well EUR			
(Constant 6.5% Cost of Debt)	5.25 Bcf EUR	3.86 Bcf EUR	2.3 Bcf EUR	1.15 Bcf EUR
0% Return on Equity Capital	5.00	6.46	8.89	13.19
5% Return on Equity Capital	5.16	6.67	9.25	13.87
6% Return on Equity Capital	5.23	6.76	9.40	14.17
7% Return on Equity Capital	5.30	6.85	9.56	14.47
8% Return on Equity Capital	5.37	6.94	9.71	14.76
9% Return on Equity Capital	5.44	7.04	9.87	15.06
10% Return on Equity Capital	5.51	7.13	10.02	15.36

From Table 4, the current breakeven price is $5/Mcf. How can E&P companies survive with wellhead natural gas spot prices of $3-4/Mcf.? The answer is hedged positions in the natural gas futures market. Even with hedged positions, it is reported that E&P companies that are focusing on dry gas production in shale gas plays are operating at a breakeven level [5].

The conundrum confronting shale gas E&P companies is ongoing competition to secure lease rights to the highest quality areas of the numerous U.S. shale gas plays. This keeps production high and prices low. When saturation of lease rights occurs, then shale gas companies will be in a position to moderate production and bring wellhead prices into line with their cost structures. Then, wellhead natural gas prices should resemble those in Table 4.

Once shale gas production is rationalized, natural gas prices will stabilize at an equilibrium price that is a step function greater than the natural gas prices in the previous equilibrium price regime, 1990-2000. Historical U.S. natural gas prices are presented in Fig. 3. When offshore conventional gas production began to decline in 2001, natural gas supply tightened, and wellhead gas prices rose to a high in 2008 at $8/Mcf (2010 $). The tight supply and rising prices post-2001 established the financial incentives for the current large scale-up in shale gas production.

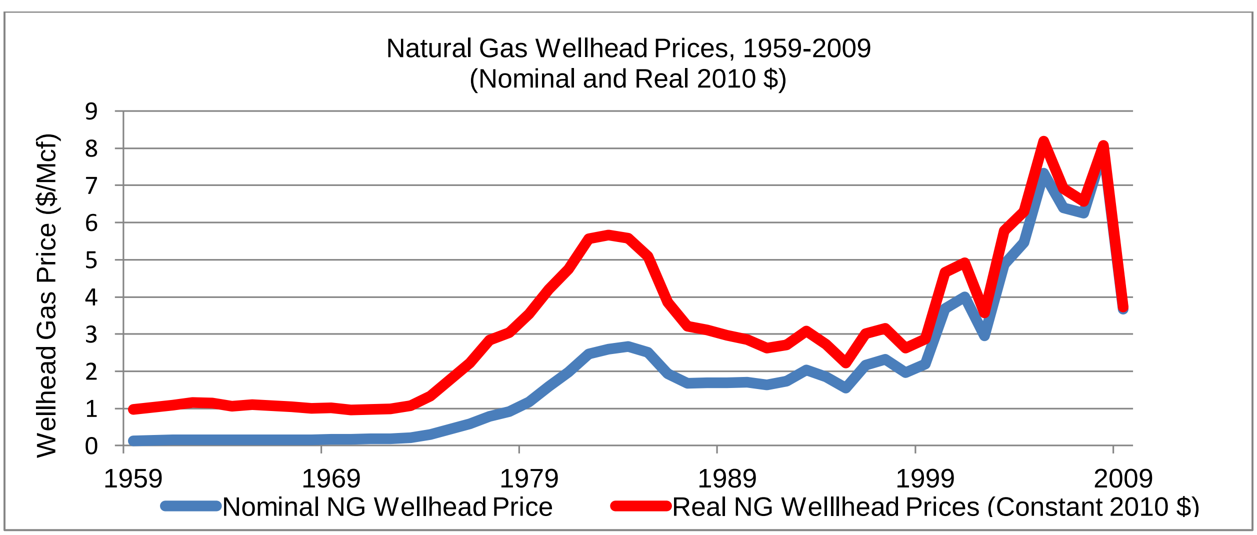

Figure 3. Historical U.S. natural gas prices, nominal and real (constant 2010 $).

What does the future hold in terms of U.S. natural gas supply and prices? Energy pundits are stating that the U.S. has over a hundred years of natural gas supply and that the low natural gas prices make the expanded use of natural gas attractive as a transportation fuel, for added electricity generation, and for export. The reality is more complex.

The trajectory of Marcellus natural gas production and wellhead gas prices is investigated using the EIA/INTEK Marcellus resource data in Table 3 and the wellhead price structure in Table 4. For purposes of this analysis, it is assumed that it is in the nation's economic interest to maintain natural gas prices at less than $10/Mcf, which is representative of the prices for the 2.3 Bcf EUR well production profile in Table 4. This defines economically recoverable resources (ERR).

The key variable in estimating the trajectory of future Marcellus wellhead gas prices is the "timing of well saturation" of the Marcellus shale gas production areas in Table 3 with average well production rates equal to or greater than 2.3 Bcf EUR. When well saturation of these areas occurs, it is likely that Marcellus wellhead gas prices will exceed $10/Mcf.

Well saturation of specific well development areas is a function of annual shale gas production levels, well development area, average well production rates associated with the well development area, and well spacing. With these variables, well counts that correspond to well saturation of the defined well developments areas can be calculated. In addition, it is important to note that the EIA/INTEK Marcellus shale gas resource estimates are based on well development of 60% of the active area, 30% of the inactive area, and 80 acre well spacing [2].

Another important characteristic of horizontal shale gas well production is the number of wells that are required to maintain a constant annual natural gas production level. A prominent feature of horizontal well production is the steep decline in gas production in the initial years of well production, which is evident in the average well production profiles in Fig.2. This means that as well saturation of higher quality production areas occur, average well production rates decrease, and the number of wells to maintain constant annual production increases.

The Marcellus analysis will provide a projection of the number of wells that is required to supply a constant annual natural gas production level over time. The trajectory of future shale gas production resembles a treadmill where annual well completion rates have to continuously increase over time to maintain a constant annual natural gas production level. This is why the statement that we have over a hundred years of natural gas supply is overly simplistic.

The organization of the Marcellus shale gas production analysis is as follows. First, Marcellus shale gas production schedules for 2011-2035 are defined. Second, the well development areas with well production rates equal to and greater than 2.3 Bcf EUR in Table 3 are specified. It is assumed that well development progresses from the highest well production areas to ever lower well production areas. Third, a well count for the number of wells that will saturate the specified well production area is calculated. From the Marcellus shale gas production schedules, the well development area, and the well count, the timing, i.e., year, of well saturation of the specified well development area is calculated. The study concludes with a discussion of the findings in terms of policy implications.

2. Well Development of the Marcellus Shale Gas Play

2-A. Marcellus Shale Gas Production Schedule

The assessment of Marcellus well development first requires establishment of a shale gas production schedule. Two Marcellus shale gas production schedules, a low and high, are defined. The low production schedule is derived from the EIA shale gas production forecast to 2035 [1]. Since the Marcellus play contains over 50% of the total U.S. shale gas resource base, it is reasonable to model Marcellus shale gas production at 50% of the EIA forecast for U.S. shale gas production. The EIA and Marcellus shale gas production forecasts are presented in Fig. 4. Marcellus production is designed to reach 50% of the EIA forecast in 2022, which provides time for Marcellus well development to become synchronized with well development and production in other U.S. shale gas plays. In 2035, Marcellus shale gas production is 6.0 Tcf.

The EIA natural gas and shale gas forecast is a business-as-usual forecast since it does not include an increase in natural gas demand for expanded uses such as a transportation fuel or for added electricity generation. Nor does the EIA forecast include supply of Alaskan North Slope natural gas. In essence, the EIA forecast models increases in shale gas supply to replace declines in other sources of natural gas supply such as conventional onshore and offshore sources.

Due to the dramatic increases in shale gas resource estimates in recent years, there are proposals to increase U.S. natural gas use as a transportation fuel, for added electricity generation, and for export. Therefore, the EIA shale gas production forecast is labeled a low case. If natural gas use is expanded, then there is a need to increase the forecast of shale gas production since shale gas is the current marginal unit of U.S. natural gas supply.

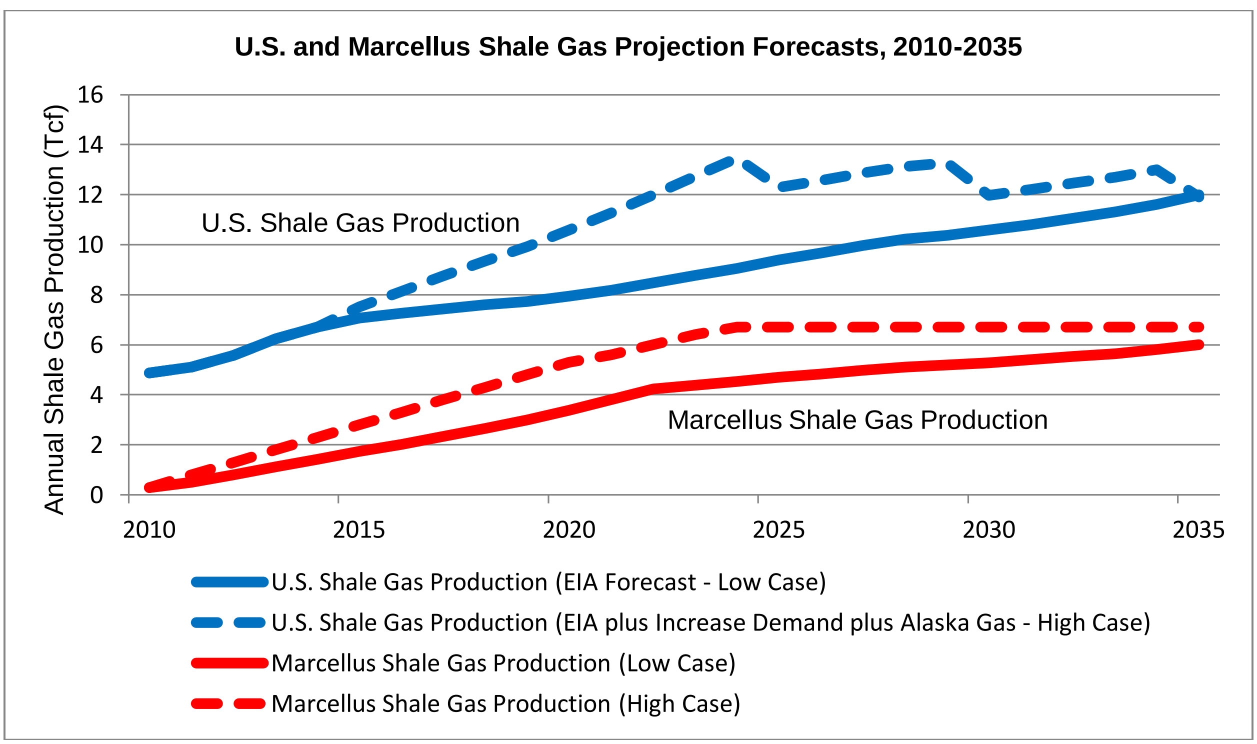

Figure 4. U.S. and Marcellus shale gas production forecasts, 2010-2035.

The high case shale gas production schedule is derived from a Pennsylvania State University Marcellus shale gas study, which states that the Pennsylvania portion of the Marcellus play has the potential to produce over 6.0 Tcf by 2020 [6]. Marcellus production is increased by 0.5 Tcf per year until production reaches 6.0 Tcf in 2022 and then levels off at an annual production rate of 6.7 Tcf from 2025 through 2035. In addition, the high case includes supply of Alaskan North Slope gas in 1.5 Tcf increments in the years 2025, 2030, and 2035, which creates the declines in the U.S. shale gas production graph in Fig. 4 and increases total natural gas supply by 4.5 Tcf.

To provide prospective to the 4.5 Tcf increase in natural gas demand, the increase in natural gas consumption associated with selected increases in natural gas use as a transportation fuel and for added electricity generation to replace coal electricity supply are presented in Table 5.

Table 5. Expanded Natural Gas Use for Transportation and Electricity Generation.[a]

	Increase in Natural Gas Use (Tcf)	Reduction U.S. Oil Imports	Reduction U.S. CO2 Emissions
Transportation			
Natural Gas for 33% of Light Vehicles with + 50% Fuel Economy	3.5	22%	3%
Natural Gas for 100% of Heavy Freight Trucks and Buses	4.5	19%	6%
Electricity Generation to Replace 33% of Coal Electricity (600 TWh)			
Natural Gas Combined-Cycle (NGCC) Power Plants	3.8	0%	7%
Wind with NGCC Power Plants	2.3	0%	10%
Wind with CAES (Compressed Air Energy Storage) Power Plants	0.6	0%	15%

Notes:

a. The assumed transportation transition rates are 10%/year, 2015-2024.

2-B. Marcellus Well Development

Well development of the Marcellus play is evaluated within the context of two assumptions: 1) well development progresses from the highest production areas to the lower; and 2) well development occurs in areas with wellhead gas prices less than $10/Mcf. From Table 4, the minimum average well EUR with a wellhead gas price less than $10/Mcf is 2.3 Bcf EUR The total well production area is the sum total of areas in Table 3 with average well EUR's 2.3 Bcf or greater. Since the well production estimates are averages, only 50% of the areas with an average well EUR of 2.3 Bcf are included.

The EIA/INTEK estimates for the active area are: a 178 Tcf TRR; an average well EUR of 3.5 Bcf; and 80 acre well spacing, which is 8 wells per square mile (640 acres/mi^2). This implies that 60% of the active area's 10,622 square miles is available for well development, which is 6,373 square miles. The sum of the active area percentages with average well EUR's of 2.3 Bcf or greater is 66% of the total available area or 4,206 mi^2. The well count is 33,648 wells.

The EIA/INTEK estimates for the inactive area are: a 232 Tcf TRR; an average well EUR of 1.15 Bcf; and 80 acre well spacing. This implies that 30% of the inactive area's 83,627 square miles is available for well development, which is 25,088 square miles. The sum of the inactive area percentages with average well EUR's of 2.3 Bcf or greater equals 7.5% or 1,882 square miles. The corresponding well count with 80 acre well spacing is 15,056 wells.

The total active and inactive area suitable for well development with a minimum average well EUR of 2.3 Bcf is 6,088 square miles. The total number of wells that can be located on this area with 80 acre well spacing is 48,703 wells. The weighted average well EUR for the 48,703 wells is 3.86 Bcf, and the corresponding shale gas TRR is 188 Tcf. The 188 Tcf TRR is 46% of the total 410 Tcf EIA/INTEK TRR estimate.

The well count associated with the EIA Marcellus proved reserves of 4.5 Tcf, minus production of 0.3 Tcf in 2010 and 2011, needs to be added to the well count for the TRR resource estimates. It is assumed that the average well EUR is the same as above. The additions are 136 mi^2 and 1,088 wells. The resulting well count for well saturation becomes 49,792 wells.

Modeling well development of a shale gas play is complicated by steep annual well production decline rates in the early years of well production, as is shown in Fig. 2. In the first five years, monthly well production declines 87%. To maintain a constant annual production level over an extended period of time requires adding new wells each year to make-up for annual declines in well production. For wells with an average well EUR of 3.86 Bcf, it takes 1,303 wells to produce 1.0 Tcf in the first year and an additional 8,415 wells to maintain the annual 1.0 Tcf production level for thirty years. Wells counts to produce a constant 1.0 Tcf/year for thirty years with average well EUR's of 3.86 Bcf, 2.3 Bcf, and 1.15 Bcf are presented in Fig. 5.

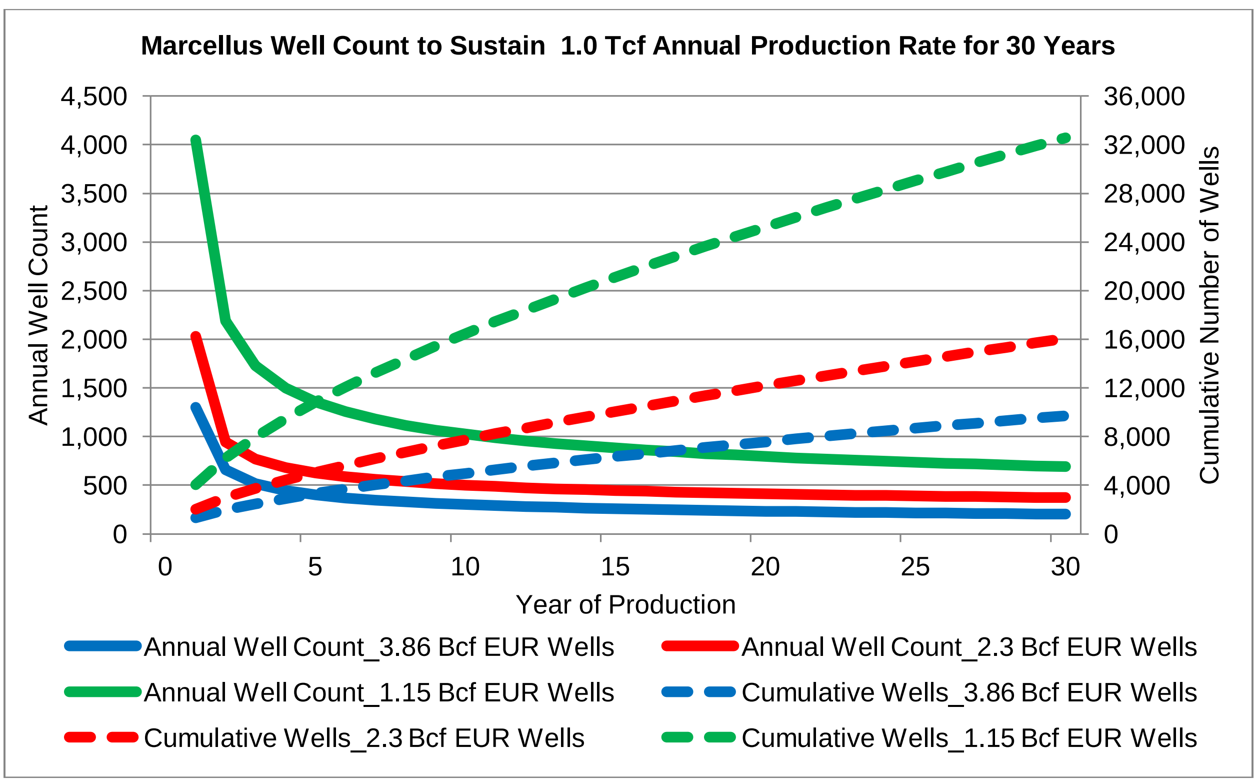

Figure 5. Marcellus well counts to sustain shale gas production at 1.0 Tcf/Year. The hyperbolic B factor is 1.4, which is from Chesapeake Energy's Marcellus well production profile [4].

Attention is now turned to the evaluation of well development for the two Marcellus shale gas production schedules presented in Fig. 4. The low shale gas production schedule is based on the EIA business-as-usual natural gas forecast through 2035 and does not include an increase in natural gas demand for transportation or added electricity generation. In contrast, the high shale gas production schedule is premised on an increase in natural gas demand for transportation and added electricity generation. The increase in natural gas demand, above the EIA forecast, is 4.5 Tcf in 2035. The high production schedule includes 4.5 Tcf supply of Alaskan North Slope gas by three 1.5 Tcf pipelines completed in 2025, 2030, and 2035.

The well count in 2035 for the low Marcellus shale gas production schedule is 35,892 wells. The well count trajectory 2010-2035 is presented in Fig. 6. This is 72% of the total 49,792 wells that can be placed on the areas with well EUR's of 2.3 Bcf or greater. Well saturation of the 2.3 Bcf EUR or greater well production areas occurs in 2049.

The well count in 2035 for the high Marcellus shale gas production schedule is 48,881 wells, which is 98% of the total 49,792 wells that can be placed on the well production areas with well EUR's of 2.3 Bcf or greater. Well saturation in the high production case occurs in 2036. Well saturation in the high production case is thirteen years earlier than in the low production case.

In summary, with an assumed maximum wellhead price of $10/Mcf, well saturation of the Marcellus play occurs in 2036 for the high production schedule and in 2049 for the low production schedule. While the Marcellus shale gas resource is large, the annual shale gas production rate affects the trajectory of wellhead natural gas prices.

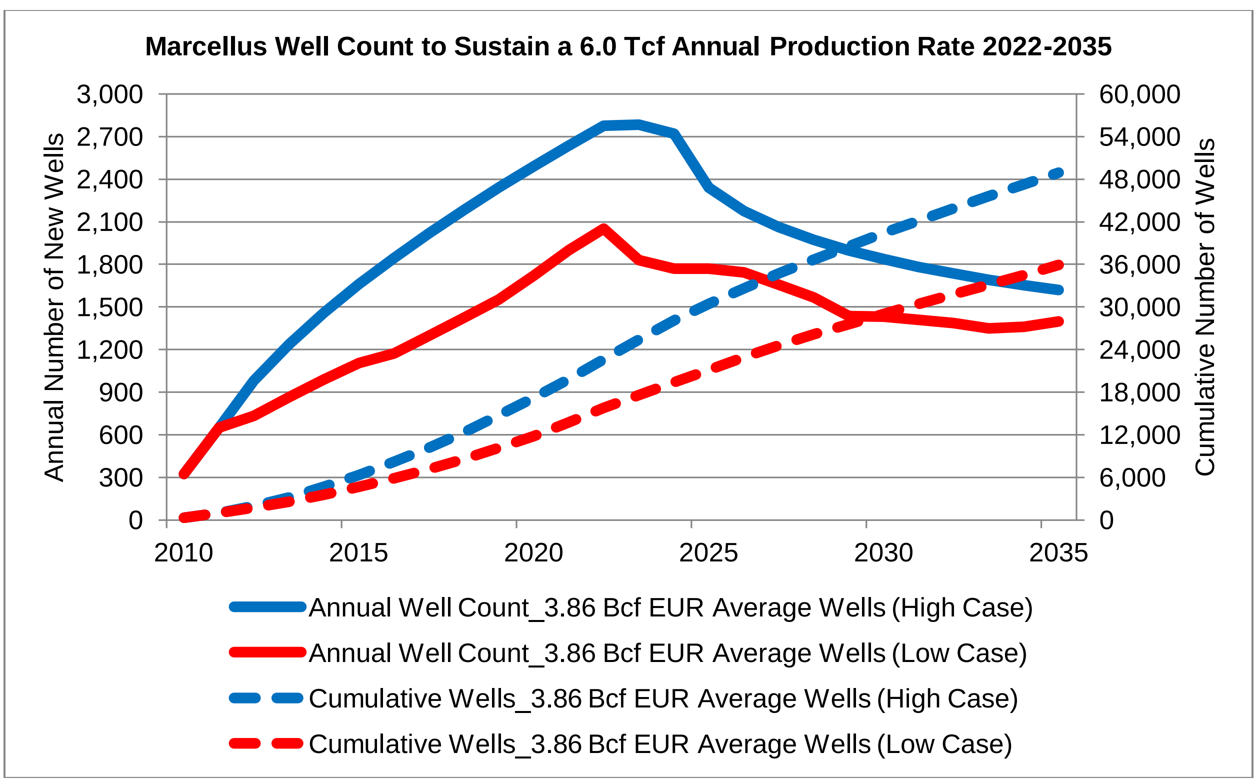

Figure 6. Well counts for low and high Marcellus shale gas production schedules, 2010-2035.

3. Conclusions

Marcellus shale gas production needs to be evaluated within the context of the other U.S. shale gas plays. Based on the shale gas resource data in Table 2, well saturation of the highest quality core areas will occur in all other U.S. shale gas plays before it occurs in the Marcellus play. This conclusion is based on an analysis of the timing of well saturation in the Barnett, Haynesville, and Fayetteville shale gas plays with the same methodology as the Marcellus analysis, which is presented in the Appendix, A.3. In essence, Marcellus shale gas production will play a dominant role in defining U.S. natural gas supply and prices post-2030.

When well saturation of the highest quality areas of shale gas plays occurs, natural gas prices will likely approach \$10/Mcf. The findings of this research indicate that we have about thirty years of natural gas supply at a wellhead gas price under \$10/Mcf, which translates into a delivered natural gas price of about \$11.5/Mcf to electricity generators and industrial customers. When this occurs, the cost of space and water heating will more than double with significant negative consequences for the economy. It is important to keep in mind that over 60% of U.S. natural gas consumption is for residential, commercial, and industrial space and water heating.

If the objective is to maintain natural gas prices at as low as possible levels, then the expanded use of natural gas for transportation, added electricity generation, and export is called into question. However, an increase in natural gas demand is inevitable if the U.S. wants to increase the penetration of wind and solar electricity to at least 30% of total U.S. electricity generation. Intermittent wind and solar electricity supply requires the application of natural gas power plants to firm variations in electricity supply and maintain grid stability, which in turn increases natural gas consumption. The use of natural gas as a transportation fuel creates the largest increase in natural gas demand as shown in Table 5.

The economically prudent course is to minimize increases in natural gas demand to secure as low as possible long-term natural gas prices. For example, with wind power at a 30% penetration level in total U.S. electricity generation, the use of compressed air energy storage (CAES) power plants to firm intermittent wind electricity in comparison with the use of natural gas combined-cycle power plants annual natural gas consumption is reduced by more than 1.5 Tcf, which is shown in Table 5 [7]. Also, because of the large quantity of natural gas that will be required for its use as a transportation fuel to significantly reduce oil consumption, economic prudence suggests precluding natural gas as a transportation fuel. The same holds for natural gas export.

This analysis does not take into account growing concerns about the effects of shale gas production by hydraulic fracing on the environment. Some of the major issues are methane releases, contamination of potable water supplies, frac water disposal, and seismic activity. These issues may increase the cost of horizontal well shale gas production and impose limits on the production areas that can be exploited. In fact, a large portion of the highest quality core area of the Marcellus play lies in the Delaware River Basin may be excluded for shale gas production because of concerns about pollution of the New York City and Philadelphia watershed supplies.

And finally the question: When will Marcellus shale gas production go into decline and quite likely U.S. natural gas production since Marcellus shale gas production will likely be the marginal unit of U.S. natural gas production post-2030? The timing of Marcellus shale gas production decline is related to two events that occur with a decrease in average well EUR's: 1) wellhead gas prices increase; and 2) the well count to sustain a given annual production rate increases. It is conceivable that Marcellus shale gas production will go into decline when well saturation of areas with average well EUR's between 2.3 Bcf and 1.15 Bcf occurs.

A large portion of the Marcellus inactive area likely represents resources that are not economically recoverable. This is based on the wellhead price estimates for wells with an average well EUR of 1.15 Bcf in Table 4 and the well count findings for an annual 1.0 Tcf production level in Fig. 5.

With average well EUR's of 1.15 Bcf or less the wellhead price increases to $14/Mcf and greater, and the corresponding delivered price to electric generators and industrial customers increases to $16/Mcf and greater. The cost of delivered gas to residential and commercial customers is even higher. These increases in natural gas prices will have a significant negative macro-economic impact on the U.S. economy.

Also, when average well production falls to 1.15 Bcf EUR, the well count to maintain an annual production rate of 1.0 Tcf is over 33,000 wells. To produce 6.0 Tcf annually, the well count is about 200,000 wells. This raises the question of whether this level of horizontal well hydraulic fracing activity is technologically and/or economically manageable or publicly acceptable.

If wells with average well EUR's of 1.15 Tcf or less are not economically viable, then 65-70% of the Marcellus inactive area will not be developed. This implies that 25-30% (110-130 Tcf) of the Marcellus shale gas TRR is not economically recoverable. It is not known with certainty the impact of the USGS estimates of undiscovered resources, but it is reasonable to assume that the undiscovered resources are on the low end of average well EUR's since so much effort has been expended in identifying the highest quality areas of the Marcellus play.

In conclusion: This analysis strongly suggests the need for careful planning in the development of the Marcellus shale gas resource as well as U.S. natural gas consumption levels. Shale gas is not a panacea for U.S. future energy needs. It is only providing the U.S. and possibly the world a two to three decade breather space to make a transition to sustainable wind and solar energy sources.

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Appendix

A.1. Estimation of Levelized Prices and a Discussion of F&D Costs and O&M Expenses

Table A.1-1. Financial Assumptions for Wellhead Gas Price Estimates by the Net Present Value, Cash Flow Method.

Well Drilling Costs	$5,000,000
Well Finding and Development Costs[a]	$1.14/Mcf
Well O&M Expense (Fixed and Variable)[a]	$1.40/Mcf
Well Production Life	30 Years
Well Expected Ultimate Recovery (EUR) (Bcf)	5.25, 3.86, 2.3, 1.15
Debt/Equity Ratio	30/70
Return on Equity Capital	0-10%
Return on Debt Capital	6.5%
Depreciation	10 Year MACRS
Debt Payback Period	10 Years
Real Discount Rate (WACC)[b]	0.1-5.19%
Royalty Rate	15%
Severance Tax	$.047/Mcf + 5% of Gas Value
Working Capital	10% of O&M
Well Replacement Costs	10% of Capital in Year 15
Income Tax Rate	39%
Annual Inflation Rate	3%

Notes:

a. The F&D costs and O&M expenses are from Chesapeake Energy with an assumed 5.25 Bcf average well EUR and will increase in terms of $/Mcf with decreases in average well EUR since the costs are aggregated over long-term shale gas production estimates [8].

b. The discount rate is a weighted average cost of capital (WACC), which includes the firm's capital structure (debt/equity ratio), the cost of equity and debt capital, and taxes. The formula is: Real Discount Rate (WACC) =

$$\{[(\%\text{ equity})\ (k\text{ equity})] + [(\%\text{ debt})\ (k\text{ debt})\ (1 - t)]\} - \text{I},$$

where % equity is the percentage of the firm's market value owned by shareholders, *k* equity is the cost of equity capital, % debt is the percentage of firm's market value owned by creditors, *k* debt is the cost of debt, *t* is the tax rate, and I is the annual inflation rate. The adjustment for inflation converts a nominal discount rate into a real discount rate.

A levelized price of a product is the price that creates the discounted revenue stream to recover all capital investments (debt and equity), fixed and variable operating expenses, and taxes over a pre-determined the investment period. The levelized wellhead shale gas prices are estimated using a net present value cash flow method with the financial assumptions in the Appendix, Table A-1. It should be noted that wellhead price estimates are sensitive to changes in the underlying financial assumptions. The financial variables with the least confidence are finding and development (F&D) costs and O&M expenses.

The F&D cost of $1.14/Mcf is from Chesapeake Energy's pro forma well production profile for a 5.25 Bcf EUR horizontal well and the O&M expense of $1.16/Mcf is from Chesapeake Energy's 3rd Quarter, 2011 financial report for their total operations. O&M expenses include all well operating and administration expenses.

F&D costs and O&M expenses are reported in an aggregate form, $/Mcf, which means that a decrease in average well production results in an increase in these costs. The F&D cost estimate is based on Chesapeake Energy's 5.25 Bcf EUR horizontal well production profile, and it is assumed that the O&M cost is also for a high end average well production. Therefore, F&D costs and O&M expense estimates have been adjusted proportionately for changes in average well production for the estimation of the levelized wellhead prices reported in Table 3. Whether this is accurate or not requires more transparent data about shale gas specific F&D costs and O&M expenses. Regardless of the accuracy of specific costs, the overall effect of average well production rates on wellhead gas prices remains valid.

Table A.1-2. Shale Gas Horizontal Well Production and Cost Estimates.[a]

	Barnett	Fayetteville	Marcellus	Haynesville
Expected Ultimate Recovery (EUR)	3.0 Bcf	2.6 Bcf	5.25 Bcf	6.5 Bcf
Initial Production (IP First Month)	2.7 MMcf/d	2.1 MMcf/d	4.0 MMcf/d	10.6 MMcf/d
Risk Factor	15%	20%	60%	30%
Estimated Drilling Density (Acres)	60	80	80	80
Finding and Development Costs	$1.24/Mcf	$1.48/Mcf	$1.14/Mcf	$1.60/Mcf
Drilling Costs ($ millions)	2.8	3.2	5	7.8
B-Factor (Hyperbolic Formula)	1.6	1.5	1.4	1.4
Gas-in-Place (GIP) (Bcfe/mi^2)	65	55	130	190
Anticipated GIP Recovery Factor	40%	38%	30%	28%
Royalty	25%	17%	15%	25%
Operating Costs	$1.16/Mcf	$1.25/Mcf	$1.40/Mcf	$1.40/Mcf

Notes:

a. Data sources: All well data except royalty and operating costs are from a Chesapeake Energy investor presentation [8]. Royalty costs are from Range Resources [9]. Operating costs are derived from Southwestern Energy [9] and Chesapeake Energy [8] financial reports.

A.2. Pennsylvania Marcellus Horizontal Well Findings: PADEP data through June 2011 [3].

The core area of the Pennsylvania portion of the Marcellus play is in the Northeast counties: Susquehanna, Bradford, Wyoming, Lycoming, Sullivan, and Clinton. The southwest portion of the play has wet gas potential, particularly Washington County. Greene County, which borders West Virginia and is not included among the northeast core counties, has an average well production rate greater than those for some of the core counties. A summary of findings follow.

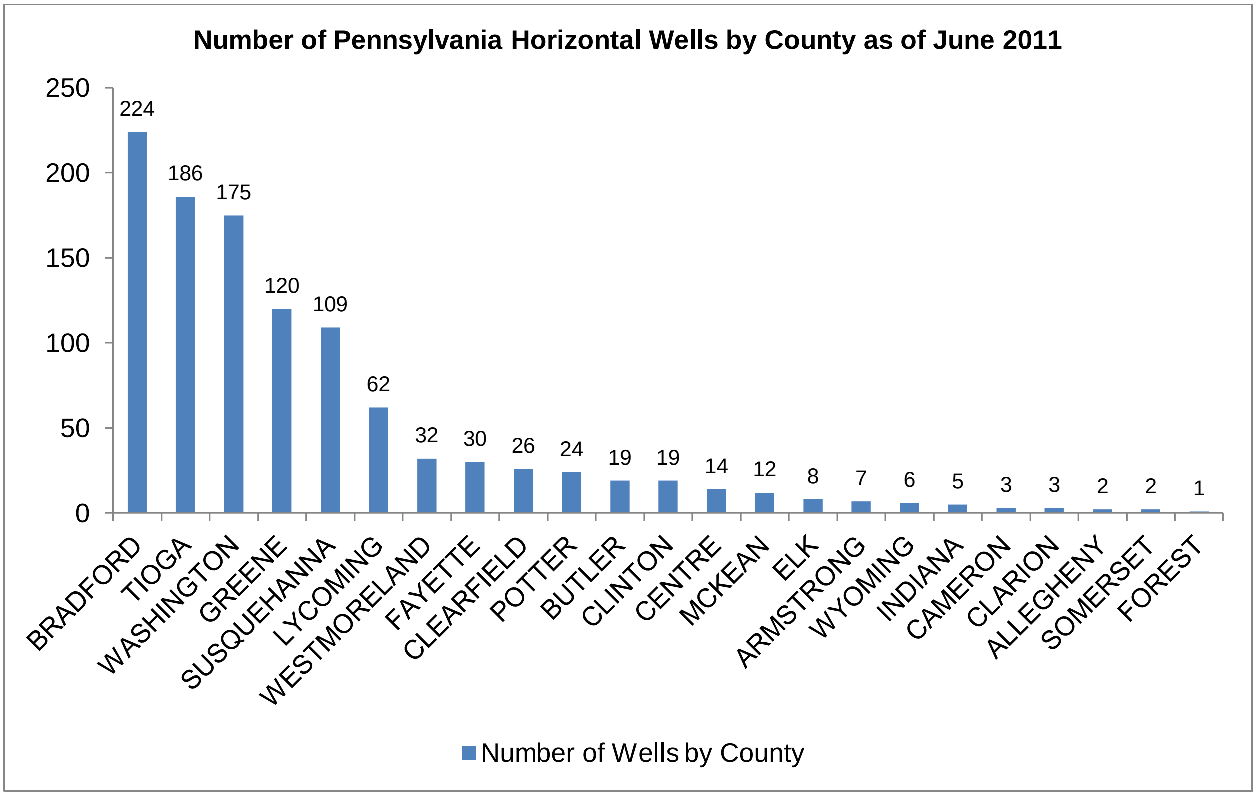

Figure A.2-1. Pennsylvania county well count of horizontal shale gas wells.

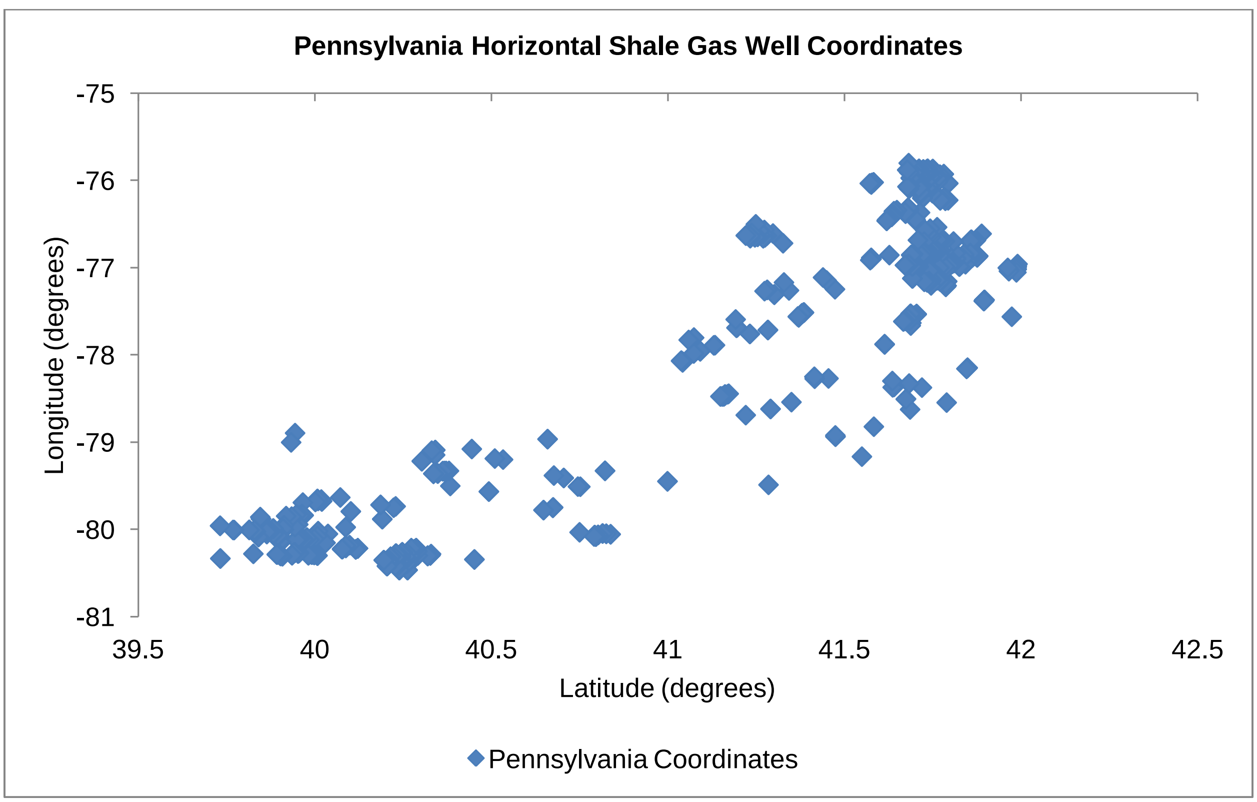

Figure A.2-2. Coordinates of horizontal wells in the Pennsylvania Marcellus play.

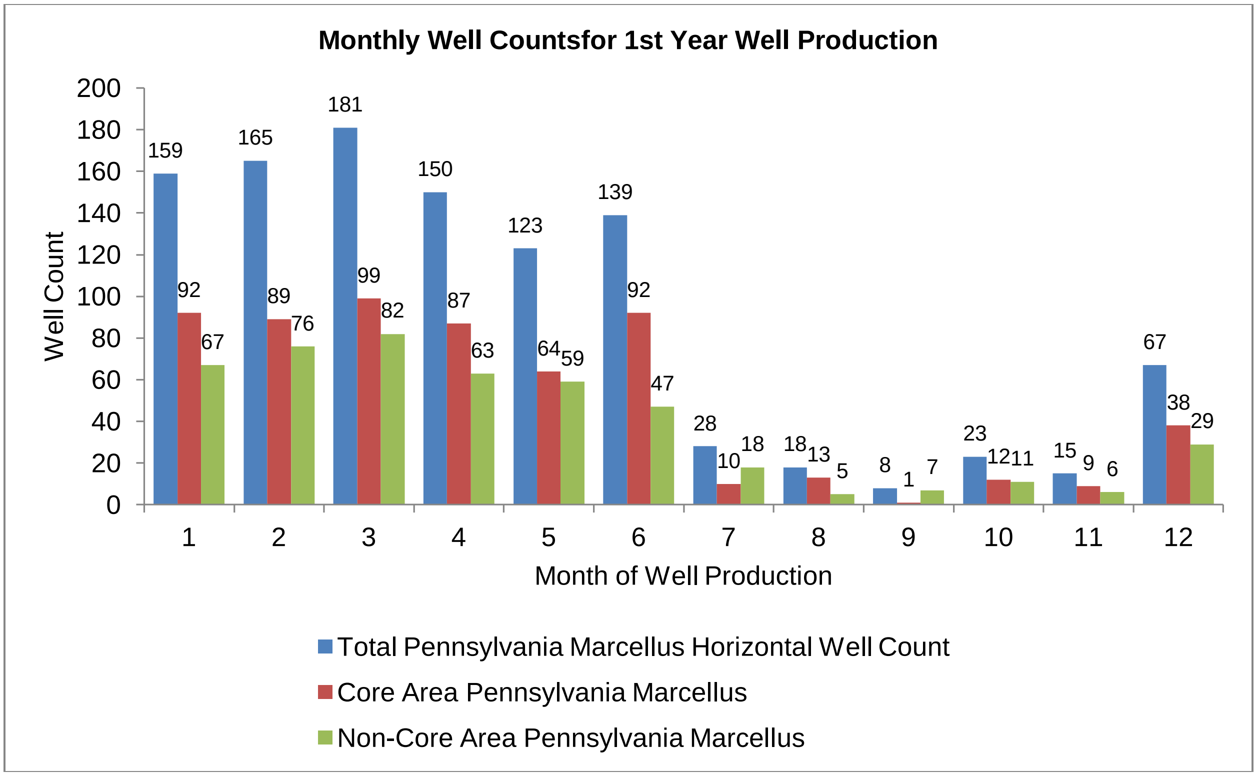

Figure A.2-3. Well counts for calculation of first year average monthly well production totals.

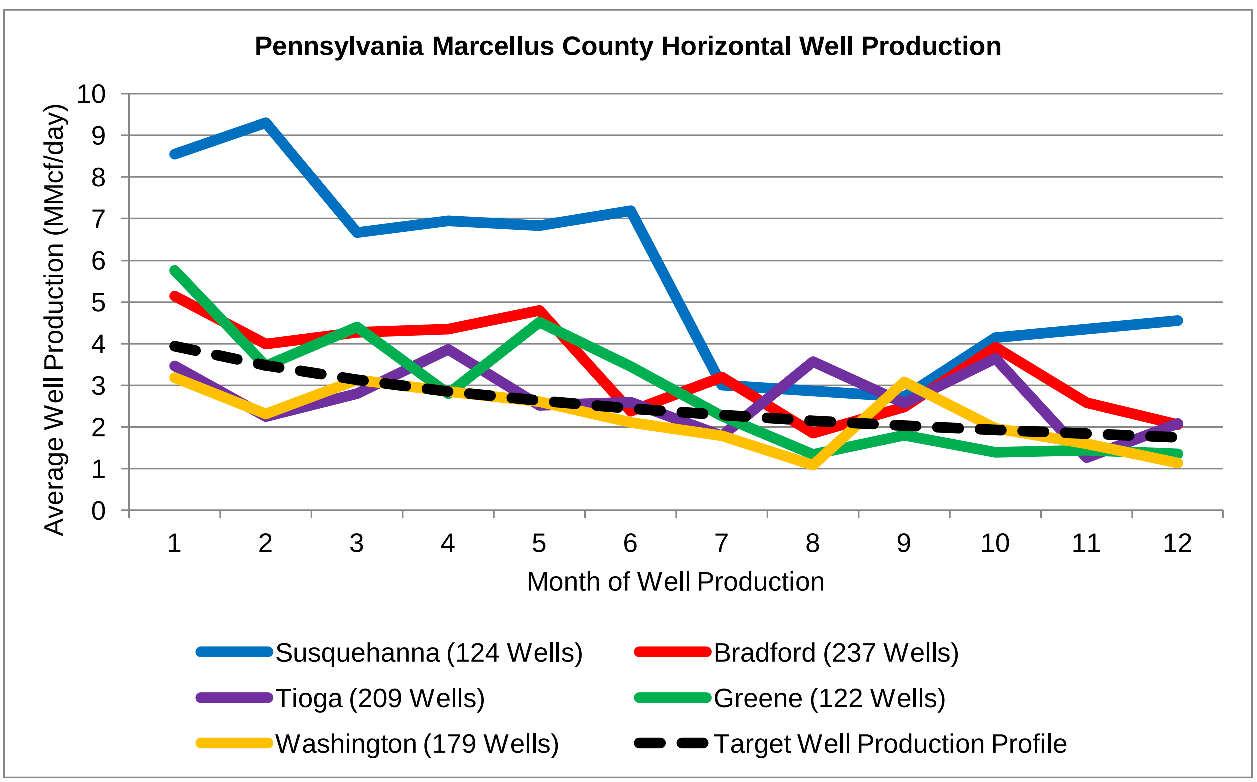

Figure A.2-4. Horizontal well production for selected counties. Pennsylvania Marcellus core area Counties: Bradford, Susquehanna, Tioga, Wyoming, Lycoming, Clinton, Sullivan.

A.3. Well Saturation Analysis of Barnett, Fayetteville, and Haynesville Plays with INTEK Data.

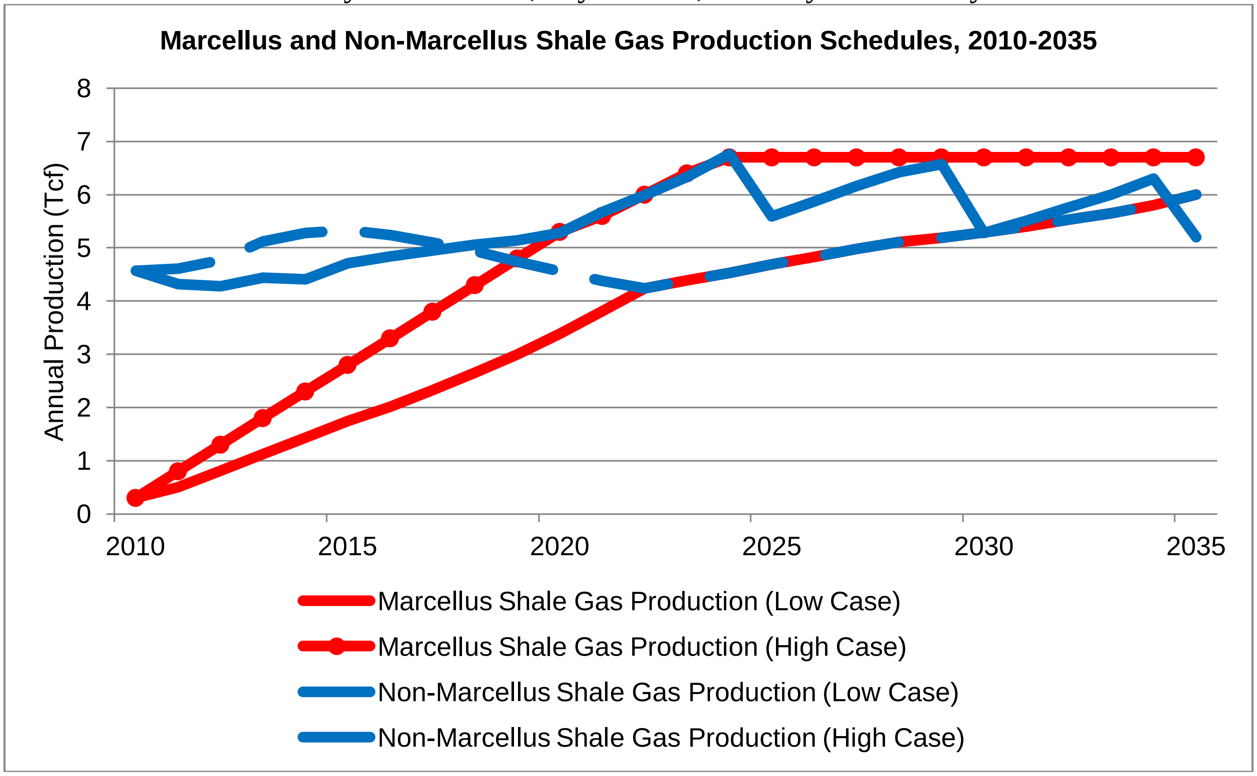

Figure A.3-1. Marcellus and Non-Marcellus shale gas production schedules, low and high cases.

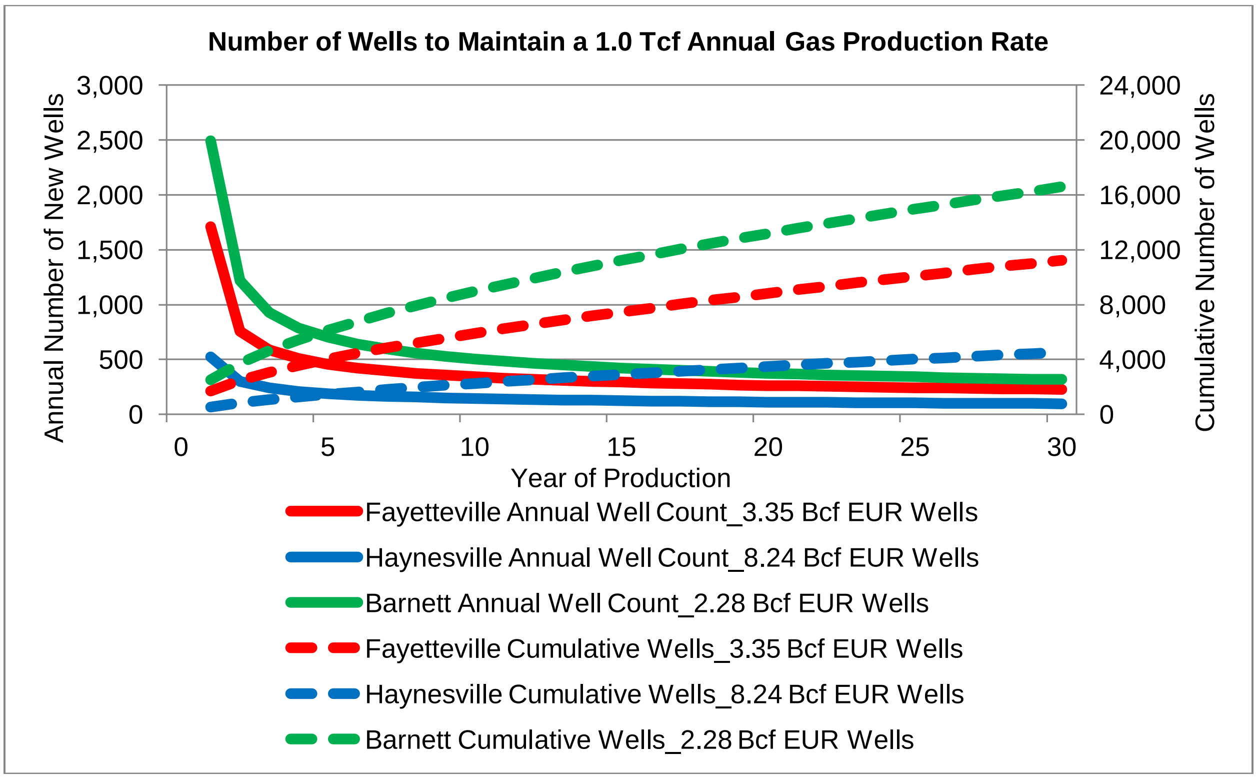

Figure A.3-2. Number of wells to maintain a 1.0 Tcf/year shale gas production rate.

Table A.3-2. Wellhead Gas Price Estimates for Current and Low Well EUR's.

(Constant 6.5% Cost of Debt)	Fayetteville 2.6 Bcf EUR	Fayetteville 1.65 Bcf EUR	Haynesville 6.5 Bcf EUR	Haynesville 4.5 Bcf EUR	Barnett 3.0 Bcf EUR	Barnett 1.45 Bcf EUR
0% Return on Equity Capital	5.82	8.93	6.86	9.26	5.45	9.19
5% Return on Equity Capital	6.03	9.30	7.06	9.55	5.64	9.58
6% Return on Equity Capital	6.13	9.46	7.15	9.68	5.72	9.75
7% Return on Equity Capital	6.23	9.62	7.24	9.80	5.81	9.92
8% Return on Equity Capital	6.32	9.78	7.32	9.93	5.89	10.09
9% Return on Equity Capital	6.42	9.94	7.41	10.05	5.97	10.25
10% Return on Equity Capital	6.51	10.10	7.50	10.18	6.06	10.42

Table A.3-3. INTEK Estimates for Economically Recoverable Reserves (ERR < $10/Mcf).

	ERR (Tcf)	Total Area for Wells (mi^2)	Average Well EUR (Bcf)	Total Number of Wells	Year of Well Saturation
Fayetteville Central Area	32	1,193	3.35	9,547	2032
Haynesville Developed Area	50	752	8.24	6,017	2025
Barnett Core and Extension Areas	50	3,323	2.28	22,039	2020

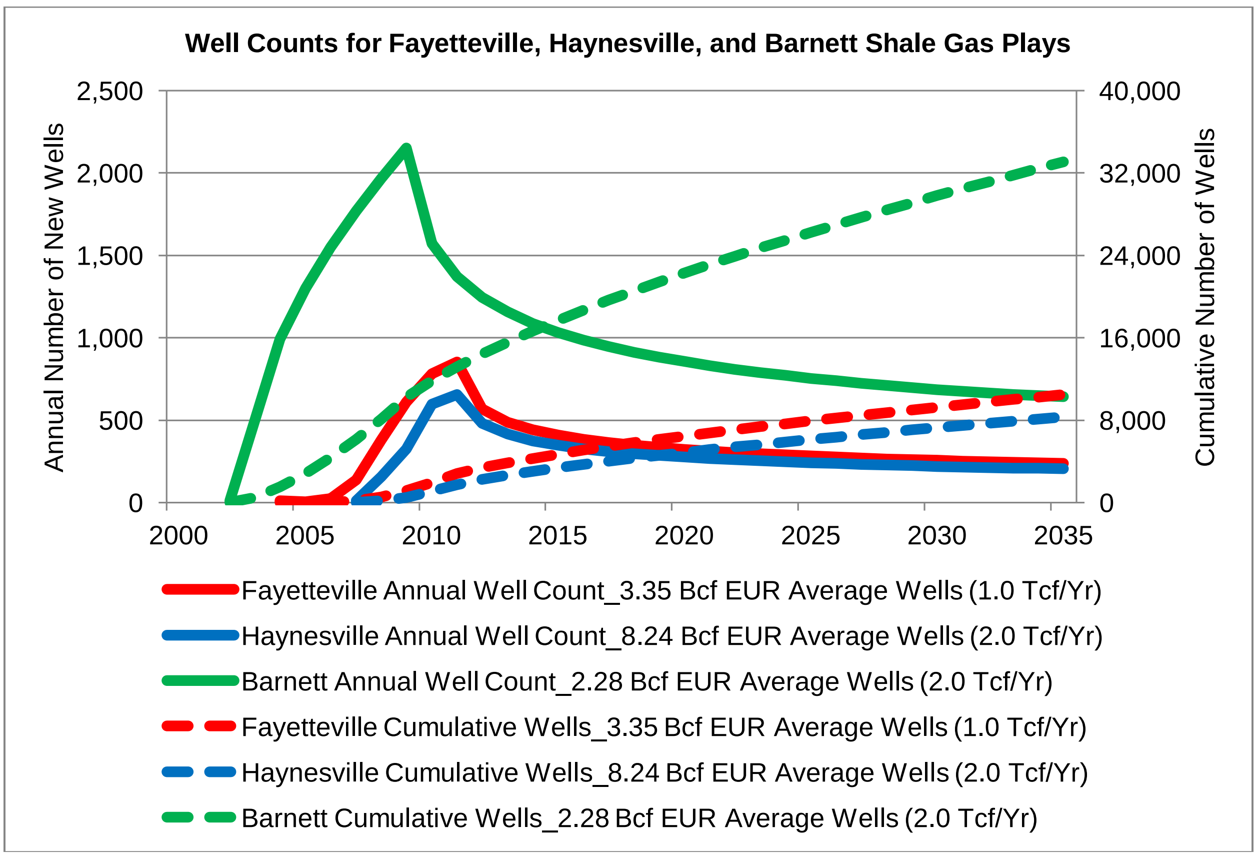

Figure A.3-3. Well counts of Fayetteville, Haynesville, and Barnett for specified annual shale gas production rates. Well saturation of areas with ERR < $10/Mcf occurs in each of plays occurs by 2035 based on the total number of well estimatess presented in Table A.3-3.

A.4. Well Spacing and Factors Affecting Well Drainage Area.

The well drainage area for 80 acre well spacing and 5,000 foot laterals is shown in Fig. A-4.

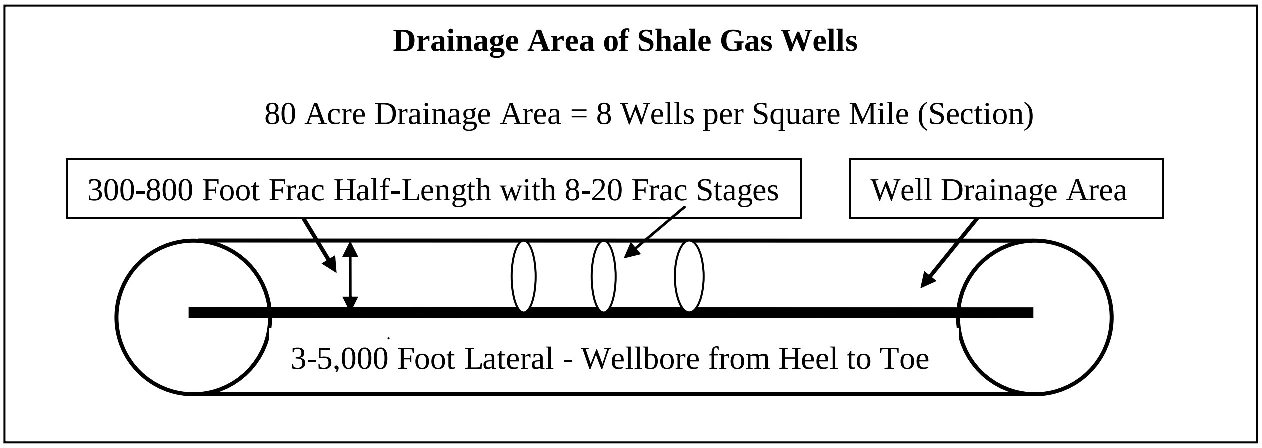

Figure A-4. Representative drainage area of shale gas wells.

The tendency in recent years is an increase in horizontal wellbore lateral length and the number of frac stages. While this increases well drilling costs, the increase in natural gas production offsets the added drilling costs to where drilling expense stated in terms of $/Mcf has remained relatively stable and even reduced when inflation is taken into account.

The increases in wellbore lateral lengths, number of frac stages, and frac half-lengths raise the issue of well drainage area and future well production rates. What is the effect of increased lateral lengths, frac stages, and frac half-lengths on future well production rates of well refracs and well infills? These issues need research attention to gain a better understanding of future well development and price dynamics.