Carnegie Mellon Electricity Industry Center Working Paper CEIC-06-12 www.cmu.edu/electricity

The Value of Using Coal Gasification as a Long-Term Natural Gas Hedge for Ratepayers

David C. Rode
Managing Director
DAI Management Consultants, Inc.

Dept. of Social and Decision Sciences
Carnegie Mellon University

Paul S. Fischbeck, PhD
Professor of Social and Decision Sciences
Dept. of Social and Decision Sciences
Carnegie Mellon University

December 11, 2006

Corresponding Author: David Rode
DAI Management Consultants, Inc.
1370 Washington Pike
Bridgeville, PA 15017

Voice 412.220.8920
Fax 412.220.8925
www.daimc.com

ABSTRACT

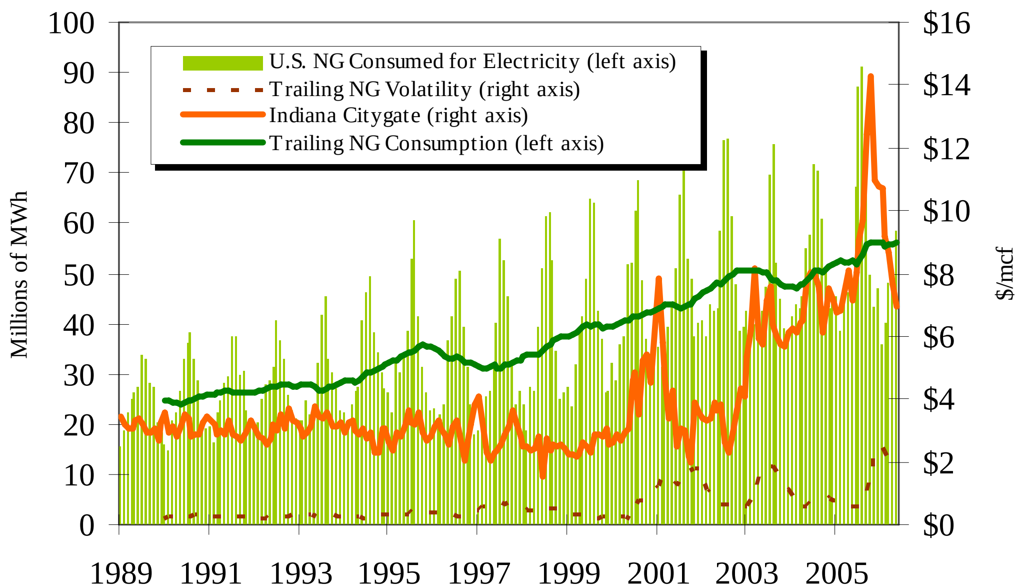
Natural gas has become a commodity of extraordinary volatility, with a growing share of demand met by imports. Demand growth resulting from the rapid expansion of gas-fired power-generation capacity over the last decade has introduced a substantial element of fuel price risk into basic goods (natural gas and electricity) required by consumers, exacerbating the already-high level of price volatility in natural gas used for heating. Because of the highly inelastic nature of both electricity and home-heating demand, volatility in natural gas prices can be a particular burden to residential and commercial consumers. Despite the potentially significant value to be gained from developing a means of limiting price risk for consumers, there are very few alternatives available for long-term hedging of natural gas prices. Coal gasification represents not only a means of obtaining a large long-term supply of natural gas at a reasonable price, but also one of the few alternatives available as a long-term physical hedge for natural gas price volatility. In this paper we determine the value of using coal gasification as a long-term hedge to consumers and discuss the potential value to gas utilities. Although the results presented in this paper can be applied generally, our analysis focuses specifically on the value to Indiana residential and commercial heating consumers of a proposed SNG project in Southwest Indiana.

Keywords: 3 Party Covenant, Coal Gasification, Long-Term Hedging, Natural Gas, Public Policy, Risk Analysis, Risk Elasticity, Risk Management, Simulation

The results in this working paper are preliminary and subject to change. In particular, the design of the gasifier and the terms of the proposed contracts have not been finalized at the current time. The results discussed in this paper are meant to reflect the current status of the proposed project, subject to agreement by all affected parties (regulators, gas utilities, consumers, and the project's sponsor). Further, the technical and contractual inputs, such as availability of the gasifier and pricing of the SNG, have been provided by third-party sources and DAI and Carnegie Mellon University render no opinion as to their feasibility and/or reasonableness. Changes to the technical or contractual specifications of the project may substantially change the results of this analysis.

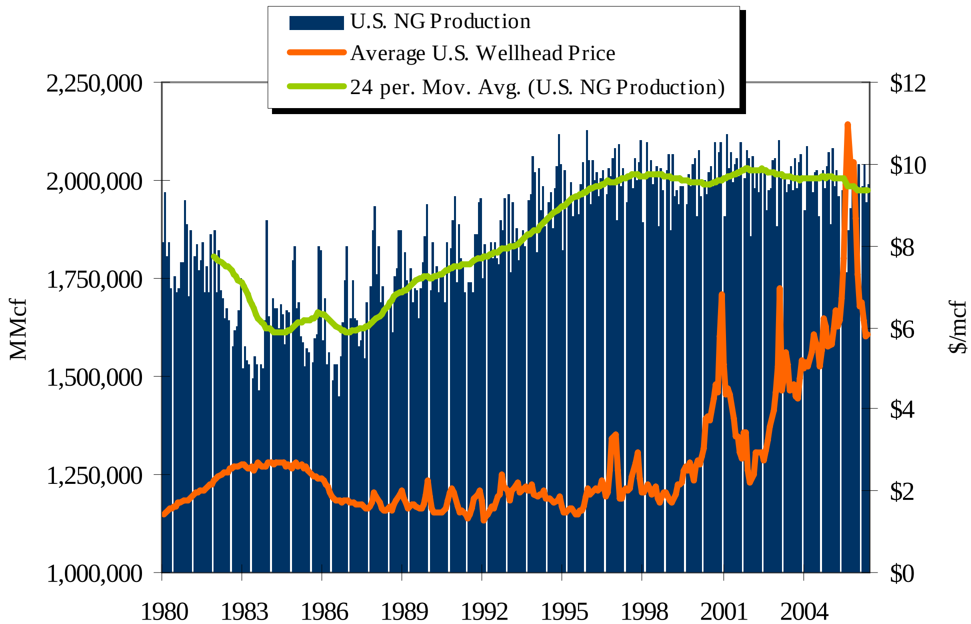
EXECUTIVE SUMMARY

Natural gas is among the most volatile of commodities. Owing to constraints on its transportability and storage, natural gas prices fluctuate widely both within and across years. This "baseline" volatility is now set against a backdrop of soaring demand for natural gas. Demand for natural gas – which has always varied with economic activity and seasonal consumption – has increased because of a doubling of the natural gas consumed by power generators over the past fifteen years.



Source: Energy Information Administration, U.S. Dept. of Energy

As the above figure illustrates, not only are consumers using twice as much natural gas to generate electricity as they were fifteen years ago, they are now paying as much as four times what they were fifteen years ago. Together, this is a staggering increase in costs facing consumers. And this increase in costs is not temporary. A decisive strategic shift by power generators toward long-lived gas-fired capacity means that demand – and therefore, likely, prices – will remain elevated for decades. The increased pressure on the supply-demand balance for gas in the face of declining domestic well production (see figure below) will also ensure that volatility remains elevated.



Source: Energy Information Administration, U.S. Dept. of Energy

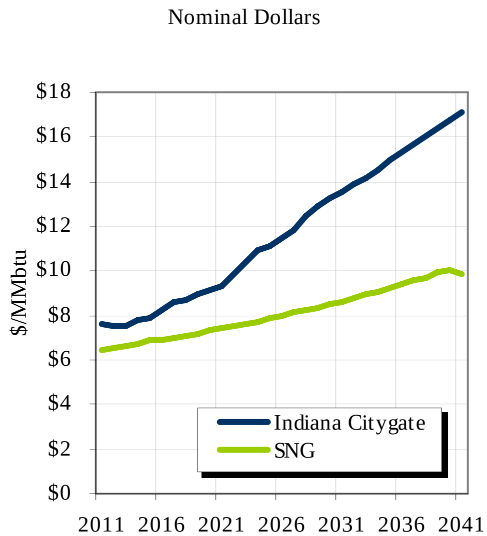
It is important to bear in mind that *both* cost *and* risk are at play here, and both are costly to consumers. The impact of higher costs on consumers is transparent; the impact of greater uncertainty faced by consumers is more subtle, but just as potent. Faced with uncertain and potentially very high natural gas prices, consumers are forced either to engage in costly precautionary saving or be willing to make large and sudden adjustments to their consumption to accommodate erratic price movements. To consumers, then, price uncertainty is distortionary. It alters behavior in ways inconsistent with ideal behavior by clouding consumers' perception of true costs. Consequently, consumers respond not only to high prices, but also to expectations of future high prices *and* to the threat that future prices may be very high – even if only for a brief period.

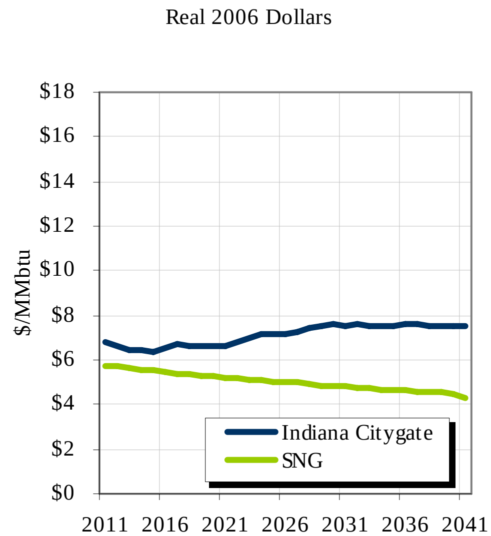
These costs and this volatility are a burden for consumers because few alternatives exist in the short-run for reducing consumption or moderating their exposure. Numerous economic studies show that short-run price elasticity for natural gas (and for electricity) is low. In other words, consumers are "stuck" facing these costs and risks until they are able to substitute away. In the long-run, consumers may substitute electricity for natural gas, or invest in more efficient appliances, but such changes are often costly in their own right. Additionally, the costs of long-term switching are problematic for gas utilities, as it reduces their economies of scale if consumers reduce their consumption by switching to competing forms of energy.

In this paper, we evaluate one potential alternative that has the potential to produce benefits for both consumers and gas utilities. Specifically, we examine the potential costs and benefits to consumers from a proposed coal gasification project to be developed in Southwest Indiana for the production of substitute natural gas ("SNG"). Typically, such analyses are done from the perspective of the project's debt or equity participants. One novel aspect of our analysis is that we examine instead the *consumer's* costs and benefits from the project. This analysis is different, because it incorporates not only traditional sources of uncertainty (such as fuel prices), but also the structure of contracts. In the case of this project, much of the value accruing to all parties is derived from the use of the 3-Party Covenant structure, which permits the use of Federally-guaranteed debt and the financial benefits from the resulting high leverage potential. Thus, the costs and benefits that we examine in this paper are as much contractually-derived as market-based. In other words, the project represents an implicit hedge transaction for consumers.

Just as a market participant may enter into a derivative contract (*e.g.*, a futures contract) in order to obtain a particular risk or return profile, consumers in this analysis will enter into a contract (or, more correctly, several stakeholders will enter into the multi-lateral 3-Party Covenant) that allows them to swap one cost/risk profile for another. Pure and simple, this is a hedge.

To examine the consumer consequences of this hedge, we develop a Monte Carlo simulation model that evaluates costs and uncertainties faced by consumers under two scenarios: Option #1 (the *status quo*) and Option #2 (the SNG project). We also analyze consumer preferences for risk with a traditional economic decision analysis approach and derive the value to consumers of the risk reduction reflected in our simulation results. Finally, we use traditional financial portfolio theory to examine the tradeoffs faced by consumers between cost and risk in the context of Indiana's natural gas supply portfolio.





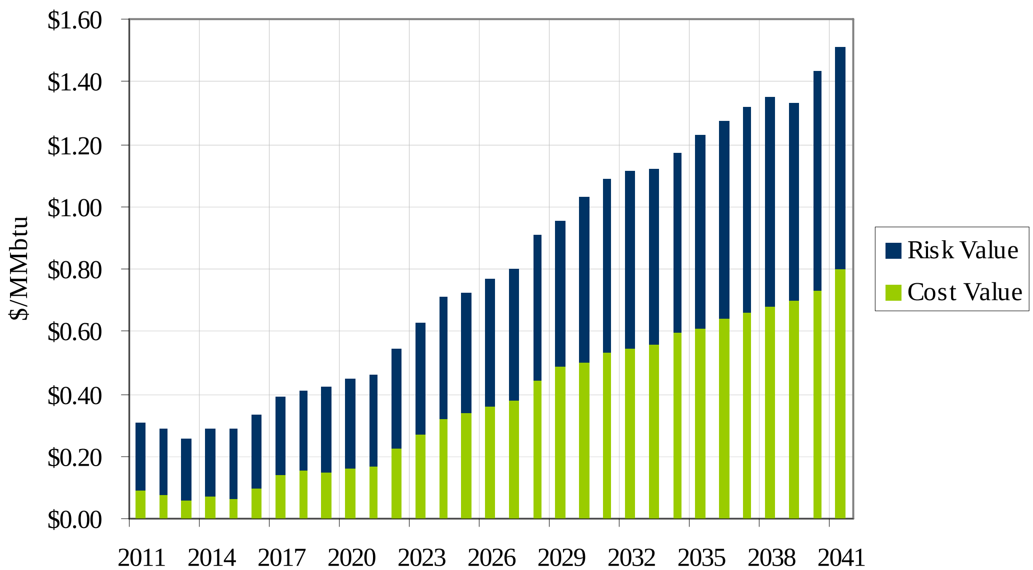
As a result of these analyses, we determined that the proposed project and its contract terms provide consumers with a real, lasting, and significant cost savings across the life of the project. The above graphs illustrate the different projected median prices for natural gas and for SNG in both nominal and real 2006 dollars. On average, SNG is approximately 30% less expensive than natural gas.

In addition to the cost savings, however, SNG is far less volatile than natural gas (because of the large percentage of fixed costs in the price of SNG). We calculated that over the life of the project natural gas prices (the *status quo*) are 11.7x as volatile as SNG prices.[1] The ability of SNG to reduce consumer price volatility is dramatic, and this reduction in risk is valuable. By examining consumer preferences for risk, we can calculate the value of such a reduction in risk. The graphic below illustrates the annual

[1] Here, we are measuring volatility as the difference between the 5th and 95th percentiles of prices in each year.

per-MMbtu savings to ratepayers from obtaining a lower risk profile, in comparison with the cost savings of the project.

Annual Nominal Ratepayer Savings



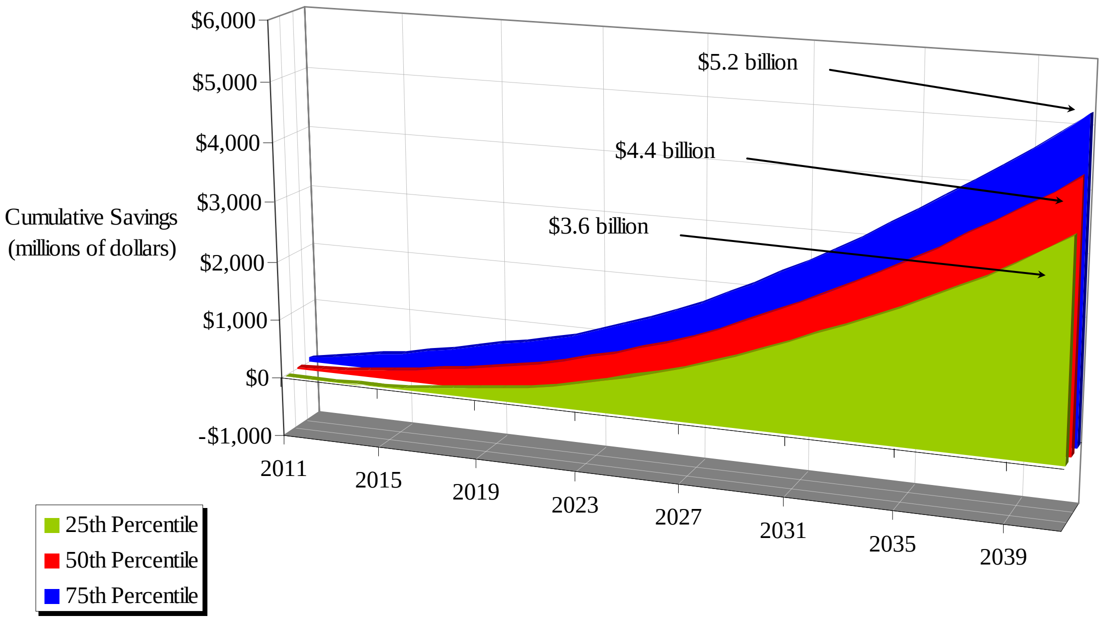
In the early years of the project, the risk reduction savings are most prominent; in the later years of the project, the cost savings are most prominent. In *every* year, in the median case, consumers are not only saving money, they are taking less risk to do so. The analogy that is appropriate here from a hedging perspective is to preferences for fixed-rate versus variable-rate mortgages. Although the initial rate of a variable-rate mortgage may appear lower, many consumers prefer the stability of a fixed-rate mortgage, even if it comes at a higher price. In the case of the SNG project, consumers are getting a fixed-rate mortgage at a rate *lower* than the initial rate of a variable-rate mortgage. Consumers benefit not only on the risk side, but also on the cost side as well. Such opportunities are rare, and are a direct result in this case of the contractual structure available to consumers.

Summary of Modeling Conclusions
(Median values are presented)

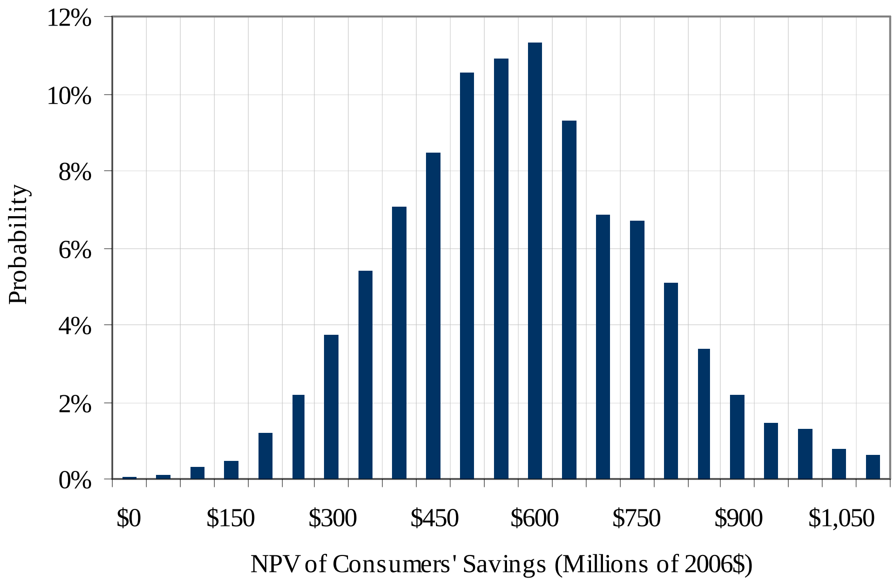
	Millions of Dollars		Cumulative Nominal $/MMbtu	Average 2006$/ MMbtu
	Nominal (Cumulative)	2006$ (NPV)		
Cost Reduction Value	$4,363	$557	$3.62	$0.20
Risk Reduction Value	$1,131	$646	$0.94	$0.30
Total Hedge Value to Ratepayers	$5,494	$1,203	$4.56	$0.50

Based on our analysis, as described in greater detail in this paper, our conclusions are summarized in the table above. These results are all related, but we present them in a variety of formats to illustrate both personal benefits to ratepayers and consumers, as well as aggregate benefits to the state as a whole. Over the thirty-year life of the project, Indiana consumers will realize $4.4 billion in cost savings (see graph below) and an additional $1.1 billion in the value of risk reduction. In present value terms, these benefits amount to a more than $1 billion increase in consumer welfare (the present value of cost savings alone is $557 million; see below). These benefits are provided to consumers without upfront cost, making the project a compelling proposition for Indiana consumers.

Cumulative Cost Savings to Ratepayers



Present Value of Cost Savings to Ratepayers



INTRODUCTION

Natural gas is a volatile commodity. Since its deregulation in 1985 with FERC's Order 436, prices for natural gas have exhibited a substantial level of variability. Although natural gas is a commodity in abundant domestic supply, transportation constraints and a large, sudden increase in demand from power generators have led frequently to erratic price swings. This volatility is costly to both end consumers and to gas utilities, as well as industrial users and power generators. Several decades of studies into energy demand demonstrate that natural gas consumption is highly inelastic with respect to price. As a result, retail consumers are especially vulnerable to sudden, substantial, and largely unpredictable increases in expenditure for a common input to many basic necessities.

In spite of the interest in mitigating this volatility, there are very few risk-reduction alternatives that are feasible. Those that are available are primarily short term in nature. Even in the most liquid of markets (*e.g.*, NYMEX futures for Henry Hub delivery), practical availability is limited to approximately three years. Most basis differential contracts for other delivery points are limited to twelve months in term. Opportunities in long-term bilateral hedging are exceedingly rare and often costly, leaving physical hedges as one of the only feasible options for mitigating volatility. Such alternatives, however, have very limited flexibility and introduce operational risks and opportunity costs.

In this paper, we explore the use of coal gasification technology as a means of mitigating price volatility with reference to an actual project being proposed in Indiana. Succinctly, coal gasification can be used to generate substitute natural gas ("SNG") for which the commodity exposure is not natural gas, but coal. Coal prices are far less volatile than natural gas and, in contrast to the operation of natural gas markets, long-term contracting in coal markets is commonplace and often indexed only to inflation. Securing fixed price terms over ten years or more is not difficult. Further, the United States has an abundance of coal available to virtually every region in the country. On an energy-equivalent basis, coal is also considerably less expensive than natural gas.

Previous studies of coal gasification (*e.g.*, Keeler [2003], Ono [2003], Berg and Patterson [2004], NETL [2004]) have focused largely on financial and technical feasibility; we do not address those areas here. Rather, we are interested in the consumers' role in such a transaction. Additionally, we address the role of gas utilities as "indirect consumers."[2] Much has been made anecdotally of the value of coal gasification for consumers. In this study, however, we seek to quantify the precise nature of the gains *to consumers* from a typical coal gasification project. The nature of these gains is important to the extent that it reveals the value to consumers of alternatives that offer improved cost *and* risk metrics. In the absence of a market for risk-mitigating securities (or "hedges"), consumer willingness-to-pay or willingness-to-accept *is* the value of a long-term hedge. The application addressed here is to coal gasification, but the role of the consumer in long-term hedging is ubiquitous.

[2] We define an "indirect consumer" here as a party that is responsible for contracting for gas, but is not responsible for the ultimate cost of such contracts. From a cost standpoint, gas utilities act only as a proxy for ratepayers when purchasing natural gas.

The analysis that follows outlines the structure of the simulation model developed, describes the input-variable assumptions, and examines costs and risks to consumers using three separate approaches. First, we develop a cost metric that reflects probabilistically the sources of uncertainty facing natural gas consumers. Second, we develop via certainty equivalence methods a risk-reduction value. Finally, we develop a portfolio-theoretic methodology for examining consumer attempts to balance risk and cost and attribute values to each. We conclude by examining how consumer attempts to balance cost and risk the role of coal gasification as a long-term natural gas price hedge and how such behavior also benefits gas utilities subject to related risks.

CONSUMER RESPONSE TO PRICE

Economists measure the responsiveness of demand to changes in price with a concept known as elasticity. The price elasticity of demand for a good is given by $\varepsilon = \partial Q / \partial P$, reflecting the ratio of a unit change in quantity demanded (*Q*) to a unit change in the price (*P*).[3] Typically, as prices increase, demand decreases. Demand for a good is said to be inelastic if the percentage quantity decrease is less in absolute value than the percentage price increase.

Studies over the last forty years have found varying levels of price elasticity in the demand for natural gas and electricity, but the overall range of values has been

[3] An alternative definition that may also be of interest is the partial elasticity of substitution [Allen, 1938], which is intended to exclude the effect of income (*Y*) in the resulting calculation: $\varepsilon_P = \frac{\partial Q_i}{\partial P_j} + Q_j \frac{\partial Q_i}{\partial Y}$.

remarkably steady in support of the inelastic nature of demand for both goods. Table 1 summarizes the results of this research.

Table 1: Summary of Studies Examining Price Elasticity of Demand for Natural Gas and Electricity

Year	Study	Natural Gas	Electricity	Notes
1966	Balestra and Nerlove	-0.63		Examined long-run elasticity
1974	Houthakker, Verleger, and Sheehan		-0.45 to -1.20	Examined long-run elasticity at state level
1975	Taylor		Short-run: -0.13 to -0.90 Long-run: -1.02 to -2.00	Range depends on type of data examined
1980	Houthakker		-0.11	Examined at the state level
1981	Barnes, Gillingham, and Hagemann		-0.55	Examined at the household level
1984	Bohi and Zimmerman	Short-run: -0.2 Long-run: -0.3		
1993	Branch		-0.2	Examined at the household level
2005	Bernstein and Griffin	Short-run US: -0.12 Short-run IN: -0.139 Long-run US: -0.36 Long-run IN: -0.163		

Sources: Balestra and Nerlove [1966], Houthakker, Verleger, and Sheehan [1974], Taylor [1975], Houthakker [1980], Barnes, Gillingham, and Hagemann [1981], Bohi and Zimmerman [1984], Branch [1993], and Bernstein and Griffin [2005].

We include demand for both natural gas and electricity because the two goods are frequent substitutes. In fact, Balestra and Nerlove [1966] were among the first to develop a formal substitution argument based on the stock of appliances and the demand for natural gas. In a later survey piece, Taylor [1975] notes that there is virtually no substitution in the short-run because the stock of appliances is essentially fixed, but in the long-run, consumer substitution is prompted by both high prices and volatility in prices, producing highly elastic long-run demand.

The substitution argument is supported further by Beierlein, Dunn, and McConnon [1981] who estimate the cross-price elasticity between natural gas and electricity. In the short-run, Beierlein *et al*. note that cross-price elasticities are "unimportant" because substitution is limited. The long-run cross-price elasticity, however, is considerable, at 1.7, indicating that a 10% increase in natural gas prices would increase electricity consumption by 17% as consumers substituted away from natural gas and toward electricity.

The inability of consumers to substitute away in the short-run is an important consideration from a public policy perspective, as supply of natural gas (and electricity) is often seen as essential for health and safety. The *ability* of consumers to substitute in the long-run is an important consideration for natural gas utilities, as substitution away from natural gas may result in long periods of reduced demand and growth (and therefore lower regulated returns). Thus, from both perspectives, there is an interest in avoiding high prices in both the short-run and long-run.

Consumer substitution decisions are made not just on experienced high prices, but rather on the *expectation* of future high prices. In other words, a consumer's willingness to incur the cost of a capital stock adjustment (*e.g.*, purchase of an electric range in place of a natural gas range) is a function of the consumer's belief about whether or not high natural gas prices will be sustained in the long-run. This suggests that uncertainty about future price levels also plays an important role in both consumer well-being and long-run substitution behavior.

CONSUMER RESPONSE TO RISK

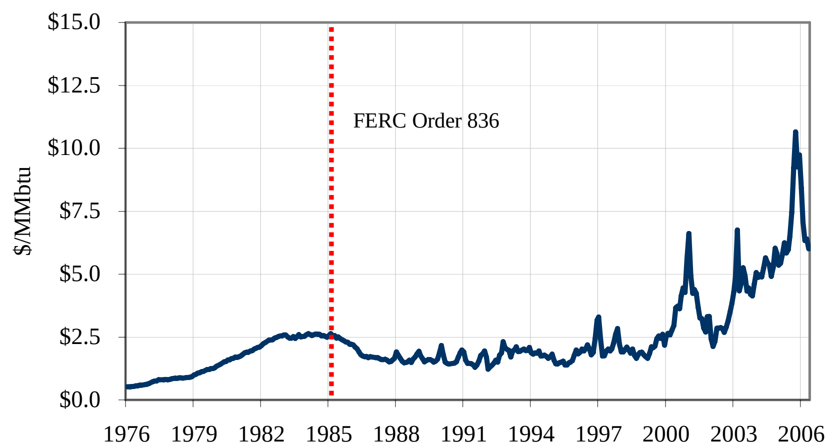
Volatility is costly for several reasons. To understand fully its cost, however, it is useful to analyze it at two levels: period-to-period price variability and unpredictability over long time periods. Naturally, these are related, but we wish to emphasize them individually because of their impact on consumers and gas utilities.

For consumers, price volatility in a good for which demand is inelastic has several negative consequences. Unable to reduce consumption of the inelastic good to compensate for high prices, consumers are forced either to reduce discretionary consumption or increase income through negative saving (borrowing). Alternatively, in a precautionary sense, price volatility requires consumers to maintain a large capital stock or "buffer" to guard against unanticipated price shocks. This too has a cost.

For gas utilities, the impact of price volatility is an indirect one. Because utilities typically pass through commodity prices to consumers, their exposure is to long-term elasticity. Faced with the prospect of extended high prices for natural gas, consumers may choose to incur a fixed cost (*e.g.*, to purchase a new furnace) and substitute away from natural gas toward electricity, for example. Thus, gas utilities face a volumetric risk as a result of long-term or sustained price uncertainty. Any reduction in purchases by consumers reduces the regulated profit that the utilities are permitted on each sale. In each case, the effects have costly long-term implications.

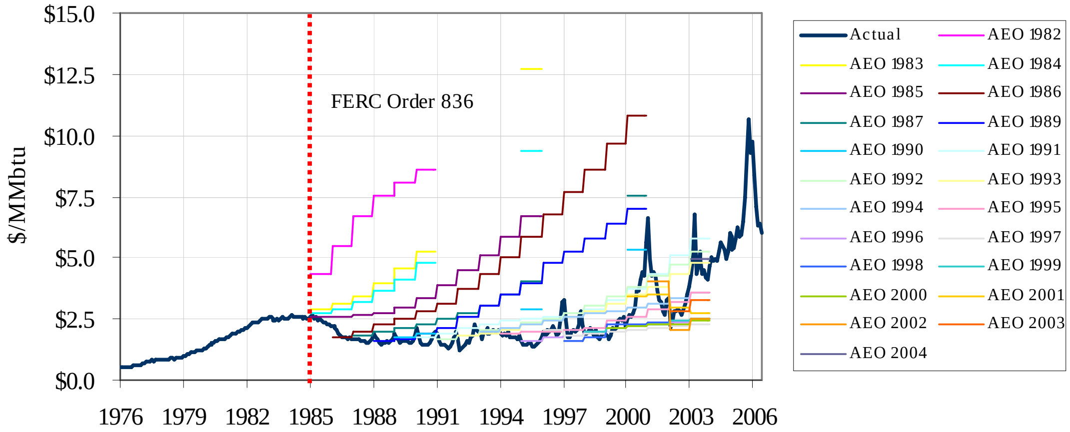
In the short-run, given that consumption patterns for consumers are largely fixed, it is primarily price volatility that is prominent. Figure 1 illustrates the historical volatility of natural gas prices. Although consumers are largely unable to respond to short-run volatility, the negative experience of price spikes can result in a growing interest in substituting away from natural gas. More important, then, are consumers' beliefs as to the likelihood of future volatility (or high prices) (as in "fool me once, shame on you; fool me twice, shame on me"). In that sense, it is unpredictability that is costly to consumers. Figure 2 illustrates actual prices against annual long-term forecasts from the U.S. Department of Energy's *Annual Energy Outlook*. As is clearly evident, there is a broad divergence between *expectations* concerning future prices and *realized* future prices.

Figure 1: Average U.S. Wellhead Prices



Source: Energy Information Administration, U.S. Dept of Energy

Figure 2: Average Actual U.S. Wellhead Prices with Forecasted AEO Price Levels



Source: Energy Information Administration, U.S. Dept of Energy

The fact that uncertainty about future consumption expenditures influences decision-making about complementary goods (and thus actual future consumption) is not an unprecedented concept. Just [1974] explored the effect of farm price stabilization policy on supply and demand behavior, noting that reductions in uncertainty about future prices (such as is provided by government price supports) alter the decisions made by farmers.

This path of research is explored empirically by Lin [1977], Hurt and Garcia [1982], Chavas and Holt [1990], and Lin and Dismukes [2004]. In particular, Chavas and Holt provide a framework that explicitly characterizes the response behavior in a manner reminiscent of elasticity: change in production divided by the change in price risk. In their empirical work, Chavas and Holt demonstrate that this ratio is statistically significant with respect to behavior. In other words, changing the risk level alone alters behavior.

We shall, for the sake of comparison, label this phenomenon the *risk elasticity of demand* and define it abstractly for now as $\varepsilon_\sigma = \partial Q/\partial\sigma$, where σ is the standard deviation of the price of the good under consideration. This definition notwithstanding, Hurt and Garcia [1982] note that risk is influential when measured either as variation in past prices or as deviations between actual and future outcomes. Clearly, both measures are appropriate with respect to natural gas.

More importantly, Lin [1977] notes that the responses to both actual *and* perceived risks are influential on behavior *above and beyond* the influence of the price effect. We should note that this body of literature was developed in agricultural economics; we know of no similar investigation outside of that domain. Nevertheless, the exact same principles are at work. Consumer uncertainty about the future price of a good for which demand is inelastic with respect to price is, in and of itself, a potential deterrent to consumption. Faced with an inability to substitute in the short-run, consumers may therefore be willing (and eager) to entertain strategies for mitigating that uncertainty.

Such strategies – or “hedges” – would be analogous to purchasing insurance. In essence, a consumer would be willing to pay a higher price with a greater degree of certainty in order to avoid a consumption path with more risk, even if expected expenditures on that consumption path were lower. Of course, consumer willingness to pay would depend directly on the degree of uncertainty in the consumption path, the consumer’s risk aversion level, and the proposed “premium” to be paid in exchange for the “insurance” provided by the hedge. The remainder of this paper examines this problem in the context of Indiana consumers and gas utilities.

THE PROBLEM ENVIRONMENT

The project in question is a proposed coal-to-substitute natural gas plant in Southwest Indiana that converts coal into pipeline-quality gas sold to gas distribution utilities under long-term contracts approved by the Indiana Utility Regulatory Commission. The project’s approximate cost of well over $1 billion is to be financed in large part (80%) by Federally-guaranteed debt. The Federal loan guarantee program was authorized under the Energy Policy Act of 2005.

The financing of this project is contingent on obtaining a “3 Party Covenant” [Rosenberg, Alpern, and Walker, 2005] between the project’s sponsor, the Federal government, and the state regulators and legislature. The project benefits from low-cost debt as a result of the Federal loan guarantee. However, contractual coverage of the debt service is required to minimize the cost of the loan guarantee. The contractual coverage, however, must extend to the full thirty-year term of the project. Obtaining such long-term purchase agreements requires the approval of the state regulators that the gas utilities will be able to recover the costs of the contracts (and that future regulators will not be able to “undo” these commitments).

Naturally, regulators are hesitant to provide a “blank check” for new projects in the face of gasification’s history of cost overruns. As a result, a third component of the financing structure requires a commitment by the project sponsor to fix the development costs and provide a long-term gas supply agreement.

As noted previously, we are not evaluating the financial performance of the project from the traditional perspectives of the sponsor or lender. Rather, we are evaluating the opportunity offered by the sponsor to consumers. This offer is of direct interest as well to the regulators and to the gas utilities, as both serve as “intermediaries” of sorts between consumers and the project. Three questions serve to guide our analysis: (*i*) are the contractual terms offered by the gasifier attractive to consumers, (*ii*) if so, of what value are they, and (*iii*) is there reason to believe that gas utilities may also benefit?

ASSUMPTIONS AND MODEL INPUTS

The Objective Function

We assume that consumers face a choice between two alternatives: Option #1 and Option #2. Option #1 is the *status quo* scenario, under which all natural gas procured by the local gas utilities is obtained at the average annual spot price.[4] This price is estimated to be the Henry Hub forecasted price, adjusted for a regional basis differential to reflect delivery to the Indiana Citygate.

[4] We have converted all pricing and production units in this analysis into millions of British thermal units (MMbtus) for ease of comparison on the basis of 970 btu/ft^3. The actual conversion for SNG will depend on the final technical specifications of the project and may be slightly different from the level assumed here.

Option #2 reflects operation of the gasifier by delivering 40 BCF/year (38.8 million MMbtu/year) of SNG to utilities. Any remaining SNG produced is sold at then-prevailing competitive market prices (determined as above). All remaining consumer demand is met with natural gas purchased at the average annual spot price.

Preference between the two options is determined on the basis of both year-by-year annual costs and comparison of the net present value ("NPV") of future costs. If the cost of Option #2 is less than Option #1, then consumers are saving money as a result of the SNG project. In contrast, if the cost of Option #2 is greater than Option #1, then consumers are incurring additional costs as a result of the SNG project.

To make the structure of the model explicit, let *D* be total demand, *H* be the forecasted Henry Hub price, *A* be the Indiana Citygate adder, *C* be the production capacity of the gasifier, *B* be the base SNG price, and *V* be the availability of the gasifier. The costs of each option in a particular year are as follows:

Option #1 ("*Status Quo*"): Cost = $D \times (H + A)$

Option #2 ("SNG Mix"): Cost = $C \times V \times B + (D - C \times V) \times (H + A)$

Demand

Demand was modeled with respect to actual 2004 demand as a base year and subsequent years determined as $D_t = D_0 (1 + g_D)^t$, where g_D is the long-run average annual demand growth rate. For the purposes of this analysis, we considered only residential and commercial demand for the state's four largest gas utilities. These utilities and their total demand as of 2004 are presented in Table 2. This total demand represented approximately 79% of the state's total residential and commercial demand in 2004.

Table 2: Indiana State Base Demand Figures (2004 MMbtu)

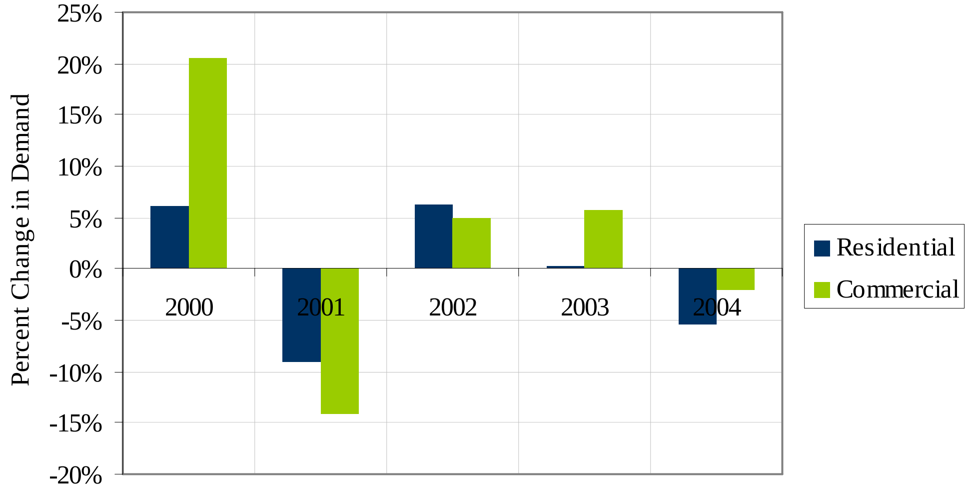
Utility	Residential	Commercial	Total
Citizens Gas	23,018,806	12,969,010	35,987,816
Indiana Gas	44,661,000	19,108,000	63,769,000
NIPSCO	57,675,495	23,057,382	80,732,877
SIGECO	7,937,903	3,610,387	11,548,290
Total	**133,293,204**	**58,744,779**	**192,037,983**

Source: Indiana Utility Regulatory Commission

Demand Growth

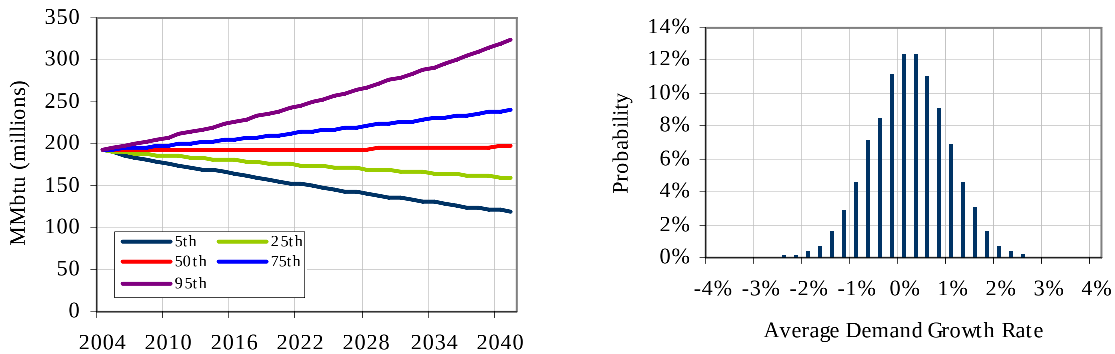
Demand growth typically varies widely across years in response to changing weather patterns and economic activity. Figure 3 illustrates the annual changes in demand for the five years preceding our 2004 baseline. The average rate of growth for the residential rate class was -0.3% and for the commercial rate class it was 3.0%. The growth rate correlation between rate classes was 0.88. The belief among the gas utilities is that demand is declining in the state. We assume that the annual demand growth rate would be drawn from a normal distribution with a mean of zero and a standard deviation of 1%. Figure 4 illustrates the average growth-rate distribution and the resulting distribution of demand forecasts.

Figure 3: Historical Indiana State Demand Growth



Source: Energy Information Administration, U.S. Dept of Energy

Figure 4: Distribution of Demand and Average Demand Growth Rate



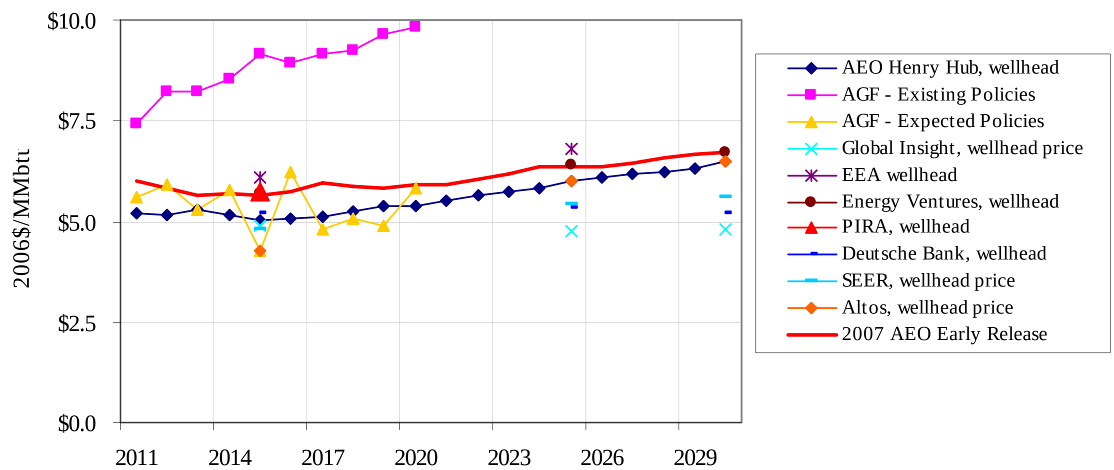
<u>Incorporation of the AEO Forecast</u>

We relied on the U.S. Department of Energy's *Annual Energy Outlook 2007 Early Release* ("AEO") forecast for natural gas prices [U.S. Dept of Energy, 2006].[5] The AEO forecast is for Henry Hub wellhead prices, which require further adjustment before

[5] The 2006 AEO forecast ends in 2030. Because the term of the project extended to 2041, we assume that prices after 2030 remained constant in real terms at the 2030 forecasted level.

use in the simulation model. Although the AEO forecast is broadly consistent with other prominent long-term natural gas price forecasts (see Figure 5), our rationale for using the AEO forecast is primarily the availability of long-term forecast performance data.

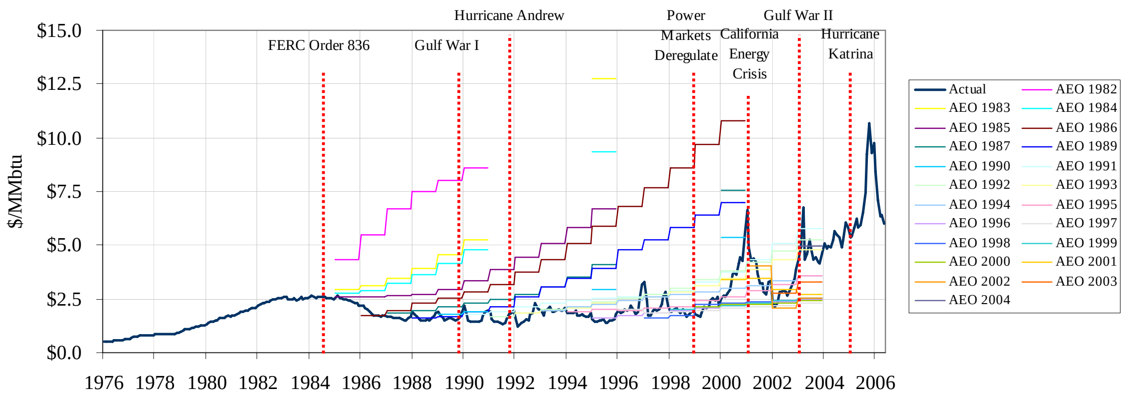
Figure 5: The AEO Forecast in Comparative Perspective



Sources: 2006 AEO, American Gas Foundation Existing and Expected Policies Scenarios, Global Insight Summer 2005 U.S. Energy Outlook (August 2005), Energy and Environmental Analysis Compass Service Base Case (October 2005), Energy Ventures FUELCAST: Long Term Outlook (August 2005), PIRA Energy Group (October 2005), Deutsche Bank (October 2005), Strategic Energy and Economic Research 2005 Energy Outlook (October 2005), Altos Partners North American Regional Gas Model Long-Term Base Case (October 2005)

The Department of Energy's Energy Information Administration regularly publishes an analysis of the AEO's long-term forecasting performance [U.S. Dept. of Energy, 2005]. Since a key component of our study is the reaction of consumers to variability in prices, this long-term time series of forecast performance serves as an invaluable reference point. Understanding the historical deviation of actual from forecasted prices is a means of measuring that uncertainty. It is important to note that we are not offering a forecast of natural gas prices. Rather, our analysis depends on a forecast of typical errors in long-term forecasts of natural gas prices. These errors occur because of unforeseen factors not captured by forecasters, such as extreme weather events, changing regulation, macroeconomic shocks, and technological changes. Figure 6 illustrates the time series of natural gas prices and AEO forecasts together with key events that would not have been captured by a forecasting model.

Figure 6: Forecasting Errors and Unforseeable Events



Historically, the AEO's forecasts have followed a cyclical pattern of over-estimation followed by under-estimation (see Figure 7). On average, over long periods of time, the AEO's natural gas forecasting performance has been good, although subject to periods of high volatility and strong serial correlation (see Table 3). Based on our analysis of this historical record, we modeled the AEO's forecast error as a normal distribution with a mean of -0.7% and a standard deviation of 34.2%. Figure 8 illustrates this fit relative to the actual error information. We also incorporated a serial correlation coefficient of 0.75.[6]

[6] Serial correlation measures the dependence between observations of a single variable measured at different time periods. For example, if a year in which prices were high was most likely to be followed by another year of high prices, the serial correlation of prices may be said to be high and positive.

Figure 7: Cyclicality in the AEO's Forecasting Performance

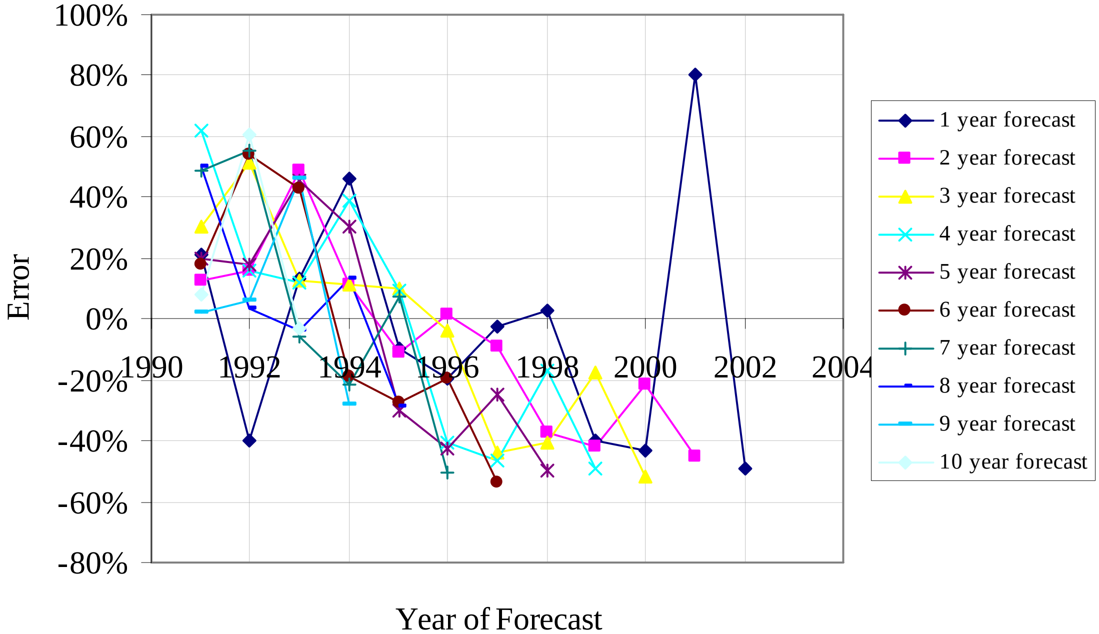
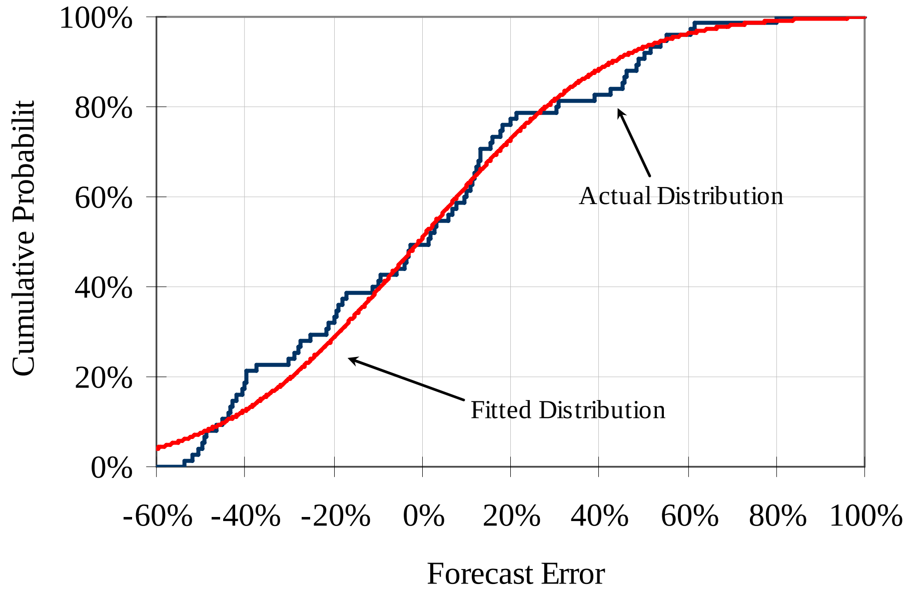


Table 3: AEO Forecasting Percentage Errors

	Forecast Horizon (years forward)									
	1	2	3	4	5	6	7	8	9	10
1991	21.3%	12.8%	30.6%	61.7%	19.9%	17.9%	48.5%	50.2%	1.8%	7.8%
1992	-40.0%	16.1%	51.6%	15.7%	18.2%	53.7%	55.1%	3.5%	5.9%	60.5%
1993	13.0%	48.5%	12.4%	12.0%	45.2%	42.7%	-5.8%	-3.9%	45.9%	-3.4%
1994	46.2%	11.0%	11.5%	39.2%	30.4%	-19.0%	-21.5%	13.4%	-27.9%	
1995	-10.0%	-11.0%	9.8%	9.6%	-30.2%	-27.6%	7.1%	-28.6%		
1996	-19.7%	1.6%	-3.9%	-40.4%	-42.8%	-19.4%	-50.3%			
1997	-2.8%	-9.2%	-43.9%	-46.6%	-25.0%	-53.5%				
1998	3.0%	-37.2%	-40.5%	-17.1%	-49.5%					
1999	-40.1%	-42.1%	-17.8%	-49.2%						
2000	-43.3%	-21.4%	-51.9%							
2001	80.0%	-45.0%								
2002	-49.1%									
Average	-3.5%	-6.9%	-4.2%	-1.7%	-4.2%	-0.7%	5.5%	6.9%	6.4%	21.6%
Std Dev	39.3%	28.7%	34.0%	39.2%	36.6%	39.5%	40.7%	28.7%	30.3%	34.1%

Source: U.S. Dept. of Energy [2005]

Figure 8: Probability Distribution Fit to Historical Accuracy Data



Adjusting for Regional Basis Differentials

The AEO forecast reflects natural gas on a wellhead basis at Henry Hub. To model the prices paid by Indiana consumers, the pricing needs to reflect gas delivered at the Indiana Citygate. To adjust for any regional basis differential and interstate transportation, we added an "adder" to the AEO's forecasted natural gas price that is randomly-drawn from a distribution based on the actual historical difference between Indiana Citygate and Henry Hub wellhead prices. Table 4 presents the basis differential data for the last five years. Our model incorporates this adder as a triangular distribution with parameters \$0.08 (minimum), \$0.08 (mode), and \$1.44 (maximum).

Table 4:Indiana Citygate Basis Differential

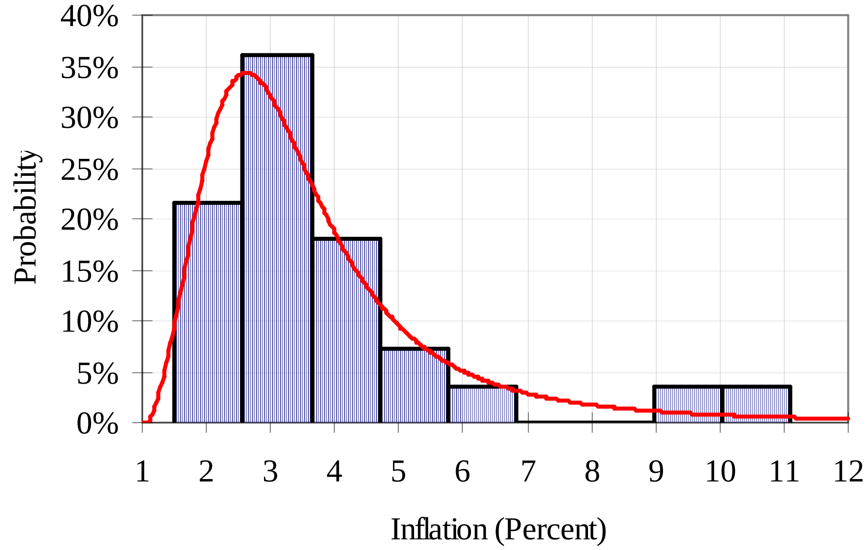
	Indiana Citygate	Henry Hub	Difference
2001	$ 4.37	$ 3.21	$ 1.16
2002	$ 3.48	$ 3.33	$ 0.15
2003	$ 6.01	$ 5.57	$ 0.44
2004	$ 6.57	$ 5.89	$ 0.68
2005	$ 8.57	$ 8.49	$ 0.08

Average	$ 0.50
Std. Deviation	$ 0.44

Inflation

Our estimates for inflation are based on the average inflation rate assumed by the Congressional Budget Office and Office of Management and Budget through 2014. We then extend this average throughout the life of the project (2041). Additionally, we derive a probability distribution for inflation based on actual historical (CPI) inflation since 1980. The mean projected inflation level is estimated to be 2.2%. Figure 9 illustrates the probability distribution used to model inflation in this analysis. Serial correlation is estimated to be 0.60 based on historical experience. Inflation is present in the analysis because the 2005 AEO price forecasts are provided in 2004 dollars. In order to reflect the actual project cash costs to ratepayers in the future, we adjust these amounts for inflation.

**Figure 9: Historical Inflation since 1980
with Log-Logistic Fit**



Availability

The availability of the gasifier is a key component in our analysis, as it drives unit SNG costs (because total costs are largely fixed independent of production). A high availability level is essential to keeping the costs of the SNG low and at a level competitive with natural gas. The distribution for gasifier availability was estimated by Black & Veatch based on a "3+1" design (three operating gasifiers and one spare).[7] Table 5 illustrates the parameters of the Black & Veatch distribution of availability by year.

[7] Black & Veatch Draft Availability Estimates (June 9, 2006).

Table 5: Black & Veatch Availability Estimates

Probability that a lower availability number is observed:

	0%	2%	20%	50%	80%	95%	100%	
Year 1	25%	N/A	50%	65%	80%	98%	100%	
Year 2	25%	N/A	60%	73%	85%	98%	100%	
Year 3	25%	60%	70%	80%	88%	98%	100%	
Year 4	25%	60%	80%	85%	90%	98%	100%	
Year 5	25%	60%	80%	83%	86%	98%	100%	Planned Major Overhaul Year
Year 6	25%	60%	87%	90%	93%	98%	100%	
Year 7	25%	60%	87%	90%	93%	98%	100%	
Year 8	25%	60%	87%	90%	93%	98%	100%	
Year 9	25%	60%	87%	90%	93%	98%	100%	
Year 10	25%	60%	87%	90%	93%	98%	100%	
Year 11	25%	60%	85%	88%	91%	98%	100%	Planned Major Overhaul Year
Year 12	25%	60%	87%	90%	93%	98%	100%	
Year 13	25%	60%	87%	90%	93%	98%	100%	
Year 14	25%	60%	87%	90%	93%	98%	100%	
Year 15	25%	60%	87%	90%	93%	98%	100%	
Year 16	25%	60%	87%	90%	93%	98%	100%	
Year 17	25%	60%	85%	88%	91%	98%	100%	Planned Major Overhaul Year
Year 18	25%	60%	87%	90%	93%	98%	100%	
Year 19	25%	60%	87%	90%	93%	98%	100%	
Year 20	25%	60%	87%	90%	93%	98%	100%	
Year 21	25%	60%	87%	90%	93%	98%	100%	
Year 22	25%	60%	87%	90%	93%	98%	100%	
Year 23	25%	60%	85%	88%	91%	98%	100%	Planned Major Overhaul Year
Year 24	25%	60%	87%	90%	93%	98%	100%	
Year 25	25%	60%	87%	90%	93%	98%	100%	
Year 26	25%	60%	87%	90%	93%	98%	100%	
Year 27	25%	60%	87%	90%	93%	98%	100%	

For example, in Year 4 there is a 2% chance than availability is less than 60%, but a 20% chance than availability is greater than 90%. The figures in this table reflect a ramp-up of availability in the first two years of the project, followed by regularly-scheduled maintenance outages every sixth year.

Capacity and Production

Based on information provided by the project's sponsor, capacity of the gasifier was estimated to be 47 BCF per year at theoretical 100% availability. At its "steady-state” operating level after ramp-up and during a year in which no major overhauls are planned, average annual production was estimated to be 38.8 million MMbtu/year.

Contractual Terms

Because the perspective of our modeling reflects the impact on consumers, an important detail of the analysis is the contractual relationship between the gasifier and gas utilities (which serve as intermediary for consumers in the purchase of natural gas or SNG).

Pricing to consumers reflects a commercial operation date of 2011 and a starting contract price of $6/MMbtu (in 2006 dollars). Pricing is based on three components: capital (41%), fuel (40%) and operations and maintenance costs (19%). The proposed contract calls for pricing to be adjusted annually subject to different escalation rates for each of the three components. In addition, the proposed contract includes a temporary $0.10/MMbtu adder collected from ratepayers to fund a debt service reserve account.

The proposed contract also calls for incremental production profit sharing between the gasifier and ratepayers. Any production in excess of the contract base quantity (38.8 million MMbtu/year) is sold at competitive market prices and the resulting profit divided equally between the gasifier and ratepayers. Ratepayers profits are treated in our model as a credit toward SNG costs. This profit is based on the sale of non-firm incremental production at competitive market prices, where profit per MMbtu is measured as max[0, Spot Price – (Fuel + O&M Costs)]. There is no incremental capital cost, suggesting that incremental SNG is virtually always price competitive.

The project has two sources of credit support: a letter of credit provided by the sponsor and a debt service reserve account ("DSRA") funded by ratepayers. Together, the objective of this coverage is to provide one full year of debt service coverage: approximately $94 million. Any shortfall in revenue from this debt service requirement is drawn 25% from the letter of credit and 75% from the DSRA. The project's sponsor is responsible for maintaining the letter of credit, with any draws against the letter restored from the cash flow waterfall prior to any distributions to equity.

The DSRA is funded by a $0.10/MMbtu adder collected from ratepayers. This adder is collected until the balance of the DSRA, including interest, reaches 75% of the annual debt service requirement (75% of $94 million = $70.5 million). Once the balance in the DSRA reaches $70.5 million, further collection of the adder is suspended (although it can be reinstated if any draws are made) and any undrawn interest earned is refunded to ratepayers to maintain the balance at exactly $70.5 million. Upon termination of the project, any remaining balance in the DSRA is allocated to ratepayers in the final year.

For modeling purposes, we have assumed that balances in the DSRA earn interest at the rate of 5% per year. Additionally, any excess shortfall in the DSRA (because ratepayer contributions have not yet accrued sufficiently) are carried forward and recovered from future years.

Discount Rate

Office of Management and Budget Circular No. A-94 establishes the "Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs." Because of the semi-public nature of this project, we elected to use the discount rate methodology outlined in §8(b)(1) of the Circular to determine the discount rate. The indicated required rate of return is 7% real, to be grossed up by the expected average inflation rate (2.2%) for a nominal discount rate of 9.2%.

Inflation of the SNG Costs

Each of the three components of the SNG price is subject to a pre-specified escalation rate. A key advantage of the project is that the capital component is not subject to escalation and remains fixed in nominal terms (declining in real terms) over the life of the project. The O&M and fuel components are modeled at the general inflation rate outlined above. It should be noted that *no* escalation is tied to commodity fuel prices. In essence, commodity price risk (to both natural gas and coal) has been removed from the consumers' position.

SIMULATION MODEL RESULTS

The primary output of the simulation model is an understanding of costs.[8] The secondary output of the simulation model is an understanding of the uncertainty in the costs faced by consumers. One of the important sources of the long-term cost advantage of SNG is the fixed capital component. By trading off variable costs for fixed, the project obtains a cost structure in which a large portion of the costs are not subject to escalation. Further, the remaining costs are indexed to general inflation. This is natural gas without natural gas price risk.

This result is more clearly illustrated in Figure 10, which plots selected percentiles in the distributions of both natural gas and SNG prices. Not only are the comparable percentiles lower for SNG, the dispersion in the percentiles is lower as well. SNG is both lower cost and lower risk over the life of the project. One illustration of this, as presented in Figure 11, is to compare the distance between the 5th and 95th percentiles for the unit costs of natural gas and SNG. This distance is one measure of how “extreme” each distribution could be. Citygate natural gas is 17.0x more variable than SNG in the first ten years of the project.

[8] The simulation model itself was built in Microsoft Excel using Palisade’s @Risk package for simulation.

Figure 10: Comparison of Natural Gas and SNG Distributions

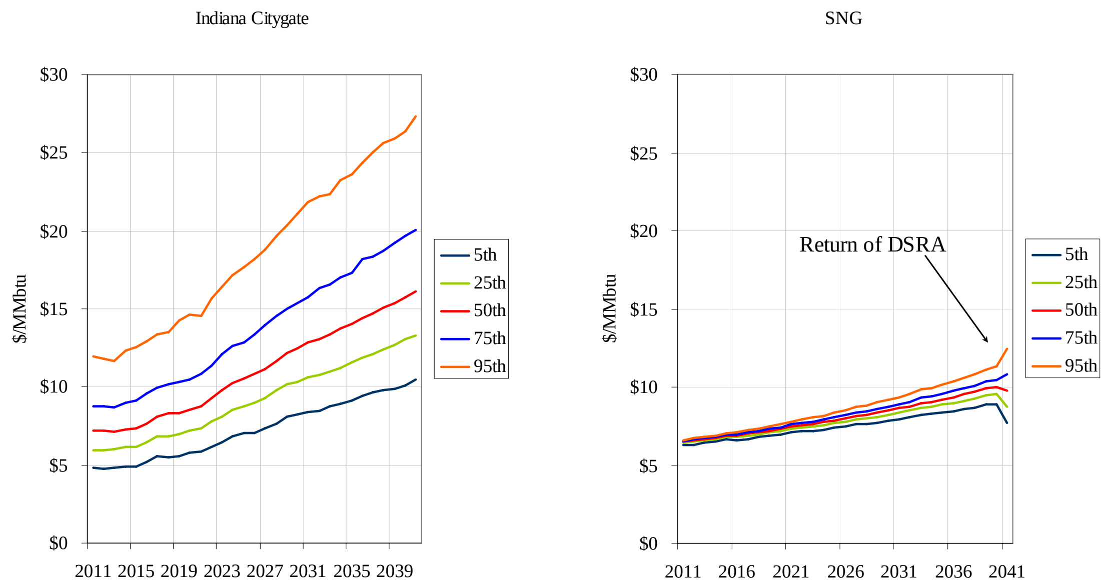
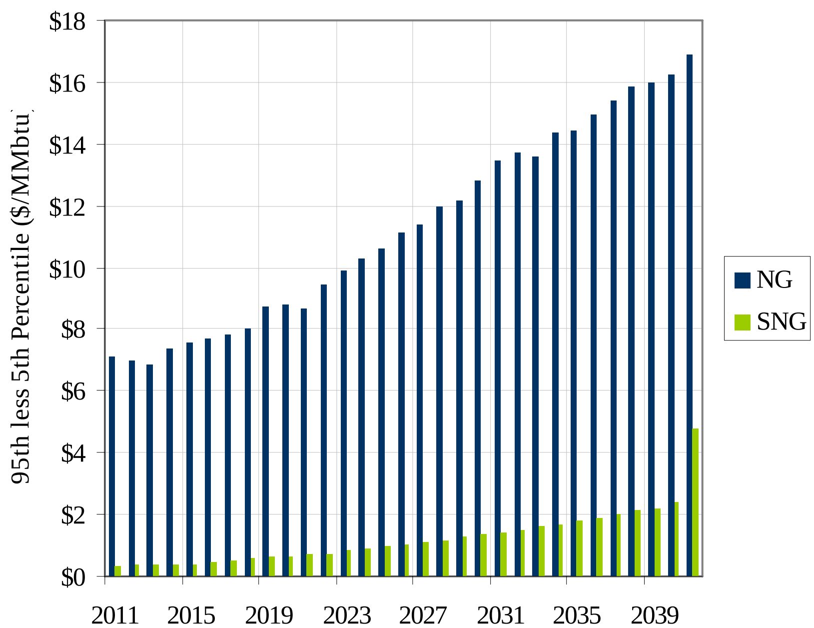
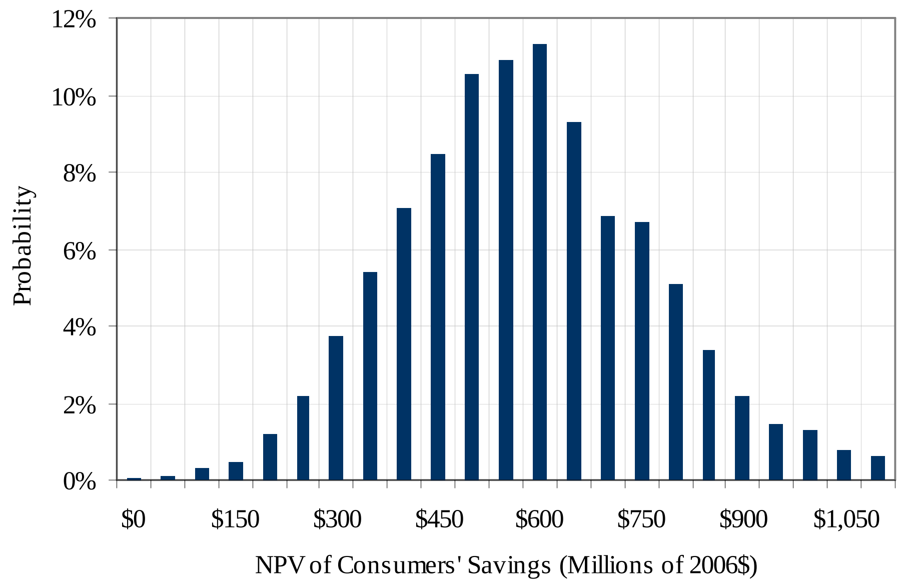


Figure 11: Comparative Risks of the *Status Quo* and SNG Options



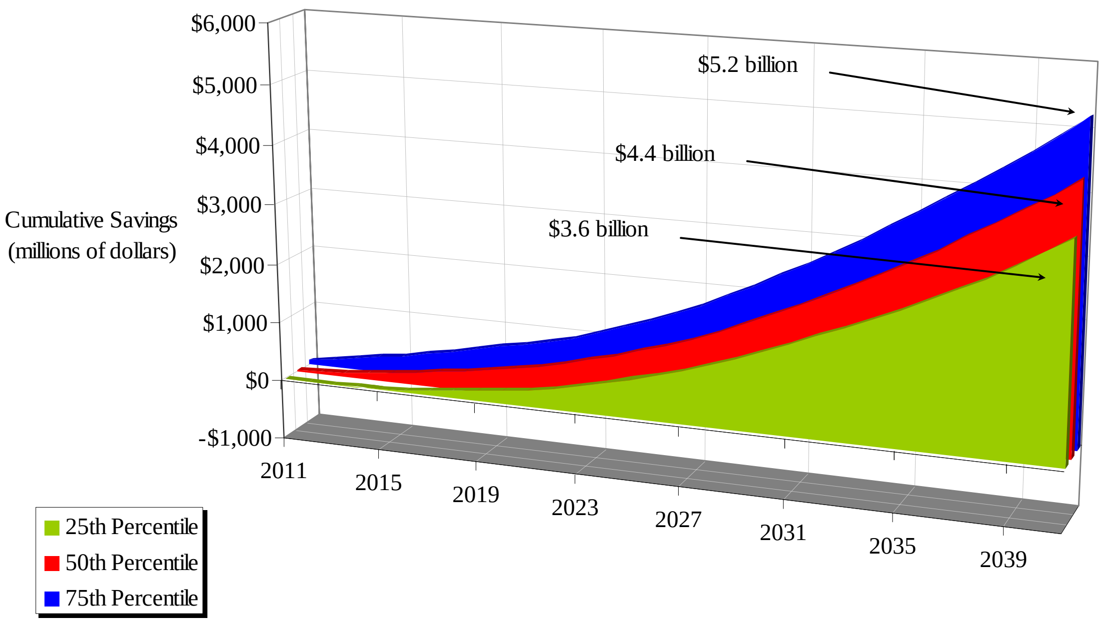
The low-cost, low-risk nature of the project (from the consumers' perspective) translates directly into cost savings. Figure 12 presents the distribution of the net present value of savings to consumers, and Figure 13 presents the cumulative savings to consumers over the life of the project. We should note that these savings are strictly savings realized by natural gas consumers of the four included utilities – they do not include other public benefits generated by the project (*e.g.*, increased employment, tax payments, coal mining revenues).[9] There is less than a 0.5% chance that the NPV of consumer benefits is negative.

Figure 12: Net Present Value of Consumer Savings



[9] In the current proposal, some of the SNG is being delivered to an electric utility for use in power generation. Our model assumes, as the agreement intends, that the electric utility would otherwise have procured spot natural gas and has obtained a regulatory commitment to allow full fuel cost recovery over the thirty year term of the project. Accordingly, cost savings to ratepayers are preserved in our analysis whether the SNG ends up on the gas or on the electric side, although we have not modeled the electric side directly.

Figure 13: Cumulative Savings to Consumers



The end result of the simulation modeling is that the savings to consumers are substantial. The average present value of consumer savings is $557 million. Although the first several years of the project are largely break-even from a cost savings perspective, they expose consumers to several times *less* risk than the *status quo*. Over time, the magnitude of the cost savings that consumers realize from the project grows as the benefits of the large fixed-cost component become prominent. Over the life of the project, in nominal terms, consumers will realize approximately $4.4 billion in savings (this is the median case). Since the project will produce some 1.2 billion MMbtu over that period, the savings equate to $3.62 for every MMbtu produced by the project for consumers.

As substantial as these numbers are, however, they do not fully reflect consumer gains from the project. Of equal, if not greater value to consumers (given the inelasticity of demand) is the reduction in risk. The simulation analysis does not address this component of value directly, beyond illustrating the lower variability of Option #2. The question to be answered is what that reduction in risk is worth to consumers. We turn to that question now.

UTILITY THEORY RESULTS

It is essentially axiomatic that consumers are risk-averse with respect to consumption of goods for which demand is inelastic to price. If consumers cannot control their "consumption destinies" by altering their consumption profiles, they are reluctant to expose themselves to price shocks that could substantially reduce their welfare. The SNG project serves as a long-term hedge against natural gas price volatility by allowing consumers to exchange a variable cost (natural gas) for a cost that is largely fixed (SNG).

This is, in many respects, equivalent to insurance. In the typical insurance transaction, consumers pay a premium in return for avoiding the *possibility* of an extreme negative outcome. They are willing to pay a premium because the certainty of paying a little bit more now is preferable to the possibility of paying a lot more later. By analogy, then, one might expect to find consumers willing to pay a premium for SNG in return for the certainty of avoiding the occasional extreme swings in natural gas prices. In fact, as the simulation model results demonstrated, the SNG option actually saves money over time. Consumers are, in effect, being paid to take less risk. Such opportunities are rare.

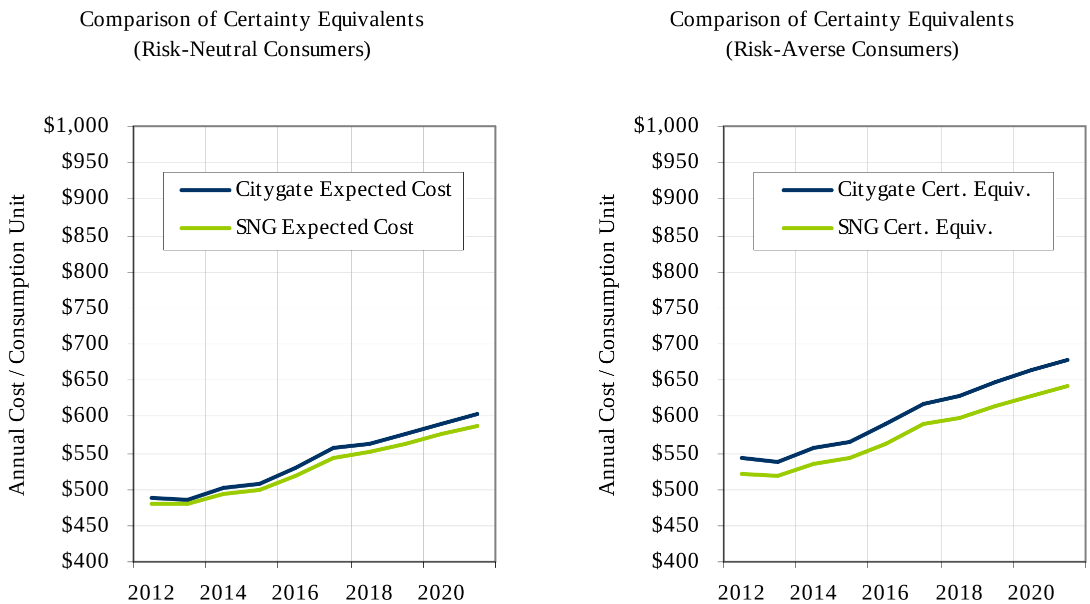
In order to determine the value consumers would place on obtaining a lower risk profile, we made certain assumptions about risk preferences. We posited a negative exponential utility function belonging to a representative risk-averse consumer and examined annual expenditures on natural gas: $u(c) = 1 - \exp(-\gamma\, c)$, where c is the annual consumer expenditure on natural gas, and γ is the coefficient of risk aversion.[10]

Average annual Indiana residential and commercial unit consumption is 64.6 MMbtu of natural gas per year. We assume that this amount remains constant (just as we assumed an average demand growth rate of zero in the simulation model). In order to derive an appropriate comparison between the *status quo* and SNG options, they must be compared on a risk-equivalent basis. The standard approach to this is to evaluate the certainty equivalent amount for each risky consumption path.

By comparing the certainty equivalents for both options, it becomes immediately apparent that the seeming indifference to consumers between the options during the first five years of the project becomes a strong preference for the SNG option. This preference is a direct result of the risk-reduction value. Figure 14 illustrates the comparable consumption paths for risk-neutral consumers (as in the simulation model) and for risk-averse consumers during the first ten years of the project. For risk-averse consumers, the SNG option clearly dominates.[11]

[10] We use a coefficient of risk aversion of 200 in all analyses unless otherwise noted.
[11] Because 15 BCF/year of the gasifier's production is being diverted to electric power generators, we remove that portion from our calculation of risk value. Our analysis focuses exclusively on residential and

Figure 14: Costs and Certainty Equivalents for Risk-Neutral and Risk-Averse Consumers

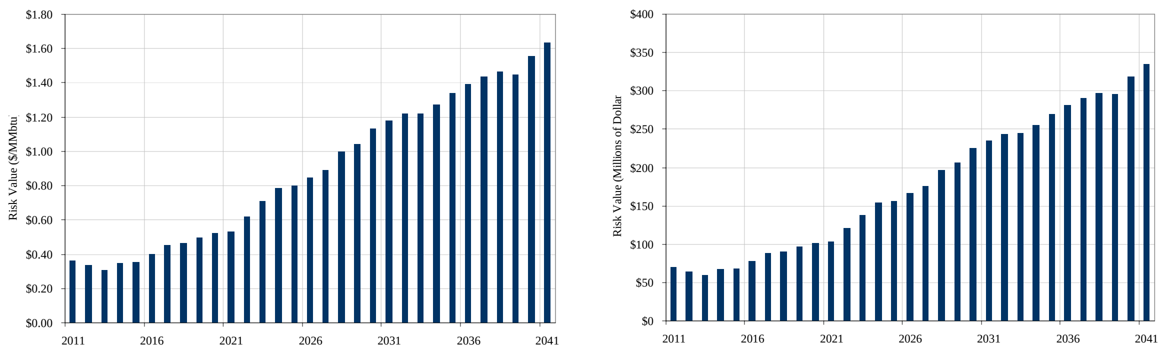


The value attributable to risk reduction can also be expressed on a per-MMbtu basis. Figure 15 illustrates what consumers (both individually and collectively) would be willing to pay in order to switch from Option #1 (the "high-risk" *status quo*) to Option #2 (the "low-risk" SNG option). The average incremental value of Option #2 across all years of the project is $0.89/MMbtu (or $177.2 million collectively). Stated differently, consumers would be indifferent between (*i*) implementing the SNG project and (*ii*) retaining the *status quo* plus receiving a rebate annually in the amounts indicated by Figure 15 (the right graph). In essence, the average cost of SNG is more valuable than an equivalent average natural gas price because consumers know that the SNG *average* price

commercial heating ratepayers. Although electric power ratepayers also likely benefit, such a calculation is beyond the scope of our present analysis.

is more representative of the *likely* price they will actually experience because it is less variable and risky.

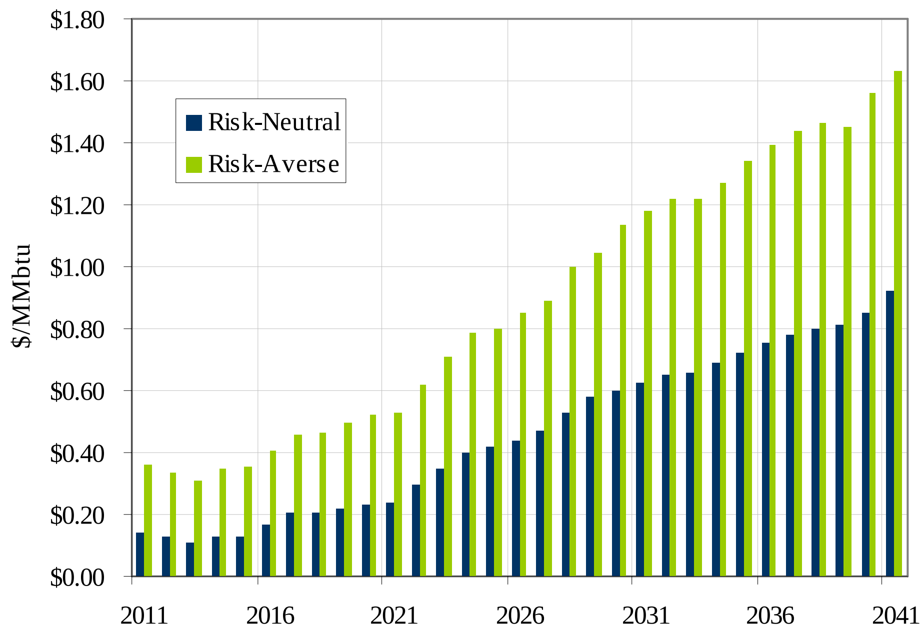
Figure 15: Growth in the Risk Reduction Value Over Time



Given that consumers benefit from both lower costs and lower risk, it is illustrative to decompose the benefits into each type of gain. Figure 16 illustrates the value of the project on a per-MMbtu basis to consumers who are risk-neutral and risk-averse. The risk-neutral case reflects gains realized *only* because of lower costs (irrespective of risk). The risk-averse case reflects gains realized by consumers as a result of *both* lower costs *and* lower risk.

What is readily apparent is that the value to consumers of risk reduction is approximately equal magnitude to the cost reduction benefit of the project. Additionally, it complements the cost reduction aspect by equalizing gains across time. The risk-reduction benefits are most dramatic in the early years of the project; the cost-reduction benefits are most dramatic in the later years of the project. Although the actual value to each consumer will remain a function of that consumer's actual risk tolerance level, the value of the project across a broad spectrum of risk tolerance levels is material. This value is made more significant because there are few alternatives available to consumers that provide equivalent long-term risk-reduction benefits.

Figure 17: Contrasting Risk-Averse and Risk-Neutral Consumer Values



PORTFOLIO ANALYSIS RESULTS

Classical financial portfolio theory was developed by Markowitz [1959] to examine investor behavior with respect to financial securities (stocks, bonds, *etc*.). Markowitz's contribution was to demonstrate formally what had been accepted anecdotally since at least Cervantes in the 17th century (*Don Quixote*: "It is the part of a wise man to keep himself today for tomorrow, and not venture all his eggs in one basket."). The underlying premise of portfolio theory is that an individual's utility (or well-being) is improved by making optimal tradeoffs between return/cost and risk, and that combinations of assets are necessarily less risky than holding individual assets.

With respect to the SNG project, we analyzed the portfolio problem in the context of Indiana's supply portfolio: would consumer welfare be improved by adding the SNG project as a possible supply source of natural gas for Indiana consumers?

Typically, portfolio theory is useful for making tradeoffs between assets for which there is no clear "winner" – no single asset has both the lowest cost and the lowest risk. Under the proposed terms offered to ratepayers, a very different situation is present here. Consumers can reduce both costs *and* risks by switching to SNG. It is, in many respects, one of the very few conditions under which "venturing all of one's eggs in one basket" can make sense.

Figure 17: Efficient Frontier of Natural Gas Supply Portfolios

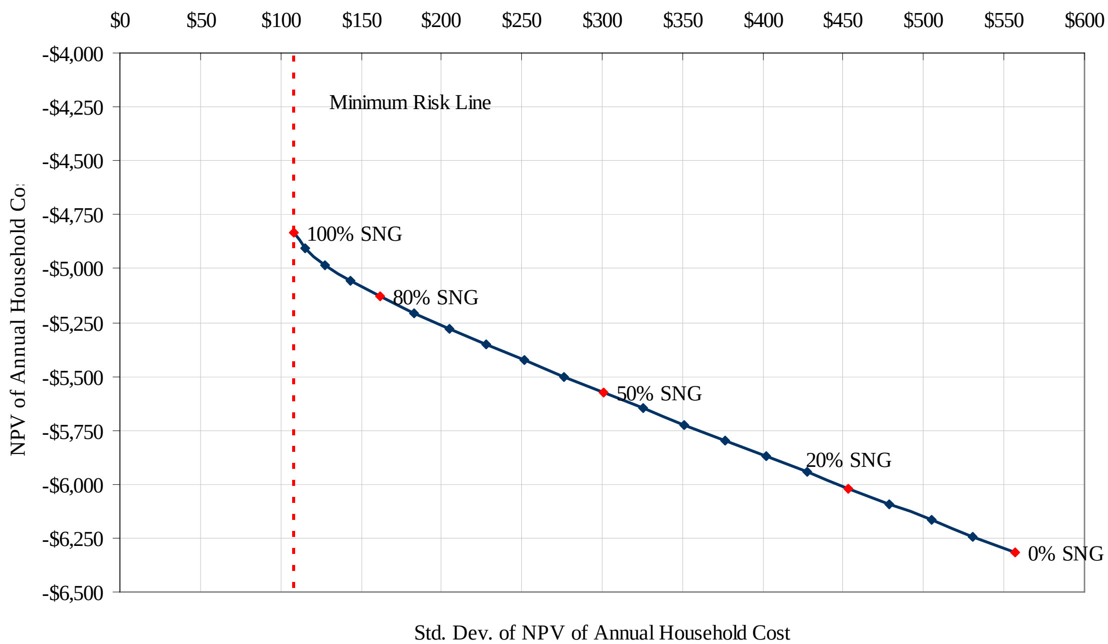


Figure 17 illustrates the cost/risk combinations of various supply portfolios. Each point on the curve reflects a different combination of Citygate natural gas and SNG in the average consumer's "consumption bundle." For example, at the 0% SNG point (the *status quo* case), the typical consumer faces an NPV of annual fuel expenditures over the thirty-year life of the project of approximately $6,300. The standard deviation of this number is approximately $557, reflecting how certain that consumer can be in that level of expenditure. In contrast, at the other end of the frontier is the 100% SNG point. In this extreme case, the present value of consumer expenditures on fuel is approximately $4,800, but the standard deviation is only about a fifth of the *status quo* level.

The message of the portfolio analysis is clear: increasing the amount of SNG in the state's supply portfolio reduces consumer expenditures and dramatically reduces consumer risk. It should be noted, however, that the example here is extreme because it assumes that consumers care only about cost and risk. In reality, we realize that other factors may matter as well: supply diversity, creation of jobs, local sourcing of energy, *etc*. When cost and risk are the sole criteria, however, the message to consumers is that benefits grow proportionally to the presence of SNG in the market.

CONCLUSIONS

In this paper we analyze the costs and risks faced by consumers from a proposed coal gasification project to be developed in Southwest Indiana. The proposed contract is structured to insulate consumers from exposure to volatile and rising natural gas prices by exploiting new technology to convert coal, a fuel source with low volatility, into natural gas. Because the costs of this project are predominantly capital costs, and therefore fixed, long-term prices for SNG are far less volatile than natural gas prices. Additionally, the ability of the project to exploit a 3-Party Covenant structure and receive Federal loan guarantees also reduces consumer costs.

Table 6: Summary of Modeling Conclusions

	Millions of Dollars		Cumulative Nominal $/MMbtu	Average 2006$/ MMbtu
	Nominal (Cumulative)	2006$ (NPV)		
Cost Reduction Value	$4,363	$557	$3.62	$0.20
Risk Reduction Value	$1,131	$646	$0.94	$0.30
Total Hedge Value to Ratepayers	$5,494	$1,203	$4.56	$0.50

Based on the results of our modeling, the ultimate benefits to consumers are two-fold. In addition to receiving a significant long-term cost reduction, consumers also benefit from a substantially lower risk profile as a result of incorporation of the SNG project into the state's natural gas supply portfolio. Table 6 summarizes the benefits of the project, which are discussed throughout the report.

Cumulative nominal cost savings to ratepayers total $4.4 billion ($557 million in present value terms). In addition to this amount, the value of risk reduction to consumers is $1.1 billion ($646 million present value terms). Based on the proposed production of the gasifier, these savings represent a total average savings to consumers across the life of the project of $0.50/MMbtu (in 2006 dollars) and they require no upfront cost from consumers. The magnitude of these savings is made more substantial when considering that the project will provide less than 15% of the state's residential and commercial heating natural gas supply.

Although the project faces several risks, including availability and natural gas price uncertainty (for comparison purposes only), the ultimate risk to consumers is such that there is less than a 0.5% chance that the present value of consumer savings will be less than zero. More importantly, our modeling incorporates these sources of uncertainty. Thus, the results we have presented reflect the inclusion of such risks and nevertheless produce substantial improvements in consumer welfare.

ABOUT THE AUTHORS

David C. Rode, Managing Director of DAI Management Consultants, Inc., oversees all aspects of quantitative and economic modeling at DAI, including the development of cash flow forecasts, simulation-based risk analysis, and discount rate modeling. Mr. Rode's models have been used in a broad range of consulting assignments for investment banks, institutional investors, regulators, municipalities, and utility clients. These models have been used for capital investment, operating lease valuation, and portfolio optimization. Mr. Rode has also performed economic studies of electric and gas markets, provided expert testimony on financial decision making issues, and has applied state-of-the-art probabilistic methods in forecasting market prices. His research has appeared in such publications as the *Journal of Structured and Project Finance,* the *Journal of Economic Behavior and Organization,* and *The Appraisal Journal*. Mr. Rode has a B.S. in Economics (Finance and Decision Processes) from the Wharton School of the University of Pennsylvania, an M.S. in Behavioral Decision Making and Economics from Carnegie Mellon University, and is currently completing his Ph.D. in Decision Sciences, also at Carnegie Mellon. He has also served as an adjunct professor in the Department of Social and Decision Sciences at Carnegie Mellon.

Paul S. Fischbeck, PhD, is a Professor in the Department of Engineering and Public Policy and in the Department of Social and Decision Sciences at Carnegie Mellon University, in Pittsburgh, Pennsylvania. His general research involves normative and descriptive risk analysis. Past and current research includes the development of a risk index to prioritize inspections of offshore oil production platforms, an engineering and economic policy analysis of air pollution from international shipping, a large-scale probabilistic risk assessment of the space shuttle's tile protection system, and economic valuations of power generation facilities under different market and regulatory conditions. Dr. Fischbeck is a graduate of the University of Virginia (B.S. in Architecture), the Naval Postgraduate School (M.S. in Operations Research and Systems Analysis), and Stanford University (Ph.D. in Industrial Engineering and Engineering Management). He is the Director of Carnegie Mellon's Center for the Study and Improvement of Regulation and has won several awards from the Institute of Operations Research and Management Sciences (INFORMS).

REFERENCES

Allen, R. *Mathematical Analysis for Economists* (London: Macmillan, 1938).

Balestra, P., and M. Nerlove. "Pooling Cross Section and Time Series Data in the Estimation of a Dynamic Model: The Demand for Natural Gas." *Econometrica* **34:3** (1966): 585-612.

Barnes, R., R. Gillingham, and R. Hagemann. "The Short-Run Residential Demand for Electricity." *Review of Economics and Statistics* **63:4** (1981): 541-552.

Beierlein, J., J. Dunn, and J. McConnon Jr.,"The Demand for Electricity and Natural Gas in the Northeastern United States." *Review of Economics and Statistics* **63:3** (1981): 403-408.

Berg, D., and A. Patterson. IGCC Risk Framework Study. U.S. Dept. of Energy Policy Office Presentation to the Gasification Technologies Council (May 20, 2004).

Bernstein, M. and J. Griffin. Regional Differences in the Price-Elasticity of Demand for Energy. RAND Technical Report (2005).

Bohi, D., and M. Zimmerman. "An Update on Econometric Studies of Energy Demand Behavior." *Annual Review of Energy* **9** (1984): 105-154.

Branch, E. "Short Run Income Elasticity of Demand for Residential Electricity Using Consumer Expenditure Survey Data." *The Energy Journal* **14:4** (1993): 111-122.

Chavas, J., and M. Holt. "Acreage Decisions Under Risk: The Case of Corn and Soybeans." *American Journal of Agricultural Economics* **72:3** (1990): 529-538.

Houthakker, H. "Residential Electricity Revisited." *The Energy Journal* **1** (1980): 29-41.

Houthakker, H., P. Verleger Jr., and D. Sheehan. "Dynamic Demand Analyses for Gasoline and Residential Electricity." *American Journal of Agricultural Economics* **56:2** (1974): 412-418.

Hurt, C., and P. Garcia. "The Impact of Price Risk on Sow Farrowings, 1967 – 1978." *American Journal of Agricultural Economics* **64:3** (1982): 565-568.

Just, R. "An Investigation of the Importance of Risk in Farmers' Decisions." *American Journal of Agricultural Economics* **56:1** (1974): 14-25.

Keeler, C. Operating Experience at the Wabash River Repowering Project. Presentation at the 2003 Gasification Technologies Conference. San Francisco, CA (October 2003).

Lin, W. "Measuring Aggregate Supply Response under Instability." *American Journal of Agricultural Economics* **59:5** (1977): 903-907.

Lin, W., and R. Dismukes. Risk Considerations in U.S. Supply Response. Presented at the ERS-Farm Foundation Workshop "Modeling US and EU Policy: Focus on Decoupled Payments." Washington, DC (October 4-5, 2004).

Markowitz, H. *Portfolio Selection* (Cambridge, MA: Basil Blackwell, 1959).

NETL. "Potential for NRCC Plant Conversion to a Coal-Based IGCC Plant: A Preliminary Study" National Energy Technology Laboratory (NETL) Study (May 2004).

Ono, T. NPRC Negishi IGCC Startup and Operation. Presentation at the 2003 Gasification Technologies Conference. San Francisco, CA (October 2003).

Rosenberg, W., D. Alpern, and M. Walker. "Deploying IGCC in this Decade with 3 Party Covenant Financing: Volume I." ENRP Discussion Paper 2004-07. Cambridge, MA: Belfer Center for Science and International Affairs, Kennedy School of Government, Harvard University (May 2005).

Taylor, L. "The Demand for Electricity: A Survey." *Bell Journal of Economics* **6:1** (1975): 74-110.

U.S. Department of Energy. Energy Information Administration. *Annual Energy Outlook Forecast Evaluation*. Washington: GPO, February 2005.

U.S. Department of Energy. Energy Information Administration. *Annual Energy Outlook 2007 (Early Release)*. Washington: GPO, 2006. Report #DOE/EIA-0383(2007).