

The goal of our economic analysis was to estimate the amount of technically recoverable natural gas and oil in the Greater Green River Basin that can be extracted profitably at a given market price. The cost of extracting gas and oil in the Greater Green River Basin was estimated in two components: the wellhead cost and the infrastructure cost. The wellhead cost includes those costs associated with bringing the resource to the surface, as well as a number of additional steps such as compression, processing, water disposal, and initial gathering of resources from individual wells. The infrastructure cost refers to the costs associated with transporting the resource from the lease boundary to the interstate transmission pipelines. This is an important consideration in the Greater Green River Basin because of the remoteness and lack of existing infrastructure over parts of the region; substantial amounts of resources cannot be developed without constructing additional infrastructure. With production in the Rocky Mountain region increasing rapidly (Energy Information Administration, 2001a), infrastructure is expected to be an important part of future development.

The economic analysis consisted of constructing cost-supply relationships. To maximize the accuracy of the cost estimates, separate costs were estimated for multiple resource categories within each subplay. Cost estimates were further refined by modeling resource depletion through time.¹

WELLHEAD COSTS

Wellhead costs per volume of resource were estimated separately for each resource subcategory within each subplay (e.g., undiscovered nonassociated gas in Mesaverde subplay 2). The distinction between resource categories is made because reserve appreciation applies to reserves from existing fields, for which many of the exploration costs have already been incurred. The finding and development costs for resources from reserve appreciation are thus lower than for undiscovered resources. No costs were estimated for proved reserves; production costs were assumed to be zero for all proved reserves.

¹RAND obtained the services of Energy and Environmental Analysis, Inc., to estimate the wellhead costs. A full technical description of this analysis is available online at www.rand.org/publications/MR/MR1683.1. Infrastructure costs were estimated by RAND.

Costs for each of these analysis units were further broken down into ten separate increments reflecting the effect of resource depletion on well recovery and drilling success rates. As a basin is developed over time, well recovery declines because the better areas are developed first. Drilling success rates also decline through time as exploration targets become smaller and more difficult to find.² This breakdown structure resulted in over 1,200 individual analysis units for which separate costs were calculated.³

Both nonassociated gas (gas from gas wells) and associated gas (gas from oil wells) are included in the analysis. Natural gas liquids from gas wells were also included and amounts and costs are combined with the results for oil and collectively referred to as “total liquids.”

Cost estimates were constructed from estimates of a number of individual cost elements using a discounted cash flow model. The model calculates the amount of resource that can be produced in the Greater Green River Basin for a given cost, which is equivalent to the selling price at which the resource can be produced profitably.

Cost Elements

Important cost elements are discussed very briefly below.⁴

Drilling. Drilling costs increase with depth and differ for gas wells, oil wells, and dry holes. For gas wells, separate costs were further distinguished for coalbed methane and sour (corrosive) gas.

Stimulation. Most deposits in the Greater Green River Basin require stimulation (typically hydraulic fracturing) to extract the resource. Costs were estimated using historical data on the number of stimulation zones per well in each subplay.

Equipment. Equipment includes such items as flowlines, separators, dehydrators, pumps, compressors, and storage tanks. Costs were estimated from the results from the Rocky Mountain region of a survey conducted by the Energy Information Administration. Costs vary with well depth as well as with the characteristics of the resource.

Operations and Maintenance. Operating costs include such items as labor, overhead, fuel, chemicals, and surface and subsurface maintenance. Costs were estimated from the Energy Information Administration survey.

²See supplementary material at www.rand.org/publications/MR/MR1683.1 for more discussion.

³Individual costs are calculated for each of 50 subplays, two resource categories (reserve appreciation and undiscovered resources), two resource subcategories (associated and nonassociated gas in the case of gas or oil and natural gas liquids in the case of total liquids), and ten increments, giving a total of 2,000 cost analysis units. Many of these have zero values (e.g., there is no associated gas in coalbed methane deposits), leaving 1,221–1,391 calculated cost analysis units, depending on the scenario.

⁴Details on cost elements, including data sources, are given in the supplementary material available at www.rand.org/publications/MR/MR1683.1.

Processing. Some of the gas in the basin (primarily in the Deep Basin play) contains substantial quantities of nonhydrocarbon components. Interstate pipelines specify maximum impurity levels for gas entering the pipelines, and gas with higher levels (often referred to as low quality or low Btu gas) must undergo purification or blending before delivery. Processing costs are derived from the gas composition in each subplay.

Gas Compression. Gas entering interstate pipelines must be supplied at a pressure of approximately 1,000 pounds per square inch (psi). Coalbed methane is produced at very low pressures (~100 psi) and so must be compressed. Compression costs are based on the compression ratio, amount of gas to be compressed, and fuel requirements and also include capital and operation and maintenance costs. Noncoalbed gas is assumed to be produced at 600–700 psi in the early part of a well’s life and hence compression costs are negligible (<5¢ per thousand cubic feet (Mcf) and were ignored.

Water Disposal. Coalbeds have high porosities and are water saturated; this water must be removed before the methane can be desorbed from the coal. Coalbed methane production is therefore accompanied by large volumes of formation water. Although coalbed methane production is just beginning in the Greater Green River Basin, formation water will probably have to be reinjected into the subsurface because of its high salinity. Subsurface reinjection is more costly than the surface discharge currently used in the Powder River Basin. Preliminary estimates of water production rates and disposal costs were taken from environmental impact statements and industry press releases.

Geological, Geophysical, and Lease. Per well geological and geophysical costs were estimated by distributing national totals for geologic and geophysical investment as reported to the American Petroleum Institute across all wells drilled. Lease costs were based on actual lease costs (bonus cost) for federal and state land in the Rocky Mountain region in 2000–2001.

Taxes, Royalties, and Return on Investment. The model assumes a 6 percent Wyoming state severance tax and a 7 percent county ad valorem tax for the Greater Green River Basin area. Federal and state income tax is assumed to total 30 percent. The model assumes federal royalties of 12.5 percent. The required after-tax real rate of return in the model is 6.3 percent. This value is based on a capitalization ratio of 60 percent debt and 40 percent equity for which debt and equity have nominal rates of return of 7 percent and 15 percent, respectively, after-tax rates of 4.9 percent and 15 percent, respectively, and real after-tax rates of 2.3 percent and 12.2 percent, respectively. This ratio results in a nominal rate of 10.2 percent, an after-tax rate of 8.9 percent, and a real after-tax rate of 6.3 percent.

The values of many of these cost elements, most notably drilling, are influenced by well depth, which varies from 2,200–21,500 feet throughout the basin. Two other important characteristics of the subplays—drilling success rate and total recovery per well—also influence costs. Drilling success rates in the model range from 12 percent to 95 percent and vary by subplay, resource category, and depletion increment. For unsuccessful wells, drilling costs are somewhat lower and many of the other cost el-

ements decrease or vanish. Total recovery per well affects the total number of wells that must be drilled to extract the resource from the subplay.

Examples of subplay characteristics and values for cost elements for four subplays are shown in Table 3.1. Cloverly-Frontier Tight and Deep Basin are very deep plays and have among the highest costs in the basin. Deep Basin also requires substantial costs for gas processing. The Tertiary section of the Moxa Arch is a relatively shallow conventional subplay with relatively low costs, and Almond Coalbed illustrates the compression and water disposal costs. Overall, costs tend to be dominated by drilling and stimulation. Although Deep Basin has very large processing costs, it is one of only two subplays that require extensive processing, and processing costs are not substantial costs for the basin overall. For coalbed methane wells, compression and water disposal costs are also significant.

Table 3.1
Examples of Wellhead Cost Elements for First Depletion Increment of Undiscovered Gas from NPC-Inspired Advanced Technology Scenario

Well Characteristic	Unit	Cloverly-Frontier Tight Subplay 5	Deep Basin	Moxa Arch Upper Cre-taceous	Almond Coalbed
Average depth	Feet	21,500	18,500	4,695	2,245
Drilling success rate	Percent	83	76	84	85
Total recovery per well	MMcf	1,396	13,167	2,379	607
Cost element					
Drilling	\$1,000/well (successful)	6,867	8,863	351	190
Stimulation		657		153	31
Equipment		45	113	34	69
Geological and geophysical		31	31	23	21
Lease		61	61	47	43
Operations and maintenance	\$1,000/year	32	64	22	31
Processing	\$/MMBtu (marketable gas)		7.71		0.08
Compression					0.18
Water disposal					0.45
Infrastructure		0.12	0.06	0.07	0.13
Net gas cost	\$/MMBtu (marketable gas)	16.05	11.83	0.97	4.48

NOTE: Drilling success rate and total recovery per well decrease with increasing depletion increment, so values shown for these parameters are maximums for the plays listed.

Discounted Cashflow Model

The economic analysis of gas and oil resources was based on a discounted cash flow model developed by Energy and Environmental Analysis, Inc. Model inputs include a subplay-allocated resource assessment and assumptions for drilling and completion costs, stimulation costs, geological and lease costs, per well gas and oil recoveries, production parameters, drilling success rates, taxes, rate of return criteria, and expected Btu content and gas composition. Production from each well was characterized by a total recovery volume, Btu content of the dry hydrocarbon gas, condensate yield (for gas wells), gas yield (for oil wells), and average annual takes. A

deliverability forecast in the form of a hyperbolic decline curve was used to model production as a function of time for up to a 50 year life of the well. In addition, as discussed above, each subplay was modeled in ten depletion increments in which the total recovery per well and drilling success rate decreased with each increment.⁵

In addition to using different well recoveries, the NPC-inspired current technology and advanced technology scenarios differ in two other respects. In the advanced technology scenario, drilling costs were reduced by 5 percent and drilling success rates were increased by factors of 1.023 and 1.07 for reserve appreciation and undiscovered resources, respectively.⁶ These factors contribute to the differences in cost between these scenarios.

The output of the model is the resource cost, which is the selling price required to compensate producers for their investments, operating costs, taxes, royalties, and cost of capital. Resource costs are calculated in dollars per MMBtu of dry marketable gas.⁷ The amount of resource in the Greater Green River Basin available at a given price was obtained by summing the resource amounts in the individual cost analysis units that have a resource cost less than or equal to that price.

INFRASTRUCTURE COSTS

Assumptions

The infrastructure costs presented in this report represent a first-order estimate and neglect several factors that may influence the actual cost. In general, our assumptions likely minimize the cost estimate. For example, we include in the infrastructure costs only the cost of building pipelines to transport resources from the wellhead to the interstate transmission pipeline. Other potentially important costs, such as additional interstate pipeline capacity, operations and maintenance, capital costs for increasing processing capacity, roads, or housing, are not included. We further assume that future infrastructure costs will apply to undiscovered resources only; proved reserves and reserve appreciation are assumed to be transported through the existing pipeline infrastructure. We estimate infrastructure costs for natural gas only.

We modeled the cost of the pipeline infrastructure necessary to bring resources from the wellhead to the interstate pipeline in terms of linear distance. The pipeline is modeled as a three-stage tree structure (see Figure 3.1). The first stage comprises the flowlines from individual wells. Note that the cost of the first stage of flowlines is included in the wellhead costs and is not included here. Flowlines assumed in this estimate are one inch in diameter and one mile long. Twenty-five flowlines connect to a small gathering line, assumed to be four inches in diameter and three miles long.

⁵Cashflow model details are given in the supplementary material, available at www.rand.org/publications/MR/MR1683.1, and in Vidas et al. (1993).

⁶In all cases, drilling success rates were capped at 95 percent and 85 percent for reserve appreciation and undiscovered resources, respectively.

⁷The average heating value of dry gas in the Greater Green River Basin is 1,080 Btu per cubic foot (cf), so the cost per MMBtu is 8 percent higher than the cost per Mcf ($\$/\text{MMBtu} = 1.08 \times \$/\text{Mcf}$).

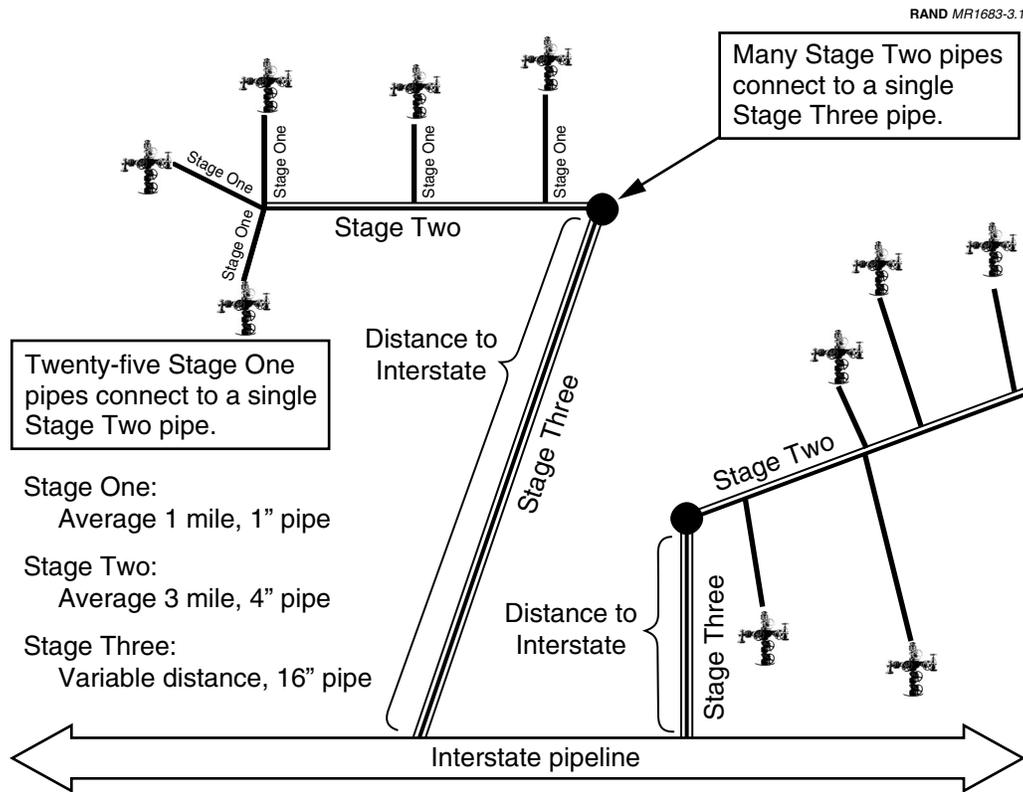


Figure 3.1—Pipeline Tree Structure Used to Model Infrastructure Costs

Three thousand small gathering lines connect to 200 16-inch diameter large gathering lines which lead, in turn, to the interstate lines.

Pipeline Capacity Requirement

The pipeline capacity required is determined by the anticipated gas production rate. Our model assumes that proved reserves and reserve appreciation will be transported to the interstate pipelines through the existing pipeline infrastructure and that new pipeline is required for undiscovered resources. That is, any remaining capacity of the existing pipeline network (excluding interstate transmission lines) is required to accommodate proved reserves and future reserve appreciation. Although this is deemed a reasonable assumption for the regional scope of this analysis, it should be substantiated through further analysis.

The total amount of undiscovered technically recoverable gas in the basin is approximately 116,000 Bcf (average of the three assessments; see Table 2.1). Using estimates for the total recovery per well, the wellhead cost model requires approximately 75,000 new field gas wells to produce the undiscovered gas.⁸ For production over 50

⁸For a productive area of 25,000 square miles, this gives a well spacing of 213 acres.

years, this equates to an average production rate over time and space of approximately 85 Mcf per day per well. In reality, a well's maximum production rate may be many times its lifetime average value, increasing the overall pipeline capacity requirement relative to the average. Conversely, not all wells in the basin will be producing simultaneously, reducing overall pipeline capacity requirement relative to the average. If these two effects are of comparable magnitude (e.g., if a well's maximum production rate is four times its average and one-quarter of the basin is producing at any one time), then the average production rate may be a good approximation to the required pipeline capacity. Assuming this requirement, the pipeline was modeled to accommodate this flow at 35 percent capacity utilization.

Costs

Cost per inch in diameter per mile in length of gathering system amounts to approximately \$10,000 to \$15,000 for the small gathering lines in the second stage and \$40,000 to \$100,000 for the large gathering lines in the third stage. The former estimate was developed from conversations with industry, and the latter from estimates of larger pipelines described by the Department of Energy's Office of Fossil Energy. The range in the latter reflects the lower marginal cost per mile of longer pipelines compared to shorter pipelines. These costs are averages and do not explicitly incorporate costs of routing through mountainous terrain and other factors that may increase the costs, siting, or building of the lines. A payback period of 50 years is used for the pipelines with a real after-tax discount rate of 7 percent.

The requirement for the first two pipeline stages is the same regardless of where the wells are located. The cost thus varies with the distance that the third stage lines must run to reach the interstate pipeline. The cost data, tree structure, and capacity requirement were then combined to generate a cost-distance relationship that was used to estimate infrastructure costs.⁹ Costs range from about \$0.05 per Mcf at five miles to about \$0.35 per Mcf at 100 miles.

Interstate transmission pipelines were defined as gas pipelines with a diameter of 25 inches or more. The locations of pipelines are shown in Map 2.2 and all subsequent gas maps in the maps section.¹⁰ Per volume infrastructure costs were estimated for individual subplays, based on distance to interstate pipelines. Using GIS, the fraction of area within five mile increments of the interstate lines was calculated for each subplay. Resource volume was estimated from this area fraction and the total undiscovered resource allocated to that subplay. This assumes that the gas volume per unit area is homogeneous over the subplay. Infrastructure costs for each distance increment were calculated with the cost-distance relationship determined above. Finally, a weighted average infrastructure cost for each subplay was calculated from the infrastructure cost for each increment weighted by the fraction of undiscovered resource in that increment. These weighted average infrastructure

⁹This cost per Mcf for infrastructure as a function of distance from interstate pipelines can be approximated as follows: $\text{Cost (\$/Mcf)} = 4 \times 10^{-7}d^3 - 7 \times 10^{-5}d^2 + 0.0061d + 0.0213$, where d = distance in miles.

¹⁰The pipeline network map was purchased from PennWell MAPSearch, Durango, CO.

costs range from \$0.07/Mcf to \$0.29/Mcf. Costs for four subplays are shown in Table 3.1.

The total cost for each subplay was calculated by adding the wellhead and infrastructure costs for each undiscovered resource analysis unit.

ECONOMIC RESULTS

The basinwide results of our economic analysis are summarized in the form of cost-supply curves in Figures 3.2 and 3.3. Each curve shows the amount of technically recoverable resource (TRR) as a function of the resource cost, which is equivalent to the selling price at which that amount can be profitably extracted and transported to the interstate transmission pipeline. An inset in each figure shows the same data over an expanded cost range. The curves are constructed from over 1,200 analysis points, each representing the cost associated with an individual increment of gas or oil.

For gas, the amount available at any cost is greatest for the NPC-inspired advanced technology scenario, least for the NPC-inspired current technology scenario, and intermediate for the USGS-based scenario. For total liquids, the USGS-based scenario yields the greatest amounts above \$12 per barrel, and the NPC-inspired advanced technology scenario gives the greatest amounts at costs lower than this. The amount

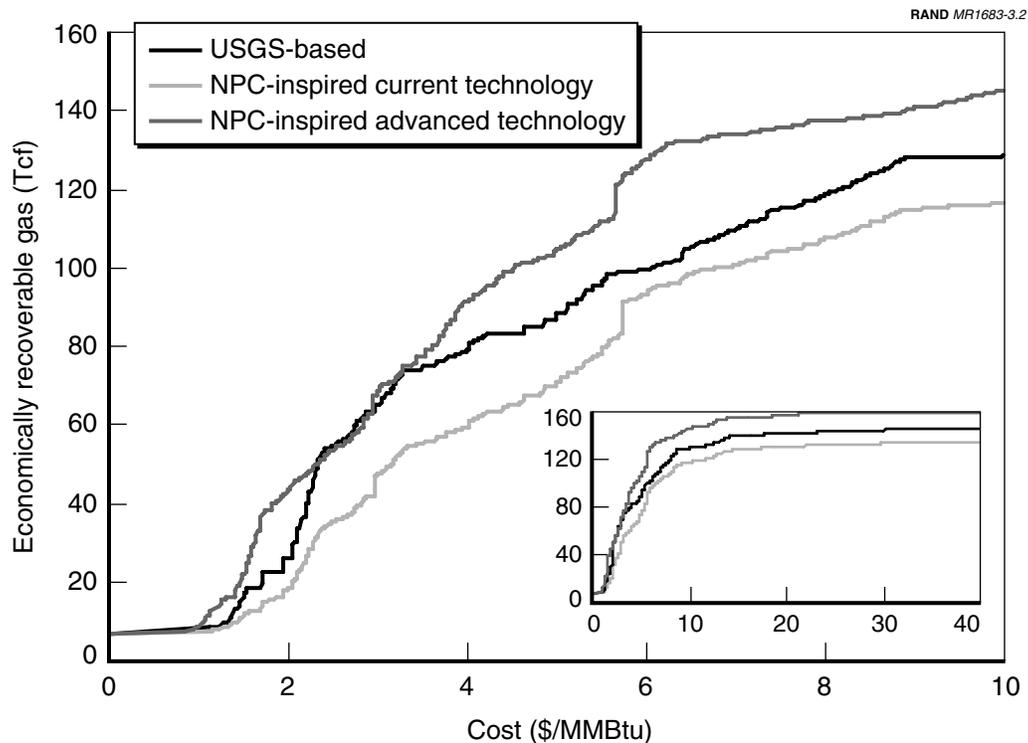


Figure 3.2—Gas Cost-Supply Curves for the Three Assessment Scenarios

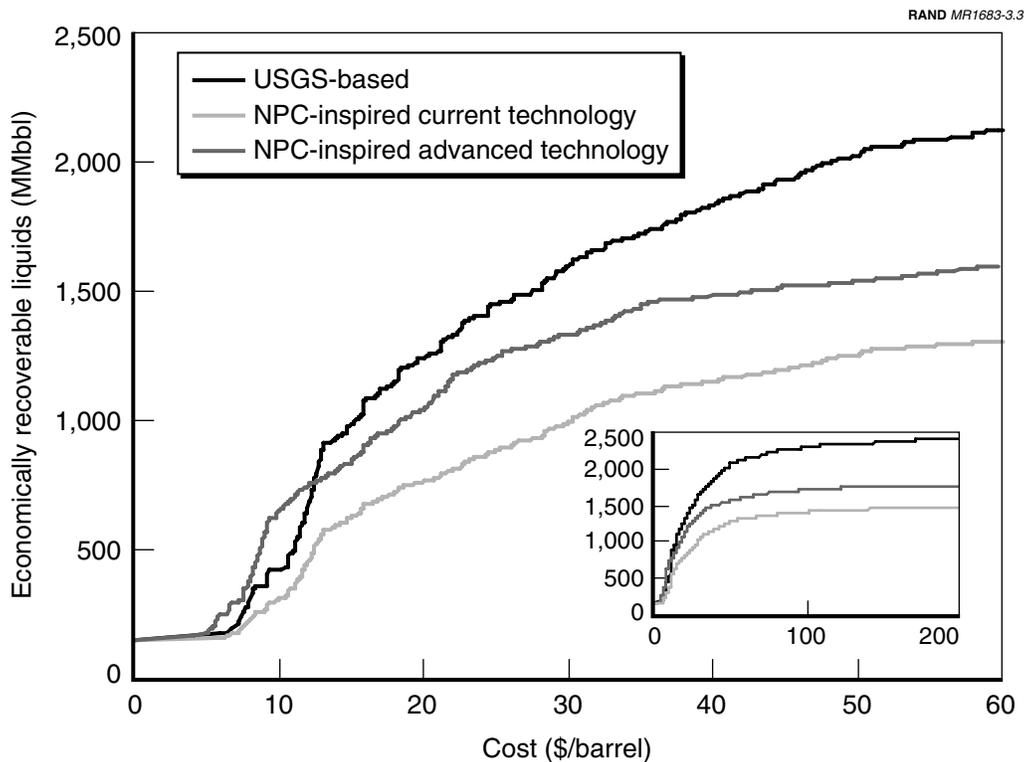


Figure 3.3—Total Liquids (Crude Oil Plus Natural Gas Liquids) Cost-Supply Curves for the Three Assessment Scenarios

of economically recoverable gas at several costs is shown in Figure 3.4 and tabulated in Table 3.2.

The results presented in Figures 3.2–3.4 and Table 3.2 represent the economic costs required to produce natural gas and oil in the Greater Green River Basin. The relationships generated in this model allow one to estimate how much resource can be profitably produced at a given price. The average wellhead price in the state of Wyoming from 1996 through 2000 was \$2.42 per Mcf, or approximately \$2.61 per MMBtu (Energy Information Administration, 2001a). At a price of \$3 per MMBtu, from 35 to 45 percent of the technically recoverable gas in the Greater Green River Basin may be economically recoverable, depending on the scenario. Approximately 90 percent of the gas is economic at \$10 per MMBtu. These estimates of economically recoverable resources are substantially greater than prior estimates for the Greater Green River Basin (Attanasi, 1998).¹¹

An example of the spatial distribution of the economically recoverable gas is shown in Map 3.1 in the maps section. This map shows the location and amount of gas that is economically recoverable at a price of \$3 per MMBtu. This map is analogous to

¹¹Note that such comparisons are problematic because of large differences in data and methods.

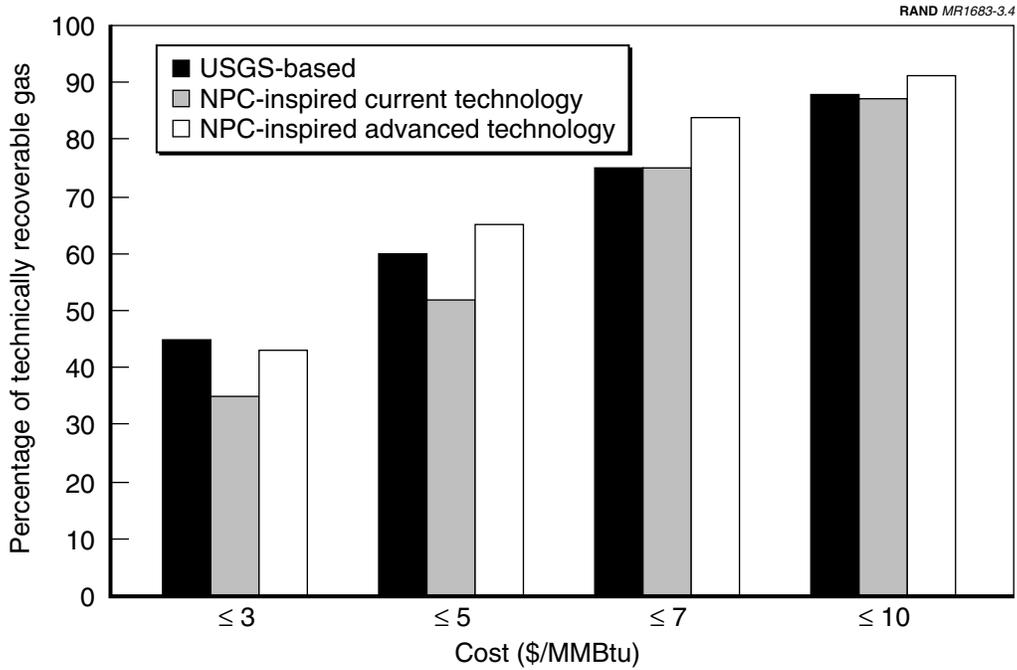


Figure 3.4—Economically Recoverable Gas at Different Costs for the Three Assessment Scenarios

Table 3.2
Economically Recoverable Gas at Different Costs

Scenario	Resource Category	Cost (\$/MMBtu)			
		≤3	≤5	≤7	≤10
USGS-based	Reserve appreciation	2.4	5.9	7.2	8.4
	Undiscovered	56	74	95	113
	Total ^a	65	87	109	128
	% of TRR	45%	60%	75%	88%
NPC-inspired current technology	Reserve appreciation	9.1	14	25	27
	Undiscovered	31	49	69	83
	Total ^a	47	70	100	116
	% of TRR	35%	52%	75%	87%
NPC-inspired advanced technology	Reserve appreciation	9.9	14	25	27
	Undiscovered	51	83	102	111
	Total ^a	68	104	134	145
	% of TRR	43%	65%	84%	91%

NOTES: Quantities are given in trillion cubic feet. TRR includes proved reserves.

^aTotal includes 100 percent of proved reserves.

Map 2.2 but instead of showing the total technically recoverable resource, it shows the amount of the technically recoverable resource that can be produced at costs of up to \$3 per MMBtu as determined from the cost-supply relationships. Additional maps for other scenarios and other prices are presented in the maps section.

Maps 2.2 and 3.1 show broadly similar patterns, indicating that the overall spatial distributions of economically and technically recoverable resources are generally similar. However, the amount of gas per area at any location is lower in Map 3.1, reflecting the lower amount of economically recoverable relative to technically recoverable gas. In addition, the difference between the amount of technically and economically recoverable resources varies from place to place. This is apparent in several areas, including much of the Washakie Basin, the northeastern portion of the Great Divide Basin, and the northwest trending area just south of the Wind River Uplift (see Figure 1.5 for locations).

The high resolution of both the cost and spatial analyses provides a useful tool for federal land managers that can help them identify areas where resources are likely to be profitable to produce at different prices. In so doing, it provides a more comprehensive picture of the values of the different subregions of natural gas and oil resources throughout the Greater Green River Basin. As an example of how it might be used, the analysis indicates that natural gas in much of the Washakie Basin, while abundant (Map 2.2), is expected to be relatively more costly to produce than that in many other areas (Map 3.1). This information could help guide a decision in permitting energy development elsewhere in the basin.

SENSITIVITY OF RESULTS TO UNCERTAINTIES

There are several sources of uncertainty in our cost estimates. To begin with, there is a fundamental uncertainty in the estimates of technically recoverable resources used as a basis for the economic analysis. Energy resource assessments attempt to estimate amounts of unexplored and undiscovered natural gas and oil and are consequently highly uncertain. Technically recoverable resource assessments are conducted periodically and estimates have historically increased from one assessment to the next (e.g., Fisher, 2002). As such, they are often referred to as being “dynamic.” The economically recoverable resource assessment presented here is based on these technically recoverable resource estimates and thus is also subject to change with time. It is therefore important to keep in mind that the results presented here reflect current knowledge and need to be revised periodically to account for increased exploration, improved technologies, and any other factors that may modify our estimates.

An additional uncertainty is the effect of the way in which resources were allocated (i) to subplays, (ii) to resource categories and areas within subplays, and (iii) within resource areas. The first two allocation steps affect total costs and all three influence the distribution of economically recoverable resources. Varying the amount of resources among the different subplays will influence total costs because different subplays have different characteristics that affect costs. Allocation of resources to resource areas within subplays is governed by the allocation of resources to resource categories (see Table 2.2), which also have different cost characteristics. Distribution of resources within resource areas does not affect costs because costs are estimated from the number of wells required. The number of wells is determined from the amount of resource and recovery per well and does not depend on the location of

those wells. Thus, modeling undiscovered resources as being homogeneously distributed throughout the new field areas of the subplays has no influence on costs or on the amount of economically recoverable resource. It does, however, affect the spatial distribution, which is an important component of our approach. To a first-order approximation, this issue has been addressed in this study by dividing the published U.S. Geological Survey plays into subplays. Further refinement would involve detailed geologic modeling that is beyond the scope of this initial analysis. In general, the influence of alternative resource allocation schemes on total costs and the distribution of economically recoverable resources is an important topic for further analysis.

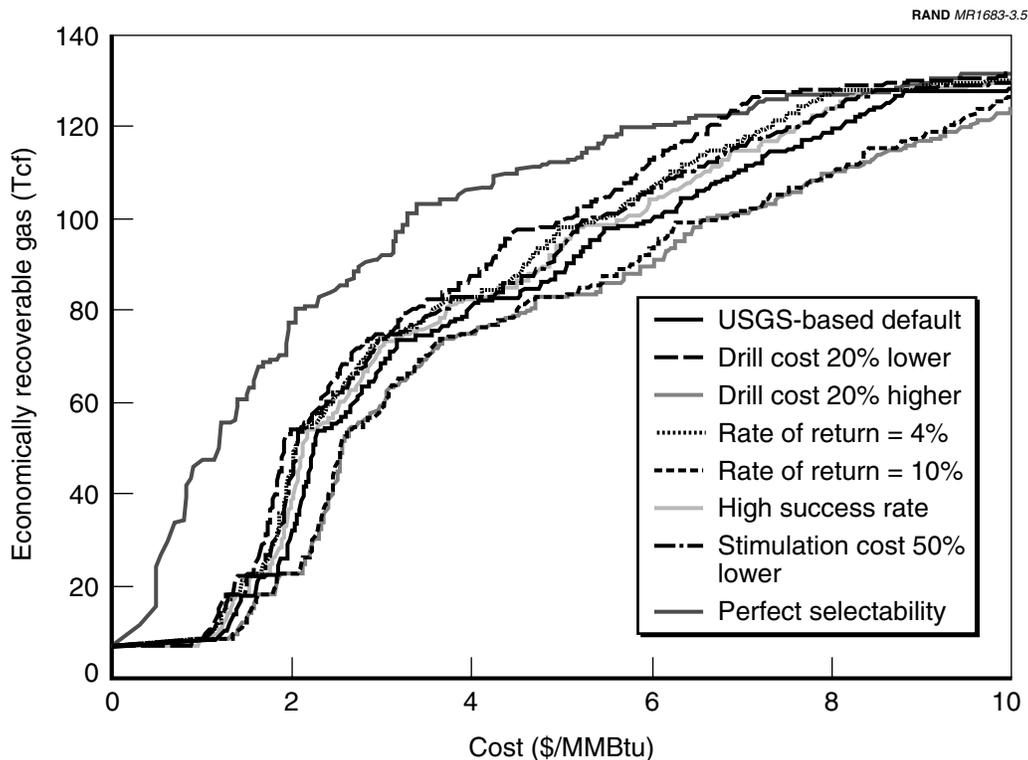
The economic analysis itself incorporates a large number of variables and assumptions. Drilling costs, for example, fluctuate in response to gas prices and drilling rig availability: Higher prices lead to greater rig demand, which drives up drilling costs (e.g., Gas Research Institute, 1999). The drilling costs used in this analysis are based on data from a single year and thus may not capture the full range of costs over longer timescales. A sensitivity analysis was conducted to estimate the effect of changes in drilling costs and a number of other variables. The effect of several variables on the amount of gas available as a function of cost is illustrated in Figure 3.5. In addition to the variables shown, halving stimulation costs, water disposal costs, and inflation has negligible effects and these cases are not shown. Most of these variables have relatively small effects, particularly at costs less than \$4/MMBtu.

Compared to most of the variables shown in Figure 3.5, the effect on costs of the different initial economic scenarios is greater. This can be seen by comparing Figures 3.2 and 3.5. The primary differences among the scenarios are the starting amount of technically recoverable resource and the modeled recoveries per well. Thus, the overall uncertainty in the economic modeling is dominated primarily by uncertainties in these two factors. The propagation of these differences in the resource distribution can be assessed by comparing Map 3.1 to maps for the other scenarios included in the maps section.

The notable exception is selectability. Selectability refers to the ability of producers to preferentially select the most economical well locations (“sweet spots”) first. Selectability is represented in the cost model by the rate of decline of well recoveries over the ten depletion increments. The model uses a different decline rate for reserve appreciation and undiscovered reserves in each of conventional, tight sandstone, low Btu, and coalbed methane deposits. These decline rates were estimated from a number of sources, including the National Petroleum Council natural gas studies.¹²

Well recoveries within a tight sandstone subplay can vary greatly depending on factors such as natural fractures and depositional trends. Industry has shown some ability to target better areas first, and this is reflected in the decline rates used in the model. However, future technology could greatly improve industry’s ability to target these better areas. This would have the effect of making more gas available at lower cost.

¹²See supplementary material at www.rand.org/publications/MR/MR1683.1 for more discussion.



NOTE: For the “high success rate” case, drilling success rates were fixed at 85 percent for undiscovered resources and 95 percent for reserve appreciation (compared to 10–85 percent in the default scenario).

Figure 3.5—Effect of Model Variables on the Amount of Economically Recoverable Gas

Petroleum Council natural gas studies, tight sandstone well recovery statistics were evaluated to determine the variability in well recoveries in groupings of 10 percent of the wells. Perfect selectability is modeled here by setting the average well recovery in the initial depletion increment equal to the best 10 percent of the total recovery distribution, recovery in the second increment equal to the next 10 percent of the distribution, and so on. The results for perfect selectability of undiscovered resources in tight sandstone subplays are shown in Figure 3.5. Note that perfect selectability is a theoretical case that is unlikely to ever be realized. It is shown to illustrate the effect of resource targeting on overall costs. Note also that substantial additional costs may be incurred by producers in improving selectability. Such costs have not been accounted for in our model.

Perfect selectability changes the shape of the supply curve so that much more of the gas is recoverable at lower costs. Note that the average cost does not change, nor does the total amount of gas produced. Rather, by the ability to target the best locations first, more of the gas is made economical at lower costs. The finding that resource costs are more sensitive to selectability than other factors has important im-

plications for understanding gas and oil costs. The results indicate that substantial cost savings may be realized from improvements in exploration technologies.

A final area of uncertainty to contend with is the appropriate spatial resolution for interpreting the economic results. A first-order estimate can be derived using the dimensions of the economic analysis units as a guide. The 33 spatially distinct subplays distributed over a total study area of 25,000 square miles gives an average economically resolvable cell length of 28 miles. This calculation is conservative in that it neglects the distinction between resource areas within individual subplays, which improves the resolution still further. However, this estimate is complicated by the fact that the various production parameters and cost estimates used in the model reflect averages over large numbers of wells. Applying these data to a small number of wells in one area may not be straightforward, as the variance in factors such as drilling success rate or recovery per well increases as the number of wells considered decreases. Thus, although the average costs will not change, costs at any given area may be higher or lower. As a target for further study it would be useful to quantify this uncertainty.