



The Influence of Shale Gas on U.S. Energy and Environmental Policy

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ABSTRACT

The emergence of U.S. shale gas resources to economic viability affects the nation's energy outlook and the expected role of natural gas in climate policy. Even in the face of the current shale gas boom, however, questions are raised about both the economics of this industry and the wisdom of basing future environmental policy on projections of large shale gas supplies. Analysis of the business model appropriate to the gas shales suggests that, though the shale future is uncertain, these concerns are overstated. The policy impact of the shale gas is analyzed using two scenarios of greenhouse gas control—one mandating renewable generation and coal retirement, the other using price to achieve a 50% emissions reduction. The shale gas is shown both to benefit the national economy and to ease the task of emissions control. However, in treating the shale as a “bridge” to a low carbon future there are risks to the development of technologies, like capture and storage, needed to complete the task.

Keywords: Natural gas, Shale, Climate policy, Energy policy

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✎ 1. THE SHALE REVOLUTION ✎

Gas production from shale resources is changing the U.S. energy outlook. Shale deposits, found in many parts of the U.S., have long been known to contain large quantities of gas but it was economically unrecoverable. It has become commercially viable in the last decade because of innovative applications of technology—mainly horizontal drilling (to access more resource rock from each well) and hydraulic fracturing of the rock to release the gas—so-called fracking. The result has been a boom in shale gas investment—creating expectations of a natural gas “revolution” (e.g., Deutch, 2011) and leading the International Energy Agency to include a scenario of the Golden Age of Gas in its 2011 World Energy Outlook (IEA, 2011).

The change in outlook can be seen in Figure 1, which shows projections of domestic gas production and imports of liquefied natural gas (LNG). Two of the production cases are from the MIT Emissions Prediction and Policy Analysis (EPPA) model described below. One is a Reference case, with no climate policy beyond that in place in 2011; the other imposes the same conditions as the Reference but assumes no shale development. Without supplies from shale, U.S. gas production in the EPPA simulations is projected to peak by around 2025.

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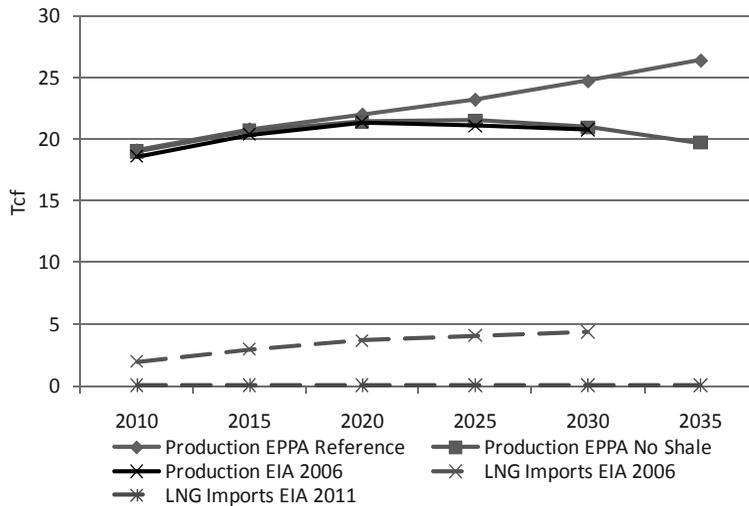


FIGURE 1
Projections of U.S. Gas Production and of LNG Imports

This was the view of the U.S. Energy Information Administration as recently as its 2006 Annual Energy Outlook (EIA, 2006), also shown in the figure.

Another feature of projections only a few years back was the expectation of growing LNG imports. In the 2006 EIA Outlook LNG imports were projected to approach 5 Tcf per year by 2030. In fact, imports are near zero in 2011 and are not now expected by the DOE analysts to recover as far out as the 2035 end-point of their projection (EIA, 2011). Unfortunately, in response to the earlier expectations the rated U.S. LNG import capacity grew from less than 1 Tcf in 2000 to over 6 Tcf today.

The development of the shale resource has implications not only for the utilization of existing infrastructure but also for future investment and for energy and environmental policy. Questions remain, however. The shale development is very recent, and it is different from previous gas resource supplies in the economics of the industry and the environmental issues it raises. As a result, there are uncertainties in the degree to which its potential will be realized—leading to controversy over the extent to which energy and environmental policy should be based on projections of shale supplies and the wisdom of looking to gas to provide a “bridge” to a low carbon future based on non-fossil energy and CO₂ capture and storage.

Here we review the nature of the shale resource and the exploitation methods being applied, and explore their implications for the economics of the industry and for two scenarios of U.S. efforts to control greenhouse gas (GHG) emissions. One approach is regulatory, mandating renewable generation and retirement of coal plants, and the other applies an emissions price to meet an emissions target. To investigate these issues we draw on data gathering and analysis by an MIT study of The Future of Natural Gas (MITEI, 2011).

2. SHALE GAS: RESOURCE, PRODUCTION AND ECONOMICS

Natural gas comes in various mixtures of hydrocarbons, and is found in a variety of geological settings. While its dominant constituent is methane it also may include heavier molecules

such as ethane, propane, butane, pentane etc. So called “wet gas” deposits contain higher proportions of these heavier compounds, which are separated and marketed as natural gas liquids (NGLs), in general at a substantially higher price than the dry gas. Some natural gas is associated with oil production, but 89% of U.S. gas is non-associated.

Natural gas resource areas or “plays” are classified by the geologic characteristics of the reservoir. Conventional gas is produced from discrete, well-defined reservoirs with permeability greater than a specified lower limit. The other three types, termed unconventional, involve reservoirs where permeability is low and they include “tight” sandstones, coal beds and shales. The shale formations include a wide range of sedimentary rock types which generally are only 100–200 feet thick but deposited over large areas. Shales serve as source rock for the gas found in conventional reservoirs, and gas that has not escaped from the shale is held in the strata in one of three ways—adsorbed on the rock surface, as free gas in fissures, or as free gas in the rock pores. Horizontal drilling creates more reservoir contact than is possible with a vertical well; hydraulic fracturing increases well permeability, enabling the gas trapped in the rock to be produced at economic flow rates.

2.1 The Scale of U.S. Shale Resources

U.S. shale deposits are extensive, though only a subset appears to have the geological histories and petrophysical characteristics to be productive. These include the Barnett, Haynesville, Fayetteville and Woodford shales in Texas, Louisiana, Arkansas and Oklahoma, along with the Marcellus shale that underlies portions of the states of Pennsylvania, West Virginia and New York. The past year has also seen substantial activity in the Eagle Ford shale in Texas and the Bakken shale in North Dakota. These latter plays have come to the fore due to their high liquids content and the large margin between the dry gas price and that for NGLs, which are priced similar to oil.

The development of these resources has had a dramatic effect on two common measures of gas resources: proved reserves and technically recoverable resources. Proved reserves are well-defined gas volumes, known to be recoverable with a high degree of certainty. Technically recoverable resources are a broader category that includes the proved reserves along with gas volumes that are not yet being exploited but which can be expected to be identified by future exploration, given currently available technology, and independent of cost considerations. Figure 2 shows the effect of shale gas on estimates over the past seven years of U.S. technically recoverable resources by the National Petroleum Council (NPC), the Potential Gas Committee (PGC) and the U.S. Energy Information Administration (EIA). Estimated shale resources have grown from near zero to 36% of technically recoverable resources. Each of the volumes shown is a single-point estimate. The MIT study probed uncertainty in the shale resource and reached a mean estimate of technically recoverable resources of 631 Tcf with an 80% confidence interval of 418 to 871 Tcf (MITEI, 2011).

The effect of shale on U.S. gas production has been similarly dramatic, rising from near zero in 1990 to 20% of domestic supply in 2010.

2.2 The Shale Gas Business

Despite this impressive performance, questions have been raised about the validity of forecasts of a “golden age” of gas (e.g., Urbina, 2011). It is observed that the rate of production decline is very high in shale wells, leading to charges that shale gas producers have overstated their proved reserves. It is also the case that the production performance can vary dramatically

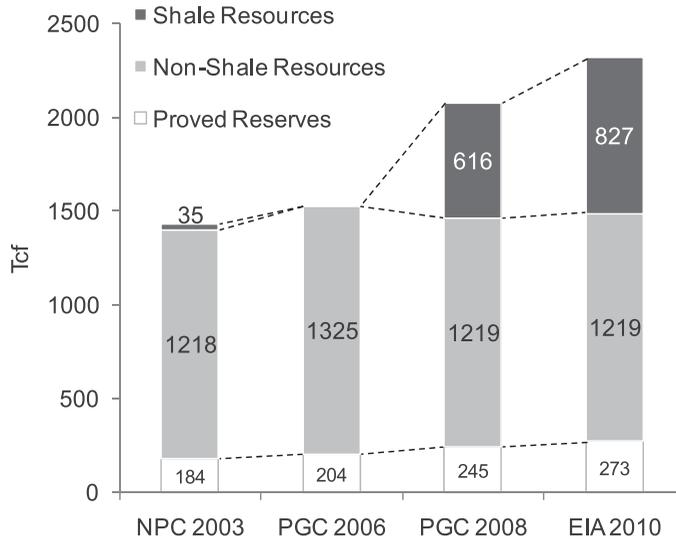


FIGURE 2

Impact of Shale Gas on Estimates of U.S. Resources and Proved Reserves

among shale wells, with many having much lower flow rates than what gas producers suggested was to be expected. This casual level of analysis leads some to the conclusion that in many instances shale wells will never make money and that the economic attractiveness of the shale resources is overstated. There is a germ of truth in each of these observations about early shale development, but the conclusions drawn from them reveal a lack of understanding of the difference between the shale business and conventional gas development.

First, regarding the issue of rapid production decline and overstated proved reserves: shale wells do show high early decline rates, in some cases by 60–80% in the first year; however, this rate of decline moderates significantly over time. In shales with longer production histories (e.g., the Barnett) well decline rates after four to five years are around 10% per year. The unique decline rate behavior of the shales is, however, taken into account in estimating shale reserves (MITEI, 2011, Appendix 2D). It is worth noting, nonetheless, there is still uncertainty in these estimates because the shale resource is so new, and wells have not yet been in production long enough to draw definitive conclusions about longer-term performance. For a useful survey of the challenge see Lee and Sidle (2010)

Next is the concern about the great variability in shale well performance, an illustration of which is shown in Figure 3 which plots the distributions of the initial production (IP) rates (30 day averages) for wells drilled in the Barnett shale. The median (P50) initial production rate for the more than 11,100 wells was 1,470 Mcf/day. However, 20% of the wells had an IP rate of greater than 2,530 Mcf/day, while another 20% had IP rates of less than 700 Mcf/day. Moreover, this wide distribution of well performance, even in the same play, remained just about the same over the 2005–2010 period when average well IP rate was improving year to year.

This performance record, which is supported by initial production data from other major shale plays, suggests that a stochastic element in well performance is a normal aspect of shale development, leading to a business model different from that familiar in the gas industry. In

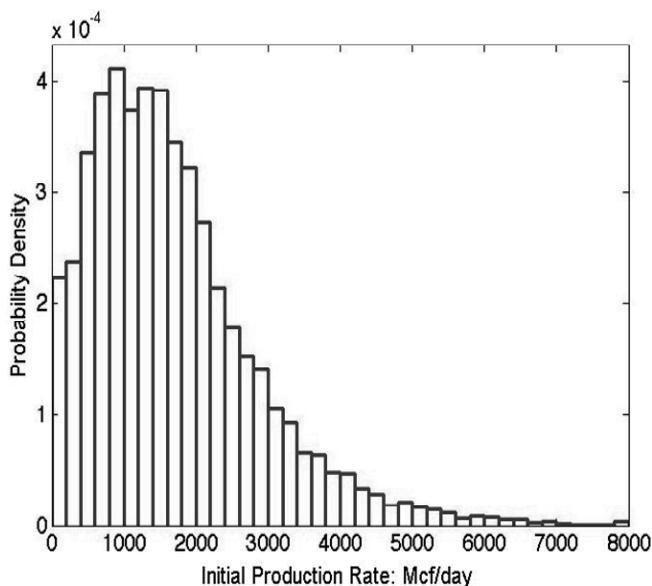


FIGURE 3

Distribution of Per-Well Initial Production Rates for Barnett Shale Wells, 2005 to 2010 (HPDI Production Data Base).

traditional gas production operators invest significant capital exploring for conventional gas reservoirs, and then only develop wells where performance is predicted to be economically attractive. The shale business differs in that, once a shale play has been proved, operators will, where possible, drill their acreage in a contiguous manner, often drilling multiple horizontal wells from one well pad. This yields significant operational advantages including a reduction in drilling time and the ability to coordinate pipeline construction with drilling schedules to allow early marketing of the gas.

This approach to development is often referred to as a “manufacturing” process, but that term fails to capture the fact that such contiguous drilling results in much greater variation in well performance than is typical of traditional exploration and selective drilling methods. A result of this variation is that shale operators must evaluate the economic performance of their acreage on a portfolio basis rather than at an individual well level. In effect, in comparison with conventional gas resources, a reduction in exploration risk has been exchanged for an increase in production risk.

Finally, there is the question whether gas developers are currently making money, and whether it matters for longer-run expectations. One of the more trenchant critiques of shale gas development is that it is a speculative bubble, that companies are not making money at 2011 gas prices (around \$4 per Mcf), and that evidence of overreaching today should dampen confidence the future of this resource. The details of individual company investments are outside the scope of this study, but useful insight can be gained from estimates of the breakeven price (BEP) in each of the major plays. For this exploration we draw on a play-level resource and cost analysis by the MIT Gas Study (MITEI, 2011, Appendix 2D) which applied a discounted cash flow analysis based on the 2009 median, high (P20) and low (P80) IP rates

TABLE 1

Initial production (IP) and Breakeven Price (BEP) for 2009 vintage wells in major U.S. shale plays based on the mean, median, P20, and P80 IP rates

		Barnett	Fayetteville	Haynesville	Marcellus	Woodford
Mean	IP: Mcf/day	1,923	2,183	7,973	3,500	2,676
	BEP: \$/Mcf	5.63	5.07	4.99	4.00	5.67
Median	IP: Mcf/day	1,727	2,030	7,693	n/a	2,520
	BEP: \$/Mcf	6.16	5.39	5.15	n/a	5.97
P20	IP: Mcf/day	2,700	3,100	12,300	5,500	4,200
	BEP: \$/Mcf	4.27	3.84	3.56	2.87	3.95
P80	IP: Mcf/day	900	1,200	3,000	1,500	1,000
	BEP: \$/Mcf	10.98	8.49	11.75	8.09	13.71

in each play, assuming a 10% target rate of return. For each play, we take the same median assumptions for lease cost, well drilling and completion, well operation and maintenance, royalties and taxes. Updates are introduced to some of the well performance data and the analysis is extended to include the BEP for the mean as well as the median IP rate. BEPs are calculated based on gas output only; some of the plays, particularly the Marcellus, contain “wet” areas that would reduce the BEP for those wells. Cost variation among the plays results mainly from differences in the depth of the shale deposit.

Several points about the BEP results (Table 1) are worth noting. First, for each play the mean BEP is less than the median, reflecting the asymmetrical distribution of resources even within a play (see Figure 3) and the fact that, at least for the 2009 vintage wells, developers were unable to identify the more productive areas. Also, the variability in IP rate within a play is very great. (Indeed, there can be great variation in productivity of wells drilled from the same pad.) In the case of the Barnett, there is a 2.5X difference between a P20 and P80 well BEP, while in the Woodford, that difference is 3.5X.¹ Because operators only develop portions of a play, their economics are biased by the relative quality of their particular acreage. Because of this intra-play variation it is certain that some operators with the 2009 vintage wells have failed to make the 10% rate of return assumed in Table 1. (Indeed, some wells may have been drilled simply to hold onto leases which require drilling investment within a specified period at penalty of lease termination.) Others, however, have achieved significantly better returns.

Even given this mixed picture of the apparent productivity of the shale business in its early years—not surprising for a newly accessible resource—the average economics of the major U.S. shale plays in recent years, with mean BEPs in the range of \$4.00-\$5.70 per Mcf, have been attractive relative to other gas resource types in the U.S. The question of a “golden era” then depends on estimates of the way this resource will progress from these early boom years.

1. Other components of the MIT study show that variation in lease and well costs, and royalty rates, could contribute plus or minus \$1 per Mcf to the estimates in Table 1. Uncertainty in well performance dominates the variation in within-play costs.

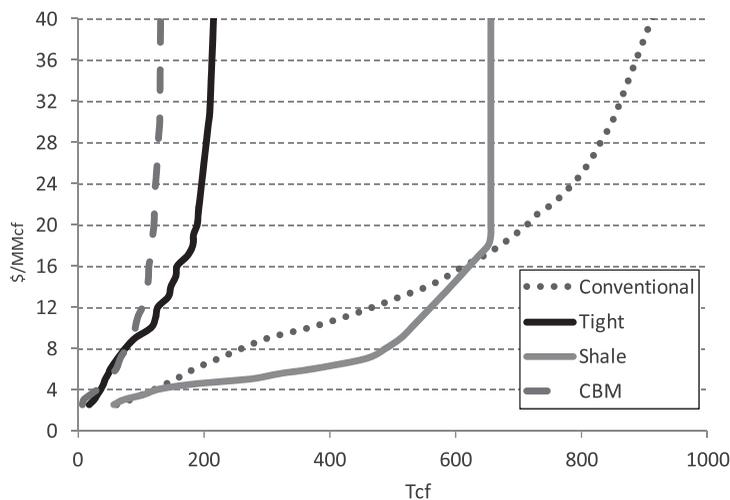


FIGURE 4
Mean U.S. Supply Curves by Type

2.3 Future Natural Gas Supply and Cost

The long-term role of natural gas will be determined by the ultimate size and economics of the shale resource, and of conventional gas, tight gas and coal-bed methane. To explore this prospect we extend the analysis of recent history to the application of long-term supply curves for each resource type. Here again we turn to the MIT study, which produced curves for the U.S. and Canada, shown in Figure 4. This effort involved the establishment of an inventory of all the known and potential gas resources including producing fields, stranded fields, likely extensions of producing fields, and estimates of resources likely to be found through future exploration (the so-called yet-to-find resource). All the volume estimates were established probabilistically. Production profiles and development costs were then estimated using algorithms that accounted for field size, drilling depth and location. The cost data used in the modeling was based on a variety of sources including the API Joint Association Survey on Drilling Costs, the Petroleum Service Association of Canada Well Cost Studies and EIA Oil and Gas Lease Equipment and Operating costs. A DCF model was used to determine the breakeven price for development and production, taking account of royalties and taxes, at a 10% real rate of return. For a detailed description of the calculation see (MITEI, 2011, Appendices 2B & 2C).

The estimates account for expenses for environmental control. However, continuing concern is expressed about water pollution in the development process, particularly methane contamination of drinking water, as documented by Osborn et al. (2011), possible spills of drilling fluids, and the management of return fracture fluids. Shale operations are regulated at the state level, and standards differ among states. Reviews of these regulations are under way in several states and at the federal level, and a tightening of regulatory standards is likely in some states. Recent analysis (Vaughan and Pursell, 2010) suggests these regulatory driven cost increases would be in the \$300-\$900K range with the most likely increase around \$500K. Given that the overall cost of well development is on the order of \$5M, these enhanced

regulations will not have a very significant impact on the economic attractiveness of the shale resource, or on the insights to be drawn from the analysis below

✎ 3. THE EFFECT OF SHALE ON POTENTIAL GREENHOUSE GAS POLICY ✎

Applying these cost data we explore the implications of shale gas for the two alternative approaches to greenhouse gas control. In each case we consider two alternative states of nature (or more accurately, states of technology and cost)—one representing resource availability as seen today and the other assuming that shale development remains uneconomic at any gas price. The emergence of shale to commercial viability is shown to have a set of contradictory effects: it stimulates the U.S. economy, yielding more emissions than if shale remained uneconomic but provides flexibility to meet reduction targets at lower cost.

3.1 Analysis Method

Model Structure. We apply the MIT Emissions Prediction and Policy Analysis (EPPA) model which is a multi-region, multi-sector representation of the global economy (Paltsev et al., 2005; Paltsev et al., 2011). It is a computable general equilibrium (CGE) model that solves for the prices and quantities of interacting domestic and international markets for energy and non-energy goods and factor markets. The model identifies sectors that produce and convert energy, industrial sectors that use energy and produce other goods and services, and households that consume goods and services (including energy)—with the non-energy production side of the economy aggregated into five industrial sectors. These and other sectors have intermediate demands for all goods and services determined through an input-output structure. Final demand sectors include households, government, investment goods, and exports. Imports compete with domestic production to supply intermediate and final demands. Demand for fuels and electricity by households includes energy services such as space conditioning, lighting, etc. and a separate representation of demand for household transportation (the private automobile). Energy production and conversion sectors include coal, oil, and gas production, petroleum refining, and an extensive set of alternative generation technologies.

The EPPA model includes all the non-CO₂ Kyoto gases, and where needed these are converted to a CO₂-equivalent greenhouse gas measure using standard 100-year global warming potentials (GWPs). The model also includes an estimate of fugitive emissions from natural gas development documented by Waugh et al. (2011) that is consistent with the level proposed by the Environmental Protection Agency (U.S. EPA, 2011). There are claims (e.g., Howarth et al., 2011) that shale wells vent substantially more methane than conventional gas development. The underlying analysis is controversial, but even the suggested increase in emissions from this component of the chain of supply and use would not diminish the contribution of shale gas under a multi-gas target by enough to change the insights to be drawn from our analysis.²

Conventional gas, tight gas, coal bed methane and shale gas resources are modeled separately, and as with other fossil energy types each is represented as a graded resource whose cost of production rises as it is depleted.³ Natural gas supply is determined by a two-stage

2. Howarth et al. (2011) further argue that natural gas may be an even greater greenhouse gas source than coal. Besides the questionable interpretation of methane leakage data, the analysis assumes an inappropriate substitution of gas for coal generation technology, and sums effects using 20-year GWP. For discussion see MITEI (2011, Appendix 1A).

3. Resources include proved reserves, reserve growth (in further development on known fields) and undiscovered resources that are expected to result from future exploration.

process where reserves are produced from resources and gas is produced from reserves. Natural gas reserves expansion is driven by changes in gas prices, with reserve additions determined by elasticities benchmarked to the gas supply curves presented in Figure 4 (see Paltsev et al., 2011).

Sixteen geographical regions are represented in the EPPA model, including eight of the largest individual countries, and the model computes the trade in all energy and non-energy goods among these regions so that results can be used to explore potential international trade in natural gas.

The advantage of this type of model is its ability to explore ways that domestic and global energy markets will be influenced by the complex interaction of influences like resource estimates, technology assumptions, and policy measures. Models have limitations, of course. Influential input assumptions—e.g., about population and economic growth, and the ease of an economy's adjustment to price changes—are subject to uncertainty over decades. Also, details of market structure and the behavior of individual industries are beneath the level of aggregation of model sectors, and are reflected only implicitly in aggregate production functions. Considering these strengths and weaknesses, results should be viewed not as predictions, where confidence can be attributed to the particular numbers, but rather as illustrations of the directions and relative magnitudes of various influences of the shale gas, and as a basis for forming intuition about desirable energy and environmental policies.

Other Influential Assumptions. Costs of other energy technologies are the same as those documented in the MIT Gas Study (MITEI, 2011, Appendix 3a). In addition, in recognition of recent difficulties of nuclear generation its growth is limited to 25% growth over the 2005 level. If this constraint is relaxed the main effect is for nuclear to displace renewable generation (so long as renewables are not mandated).

International trade in gas now takes place primarily within three regional markets—North America, Europe and Russia with links to North Africa, and Asia with a link the Middle East—with only small volumes traded among agents in the different markets. In the simulations below it is assumed that this pattern of regional markets is maintained. The implications of the emergence of a global market, akin to that for crude oil, are analyzed in the MIT study (MITEI, 2011, Chapter 3) and in Paltsev et al. (2011), and the potential effects of movement in this direction are addressed below.

3.2 Effect on Potential Regulatory Measures

To approximate national emissions policies most actively pursued at present we impose (1) a renewable energy standard (RES) requiring a 25% renewable share of electric generation by 2030, and (2) the retirement of 50% of current U.S. coal-fired generation capacity by 2030. Does the shale gas make much difference under this set of measures, and if so to whom? We begin with the hypothetical no-shale world and then consider what is different in the outlook today. Figure 5 shows the no-shale case on the left and the current estimate on the right, and provides pictures of electric generation in trillions of kWh (T kWh) and total national energy use in quadrillion BTU (qBTU). The total in each figure, including Reduced Use, is the electric generation or total energy in a no-policy reference case.

Note first that the shale resource has a positive effect on economic growth and energy use. Total energy is 8% higher in 2050 than with no shale, and sums to a 3% addition to energy use over 2010–2050. In the no-shale scenario electricity prices under the regulatory scenario rise above those projected with no policy (Figure 6), yielding an 8% reduction in

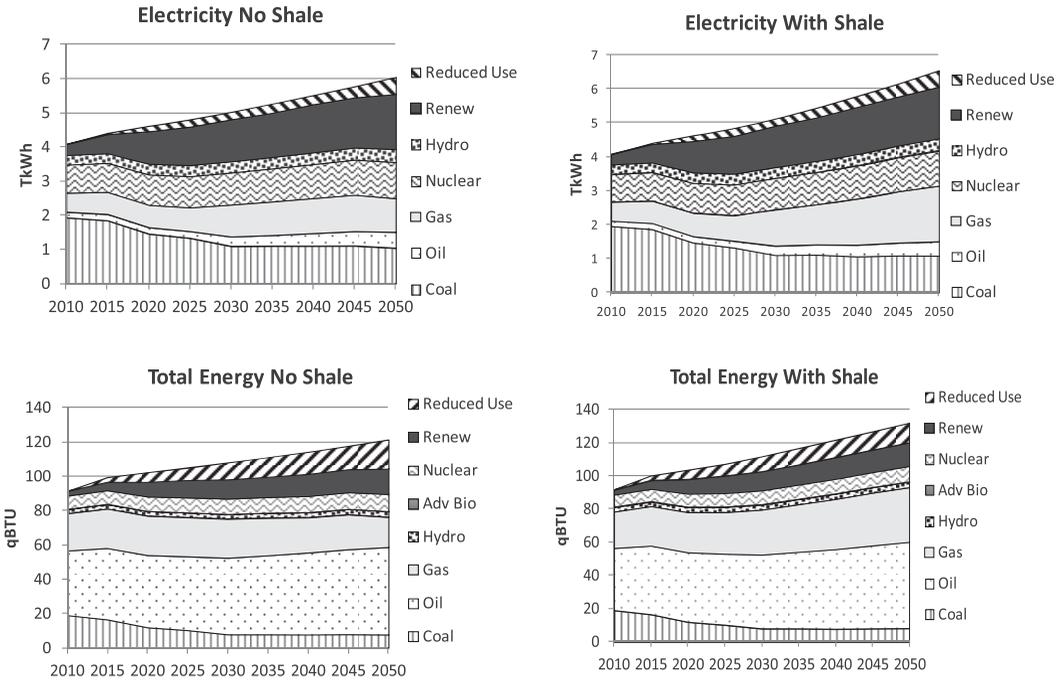


FIGURE 5
U.S. Quantities under Regulatory Policy

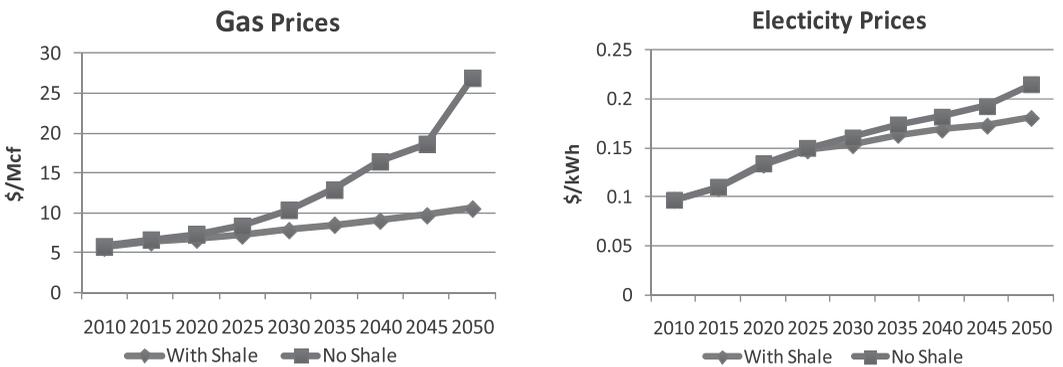


FIGURE 6
U.S. Prices under Regulatory Policy

demand by 2050. Without the shale resource, the gas price would be projected to rise substantially, to a 2050 level some 20% higher than if there were no regulatory constraint.⁴ Even at its higher price, however, gas use in electricity generation would increase, to replace the

4. In the EPPA model the assumption of regional gas markets tends to limit the flexibility to substitute imports for domestic supply at these high prices. The analysis thus may overstate the price growth in the no-shale case, depending on assumptions about development of a global LNG market, supply decisions in major exporting countries, and U.S. policy regarding import dependence (see MITEI, 2011, Chapter 3).

declining coal output. In addition, toward the end of the period renewable generation would be driven above the mandated 25% level. Nuclear output would be at its limit, and there is not much flexibility in the hydro source in any case.

The higher gas prices would then have substantial effects on non-electric sectors. By 2050 higher overall energy costs would yield a 15% reduction in total energy use. Also, gas use would be gradually squeezed out of other sectors (primarily from industry) as indicated by the fact that total gas use declines while gas fired generation increases.

The nation's current gas outlook, with shale, produces a different picture. Gas in electric generation is projected to increase by a factor of three over the simulation period, to meet the higher national energy demand under these supply and price conditions. In addition, there are a number of other changes from the assumed state with no shale: because of somewhat lower electricity prices (Figure 6) there is less reduction in use, and renewable generation never rises above the regulatory 25% minimum. The benefits of the shale resource are also reflected in total energy use. The lower gas prices lead to a lower reduction in use than would be the case under more stringent gas supplies, and total gas use expands by 50% over the period.

With no shale this set of measures would reduce GHG emissions by only 2% below 2005 in 2050 (and by 19% in cumulative emissions 2010–2050). With the current shale outlook the projections show a 13% *increase* over 2005 by 2050 (a 17% cumulative reduction from the no-policy scenario). With the lower gas resource the cost in reduced welfare (measured as aggregate national consumption) in 2050 would be 1.1% compared to a no-policy scenario, and the shale eases the task to a 0.7% 2050 reduction. Assuming a discount rate of 4% the net present value of the reduction in welfare over the period, if shale were not economic, is \$1.03 trillion (2005 dollars), while under current expectations the projected cost is \$0.98 trillion (to be considered against a larger economy).⁵ Incidentally, if this same GHG achievement were to be sought by use of an emissions price the cost over the period, assuming current gas expectations, would be only \$0.6 trillion (a 0.4% reduction in welfare in 2050 relative to the no-policy scenario).⁶

Beyond this cost reduction, the increased gas supply from shale provides useful flexibility, to meet needs for base-load power if our nuclear assumption were to prove optimistic or greater coal retirements were sought. On the other hand, if regulatory measures of this type are the only GHG actions the U.S. is likely to undertake for the foreseeable future, then there is no market for technologies like capture and storage even without the shale, and its emergence only further reduces their prospects.

3.3 Implications for Stringent Mitigation Using Price

This policy scenario, which requires a 50% GHG reduction below 2005 by 2050, involves more substantial changes in energy technology, and the imposition of a GHG price imposes a difference between the price of gas to the producer and to the consumer. Again focusing first on the electric sector (Figure 7, top left) if shale were uneconomic gas use in generation would be projected to grow slightly for a few decades, but toward the end of the period it would be priced out of this use because of the combination of rising producer price and the emissions penalty. Renewable generation would grow to 29% of total electric demand, above

5. The analysis ignores potential ancillary benefits of the fuel shift, such as reduction in air pollutants like NO_x, SO_x and particulates, and any climate change benefits.

6. This is a familiar result. As summarized by Teitenberg (1990) the high cost of command-and-control regulation in relation to a price incentive is seen in many areas of environmental control.

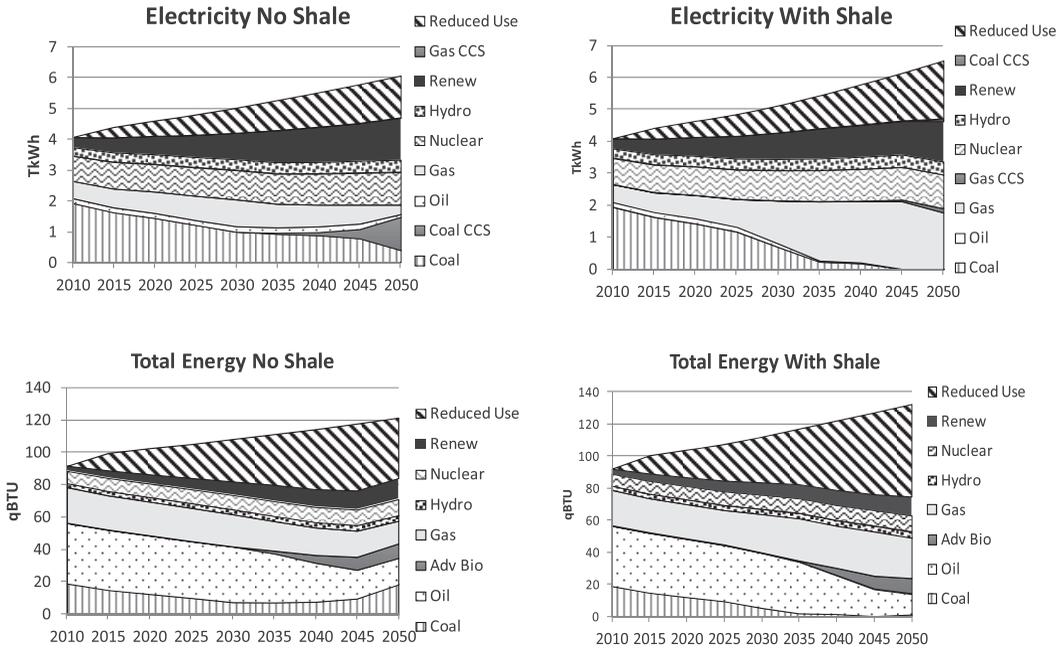


FIGURE 7
U.S. Quantities under a 50% Target

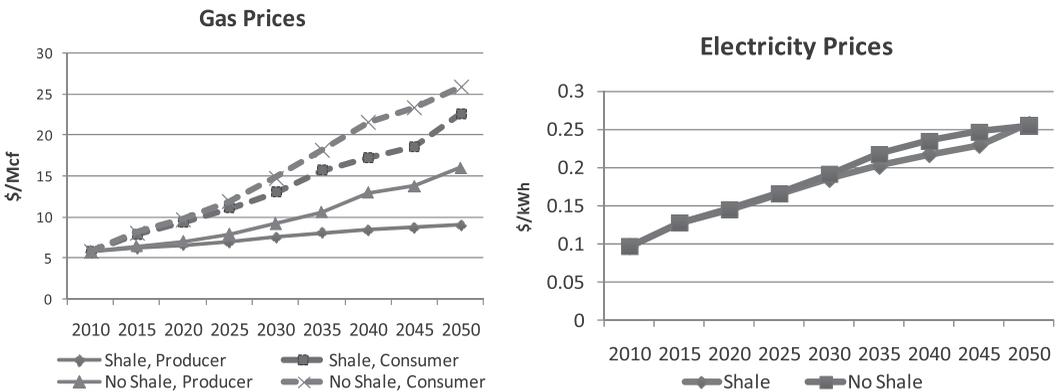


FIGURE 8
Prices under a 50% Target

level mandated in the regulatory case. Coal would maintain a substantial position in generation, though reduced, to 2025; and beginning at that point coal with capture and storage (CCS) would first become economic, growing to substantial scale by the end of the period. Nuclear would be limited by the assumption of a maximum 25% growth above its 2010 level. The remainder of the required reduction would be met by cuts in electricity use.

The effect of this 50% target on total energy use absent the shale gas (bottom left) is a reduction in demand, driven by the higher consumer gas price (Figure 8), and the introduction of advanced biofuels. Gas use declines over the period as the conventional gas, tight gas and

coal-bed methane are depleted, but by a lesser fraction than in electricity generation because at these prices the gas is relatively more valuable in industrial and other non-electric uses.

The current state of nature, shown on the right-hand side of Figure 7, creates a very different energy future. Gas is substantially cheaper (Figure 8) and increasing gas generation drives conventional coal out of the system. Toward the end of the period, moreover, the increasing gas price plus carbon charge begins to force conventional gas use out of the electric generation, and in 2040 gas with CCS is first projected to become economic. In 2045, coal with CCS also begins to become economic (producing less than 1TkWh, a level too small to show in the figure)—lagging gas because of the still relatively-low gas price. Renewable supplies are lower than they would be without the cheaper gas. The electricity price is similar between the two states of gas economics (Figure 8) but the reduction in use is somewhat higher than without shale because, nuclear being constrained, the with-shale case does not benefit soon enough from the low-emission base-load source provided by CCS technologies.

In the mix of total energy use gas is expected to grow over the simulation period. To meet the needs of the transport sector, advanced biofuels take market share beginning in 2035. With current gas resources the reduction in total energy use under this policy, relative to a no-policy scenario, is about 20% in 2010 and 45% in 2050.

The U.S. economy could adjust to either of these states of the world, and under this stringent reduction the growth-inducing effect of the larger gas resource is slightly more potent than its role in smoothing the adjustment to lower emissions. Recognizing that the figures are not directly comparable since they reflect different states of the world, we can again compare the difference in cost caused by the availability of the shale gas. The cost of the policy under current expectation, calculated as above as the net present value of the reduction in welfare over the period of 2010–2050, is about \$3.3 trillion (a 3.1% reduction in 2050), whereas if the shale resource were not economic that cost would be \$3.0 trillion (a 2.8% reduction in 2050). The slightly lower cost in the no-shale scenario is due to the lower emissions in the corresponding no-policy reference, and therefore the lower effort required to meet the 50% target.

Note that the desired pace of technology development is strongly affected by the emergence of the shale resource. The entrance of the shale supplies has the effect of driving coal out of electric generation, whereas without the shale coal would be projected to begin to recover from a “valley of death” with the introduction of coal-CCS around 2035. With the shale source this resurrection is not projected until some 10–15 years later. Moreover, gas with CCS may under these conditions be the technology likely to first see commercial viability. And, as would be expected, the cheaper gas serves to reduce the rate of market penetration of renewable generation.

✎ 4. CONCLUSIONS ✎

The emergence of shale gas supplies is a boon to the U.S. economy and an aid to potential climate policy. The lower-cost energy is projected to stimulate greater economic growth over the period to 2050, and to ease the task of GHG control over coming decades. Under regulatory constraint, one instance of which is analyzed here, the shale eases the task and provides an important source of flexibility when other sources of base-load power are under threat. Under a stringent target, implemented by emissions price, the economic benefits are even greater.

There are risks, however, in basing the U.S. energy outlook on current expectations without a careful eye on uncertainties in the future of the gas sector in the U.S. and worldwide. First of all, shale gas exploitation is at an early stage, yielding substantial uncertainty regarding future supply conditions, as there is in all the categories of domestic gas supply, including public willingness to accept its environmental side effects (e.g., see Shale Gas Subcommittee, 2011). Even given the lease, tax and development costs assumed here, there is variation around the mean estimates of gas supply curves in Figure 4. Exploration of the range of supply conditions is beyond the scope of this paper, but an impression can be gained by comparing the “with shale” cases presented here with results for an 80% confidence bound on these curves in the MIT study (MITEI, 2011, Chapter 3). Supply and cost data have been updated since that study, but the results are close enough for a rough impression. Even in the P10 case (90% probability of being exceeded) the gas production in 2050 is higher than today under the 50% reduction—instead of being reduced in half (Figure 7) if shale were uneconomic.

Also relevant is the potential evolution of the international LNG market away from the regional markets pattern assumed here and toward more interregional gas competition, loosening price contracts based on oil as are common in Europe and Asia. The MIT study (MITEI, 2011) explores a case where the gas market becomes akin to the global oil market, with a global prices differentiated only by transportation cost. In such a case the U.S. would, as U.S. gas prices rise, again import LNG originating in still lower-cost sources abroad. Movement in this direction will depend on market forces, supply decisions by major resource holders in the Middle East and Russia, and U.S. policies about import dependence. But even in the face of such a change over decades the influence of the U.S. shale gas would be the same: lowering national gas prices and stimulating the economy and energy demand and facilitating the path to emissions reduction.

Moreover, these changes in international markets may be magnified by the future development of shale resources outside the U.S., which were not included in our analysis. Though gas shale deposits are known to exist in many area of the world (Kuuskraa et al., 2011) their economic potential outside the U.S. is yet very poorly understood. If, however, preliminary resource estimates prove correct and supplies follow a path like that in the U.S., there will be dramatic implications for global gas use, trade and price, as well as for the geopolitics of energy (Medlock et al., 2011).

Finally, the gas “revolution” has important implications for the direction and intensity of national efforts to develop and deploy low-emission technologies, like CCS for coal and gas. With nothing more than regulatory policies of the type and stringency simulated here there is no market for these technologies, and the shale gas reduces interest even further. Under more stringent GHG targets these technologies are needed, but the shale gas delays their market role by up to two decades. Thus in the shale boom there is the risk of stunting these programs altogether. While taking advantage of this gift in the short run, treating gas a “bridge” to a low-carbon future, it is crucial not to allow the greater ease of the near-term task to erode efforts to prepare a landing at the other end of the bridge.

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