PRICE CREDIT AND PRICE RISK SIMULATION FOR ALASKA NATURAL GAS PIPELINE PROJECT

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A

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ABSTRACT

This work describes the price risk involved in developing an Alaska Natural Gas Pipeline. Three alternatives were developed. They are an ALCAN Only 4.5 Bcf/day case, a Y-line case, and an ALCAN Only 5.5 Bcf/day case. The simulation result supports the conclusion that the ALCAN Only 4.5 Bcf/day case would be the most feasible and flexible choice for the long-run gas development with less commodity risk. Also, the price credit simulation was run based on the EIA natural gas price forecast. It shows how a Federal Tax Credit helps to reduce price risk making this marginal project more acceptable for participating oil companies. However it might not be revenue neutral for the Federal Government.

The risk-assessment model was constructed in the Excel spreadsheet with a commercially purchased add-in feature (@RISK by Palisade Corp.) that performed the Monte Carlo simulation and the probabilistic outcomes. It was designed to be a dynamic tool that could estimate production performance with associated costs, and product prices to yield an economic analysis[1]. The model was specifically designed for the Alaska Natural Gas Pipeline.

This work could be useful for government, companies, and any individual, who is currently involved with the Alaska Natural Gas Act.

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[1] The economic evaluation model used in this study is modified from NERA Economic Model version 2.64 (Northern Economic Research Associate's Economic Model of Alaska North Slope Gas Utilization), which created by Michael Backus.

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1 INTRODUCTION

The profit margin of an oil or gas pipeline development project is very sensitive to the price of the product. Since all those developments are long-term projects and require a lot of capital investment, a pipeline project holds a lot of risk because of unpredictable gas prices. Therefore, price risk analysis is necessary for good project decision-making. It is especially true for the development of an Alaska Natural Gas Pipeline.

In the short run, project costs are predictable. We assumed that the capital investment is proportional to the level of production. However for an integral risk study of an oil or gas field development project, capital cost and production are both key uncertain factors, and need to be taken into consideration. In this study, special attention was put on gas price uncertainty.

The success of risk assessment critically depends on the reliability of the input distributions. The probabilistic estimates for gas prices were based on results generated from detailed work with historical price data and EIA projected gas prices. These results show that the historical gas prices should follow certain types of distributions, which are defined by mean and standard deviation. From the historical best-fit model, the monthly standard deviation and the yearly standard variation were obtained. Therefore, the input distribution of each price in a monthly simulation model was just a distribution function with a mean of EIA's forecast value and a monthly standard deviation. The same method was used to obtain the price distribution function of each year during production period.

2 LITERATURE REVIEW

2.1 Alaska Natural Gas Pipeline Projects

2.1.1 General Information

The North Slope contains plenty of available gas to support a large gas sale. Along with the oil, Alaska North Slope reservoirs contain at least 35 trillion cubic feet (TCF) of gas. Currently, when this field's gas comes up with the oil, the operators of the Prudhoe Bay Unit, Phillips and BP, inject this gas back into the reservoir to keep pressure levels high and recover more oil.

However, the huge costs of a gas transportation project make the prospects for this gas sale project uncertain, and the relationship between the working interest owners complicates the problem. Two key elements are especially important: pipeline route and commodity risk. The Alaska State Legislation[2] favors the Alaska Highway route for the pipeline, the same route that was designated in the Alaska Natural Gas Transportation Act of 1976, acknowledged by President Carter in 1977, and supported in international agreements with Canada. The State of Alaska supports the tax credit provision imbedded in the U.S. Congress Energy Bill to reduce the risk of investment in natural gas pipeline.

2.1.2 Background

Some background information is necessary to understand the Prudhoe Bay producers' interests in the oil and gas reserves contained in the main reservoir at Prudhoe Bay. The major producers are BP Alaska Exploration, Phillips Alaska Inc. (now ConnocoPhillips) and Exxon Mobile. These producers own leases on the land overlaying at the Prudhoe Bay reservoir. Through these leases, the producers acquired a "working interest" in the oil and gas recoverable from these leases. This "working interest" entitles the producers to ownership of recovered oil and gas with

[2] Under Sec.38.35, the State of Alaska reserves to itself all powers for right-of-way purposes.

the requirement that they pay the costs associated with such production. The producers must also pay the State's "royalty interest." This interest provides the State with a 12.5% of the produced oil and gas (or 12.5% of the value of that oil and gas) without the obligation to pay the costs associated with that production. Some of these leases originally overlay principally oil reserves, while other leases principally overlay gas reserves, in unitizing their working interests in these leases, the producers agreed on a single plan of development and operation for the field. The producer, however, did not agree to a single participating interest in the oil and gas reserves. Therefore, they created two Initial Participating Areas (IPA's): the Oil Rim Participating Area (Oil Rim), and the Gas Cap Participating Area (Gas Cap) to allocate to each producer the production and the cost obligation for the oil leases and gas leases respectively.

Because some producers mostly own leases principally overlying oil reserves, while others mostly own leases principally over gas reserves, each producer's share of oil in the Oil Rim differs substantially from that same producer's share of gas in the Gas Cap. While BP owns just slightly more than 50% of the working interest in the Oil Rim, it only has a 13% working interest in the Gas Cap. Phillips and Exxon Mobile together only have 44% working interest in the Oil Rim, but together they own about 85% of the working interest in the Gas Cap. Phillips and Exxon Mobile's 85% interest in the Gas Cap does not mean they own 85% of the reservoir gas because not all of that gas is in the Gas Cap. The gas resource in the main Prudhoe Bay reservoir includes not only the large volume of gas in the Gas Cap, but also the smaller (but still very large) volume of gas originally dissolved in the oil in the Oil Rim. If a Major Gas Sale from the Prodhoe Bay Unit were to take place, gas from the Oil (about 30% of the total gas) and the Gas Cap would be marketed together. So Phillips and Exxon Mobile will each own a 37% working interest in the total gas in the reservoir (both Gas Cap and Oil Rim gas) while BP owns a 24% working interest in this gas resource.

The governing contract for the Prudhoe Bay Unit, the Prudhoe Bay Unit Operating Agreement (1977) (PBUOA), specifies how to allocate commercial substances (oil, condensate, natural gas liquids, and natural gas) to the Gas Cap and Oil Rim, and by extension, to BP, ARCO and Exxon Mobile. The PBUOA also allocates costs and obligation to supply field fuel to the participating areas, and consequently, to the working interest owners. The producers have amended these product and cost allocation provisions of the PBUOA by, among other agreements, the Issues Resolution Agreement (1992)(IRA). Pursuant to these arrangements, the product and cost allocations change when a "Major Gas Sale", as that term is defined in the PBUOA commences. A Major Gas Sale occurs when the volume delivered to a Major Gas Pipeline for transportation off the North Slope of Alaska has equaled or exceeded 1.75 billion cubic feet.

The PBUOA provides for a myriad of product and cost allocation methods. These allocations relate first to the products or type of costs allocated, and second to three specified periods in the field's development life. The PBUOA has a different allocation method for each commercial substance-separator liquid (oil and condensate), natural gas liquids (NGLs), and sales gas. This agreement also allocates field operating costs, tax obligations, and capital expenditures in different ways.[3]

2.1.3 History

"A pipeline for Alaskan natural gas has been discussed since the 1970's. In 1977, the United States and Canada signed an agreement in principle for the Alaska Natural Gas Transportation System (ANGTS) that proposed the delivery of 2 billion cubic feet per day from the Alaskan North Slope, along the Alaskan-Canadian highway to near Calgary, Alberta, and down to the lower 48. Initial cost estimates

[3] This agreement may have been changed in 1999 or 2000 with the sale of ARCO assets to ConnocoPhillips.

for ANGTS, including delivery to the lower 48, were \$14.6 billion (1988 estimate, in 1988 dollars.)"[4]

Observers of failed previous attempts to market Alaska natural gas cite a number of reasons for no action including gas prices, producer reluctance to finance projects where they had no equity position, government controls, lack of markets, and bad economics.

Discussion of a natural gas pipeline from Alaska resurfaced in 1999 and 2000, when high gas prices[5] led to a re-evaluation of the feasibility of developing Alaskan gas reserves. Phillips, BP, and ExxonMobil formed a partnership to investigate the potential of developing gas pipeline.

2.1.4 The Complexity of the Problem

The issues surrounding the economics of various gas line alternatives are very complex. From the perspective of the State of Alaska, we can summarize the main objectives for the state into three primary components.

First Goal: Maximize Tax Revenue

First and foremost is that whichever route is undertaken, and the timing of it, ownership interests, socio-economic impacts, and other aspects such as tax matters, the amount of revenue that the state accrues over the life of the project, with consideration for the time value of money (meaning sooner is better than later), may be the most important criteria. Revenue estimates range from a low of perhaps \$3 billion to a high of \$15 billion over the life of producible reserves, depending upon the project. The problem is that what is best for the producers (such as BP, Exxon and Phillips), may not be what is best for the state. BP and Exxon have many other projects around the world that compete with Alaska gas, and it may be in their

[4] "The Effects of the Alaska Oil and Natural Gas Provisions of H.R.4 and S.1766 on U.S. Energy Markets", by EIA, February 2002.

[5] The Energy Information Agency reports that Southern California city gate spot market prices exceeded \$59 per MMbtu on December 11, 2000. This translates to over \$250 per barrel of oil.

interest to wait many years, if not decades, before internal economics would be satisfied by delivering Alaska gas to world markets. Phillips has closer interests to Alaska as more of their asset base is tied up in Alaskan oil and gas.

The way the State of Alaska most benefits from a gas line in terms of revenues is by having the highest wellhead values, meaning the value of the gas when it reaches consuming markets, less transportation and other associated costs of getting it there. High wellhead values with high production rates in the earliest possible timeframe best suits the state from a revenue perspective.

Second Goal: Maximize Gas Industry Development in State

A second goal for the State of Alaska might be to have and maintain an industry that employs many Alaskans in a value-added process after the line is finished. In this regard employment levels that exist once a pipeline project is complete are more important than construction jobs. Even though construction jobs are indeed important, they often go to transient and out-of-state workers who pay little or no taxes, but require state and local services. Federal laws prohibit strict preferences for local hire. Alaska has a history of boom and bust cycles. Only the prospects for significant permanent employment justify the costs associated with large temporary employment cycles.

Third Goal: Maximize Alaska Access to Gas for State Economic Needs

The final critical goal for the State of Alaska to achieve through a gas project is to have sufficient supplies of our own gas be made available for consumption and use within the state. Both the interior of Alaska and South central Alaska have critical needs for access to in-state gas. Not only because it represents the best opportunity for low cost energy, but also because Cook Inlet gas is running out, and the alternatives for producing electricity and heating homes are not good.

The upshot of all these is that it will take a balance of both coordinated and competing economic interests in order for a gas supply system to be developed in Alaska.

2.1.5 Gas Project Alternatives

For different economic incentives and from various perspectives, there are in effect five different gas project alternatives that are open for discussion, and under consideration. One is referred to as the "Over the Top" project that sends gas direction from the North Slope of Alaska into Canada. Another is "ALCAN Highway" project, which is embraced by the governor of Alaska. In Addition, Tidewater LNG project has been put forward for discussion and analysis for a long time. The fourth one is called "Y Project" which combines tidewater LNG and ALCAN Highway routines. The fifth one is so called Alaska GTL (Gas to Liquid) Option, which considers translating natural gas to liquid by chemical processing, and then shipping to the market through existing TAPS system. For each proposal, their pros and cons are discussed as follows.

2.1.5.1 "Over the Top" Project

This project starts on the Alaska North Slope (ANS) and then moves east along the northwestern section of Canada to pick up additional gas from their Mackenzie Delta, then south to the Lower 48 toward Chicago and the Midwest. This route may have advantages to BP and Exxon because it adds large volumes of proven reserves of gas sufficient to gain economies of scale. However, from an Alaskan perspective, because of the short length in Alaska, it will produce lower property tax revenue, and the quantity of North Slope gas sold will be limited. Even though it would provide construction and permanent jobs, they might amount to less than would be anticipated in other projects. It also has the disadvantage of not providing access to gas for Alaskan consumption.

Producers are reported to favor an option for developing Alaska's gas that would construct a large diameter (no compressor stations) buried offshore pipeline to the Mackenzie Delta, then a pipeline to carry both Alaska gas and Canadian gas to the lower 48 market. The 350 to 400 mile offshore portion of this project would be buried in approximately 40 feet of water in a trench sufficiently deep to provide a 14 foot soil cover depth for ice scour protection. It has been estimated that the offshore portion can be completed in a single year. The same issues regarding supply and demand apply to this project as apply to shipping natural gas to the lower 48 through the ALCAN project. The producers have said this route will produce the greatest wellhead netback. Some analysis shows that the economics and risk are even worse for Alaska than the ALCAN project, and that this route would increase wellhead netback for Canadian resource developers (BP and Exxon) at the cost of Alaska gas. The estimated cost reported for this option is \$6.0 billion for both the Alaskan and Canadian portions of the pipeline. A Northwest Territories (NWT) government study estimated the cost of the system at \$6.6 billion. The NWT estimate for a stand-alone gas pipeline from the Mackenzie Delta is \$2.5 billion. The press releases do not say whether or not the cost estimates include compressor stations. The cost of gas conditioning plants is most certainly not included. This would increase their estimates.

The status of route soil investigations, engineering feasibility, construction estimates and construction schedule are unknown at present.

The "over the top" options presents a formidable engineering challenge in developing the technology for laying large diameter pipelines in a deep trench considering the ice conditions in the Arctic ocean environment. Subsea permafrost could present an equally formidable challenge. The construction schedule of a single year, given the seasonal constraints and potential sea ice conditions is equally challenging. The risk of construction delays and the potential technical delays associated with this project cast considerable doubt as to the feasibility and viability of the option. Additionally, most of the route is in remote areas without existing infrastructure. Along with technical problems, the project has permitting and legal problems that may delay construction and market entry.

A more feasible engineering option for the northern segment of this project that minimizes technical risk is a smaller diameter buried onshore pipeline (with compressor stations) through the Arctic National Wildlife Refuge and the Northern Yukon Territory. The construction cost for this option is likely to be less than the offshore options when all design details and risks are addressed.

This onshore option would have to be permitted under title 11 of Alaska National Interest Lands Conservation Act.

2.1.5.2 ALCAN Highway Project

Another proposal, and one embraced currently by the Knowles aubernational administration, is the ALCAN Highway project. It would provide more Alaskan construction and permanent jobs than the "Over the Top" route, and would provide limited access to gas for Alaskan consumption. So far this project has not been adopted as a preferred project by any of the major oil company participants, but is in the running for serious consideration. It gathers less Canadian gas, and would deliver gas to a hungry lower 48 market. It may be economical from an overall investment perspective, but depending upon market conditions, may provide limited revenue to the state. This depending upon how transportation and other costs are allocated, to the potential detriment of Alaskan gas wellhead values.

2.1.5.3 Tidewater LNG Proposal

The Tidewater LNG proposal would run from the North Slope along the existing oil pipeline, and either delivers gas to Valdez or head west from the Copper River Valley and delivers the gas to Cook Inlet for conditioning into a cold liquid for transportation via special tankers. Advantages of this project include significant construction and permanent jobs, access to gas in both interior and south central Alaska, and the potential for perhaps the highest revenue source to the state. The disadvantage is that it may not represent the best deal for producers, particularly BP. Since a Tidewater project has the flexibility of delivering gas to various ports via tankers to both Asia and the West Coast and Mexico, it may compete with other projects BP has underway in Southeast Asia. It may be difficult to wrestle adequate supplies of gas from BP to generate appropriate economies of scale. The absence of a project to deliver gas to market may be better for BP than delivering Alaskan gas that competes with other supply sources they already have in place.

There have also been serious efforts on the part of communities along a proposed tidewater route by their respective mayors. This "Mayors Proposal" would anticipate tax exempt financing and may reduce the cost of construction and the cost of operations. Usually large public finance projects require significant amounts of equity capital at risk in order to attract public markets money. This one may be feasible from an economic perspective, but is currently hamstrung by a variety of factors including a lack of large amounts of equity. However it still is open for serious discussion and should not be ruled out if major obstacles could be overcome.

LNG represents only a small proportion of the natural gas market, but its share is forecast to grow dramatically, particularly in markets in the Asia Pacific region where pipeline gas supplies are for the most part not economic, infeasible due to location, or not available. LNG market prices however may continue to track world oil prices with a premium due to strong demand, the need for long-term supply from politically stable countries and the environmental benefits of using natural gas.

2.1.5.4 Alaska GTL (Gas-To-Liquid) Option

The technology for converting natural gas into high-quality liquids may satisfy the need of marketing the large volumes of available natural gas located far from markets. A literature, White Paper: Alaska Natural Gas, shows both benefits and obstacles of an Alaskan GTL Project.

Benefits

- Unlike the pipeline or LNG alternatives, a GTL project can be developed in stages reducing technological and financial risks.
- Products can be shipped on a batch basis through the existing TAPS line that will continue to have available capacity. This will extend the economic life of the pipeline reduce the cost of transporting all liquids and enhance the value of this pipeline asset. This may require the construction of additional storage.
- GTL may also be blended with ANS crude, although this would not allow producers to capture the full value of the GTL components.
- A GTL project could provide the earliest method for monetizing gas reserves for the benefit of all stakeholders, with minimum exposure of capital.
- Alaska is geographically close to consumers in the US West Coast and in the Asia Pacific region.
- Environmental opposition would be significantly less than for a pipeline or LNG alternative.
- Because of the gas volumes involved and the flexibility in expansion, the pursuit and later development of either a major LNG or pipeline project is not compromised.
- Significant facilities would need to be constructed on the North Slope.

Obstacles

- The cost of building a demonstration plant on the North Slope to verify the technology and economics would likely cost 25~30 percent more than construction in more accessible and less environmentally challenging areas.
- A North Slope GTL plant with a $1.00 per MMBtu inlet gas cost would require a $27~$28 per barrel equivalent WTI to achieve a 15 percent rate of return. This $2~$3 per barrel higher world oil price is required because of the pipeline charge between the producing area and Valdez.
- The desire for gas service that would be made possible by the building of a gas pipeline would not be realized.
- Initially only a small volume of gas would be used.

The GTL option for the development of Alaska North Slope natural gas has not received much attention before. It was thought to be less market competitive than a natural gas pipeline to the lower 48. Additionally, concerns about waxing problems in the transport of GTL products in the Trans Alaska Pipeline System have been expressed by one of the pipeline owners. However, a recent report by Purvin & Gertz may breathe new life into the Alaska GTL option.

The following excerpts are quoted from an article by Roland George, Principal, Purvin & Gertz, Inc. in Gas-to-Liquids News, Vol. 4, No. 1 via COMTEX. Purvin & Gertz assumed that a 100,000 barrels per day (b/d) GTL plant would be constructed and operated utilizing ANS/Prudhoe Bay natural gas as the feedstock. There are two possible schemes for utilizing GTL to move the gas to market a location either on the North Slope or the South Shore.

If the production is commingled with ANS crude, then its unique nature would be lost and its value would be determined through a quality bank mechanism currently in place among all the various shippers of ANS crude in the TAPS line. Under a batching operation, the product would be kept segregated through the use of either cleaning pigs or a transmit buffer between the crude and GTL output.

A GTL plant constructed at the South Shore will require a gas supply pipeline to provide the feedstock to the plant. It will be located at the export loading point and will not require any special handling to keep product quality at its maximum. The costs of construction and operation at the South Shore are expected to be less than for the North Slope due to the less severe ambient conditions and unrestricted year-round access.

Comparable producer netbacks resulted for both cases because of the tradeoff between lower capital and higher gas pipeline cost of service for the South Shore versus higher capital cost and lower TAPS tariff for the North Slope.

Based on Purvin & Gertz' analysis, the North Slope GTL plant would have a slightly higher netback price to gas producers in the Prudhoe Bay area. Construction costs play an important role in the profitability of both cases.

An option builds infrastructure in Alaska that is independent of an Alaskan gas pipeline. Existing spare capacity on the TAPS pipeline would be used to transport diesel and naphtha in batches to the Valdez Marine Terminal on the South Shore. One drawback is the possibility of cutting short the economic life of this project if the TAPS tariff increases when North Slope crude oil production declines.

A recent study suggests the option of a combined tidewater LNG and GTL plant in southern Alaska. Such a combined project could increase the economies of scale for the pipeline across Alaska and lower the cost of service for both projects. The maximum benefits for the shared pipeline would be derived from the combination of the tidewater LNG and tidewater GTL. By increasing the pipeline capacity to 3.5 bcfd from the North Slope (2.5 bcfd for a tidewater LNG and 1.0 bcfd for a tidewater GTL the competitiveness of both projects would be increased by the lower transportation cost). Although time did not permit the evaluation of this option, this option has merit for the development of North Slope natural gas and should be studied in detail to determine the impact on both projects. Additionally this option may provide an opportunity to develop a viable and smaller market entry LNG project.

2.1.5.5 Y-line Project

The Y-line project is a combination of an ALCAN and a Tidewater LNG project. In addition to the ALCAN line, there would be a spur line that takes volumes to Tidewater that could be marketed to various locations. The advantages are that it would provide significant construction and permanent jobs, would provide access to gas in Alaska, and could reap significant revenues for the State of Alaska. Also, over the potential thirty plus life of the line, gas could be delivered to where the best economics lie at various points in time. The disadvantages include a higher cost associated with the dual project, requiring quantities of gas of yet to be proven reserves in order to reach necessary economies of scale. Development in ANWR, along with other exploration efforts would likely solve this problem.

The Y-Line concept is based on the development of two gas projects that share a portion of the gas conditioning and transportation infrastructure. This cost sharing benefits both projects by allowing greater economies of scale for the first 541 miles from Prudhoe Bay to Delta Junction with separate pipelines beyond that point to both Valdez for tidewater LNG, and the Alberta/British Columbia border for the ALCAN highway project.

2.2 Monte Carlo Simulation and Its Application in Oil/Gas Industry

2.2.1 What is a Monte Carlo Simulation

A Monte Carlo simulation is a statistics-based analysis tool that yields probability vs. value relationships for key parameters. In the Oil/Gas exploration industry, key parameters include oil and gas reserves, capital cost, and various economic evaluation yardsticks, such as net present value (NPV) and return on investment (ROI). These probability relationships help the user answer such questions as "What is the probability that the NPV of this prospect will exceed the target of $1,500,000?" (Ref. 4)

Monte Carlo simulation is a part of risk analysis and is sometimes performed in conjunction with or as an alternative to decision tree analysis.

Monte Carlo simulation based on an economic model is used to quantify risks associated with a specific investment prospect. So we can define risk, a potential loss, or more generally, loss or gain (i.e., a change in assets associated with some chance occurrences). Hence, it helps the decision-maker chose the best prospect based on the decision-maker's attitude about risk – risk seeker, risk aversion, or risk neutral.

Monte Carlo simulation is an alternative to both single-point (deterministic) estimation and the scenario approach that presents worst, most likely, and best case scenarios. The term Monte Carlo dates back to the Manhattan Project in the 1940's, where it was used as a code name for simulation of problems associated with development of the atomic bomb. Today, Monte Carlo techniques are applied to a wide variety of complex problems involving random behavior. For an early historical review, see Ref. 5.

2.2.2 How to Process a Monte Carlo Simulation

The following paragraph, drawn largely from Ref. 4, offers a brief description of the Monte Carlo process.

1. A Monte Carlo simulation begins with a model, with one or more equations, together with assumptions and logic relating the parameters in the equations.

2. Define all the input variables.

3. Sort the input variables into two groups. Those variables whose values are known with certainty or reasonable precision and can be represented as single-point values (deterministic values). Significant unknowns will be represented as random variables for which exact values cannot be specified at the time of decision making (stochastic values).

4. Define distributions for the random input variables. Selecting Input Distributions. Input distributions can be themselves outputs from an economics model, the best available expert judgment, or best-fitting distribution curves obtained through historical data analysis.

5. Define correlation among inputs.

6. Define output. Usually, the output refers to the measure of value of interest to decision-maker, either Net Present Value (NPV) or Internal Rate of Return (IRR or ROR) of a prospected cash flow.

7. Run simulation. A trial consists of randomly selecting one value for each input and calculating the output. The aggregation of output for each trial generates a distribution of output, which generally has the approximate shape of a lognormal curve.

8. Prepare graphical displays of the evaluation model and results. The necessary displays are input variables distributions, output distribution—the histogram distribution or/and its equivalent cumulative frequency distribution converted from the histogram, and sensitivity chart (tornado chart). The cumulative distribution has the advantage of telling us probabilities at given levels of output (i.e. IRR) directly. The generated sensitivity chart is one of the byproducts of the simulation. A measure of significance toward a given output variable is calculated for each input variable, namely the (rank-order) correlation coefficient between the two parameters. When the correlation coefficient is close to 0, the output can

achieve a value near the upper limit of its range. These coefficients can range from -1.0 to 1.0. The most significant parameter can be identified, and the others are ranked accordingly. For a complex model, sensitivity analysis identifies the "driving variables" that merit additional scrutiny and, by contrast, helps reduce effort wasted on worrying about the wrong things. Unlike the traditional tornado chart or spider diagrams obtained by tracking the changes in an output caused by allowing exactly one model input to vary while holding the others fixed, this sensitivity analysis from Monte Carlo simulation is far more versatile because it permits functional or correlation-type relationships among the inputs.

2.2.3 Correlation among Inputs (Dependency)

Unless otherwise specified, the samples of various input distributions are taken independent of one another. On a particular trial, a high level of price may be paired with a high level of cost (Consumer Price Index, CPI, might be driven up, causing operating cost increasing). If there is an argument (or empirical data) to justify a correlation between a pair of parameters, then the simulation software can honor that relationship. Correlation among inputs may cause the range of resulting output to become either wider or narrower. It depends on the economic model. And imposing correlations among inputs can also reorder the list of sensitive variables.

2.2.4 Monte Carlo Simulation Software — @RISK by Palisade Corp

@RISK is an advanced commercial risk analysis tool which adds directly in to Microsoft Excel. It performs risk analysis on spreadsheet using Monte Carlo simulation techniques. Risk Analysis in @RISK is a quantitative method that seeks to determine the outcomes of a decision situation as a probability distribution.

In general, the techniques in an @RISK risk analysis encompass four steps:

- Developing a Model – by defining a problem or a situation in Excel worksheet format.
- Identifying Uncertainty – by taking variables in an Excel worksheet and specifying their possible values with probability distributions, and identifying the uncertain worksheet results you want analyzed.
- Analyzing the Model with Simulation – by determining the range and probabilities of all possible outcomes for the results of your worksheet.
- Making a Decision – by displaying the results for personal preferences.

You can simply replace uncertain values in your existing spreadsheet with @risk probability distribution functions that represent a range of possible values. Then, select output cells – the bottom-line cells whose values you are interested in – and simulate. @RISK gives you distributions of possible outcomes, including the probabilities that they will occur. This not only tells you what could happen in a risky situation, but helps you discover the crucial scenarios to encourage or avoid.

2.2.5 Sampling Method Offered by @RISK

Sampling is the processes by which values are randomly drawn from input probability distributions. Probability distributions are represented in @RISK by probability distribution functions and sampling is performed by the @RISK program. Sampling in a simulation is done repetitively with one sample drawn for every iteration from each input probability distribution. With enough iterations, the sampled values for a probability distribution become distributed in a manner which approximates the known input probability distribution. The statistics of the sampled distribution (mean, standard deviation and higher moments) approximate the true statistics input for the distribution. The graph of the sampled distribution will even look like a graph of the true input distribution.

@RISK offers two sampling functions, Monte Carlo sampling and Latin Hypercube sampling. Before running simulation, the pop-up Simulation Settings Menu will not only ask you to specify the number of iterations you want, but also chose the sampling method. The @RISK User's Guide recommends using Latin Hypercube, the default sampling type setting, unless the modeling situation specifically calls for Monte Carlo sampling. The technical details on each sampling type are presented in the Technical Appendices of @RISK User's Guide, Ref. 6.

Monte Carlo sampling is a traditional way to sample data. With Monte Carlo sampling, we use a random number generator to generate a uniform distribution along the cumulative probability axis. However, the randomness of random numbers cause the data we generated to be non-uniformly distributed, some values will appear to be "clustered" together, where elsewhere there appear to be gaps when a small number of iterations are performed. Monte Carlo sampling often requires a large number of samples to approximate an input distribution, especially if the input distribution is highly skewed or has some outcomes of low probability.

Latin Hypercube Sampling (LHS) is a stratified sampling method. It was invented in the late 1970s, started appearing in the petroleum literature in the 1980s, and became routine in the 1990s (Ref. 1). It is a combination of conventional Monte Carlo sampling and uniform sampling. The key to LHS is stratification of the input probability distributions. Stratification divides the cumulative curve into equal intervals on the cumulative probability scale (0 to 1.0). A sample is then randomly taken from each interval of the input distribution. Sampling is forced to represent values in each interval, and thus, is forced to recreate the input probability distribution. LHS greatly reduces the number of trials needed to achieve a desired level of precision in the simulation. From experimentation, the typical convergence using LHS is about 10 times better than with conventional Monte Carlo sampling (Ref. 1).

LHS is always a recommended sampling method even though @RISK provides the choice between using conventional Monte Carlo Sampling or LHS.

2.2.6 What Monte Carlo Simulation Does Not Do

In the paper "Monte Carlo Simulation: Its Status and Future", Ref. 4, Murtha did a good summarization of the function of Monte Carlo Simulation, which we need to keep in mind when we do risk analysis using Monte Carlo simulation.

"In spite of its power and applicability, Monte Carlo simulation does not do the following.

1. It does not make decisions; it prepares for decision making.
2. It does not analyze data; there is companion software for that purpose.
3. It does not optimize functions; the output distributions serves as ingredients for optimization
4. It does not provide ready—made models; everyone builds their own."

No matter how powerful a tool is, it is still a tool. How it works depends upon how we use it.

2.2.7 Applications of Monte Carlo Simulation in Oil or Gas Industry

In Ref. 4, four typical problems in Oil or Gas industry using Monte Carlo Simulation are introduced. Taken as a whole, they suggest a process of integrating risk analysis.

1. Volumetric-reserves Model

   Here is an example of Volumetric-reserves model:

   $N = 7{,}758A\mathit{hp}(1\text{-}S_w)/B_o$

   Where, N – oil in place;

   A – area;

h – net pay;

p – porosity;

S_w – water saturation;

and Bo – formation volume factor.

Think of A, h, p, S_w, and B_o as input parameters and N as the output. Each input parameter can be viewed as a random variable; it satisfies some probability vs. cumulative-value relationship. After simulation, a succession of hundreds or thousands of repeated trials, during which the output values are stored in a file in the computer memory, the output value, oil in place, are grouped into a histogram or cumulative distribution function.

2. Drilling Authorization for Expenditure (AFE): Estimate Total Costs and Times and Other Cost-Estimation Models

Drilling AFE estimators are prime candidates for Monte Carlo simulation, being conceptually simple, ubiquitous, and essential to the overall prospect evaluation process. One task for the user is to estimate durations for various activities, such as drilling the hole sections, completing, and testing. Another task is to estimate line-item costs. One way is to provide two values for each estimate: a low and a high estimate. A preliminary calculation in the worksheet solves some simple equations to obtain the mean and standard deviation for a lognormal distribution for that cost or time category. These high and low estimates are treated as P10 and P90: the actual value has a 10% chance of being less than the low value and a 10% chance of exceeding the high value. And also, we can use P5 and P95. Because the input parameters represent times and costs, they are generally regarded as skewed right: there are more extreme values to the right of the mode than to the left, causing a tail of large values having low probability of occurrence.

The proper role for the drilling AFE is a preliminary step to more comprehensive models. The outputs (total time and costs) can be reported as a distribution or a series of distributions over time or for each of several wells. In cases where there are multiple wells or drilling costs along with facilities costs, care must be taken to transmit the correlations between the relevant distributions.

Also, we can include other simple spreadsheet line-item models, similar to the drilling AFE, such as pipelines, platforms, and other facilities in the Monte Carlo economics model. When schedule details are paramount, a project-scheduling model is necessary. Palisade supplies @RISK 4.0 for Project for risk analysis in project management. It would be a faster and easier way to analyze schedule and cost risk.

3. Field-Development Program: To Estimate Production and Revenue Streams

Field-Development program starts with a deterministic forecast of oil production, generated by exponential-decline model. Consider both of the initial rate of production and the decline rate as probability distributions, because we do not know exactly how much oil will be produced in the first year and how sharply the production will decline from one year to the next. Assume some distribution for the capital cost of drilling and completing the well. This distribution comes from the drilling engineers who model the AFE simulators. Further assume that operating costs can be described in terms of probability distributions. Operating expense and oil production can be correlated. Finally, the discounted cash flow for some time horizon (e.g., 20 years) can be generated.

The output distributions of this model are the requisite input distributions for portfolio-optimization models. There are forecasts of aggregate field production by type, cash flows, measured by NPV or ROI, and capital and operating expense. The usefulness of this model is obvious. One can estimate the probability of achieving some hurdle rate for ROI or of failing to meet a target

NPV. The sensitivity analysis highlights the input parameters that drive the model and alerts investors to opportunities to reduce the risks.

4. Strategic Plan: Estimate Reserve Increases, NPV, and Capital Exposure

The objective of strategic plan is to aggregate various capital investments (ventures) making up a portfolio. Each investment is represented by distributions for capital, reserves, and NPV. On each trial of the simulation, samples are taken from number of discoveries for each venture, along with corresponding reserves, NPV's, and capital exposures (both exploration and development). Outputs are the aggregations of these parameters. Aggregation models rely on good input distributions and any correlations between them. These input distributions are themselves outputs from an exploration economics model.

Virtually all segments of the industry – operating companies, service companies, consulting firms, and financial institutions – are engaged in some form of risk analysis. At this time, it appears that no oil and gas operating company has a fully implemented, unified program to do probabilistic estimates of their key operating parameters: reserves, capital exposure, and NPV. A few have made efforts in this direction. The efforts on risk analysis of the petroleum exploration industry sometimes date back to the 1970's, some even further. Ref.4 mentions articles and books on Monte Carlo simulation and related topics in the petroleum literature. Those literatures represent the early efforts in industry on risk analysis.

2.2.8 Model Shortcomings

Extracting one or a few numbers from the reserve distribution to "run economics," treating well productivity and capital costs as deterministic, this approach reduces the effectiveness of the uncertainty analysis, although it is a widespread practice. This method may be good for a field-development model. For an exploration-prospect model, an integrating risk-analysis, which include scoping estimates for production forecasts and both capital and operating expenses, will help us identifying the relative importance of the various risks involved in an exploration prospect. Questions, such as how does field-size uncertainty compare with the uncertainty of the capital costs or the productivity of the wells; Where should we invest additional resources to acquire information; What are the key issues when negotiating with partners or forming alliances, may be easier to be answer.

2.3 Energy Bill S. 1766

Energy Bill S. 1766, the Energy Policy Act of 2002, was introduced by Senate majority leader Tom Daschle and Senator Jeff Bingaman on December 5, 2001. The Sec. 700, Alaska Natural Gas Pipeline Act of 2002, addresses the purposes of this subtitle:

(1) to expedite the approval, construction , and initial operation of one or more transportation systems for the delivery of Alaska natural gas to the contiguous United States;

(2) to ensure access to such transportation systems on an equal and nondiscriminatory basis and to promote competition in the exploration, development and production of Alaska Natural Gas;

(3) to provide federal financial assistance to any transportation system for the transport of Alaska natural gas to the contiguous United States, for which an application for a certificate of public convenience and necessity is filed with the Commission not later than six months after the date of enactment of this title.

The "commodity risk" amendment of S.1766, offered on April 22, 2002 by Sen. Frank Murkowski, would allow investors in the estimated $15 billion to $20 billion gas line project to take a federal tax credit if gas prices at the AECO (Alberta Energy Co.) trading hub in Alberta fall below a certain level. This amendment was adopted by the U.S. Senate unanimously on April 23, 2002.

The commodity risk provision in the Energy Bill is very important to help a North Slope gas pipeline attract financing. Senator Murkowski described the provision of commodity risk is a "true win-win". "The nation will benefit because the increased supplies of this clean-burning fuel will provide an affordable energy product for American families and allow for expanded uses of new technology at the same time," Murkowski said. "Alaska communities will benefit from the construction jobs and access to natural gas that will fuel their future energy needs. And in the end, because of the payback provision, it won't cost the federal government a penny."

3 THE EFFECT OF PRICE CREDIT

3.1 Introduction

The profit margin of Alaska Natural Gas Pipeline Project is very sensitive to the market price of natural gas. The price risk involved in Alaska natural gas development makes no producer would like to develop gas field and build a $15 billion to $20 billion gas pipeline without government incentives.

The tax mechanism proposed in Senate Energy Bill S.1766 is a simple device to increase the expected return on the Alaska Gas Pipeline and lower certain market-price related risks. The credit is available only if gas prices fall below a government-set floor, which would be trigged when average monthly prices at Alberta's benchmark AECO gas pipeline hub fall below $3.25/MMBtu, and if prices rise above a ceiling, it would be paid back when prices exceed $4.85/MMbtu.

The purpose of this study is to analyze the effect of Federal Tax Credit, which shows how well the project ROI would improve with the tax credit involved, by using risk analysis method.

In the risk model, the input, natural gas price, is the distribution of historical prices at AECO gas pipeline hub. And the output, ROI, is generated by the Monte Carlo simulation.

3.2 Base Case

Alberta Gas Price: $2.60mmBtu

ROI (nominal): 16.28%

For comparing purpose, the information of base case is shown here. The base case calculated at Alberta gas price level $2.60mmBtu generate nominal ROI 16.28%.

3.3 Simulation Based on Historic Prices

In the risk model, we consider that the input, Alberta gas price, will follow the lognormal distribution as shown in Figure 3-2. This is the best-fit distribution generated by @risk software based on the historical AECO Prices from 1993 through 2001.

Before generated best-fit distribution, the real historical prices from 1993 through 2001 of Alberta gas were adjusted in 2002 US Dollars by using the 2002 GDP Implicit Price Deflator, which was translated from the 1996 GDP Implicit Price Deflator published on EIA Short-Term Energy Outlook (October 2001)[6].

Table 3-1 shows the published GDP Implicit Price Deflator and its adjustment.

Table 3-1: 1996 GDP Implicit Price Deflator and Adjustment

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
1996 Price Deflator	94.1	96.0	98.1	100.0	102.0	103.2	104.8	106.9	109.4	111.5
2002 Price Deflator	84.4	86.1	88.0	89.7	91.5	92.6	94.0	95.9	98.1	100.0

Sources: 1996 Price Deflator is available from EIA Short-Term Energy Outlook, October 2001

Figure 3-1 shows the time series graph of the adjusted historical natural gas prices.

[6] GDP Implicit Price Deflator (Index, 1996=1.000) is published on Table A2. Annual U.S. Macroeconomic and Weather Indicators, Energy Information Administration/Short-Term Energy Outlook, October 2001.

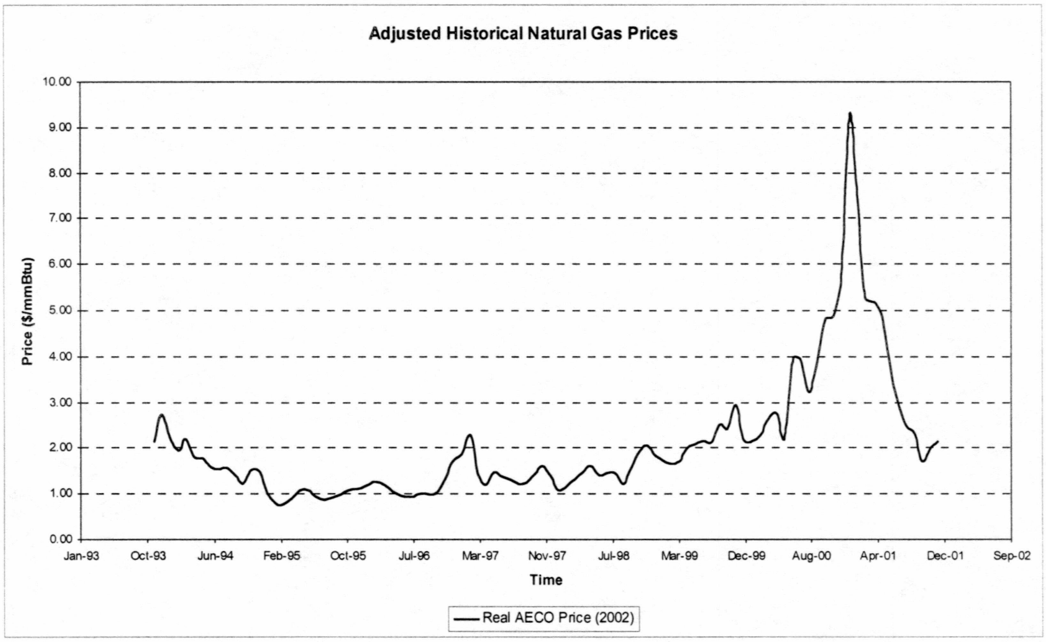

Figure 3-1: Adjusted Historical Natural Gas Prices – Time Series

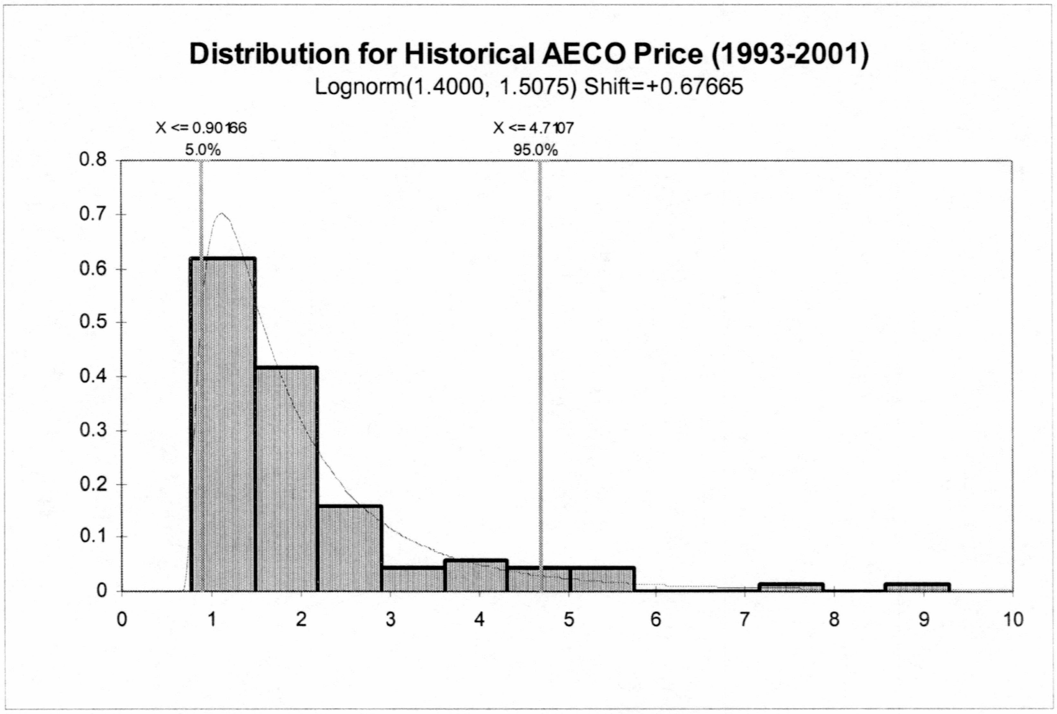

Figure 3-2: Fit Distribution for Historic Natural Gas Price

3.4 Simulation Result

In this study, risk simulation has been done to analyze the effect of the price credit supposed to be employed in Alaska Natural Gas Pipeline Development. Table 3-2 shows the summary of simulation results based on historical prices.

Table 3-2: Summary of Simulation Results (Based on Historical Prices)

	Base Case	Simulation Based on Historical Prices (without Price Credit)	Simulation Based on Historical Prices (with Price Credit)
File Name	UAF NG 3.0.1.xls	UAF NG 3.1.xls	UAF NG 3.1.2.xls
Alberta Price	2.60$/MMBtu	Distribution for AECO Historical Prices (1993-2001) Lognorm(1.4000,1.5075) Shift = +0.67665	Distribution for AECO Historical Prices (1993-2001) Lognorm(1.4000,1.5075) Shift = +0.67665
Distribution for ROI (Nominal)	16.28%	Mean = 13.32% S.D. = 5.65%	Mean = 20.19% S.D. = 2.11%
90% Confidence Interval		6.87%~23.76%	16.74%~23.01%
90% Range		16.89%	6.27%
Risk		Greater	

As shown in Table 3-2, the ROI[7] of Base Case is 16.28% when Alberta gas is $2.6/MMBtu (no price risk involved case).

When we consider price risk by setting the price possibility distribution based on historical natural gas prices (Figure 3-2), we get the ROI 90% confidence interval 6.87%~23.76% with a mean of 13.32% (Figure 3-3). With the price credit involved in the simulation model, the simulation result shows a great increase in mean value and confidence interval (90% confidence interval: 16.74%~23% with a mean of

[7] ROI means the rate of return for investment. It is used to express the internal rate of return of a project when the project has 100 percent equity.

20.19%), as shown in Figure 3-4, and the relatively narrow range. We can see that the price risk involved in Alaska Gas Pipeline Project decreases significantly with the Federal Tax Credit (Price Credit), and the return to producers would be much higher than what we might get without the price credit. As shown in Table 3-2, the tax credit could add 3-6 percent to the rate of return on this gas pipeline project.

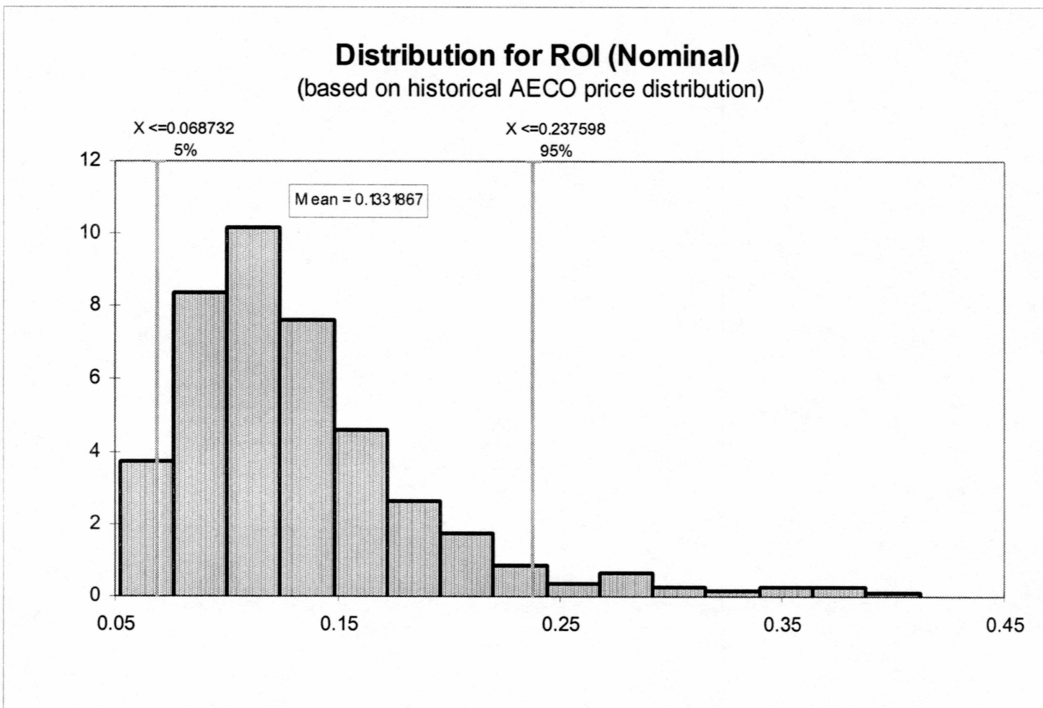

Figure 3-3: Simulation Result (without Price Credit)

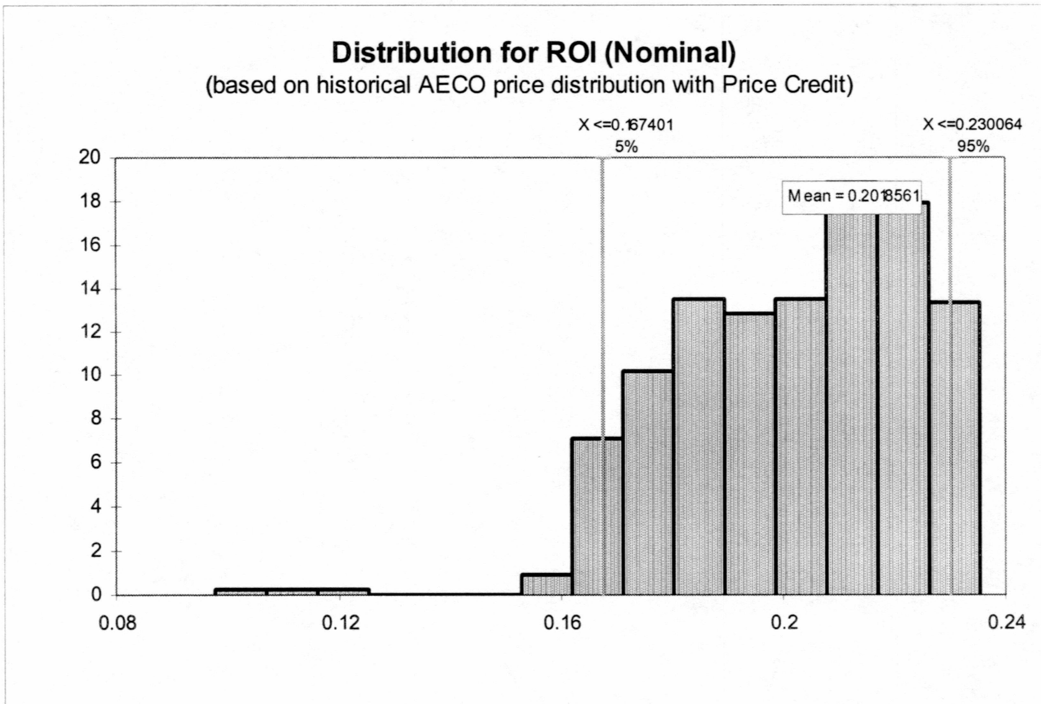

Figure 3-4: Simulation Result (with Price Credit)

4 PRICE CREDIT SIMULATION

4.1 Introduction

Also, risk analysis can be done based on EIA projected natural gas prices for the period 2010-2020. As shown in Table 4-1, EIA published three series projection prices within the last two years. The most recent projection is from June 2002, which indicates a much higher price prospect than what the EIA published in its previous forecasts (Figure 4-1).

Table 4-1: EIA Projected NG Prices

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Forecast, May 2001	2.69	2.71	2.73	2.76	2.79	2.83	2.88	2.93	2.98	3.05	3.13
Forecast, Dec 2001	2.85	2.91	2.97	3.01	3.03	3.07	3.09	3.13	3.17	3.20	3.26
Forecast, June 2002	3.27	3.31	3.32	3.32	3.31	3.35	3.41	3.50	3.58	3.63	3.65

In real 2000 dollar

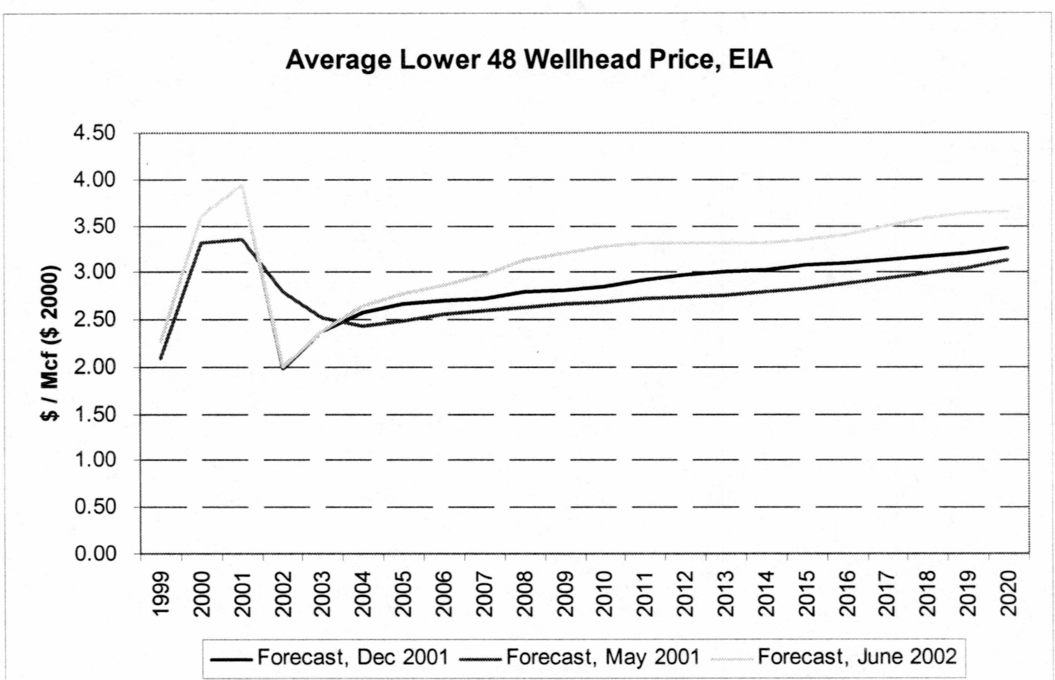

Figure 4-1: EIA NG Price Projection

This study is done mainly based on the last EIA forecast (June 2002). For comparison purpose, the other two projections are put into risk model as well.

4.2 Adjusted EIA Forecast Prices for AECO Prices

The differences between cash prices at various locations around the country are related to transportation costs, prevailing product flows, and the supply-and-demand situation in each local market. Arbitrage possibilities assure that the price differences at different locations bear a reasonably stable relationship to each other. This makes it possible for us to adjust EIA forecast prices to AECO-EIA prices. What we need to know are the price differences among EIA Prices, Henry Hub prices, and Alberta AECO prices. Some research for those price differences is available.

Before we put the forecast prices into a risk model, a necessary adjustment should be done. Here the calculations are shown:

Henry Hub Price = EIA Price + $0.21

AECO Price = HH Price – $0.50

Where, $0.21 is the average value difference between HH Price and EIA Wellhead Price for the period from November 1993 through December 2001.

$0.50 is the transportation cost of natural gas between AECO and Henry Hub[8].

And then, adjusted for inflation at an inflation rate of 2%[9].

The nominal prices are from the series calculations shown above and are the mean value of price projected for the associated year. Normal distribution function for the price of each year was assigned in the economic evaluation model. This function has

[8] Source of data: CAPP (Canadian Association of Petroleum Producers) website presentations.

[9] The average GDP deflator over the last 10 years is rounded to 2%.

a mean of projected gas price and a standard deviation of \$0.75MMBtu[10]. The distribution function looks like this: NORMAL (AECO-EIA forecast, 0.75).

4.3 Simulation Result

Table 4-2 shows the summary of price credit simulation results based on EIA forecast prices.

Table 4-2: Summary of Price Credit Simulation Results Based on EIA Forecast

Base	EIA June 2002 Forecast	EIA Dec 2001 Forecast	EIA May 2001 Forecast
File Name	UAF NG 3.2.xls	UAF NG 3.2.1.xls	UAF NG 3.2.2.xls
Forecast Model (used to forecast gas prices from 2021~2039)	$Y = 0.1494\ Ln(X) + 2.9843$ $R^2 = 0.9918$	$Y = 2.6419e^{0.01438}$ $R^2 = 0.9901$	$Y = 2.4151e^{0.023}$ $R^2 = 0.9904$
Distribution for ROI	Mean = 18.25% S.D. = 0.37%	Mean = 18.17% S.D. = 0.41%	Mean = 18.33% S.D. = 0.44%
90% Confidence Interval	17.66%~18.77%	17.55%~18.88%	17.63%~19.08%
90% Range	1.11%	1.33%	1.45%

As shown in Table 4-2, the simulation results we got based on three different projections have no big differences. The mean of ROI is around 18.2%, and the range of 90% confidence interval is only about 1.3%.

As shown in the literature review 2.4, Murkowski claim that because of the payback provision, the Federal Tax Credit on the potential Alaska natural gas pipeline won't cost the federal government a penny. Is this true? Not necessary. The simulation results do not support this option.

[10] The normal distribution of the yearly natural gas historical data has a standard distribution around \$0.75MMBtu.

Table 4-3 shows the expected tax credits and tax recaptures generated by Monte Carlo simulation based on different EIA forecast as well as historical natural gas price. The expected Tax credits are always higher than the expected tax recapture under whatever EIA forecasts. The result goes even worse when the simulation ran based on the historical price data. The best-fit distribution of historical natural gas prices from 1993 through 2001 is a lognormal distribution which is skew right. It means that the possibility of having a lower price is much higher than having a higher price, which has the same deviation away from mean. In another words, we might meet more low gas prices than high gas prices during the life periods of Alaska natural gas pipeline according to the natural gas price history. It is likely that the Federal Government might give more credit than receive recapture during the project life time.

Table 4-3: Summary of the Expected Tax Credit and Tax Recapture

Simulation Result ($million)	Based on EIA Forecast June 2002	Based on EIA Forecast Dec 2001	Based on EIA Forecast May 2001	Based on Historical Price
Expected Tax Credit	2,659	6,344	8,807	59,263
Expected Tax Recapture	2,363	2,209	6,338	15,687

Notice that the expected tax credit/recapture calculation in this study was based on the assumption that the standard deviation of a normal distribution for a yearly price forecast is 0.75. We suggest that a future analysis can look at tax credit/recapture as higher and lower variances are put into a risk model.

The following Figures show the details of prices forecast, and simulation results made based on the EIA forecast June 2002. For details of results calculated based on other two forecasts, see Appendix A and B.

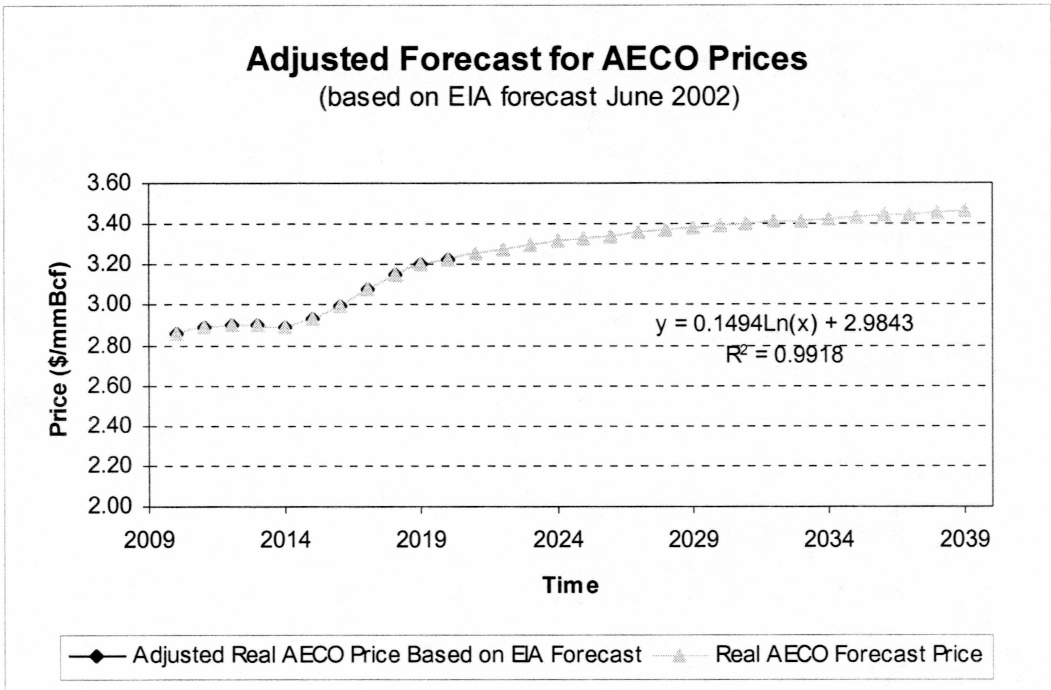

Figure 4-2: Adjusted AECO Prices Based on EIA Forecast June 2002

The price adjustments result is shown in Figure 4-2. Only the forecast prices from 2010 through 2020 are available in EIA's Natural Gas Outlook. Therefore, the prices from 2021 through 2039 are forecasted based on the trend of the last 5-year period of the EIA forecast price, which is from 2016 through 2020. The best-fit trend was used to predict future prices. In this case, the best-fit trend is a LN model. Notice that the LN model means that the tendency of price increasing would be relatively smooth while compared with EXP model.

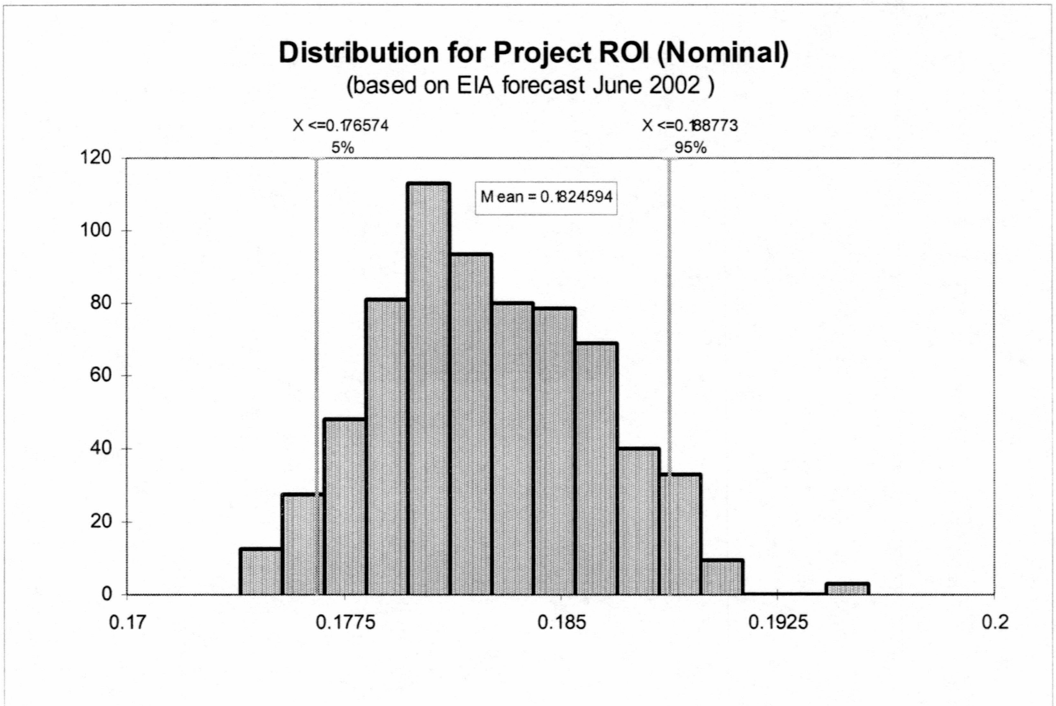

Figure 4-3: Distribution for Project ROI Based on EIA Forecast June 2002

The output distributions for the price changes during the production period summarize the price volatility and uncertainty of the project. Figure 4-3 shows the output (ROI) by probability density functions (PDF's) in histogram format.

Figure 4-3 shows the stimulation result based on EIA June 2002 forecast that there is 90% chance that the project ROI will be in 17.66% ~18.78% range with a mean value of 18.25%.

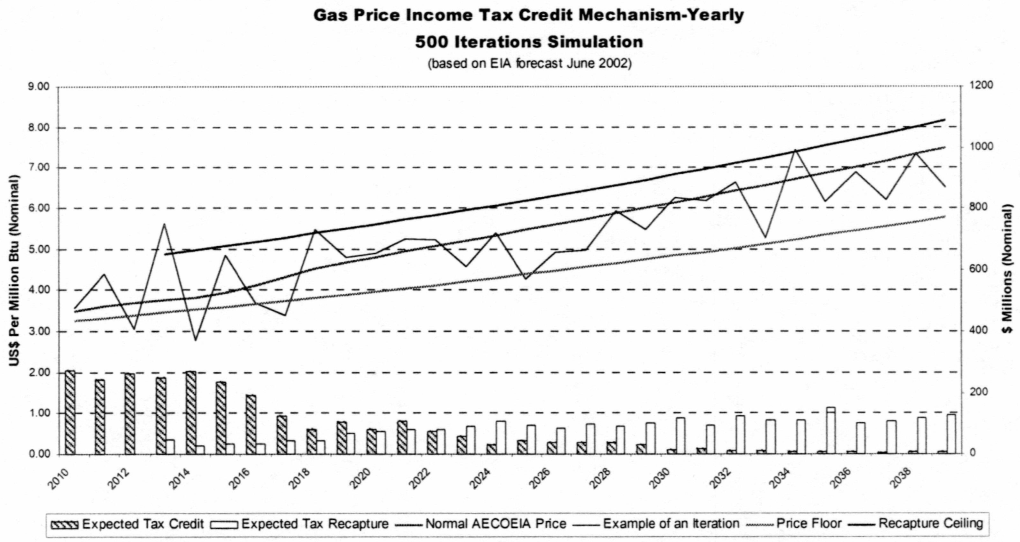

Figure 4-4: Tax Credit Yearly Simulation Based on EIA Forecast June 2002

Figure 4-4 shows the yearly simulation of prices turbulence (a trial of Monte Carlo sampling price picked from a total of 500 iterations) around AECO-EIA forecast and the possible price credits and price recaptures for each year.

The middle red line represents the AECO-EIA forecast; the upper blue line represents the price credit ceiling; and the lower grey line represents the price credit floor. The bars show the average value of 500 iterations for price credits and recaptures government will give and obtain for each year.

The price credit stimulation run based on the EIA June 2002 forecast shows that the likelihood of credit payments is smaller than for other simulations based on previous EIA forecasts. However, in the first several years of production period, the chances of getting price credits is pretty high, and the specific credit given and received situation depends on the trend of prices forecast. See Appendix A and B for the simulation results based on other EIA forecasts.

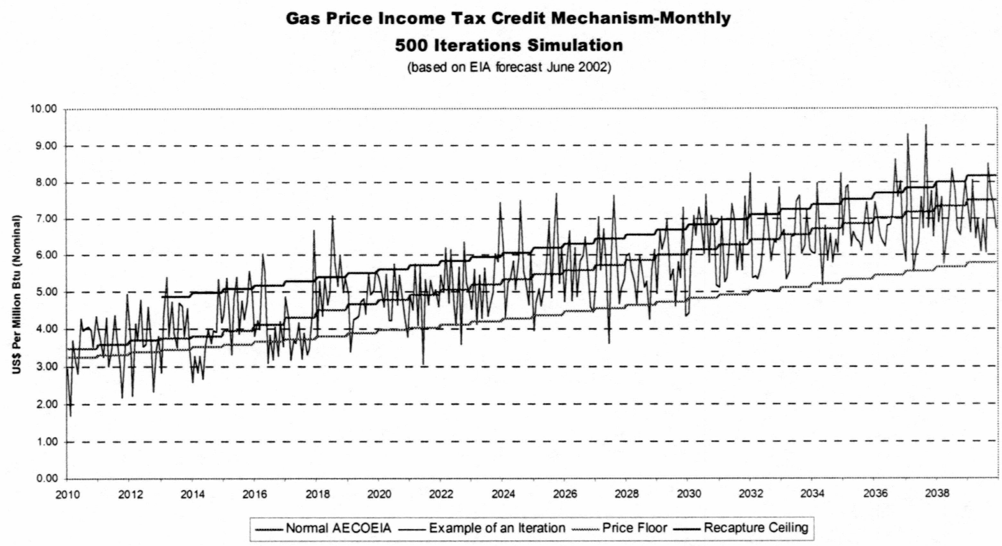

Figure 4-5: Tax Credit Monthly Simulation Based on EIA Forecast June 2002

Figure 4-5 shows the monthly simulation of prices turbulence around AECO-EIA forecast by picking a trial of Monte Carlo sampling prices from a total of 500 iterations. The middle red line represents the AECO-EIA forecast; the upper blue line represents the price credit ceiling; and the lower grey line represents the price credit floor.

4.4 Conclusion

Federal Tax Credit on Alaska natural gas pipeline project might not be revenue neutral for the Federal Government.

5 Y-LINE CASE VS. ALCAN ONLY CASE

5.1 Introduction

In this study, two gas pipeline project alternatives are analyzed to see which one is more risky according to price risk. These two alternatives are embraced currently by the State of Alaska, because both of them would provide more Alaskan construction and permanent jobs than any other routes had been considered. One is "ALCAN Only" project, also known as "ALCAN Highway" project, which would transport natural gas from the North Slope of Alaska to Alberta, Canada along with ALCAN Highway, then to Chicago. And it is thought to be economical from an overall investment perspective, depending upon market conditions. The other is called the "Y-line" project, which combines LNG and ALCAN Highway routines. In addition to the ALCAN line, there would be a spur line that takes volumes to Tidewater that could be marketed to various locations.

As our only concern here is price risk, three prices in model were treated as uncertain variables: AECO price was set based on EIA forecast; Propane price and world oil price are assigned distributions generated from historical data.

5.2 Price Distribution

The next three figures show distributions of input prices of the Alaska Natural Gas Pipeline economic model. They are a natural gas price forecast, a propane price distribution, and an oil price distribution.

To impose uncertainty on natural gas prices, a distribution function NORMAL(AECO-EIA forecast, 0.75) was introduced. This function can add some noise to the forecast prices. The adjusted forecast for AECO price and its future trend is shown in Figure 5-1.

Figure 5-2 shows an example of natural gas price distribution in a typical year – the distribution for natural gas price in 2011. It is a result of stratified sampling (500 iterations) generating from a function – Normal (3.60, 0.75). The \$3.60/MMBtu is the adjusted EIA forecast of natural gas price (nominal price) in 2011.

The historical data analysis shows that the distribution of Propane prices follows the lognormal function as shown in Figure 5-3. And the historical distribution of world oil prices follows the lognormal function as shown in Figure 5-4. Using the best-fit function of the Excel add-in tool @RISK generated these two prices distributions.

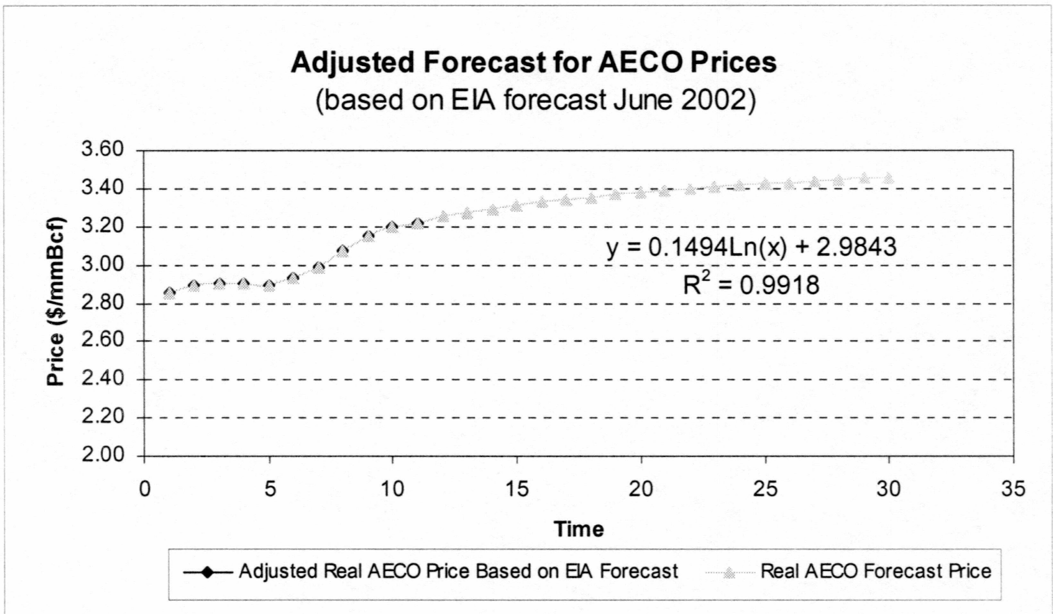

Figure 5-1: Future NG Price Trend

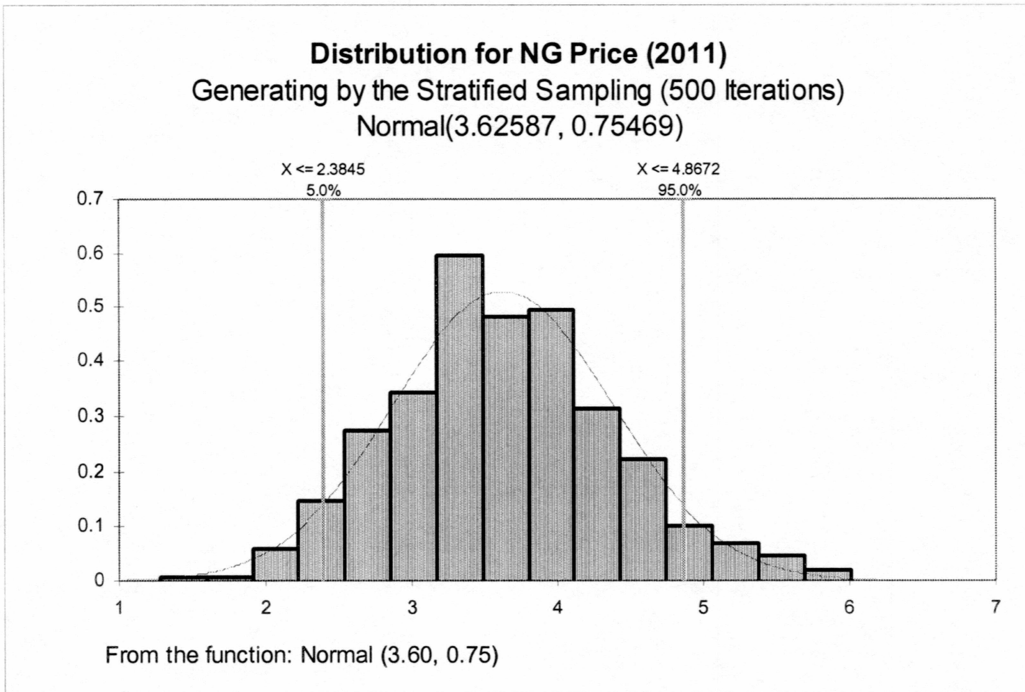

Figure 5-2: Sampled Distribution for NG Price (2011)

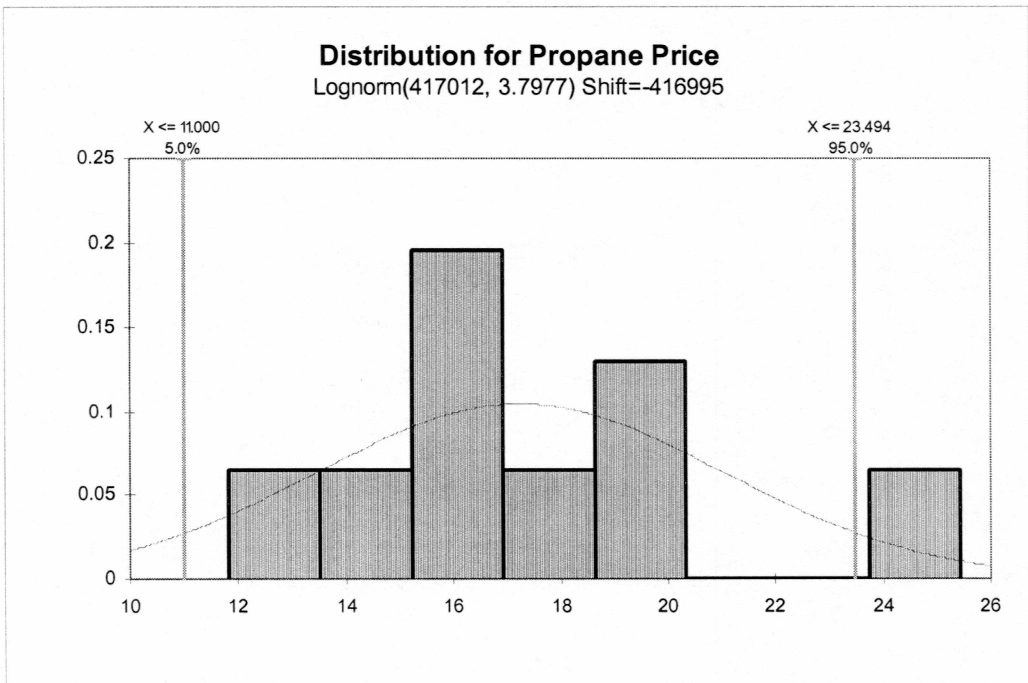

Figure 5-3: Distribution for Historical Propane Price

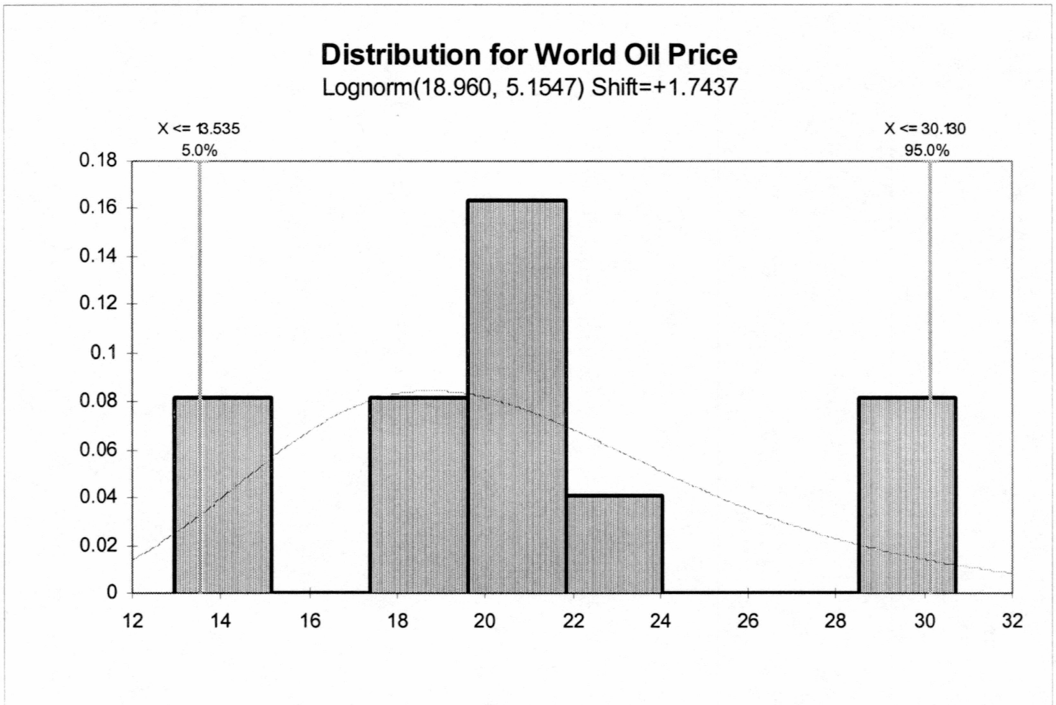

Figure 5-4: Distribution for Historical World Oil Price

5.3 Correlations among Input Variables

Before running simulations, historical data analysis had been done to determine the relationship among input variables. The correlations in Table 5-1 were calculated from real set of yearly data for a period of nine years from 1993 to 2001.The Table 5-1 shows the correlations among input variables, propane price, crude oil price, and natural gas price. The correlation between oil price and propane price is very high, about 0.95. The correlation between natural gas price and oil price, and the correlation between natural gas price and propane price are relatively low, only around 0.60.

In this study, only the correlation between propane price and crude oil price, 0.95, was considered in the simulation model.

Table 5-1: Correlation Matrix of Input Variables

	Real Propane Price	Real World Oil Price	Real AECO Price
Real Propane Price	1		
Real World Oil Price	0.95	1	
Real AECO Price	0.62	0.67	1

In 2002 US Dollars

5.4 Simulation Result

Table 5-2 summarizes the simulation results of Y-line case and ALCAN Only case. The probability distribution for Y-line Case represents greater risk than the ALCAN Only Case despite the fact that the Y-line has a smaller range of variability. The range of the variability of the Y-line includes less desirable results, even though it has a relatively narrow 90% confidence range. The ROI distribution of the Y-line is narrower than the ALCAN Only due to the 20 year contract of LNG. The ALCAN Only case is desirable economically because the Y-line case has a higher cost associated with the dual project. In a technical dimension, this project also requires quantities of gas reserves that have yet to be proven in order to reach the necessary economies of scale. Development in ANWR, along with other exploration efforts would likely solve this problem.

Table 5-2: Summary of Y-line Case vs. ALCAN Only Case

	Y- line	ALCAN Only
File Name	UAF NG 4.0	UAF NG 3.1.1
Capital Cost	$22,663million	$13,151million
Production	6.0Bcf/day	4.5Bcf/day
Result of Base Case (ROI)	14.13%	16.28%
Distribution for ROI	Mean=14.8% S.D. = 0.28%	Mean=17.7% S.D. = 0.68%
90% Confidence Interval	14.4%~15.2%	16.8%~18.7%
90% Range	0.8%	1.9%
75% Confidence Interval	14.5%~15.1%	17.0%~18.4%
Risk	Greater	

Figure 5-5 shows the simulation result for the Y-line Case. This is a histogram which shows the 90% confidence interval of ROI for the Y-line case is from 14.4% to 15.2% with a mean of 14.8%. It indicates that we have 90% confidence that the ROI of the Y-line Case will in 14.4% to 15.2% range, and the average level of ROI for 500 iterations simulation is 14.8%.

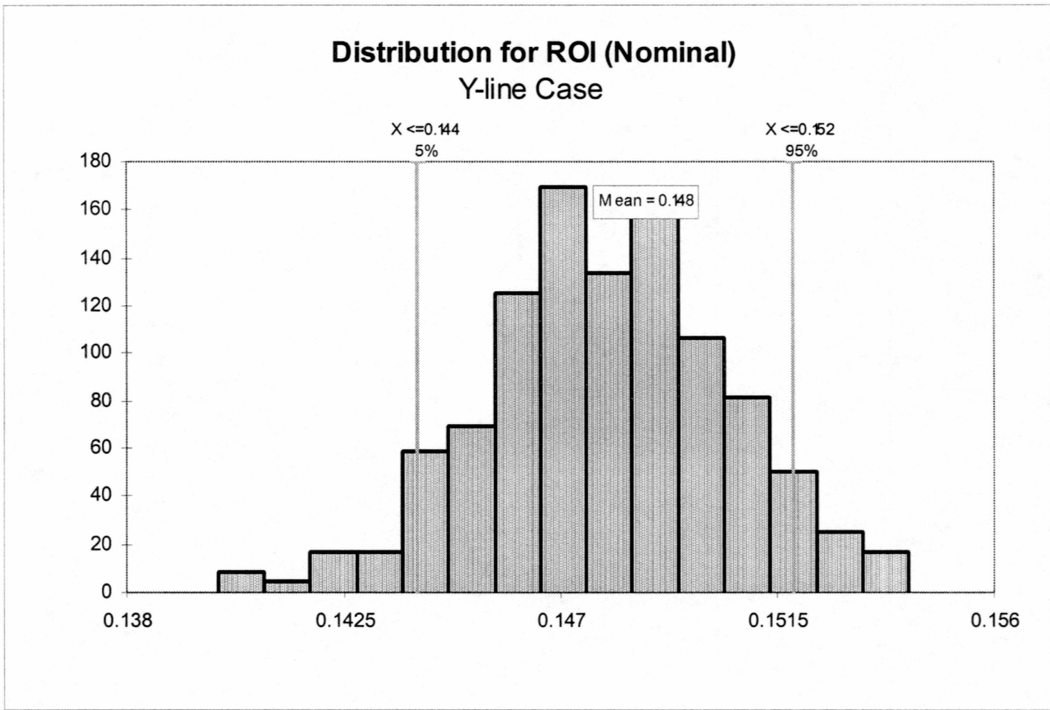

Figure 5-5: Simulation Result for Y-line Case

Figure 5-6 shows the accumulative curve of the Y-line Case. It tells us the 75% confidence interval of the ROI for the Y-line case is from 14.5% to 15.1% with a mean of 14.8%. It indicates that we have 75% confidence that the ROI of the Y-line Case will be in 14.5% to 15.1% range, and the average level of ROI for 500 iterations simulation is 14.8%.

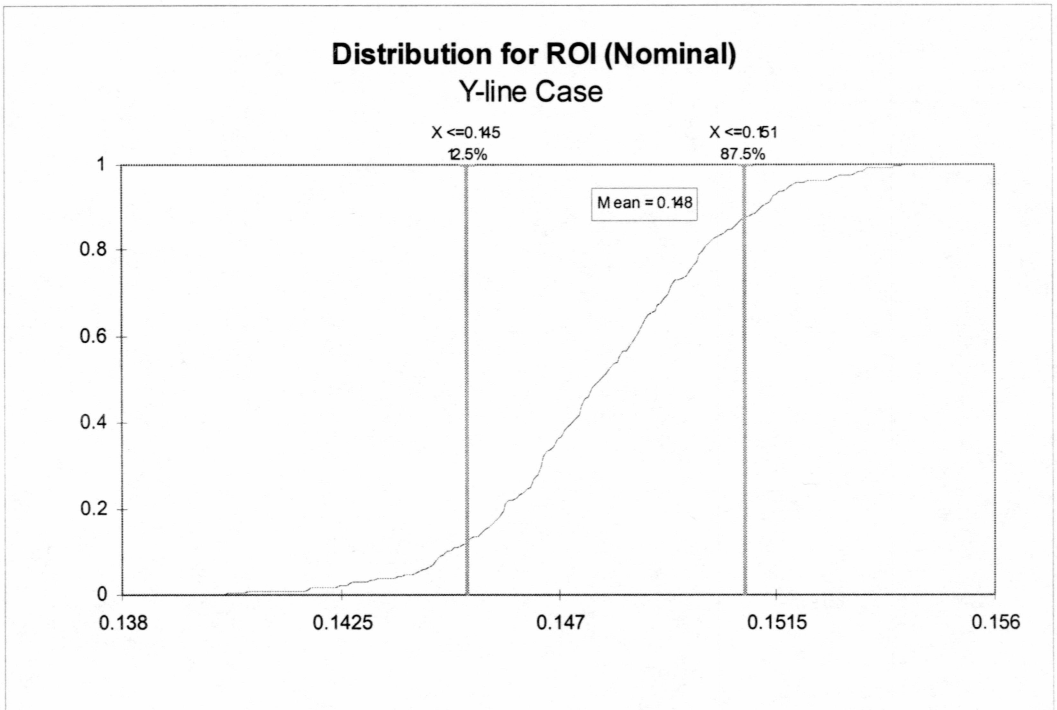

Figure 5-6: Simulation Result for Y-line Case—Accumulative Curve

Figure 5-7 shows the simulation result for the ALCAN Only Case. This histogram figure shows the 90% confidence interval of ROI for the ALCAN Only case is from 16.8% to 18.7% with a mean of 17.7%. It indicates that we have 90% confidence that the ROI of the ALCAN Only case will be in 16.8% to 18.7% range, and the average level of ROI for 500 iterations simulation is 17.7%.

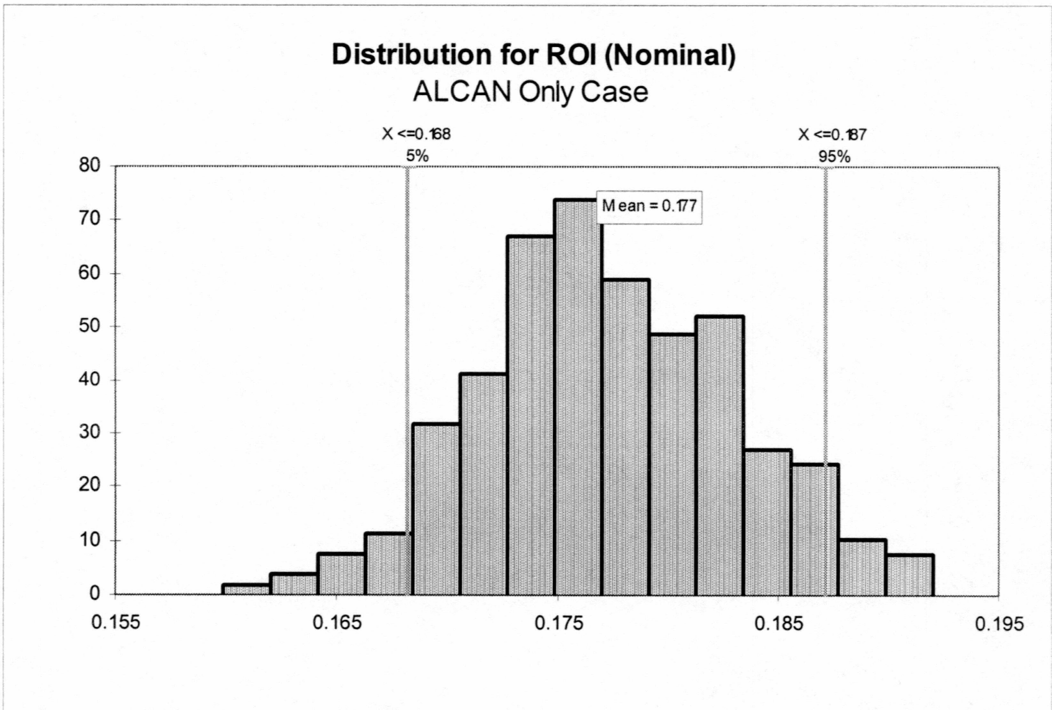

Figure 5-7: Simulation Result for ALCAN Only Case

Figure 5-8 shows the accumulative curve of the Y-line Case. It tells us the 75% confidence interval of ROI for the Y-line case is from 17.0% to 18.4% with a mean of 17.7%. It indicates that we have 75% confidence that the ROI of the Y-line case will be in 17.0% to 18.4% range, and the average level of ROI for 500 iterations simulation is 17.7%.

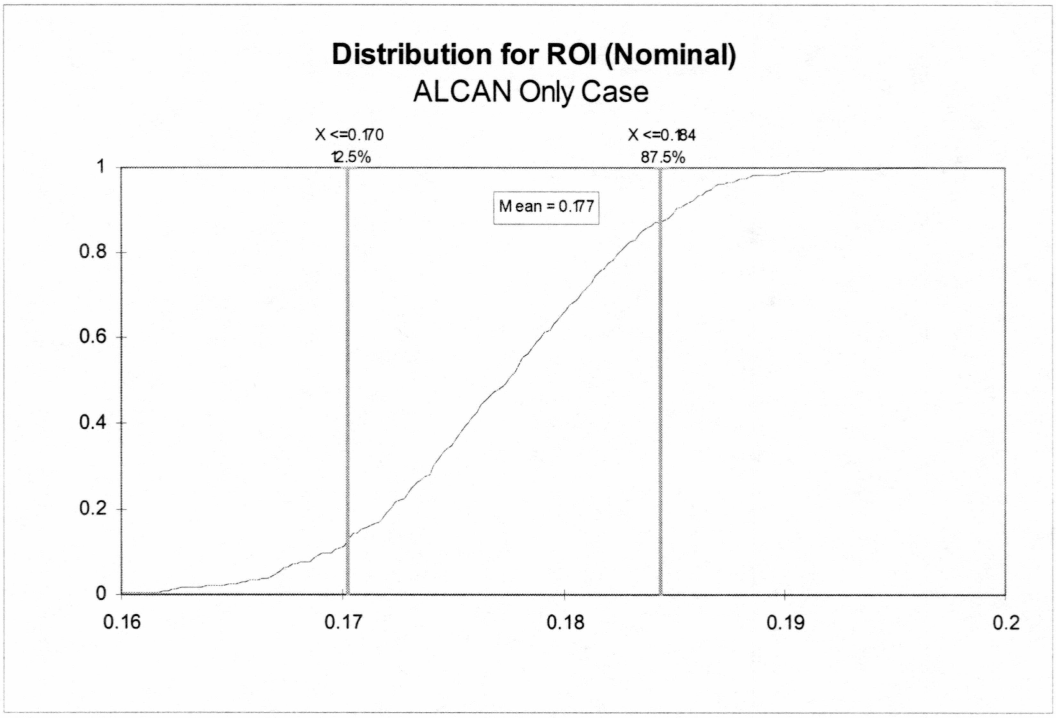

Figure 5-8: Simulation Result for ALCAN Only Case—Accumulative Curve

A tornado chart is a good way to determine the effect of each variable in a specific prospect. The variables listed at the bottom of the graph are the least important.

Figure 5-9 and Figure 5-10 show the results of sensitivity analysis for the Y-line Case and the ALCAN Only Case. The common sense for both of them is that the most recent price will be the most important and sensitive factor in the pipeline economic model. We can simply rank the sensitivity of every year's natural gas price by the year it will happen. We can also tell that for the propane, the effect on pipeline economic model depends upon its production against total production ratio of this pipeline.

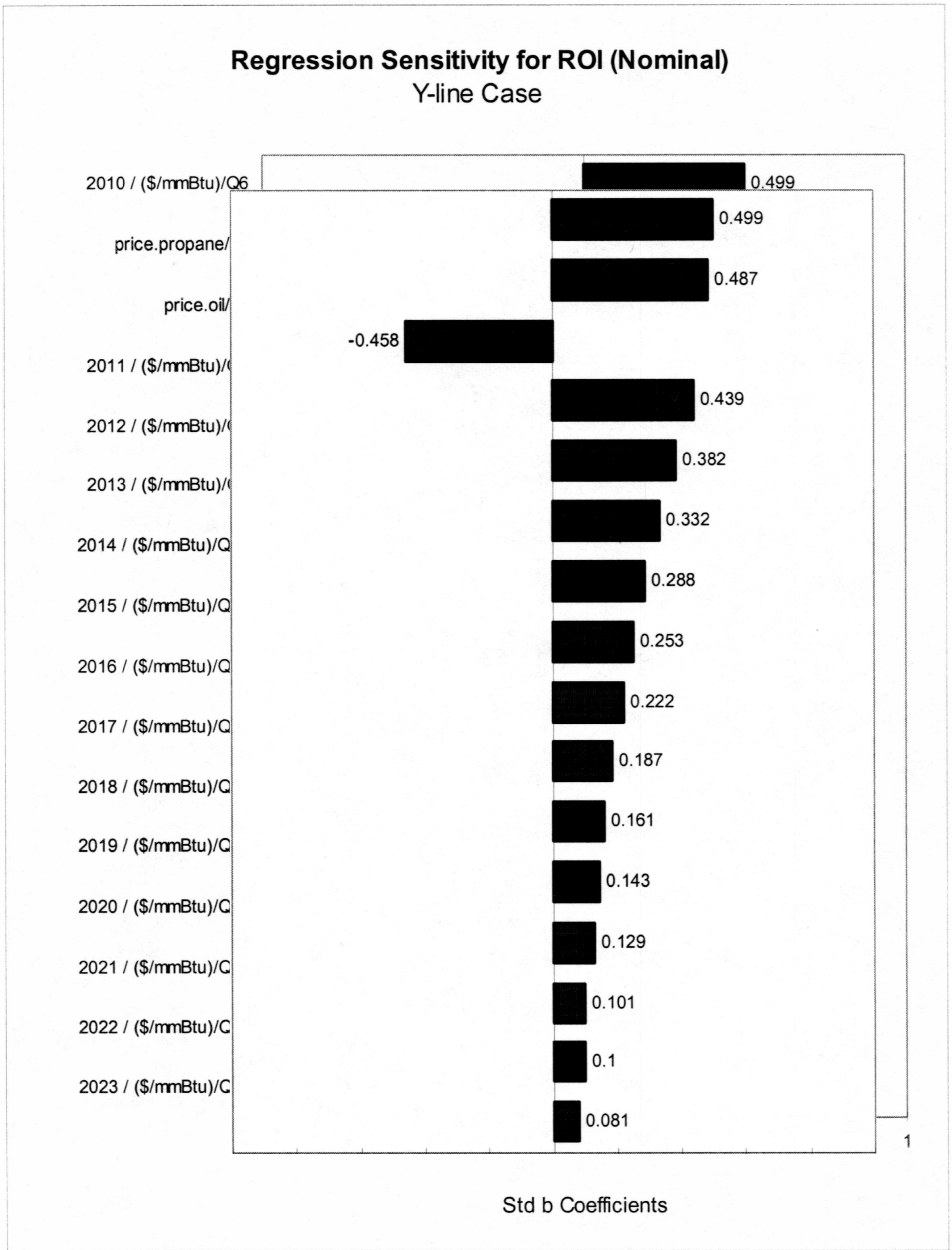

Figure 5-9: Tornado Chart for Y-line Case

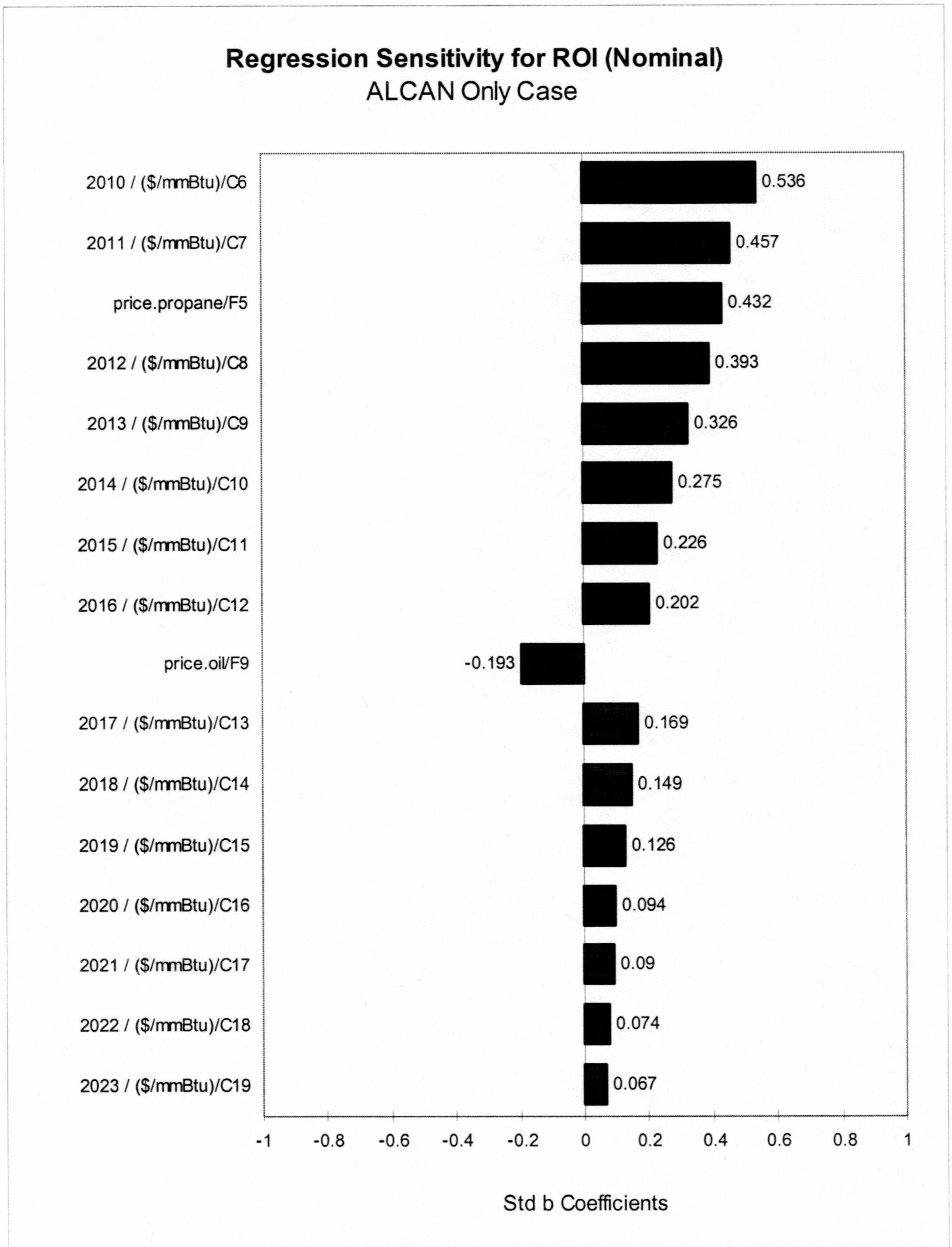

Figure 5-10: Tornado Chart for ALCAN Only Case

Oil price has a negative effect on ROI because we consider "oil lost" in our model. If a field produces gas to profit in the gas market, then the gas cannot be re-inject into oil wells to produce oil anymore. That creates a certain amount of oil lost due to this change.

We can draw a conclusion that the ALCAN Only Case is better than the Y-line Case. It is because:

1. The mean of ROI of the ALCAN Only Case is better than the Y-line Case.
2. The ALCAN Only Case generates higher ROI in any confidence level than the Y-line Case.

Therefore, even if risk-averse, we still would prefer the ALCAN Only Case.

6 5.5 BCF/DAY CASE

6.1 Introduction

A 5.5 Bcf/day production Project was developed to compare with the 4.5 Bcf/day Case (the ALCAN Only Case), in case of there are more gas source found in the coming future. 5.5 Bcf/day Project supposes that the production will increase from 4.5 billion/day to 5.5 Bcf/day in 2013.

There are two models for the 5.5 Bcf/day project. One is to use the old model with the higher thought output, i.e. 5.5 Bcf/day, called the "Build Large" model. In this model, the designed pipeline diameter changes from 49" to 54" for the additional 1.0 Bcf/day production. Thus the initial capital investment will increase to $14,773 million. These calculations were made automatically by the build-in formula in the economic model, where the pipeline diameter associates with the pipeline transportation capacity and the initial capital cost associates with the pipeline diameter.

The other is to use a 4.5 Bcf/day model and add compressor stations, called the "Compressor" model. For increasing transportation capacity from 4.5 Bcf/day to 5.5 Bcf/day in 2013, compressor stations will be built in 2012. Thus the initial capital investment may keep at $13,151 million, and there is a capital investment at amount of $1,500 million in 2012.

For the consideration shown above, we compared two cases in this study, the Build Large Case and the Compressor Case. As shown in Table 6-1, the production of these two cases is same, 4.5bcf/day from 2010 through 2012, and the production will achieve 5.5bcf/day in 2013. The differences of these two cases are capital investment and construction schedule. The Build Large Case has initial capital cost $14,773 million. This amount of money will be invested during the four-year construction period from 2006 through 2009. The Compressor Case has $13,151 million initial capital cost invests in the four-year construction period, and then

$1,500 million will be invested for compressor stations for increasing the pipeline transportation capacity to 5.5bcf/day.

Table 6-1: Inputs Comparison

	Build Large	Compressor
Capital Cost	$14,773 million (2006~2009)	$13,151million (2006~2009) $1,500million (2012)
Production	4.5 Bcf/day (2010~2012) 5.5 Bcf/day (2013~2039)	Same
Natural Gas Price	A normal distribution with a mean of Adjusted Yearly EIA Forecast and a standard deviation of 0.75.	Same
Propane Price	Lognormal distribution from historical data	Same
World Oil Price	Lognormal distribution from historical data	Same

Suppose we believe that the capital investment of the compressor stations in 2012 has a triangular distribution with a minimum of $1,000 million, a mean of $1,500 million, and a maximum value of $2,000 million. Figure 6-1 shows the probability distribution of the capital cost of compressor stations based on our assumption.

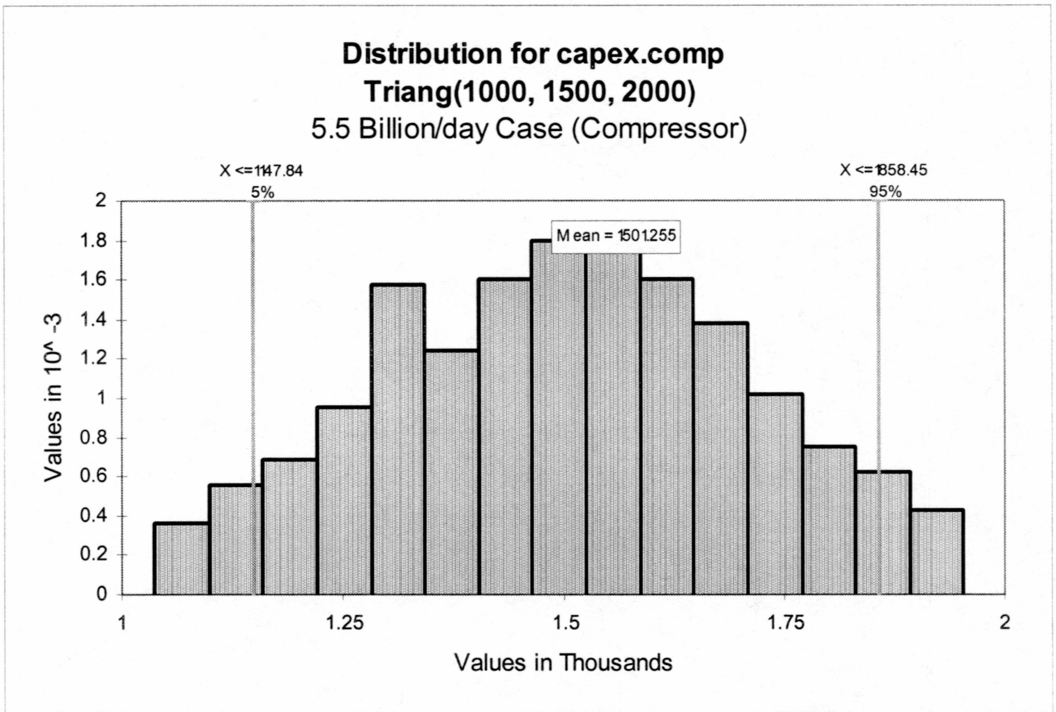

Figure 6-1: Triangle Distribution for the Investment of Compressor Stations

6.2 Simulation Result

Table 6-2 shows the summary of simulation result for the 5.5 Bcf/day Project. We would prefer Compressor Case because it has higher ROI and it is more flexible. It allows the 4.5 Bcf/day project developing to the more profitable 5.5 Bcf/day project when new gas source found in the future. Because we can add Compressor Stations whenever it is necessary, there would be no risk of wasting pipeline capacity.

Table 6-2: Summary of 5.5 Billion/day Case

	Build Large	**Compressor**
File Name	UAF NG 3.3	UAF NG 3.3.1
Capital Cost	$14,773million	$13,151+$1,500million
Production	5.5Bcf/day	5.5Bcf/day
Distribution for ROI	Mean=17.75% S.D. = 0.58%	Mean=19.40% S.D. = 0.66%
90% Confidence Interval	16.80%~18.75%	18.37%~20.57%
90% Range	1.95%	2.20%
75% Confidence Interval	17.07%~18.40%	18.66%~20.18%
Risk	Greater	

Notices that the total capital cost of two cases have no big difference. The economic analysis shows the Compressor Case is better, because the scale of initial investment has greater effect on the project net present cash flow.

Figure 6-2 shows the simulation result for the Build Large Case. This is a histogram which shows the 90% confidence interval of ROI for the Build Large Case is from 16.8% to 18.8% with a mean of 17.7%. It indicates that we have 90% confidence that the ROI of the Pipeline Build Large Case will be in 16.8% to 18.8% range, and the average level of ROI for 500 iterations simulation is 17.7%.

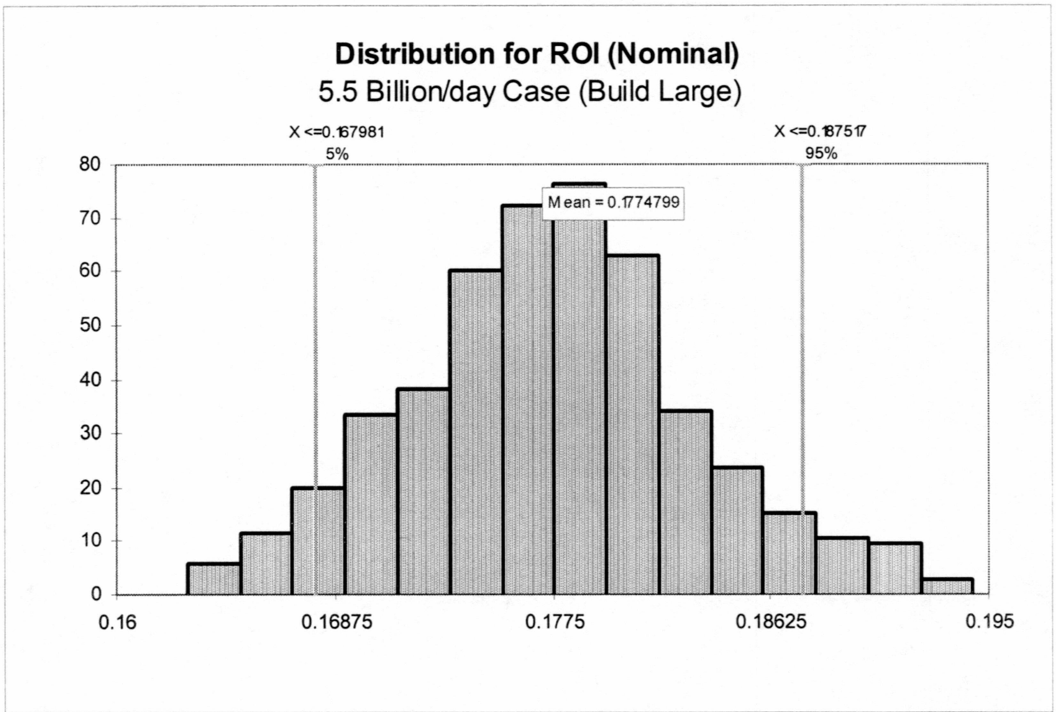

Figure 6-2: Simulation Result for 5.5 Billion/day Case (Build Large)

Figure 6-3 shows the accumulative curve of the Build Large Case. It tells us the 75% confidence interval of ROI for the Build Large Case is from 17.1% to 18.4% with a mean of 17.7%. It indicates that we have 75% confidence that the ROI of the Build Large Case will be in 17.1% to 18.4% range, and the average level of ROI for 500 iterations simulation is 17.7%.

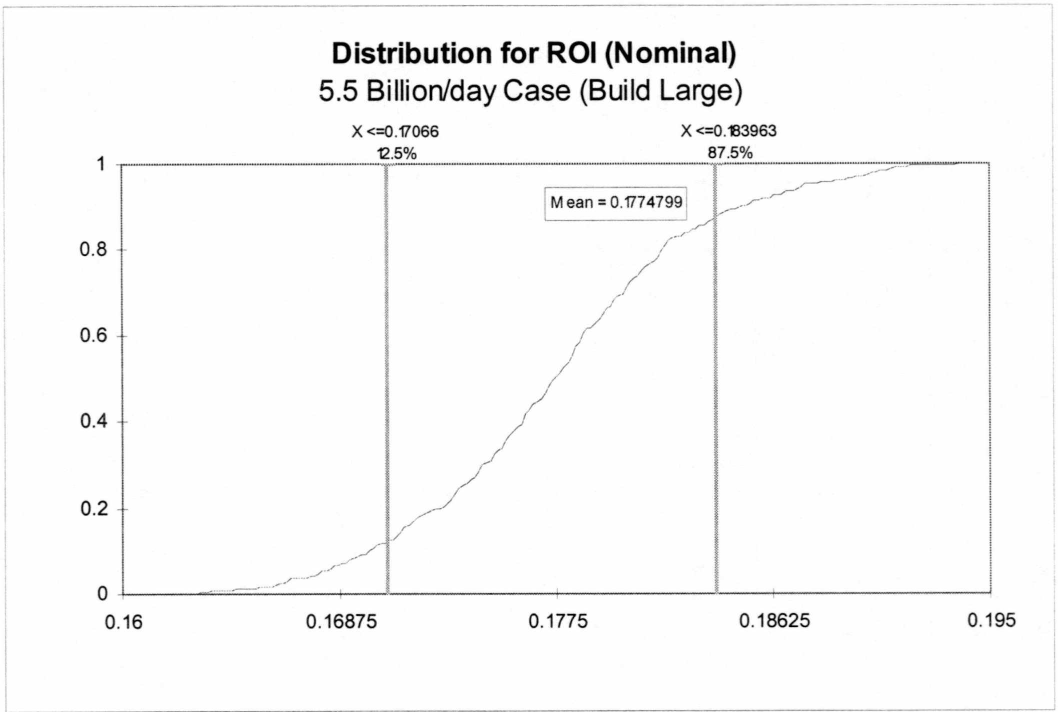

Figure 6-3: Simulation Result for 5.5 Billion/day Case (Build Large)—Accumulative Curve

Figure 6-4 shows the simulation result for the Compressor Case. This is a histogram which shows the 90% confidence interval of ROI for the Compressor Case is from 18.4% to 20.6% with a mean of 19.4%. It indicates that we have 90% confidence that the ROI of the Compressor Case will be in 18.4% to 20.6% range, and the average level of ROI for 500 iterations simulation is 19.4%.

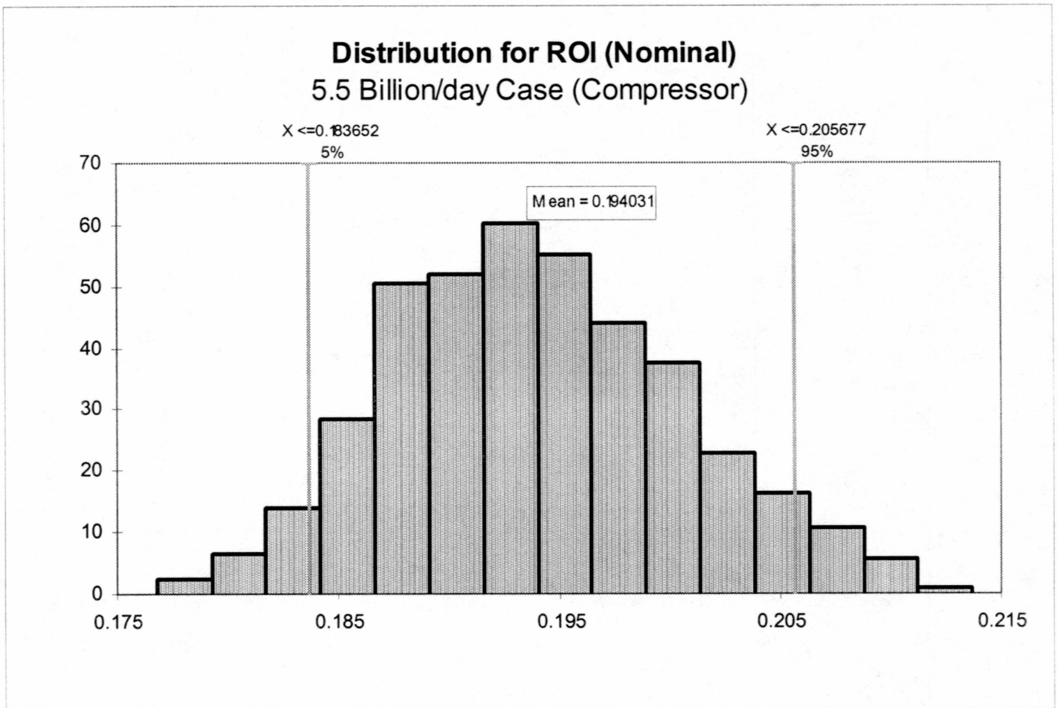

Figure 6-4: Simulation Result for 5.5 Billion/day Case (Compressor)

Figure 6-5 shows the accumulative curve of the Compressor Case. It tells us the 75% confidence interval of ROI for the Compressor Case is from 17.1% to 18.4% with a mean of 17.7%. It indicates that we have 75% confidence that the ROI of the Compressor Case will be in 17.1% to 18.4% range, and the average level of ROI for 500 iterations simulation is 17.7%.

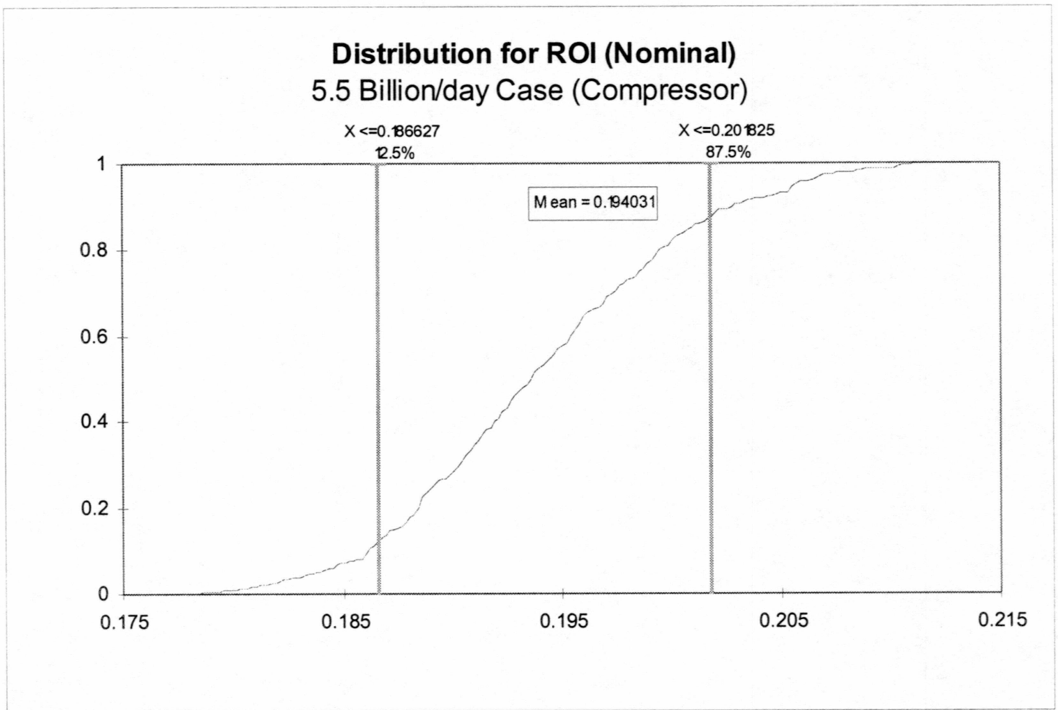

Figure 6-5: Simulation Result for 5.5 Billion/day Case (Compressor)—Accumulative Curve

Figure 6-6 and Figure 6-7 show the results of sensitivity analysis for the Build Large Case and the Compressor Case. Notice the Figure 6-7 shows that the natural gas price of 2013 is more sensitive than the price of 2012. It looks like there is a little conflict against our previous explanations. The reasonable explanation of this phenomenon is that the Compressor case has $1,500 million capital investment in 2012, and therefore the 2013 gas price would be a key factor to successfully recover this amount of money.

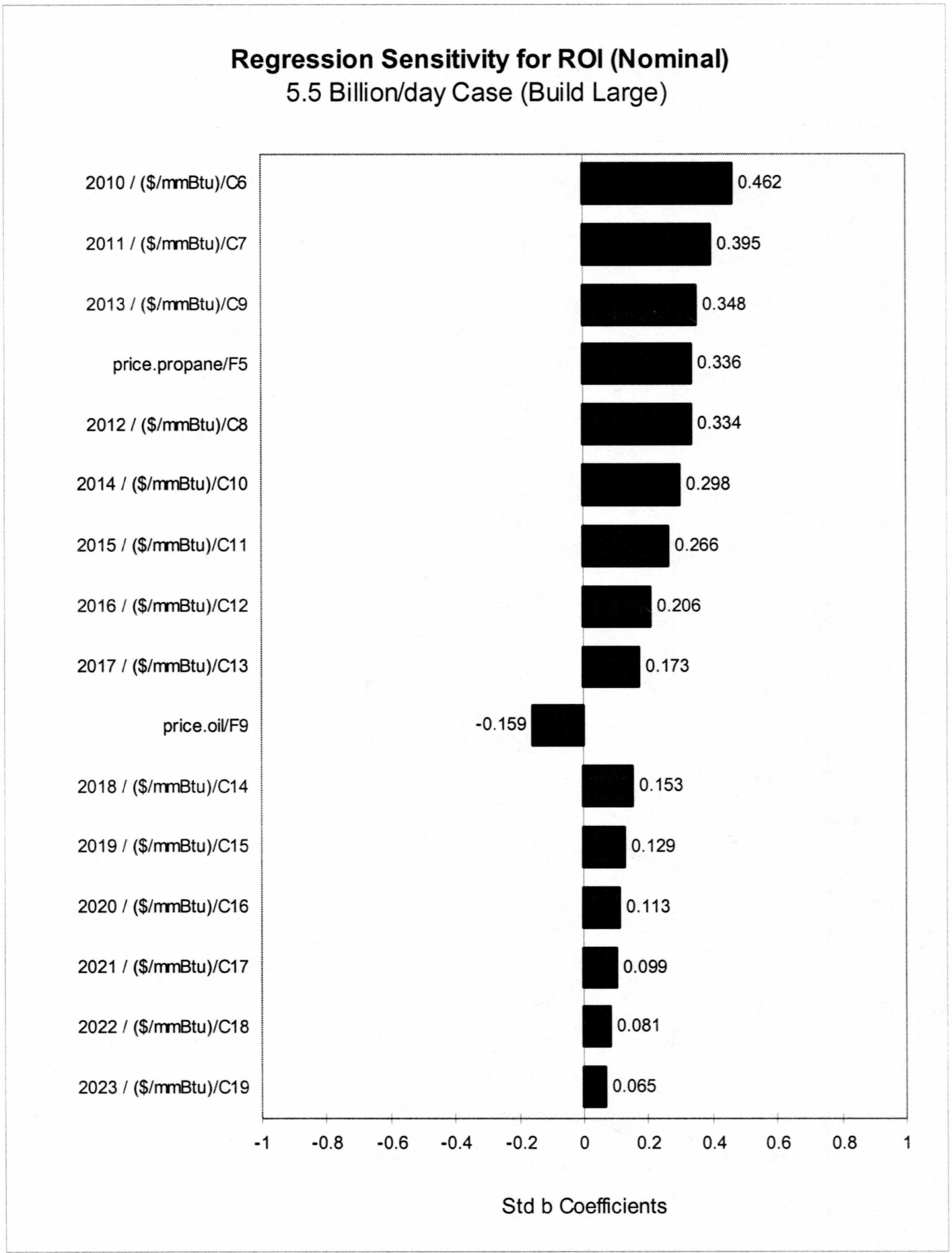

Figure 6-6: Tornado Chart for 5.5 Billion/day Case (Build Large)

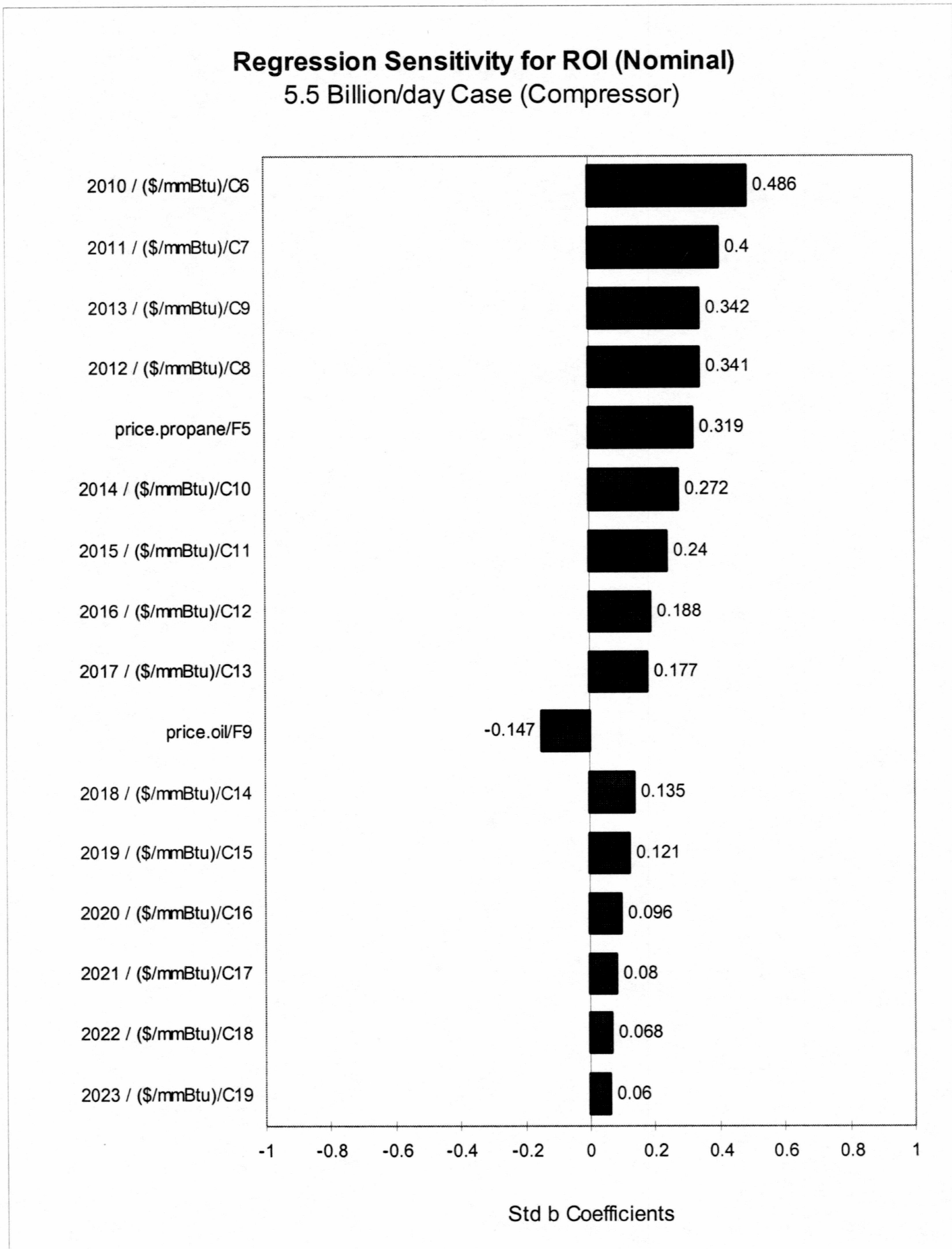

Figure 6-7: Tornado Chart for 5.5 Billion/day Case (Compressor)

7 CONCLUSIONS AND RECOMMENDATIONS

7.1 General Conclusions

It has been more than twenty years since the Monte Carlo Simulation start serving oil and gas industry. However, most of these risk analysis efforts were focusing on technical risks, such as base and incremental reserves, current field and well rates, well, platform, and facility costs, workover and operating costs, and rig scheduling. Commodity risk, like price, always be ignored or simplified. Since a natural gas development project holds a lot of risk because of unpredictable gas prices, a price risk analysis is necessary for good project decision-making.

The following conclusions are made based on the price risk analysis of this study.

1. The price risk involved in Alaska Gas Pipeline Project decreases significantly with the Federal Tax Credit (Price Credit).
2. The tax credit could add 3-6 percent to the rate of return on this gas pipeline project. However it might not be revenue neutral for the Federal Government.
3. The ALCAN Only 4.5 Bcf/day case would be the most feasible and flexible choice for the long-run gas development with less commodity risk.

7.2 Recommendations

I recommend that a reader of this study should consider rerunning simulations shown above when

1. The assumption of any determined input is changed. For example, cost estimates, production forecast, and rig scheduling may change while the further study is done on a specific pipeline route.
2. Any new reliable price forecast is available.
3. The price distribution assignments can be improved based on new knowledge.

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APPENDIX A – SIMULATION RESULTS OF PRICE CREDIT BASED ON EIA FORECAST DEC 2001

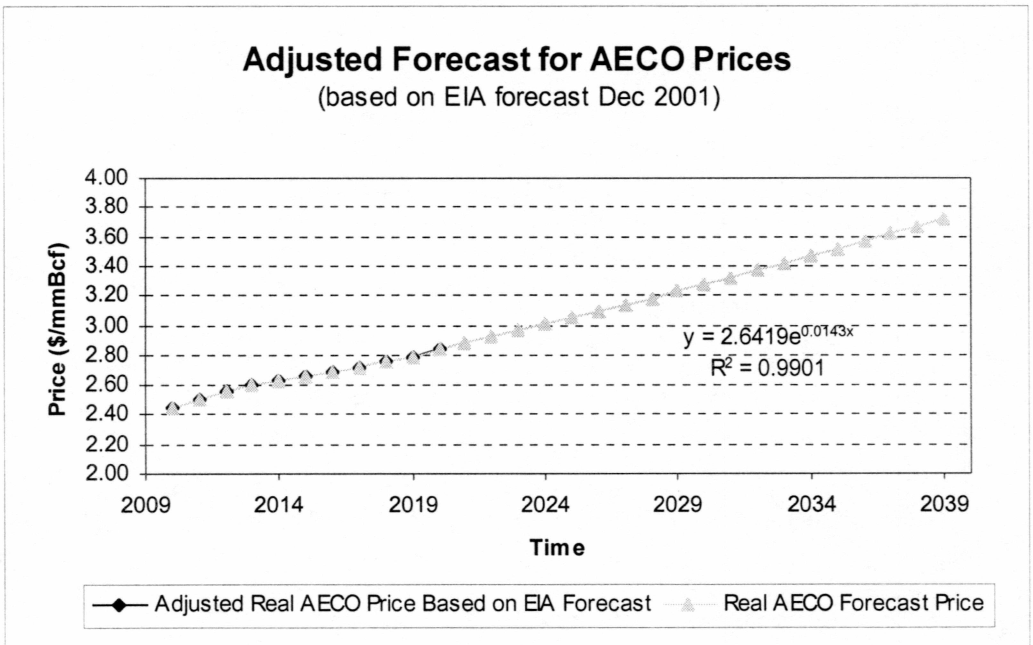

Figure A-1: Adjusted AECO Prices Based on EIA Forecast Dec 2001

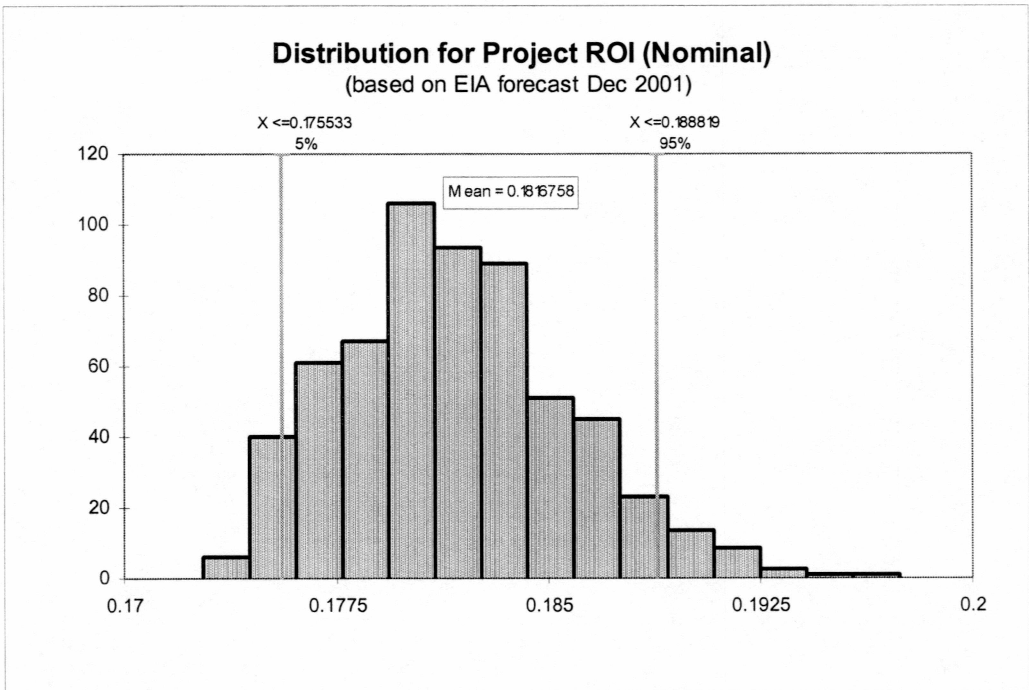

Figure A-2: Distribution for Project ROR Based on EIA forecast Dec 2001

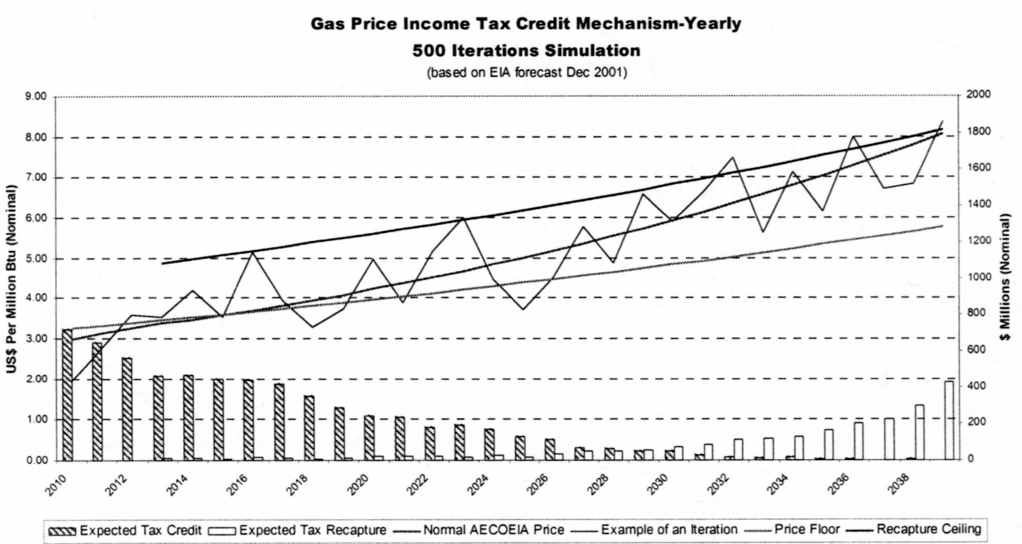

Figure A-3: Tax Credit Yearly Simulation Based on EIA Forecast Dec 2001

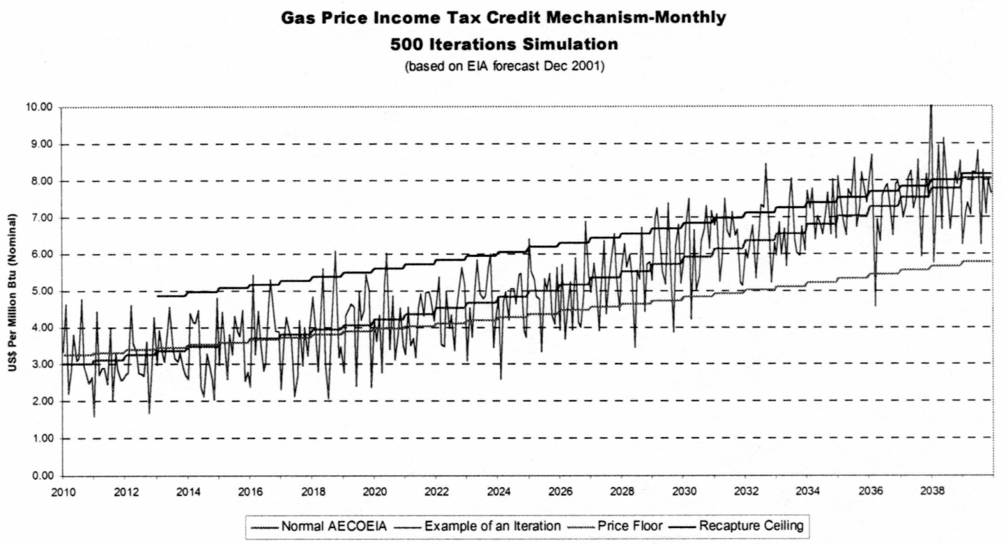

Figure A-4: Tax Credit Monthly Simulation Based on EIA Forecast Dec 2001

APPENDIX B – SIMULATION RESULTS OF PRICE CREDIT BASED ON EIA FORECAST MAY 2001

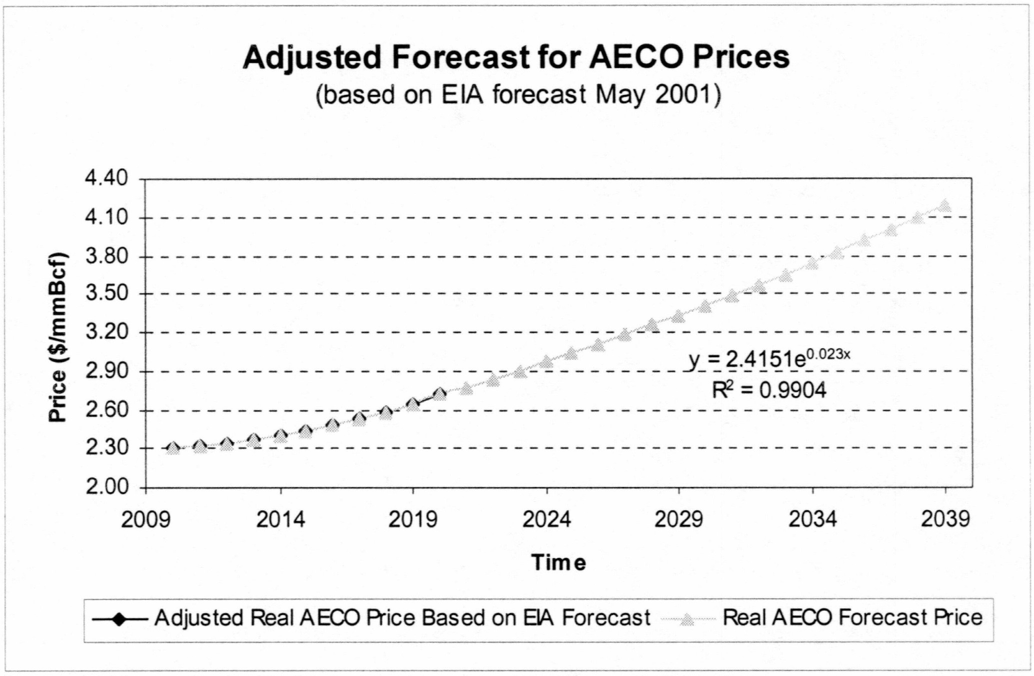

Figure B-1: Adjusted AECO Prices Based on EIA Forecast May 2001

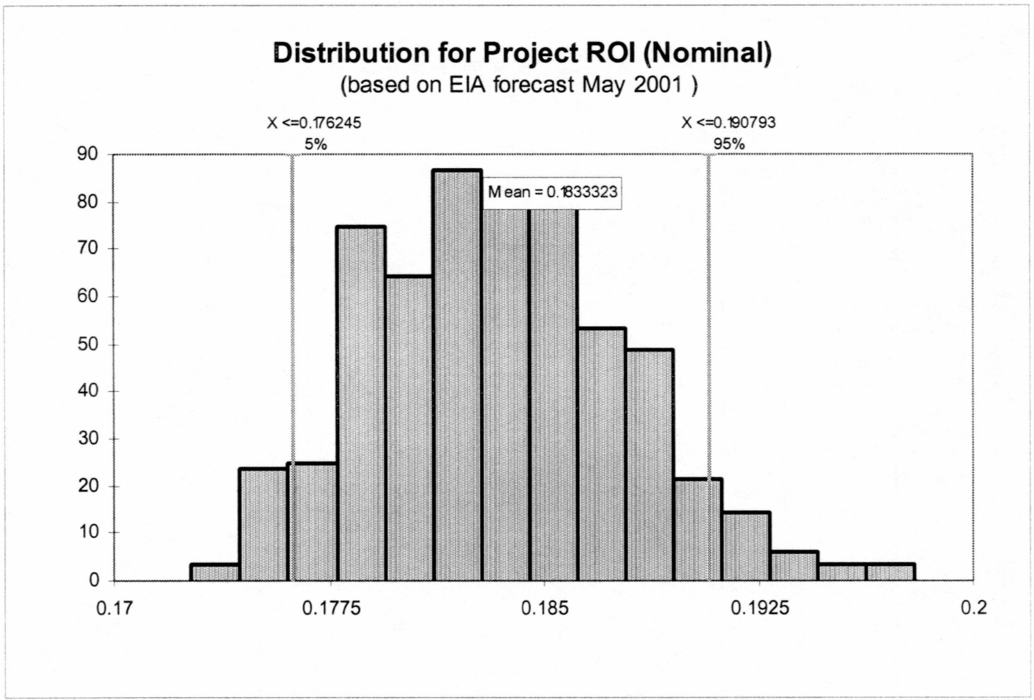

Figure B-2: Distribution for Project ROI Based on EIA Forecast May 2001

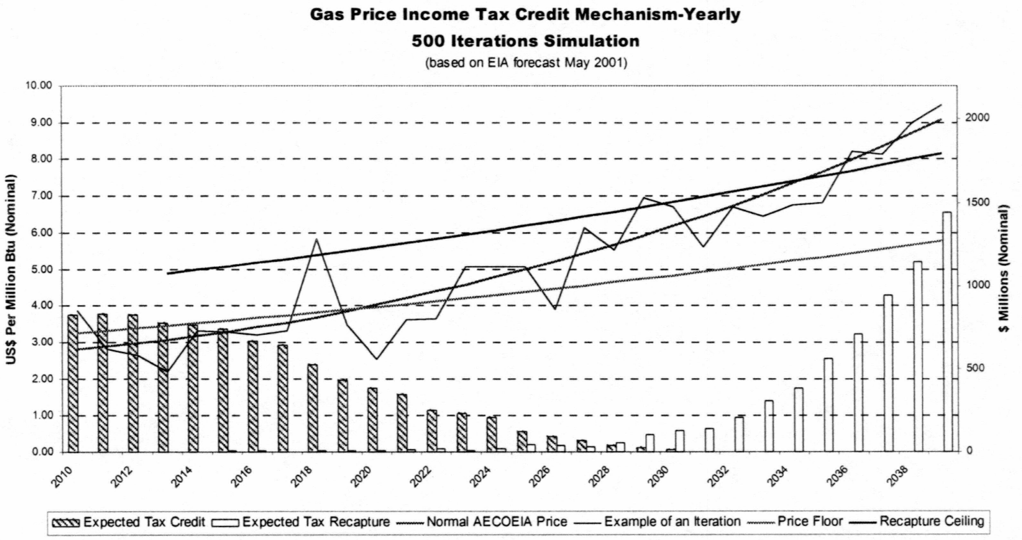

Figure B-3: Tax Credit Yearly Simulation Based on EIA Forecast May 2001

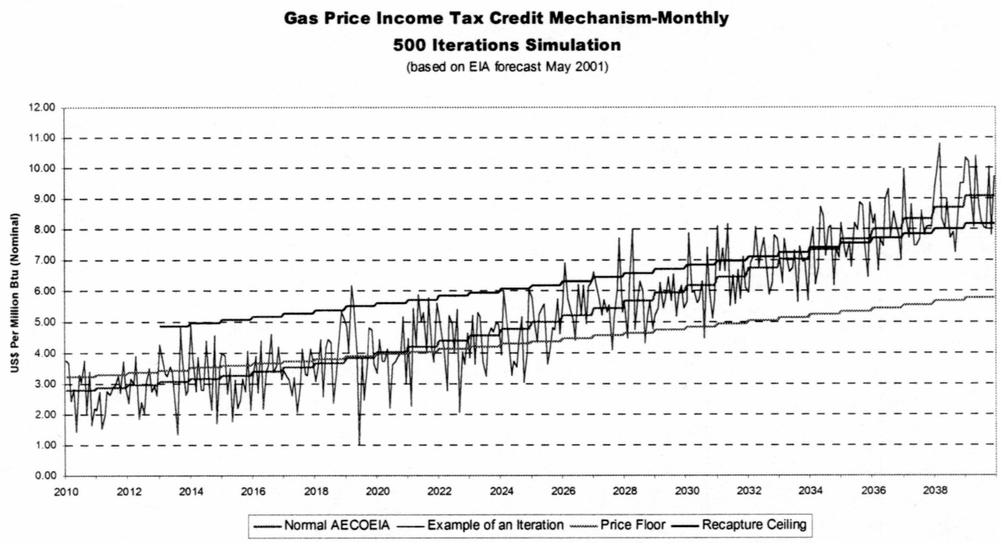

Figure B-4: Tax Credit Monthly Simulation Based on EIA Forecast May 2001