COMPREHENSIVE INVESTIGATION INTO HISTORICAL PIPELINE CONSTRUCTION COSTS AND ENGINEERING ECONOMIC ANALYSIS OF ALASKA IN-STATE GAS PIPELINE

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Zhenhua Rui, B.S., M.S.

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COMPREHENSIVE INVESTIGATION INTO HISTORICAL PIPELINE CONSTRUCTION COSTS AND ENGINEERING ECONOMIC ANALYSIS OF ALASKA IN-STATE GAS PIPELINE

By

Zhenhua Rui

RECOMMENDED:

Xiyu Zhou
Dr. Xiyu Zhou

Douglas Reynolds
Dr. Douglas Reynolds

Gang Chen
Dr. Gang Chen, Advisory Committee Co-chair

Paul Metz
Dr. Paul Metz, Advisory Committee Co-chair

Dr. Rajive Ganguli, Chair of Department of Mining and Geological Engineering

APPROVED:

Dr. Doug Goering, Dean of College of Engineering and Mines

Lawrence K Duffy
Dr. Lawrence Duff, Dean of the Graduate School

Dec 6, 2011
Date

ABSTRACT

This study analyzes historical cost data of 412 pipelines and 220 compressor stations. On the basis of this analysis, the study also evaluates the feasibility of an Alaska in-state gas pipeline using Monte Carlo simulation techniques.

Analysis of pipeline construction costs shows that component costs, shares of cost components, and learning rates for material and labor costs vary by diameter, length, volume, year, and location. Overall average learning rates for pipeline material and labor costs are 6.1% and 12.4%, respectively. Overall average cost shares for pipeline material, labor, miscellaneous, and right of way (ROW) are 31%, 40%, 23%, and 7%, respectively. Regression models are developed to estimate pipeline component costs for different lengths, cross-sectional areas, and locations. An analysis of inaccuracy in pipeline cost estimation demonstrates that the cost estimation of pipeline cost components is biased except for in the case of total costs. Overall overrun rates for pipeline material, labor, miscellaneous, ROW, and total costs are 4.9%, 22.4%, -0.9%, 9.1%, and 6.5%, respectively, and project size, capacity, diameter, location, and year of completion have different degrees of impacts on cost overruns of pipeline cost components.

Analysis of compressor station costs shows that component costs, shares of cost components, and learning rates for material and labor costs vary in terms of capacity, year, and location. Average learning rates for compressor station material and labor costs are 12.1% and 7.48%, respectively. Overall average cost shares of material, labor, miscellaneous, and ROW are 50.6%, 27.2%, 21.5%, and 0.8%, respectively. Regression models are developed to estimate compressor station component costs in different capacities and locations. An investigation into inaccuracies in compressor station cost estimation demonstrates that the cost estimation for compressor stations is biased except for in the case of material costs. Overall average overrun rates for compressor station material, labor, miscellaneous, land, and total costs are 3%, 60%, 2%, -14%, and 11%, respectively, and cost overruns for cost components are influenced by location and year of completion to different degrees.

Monte Carlo models are developed and simulated to evaluate the feasibility of an Alaska in-state gas pipeline by assigning triangular distribution of the values of economic parameters. Simulated results show that the construction of an Alaska in-state natural gas pipeline is feasible at three scenarios: 500 million cubic feet per day (mmcfd), 750 mmcfd, and 1000 mmcfd.

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CHAPTER 1 INTRODUCTION

1.1 Overview

The discussion and debate over building an Alaska in-state natural gas pipeline intensifies in Alaska as gas resources in Cook Inlet continues to deplete. The Cook Inlet Basin has supplied low cost gas for Southcentral Alaska's residential, commercial, and industrial demands, and exported large quantities of fertilizer and liquefied natural gas (LNG) since the late 1960s. However, after 2002, the lack of sufficient natural gas production from Cook Inlet led to the closure of the Agrium fertilizer plant near Kenai in 2007 and the closure of the Kenai LNG export facility in 2011 (Agrium, 2007; Petroleum News, 2011). These closures are the consequence of rapidly diminishing natural gas production in the region. The shortage of gas in Southcentral Alaska has become a major concern for the state. However, Remaining recoverable oil on Alaska North Slope (ANS) is approximately 6.1 billion barrels; discovered technologically recoverable natural gas is approximately 35 trillion cubic feet (Tcf) (Thomas et al, 2009). The most viable solution to continue to supply Alaska low cost gas is to bring future natural gas supplies from ANS fields to Southcentral Alaska. The abundance of natural gas in ANS can provide sufficient gas for a pipeline to supply the in-state needs of Alaska for the long term.

ENSTAR Natural Gas Company (ENSTAR) and Alaska Gasline Development Corporation (AGDC) have proposed an in-state gasline from the ANS to the Cook Inlet region. This gasline includes a 737- mile-long, 24-inch-diameter mainline pipeline that would run from Prudhoe Bay to Livengood, and then head south to join the Parks Highway corridor near Nenana. From there, the pipeline would continue south and terminate at milepost (MP) 737, connecting at MP 39 of the Beluga Pipeline near Big Lake. A lateral 35-mile-long, 10-inch-diameter pipeline would take off from the main pipeline a few miles north of Nenana near Dunbar and travel to the northeast of Fairbanks (AGDC, 2011).

ENSTAR and AGDC have conducted some studies of the feasibility of an Alaska in-state gas pipeline (AGDC, 2011; ENSTAR, 2011), but these studies have not provided detailed information about costs and cost sources, so a comprehensive analysis of the Alaska in-state gas pipeline with supportive historical cost data is highly necessary. This study includes three major parts: a comprehensive analysis of historical cost data of 412 pipelines; a comprehensive analysis of historical cost data of 220 compressor stations; and the development of Monte Carlo simulation models to probabilistically analyze the feasibility of the proposed Alaska in-state natural gas pipeline.

Historical pipeline cost data have been analyzed to estimate construction costs for different purposes by various researchers (Heddle et al., 2003; McCoy and Rubin, 2008; Parker, 2004). Roughly linear regression methods, multiple linear regression methods, and multiple nonlinear regression methods were applied to historical pipeline costs by different researchers, but none of the regression models were verified and validated. Most of the models only developed the relationships between length, diameter and total costs without including individual pipeline cost components. Using 10 years of pipeline cost data, McCoy developed multiple nonlinear regression cost models that included locations but did not test the validation of the models. Multiple non-linear regression models of five pipeline cost components are developed in this study with cost data from 412 pipelines constructed over a 17-year period, and include pipeline lengths, cross-sectional areas, and locations. In addition, these regression models are validated by various statistical tests.

Zhao (2000) calculated the share of material costs using pipeline costs between 1993 and 2004 and indicated that the share of material costs is constant for same-diameter pipelines, but did not investigated the share of cost components in terms of lengths and locations. Zhao (2000) also calculated learning rates for total costs without considering requirements of recurring costs. This study incorporates cost data for 412 pipelines constructed over a 17-year period, and includes an analysis of shares of pipeline cost components in terms of pipeline length, diameter, and location. It also investigates the learning curves of material and labor costs in terms of pipeline lengths, diameters, and locations.

Costs estimation errors and bias in many types of projects have been reported in numerous papers (Bertisen and Davis, 2008; Merrow, 1988; Flyvbjerg et al., 2003; Jacoby, 2001; Pohl and Mihaljek, 1992). These articles show that cost overruns occur in many different types of projects over time. Various researchers have tried to explain the project cost overrun phenomenon. Some have proposed that optimism and deception are major causes for cost overruns (Flyvbjerg et al., 2003). Some researchers state that engineers and managers have incentives to underestimate project costs (Bertisen and Davis, 2008). Flyvbjerg et al. (2003) tried to use technical, psychological, and political-economic factors to explain cost overruns. Many hypotheses have been proposed to explain cost overruns for different types of projects; however, there have been no rigorous quantitative analyses of cost overruns on pipeline projects.

Although numerous studies have been conducted on project cost overruns, there are limited available references and quantitative analyses on pipeline project cost overruns. With available pipeline data, this study conducts analyses of cost estimation errors of pipeline construction components, and investigates and identifies the frequency of cost overrun occurrences and the magnitude of difference between estimated and actual costs in pipeline projects. In addition, cost overruns in terms of pipeline project size, capacity, diameter, length, location, and year of completion are also investigated. Finally, guidelines for pipeline cost estimators are proposed.

For compressor station cost analysis, there are even fewer publicly available references. The *Oil & Gas Journal* annually publishes estimated and actual pipeline compressor station costs with basic trend analysis (PennWell Corporation, 1992-2009). An empirical formula between compressor station cost and horsepower was established by IEA Greenhouse Gas R&D Programme (2002). Compared to previous studies, my study conducts a comprehensive analysis of pipeline compressor station cost components between 1992 and 2008 using various perspectives: analyzing the distribution of pipeline compressor stations with respect to year of completion, capacity, location, and individual component costs; investigating shares of compressor station cost components and learning curves of material and labor costs with respect to capacity and location; and developing multiple nonlinear regression models of five different cost components to estimate compressor station component costs for different capacities and locations.

Although numerous studies have been conducted on other types of project cost overruns as mentioned above, there are few publicly available references regarding compressor station project cost overruns. With available compressor station cost data, this study focuses on the cost estimation errors for compressor station construction components, and investigates and identifies the frequency of cost overrun occurrences and the magnitude of difference between estimated and actual costs in compressor station projects. In addition, it also investigates compressor station cost overruns in terms of compressor station project size, capacity, location, and year of completion.

ENSTAR and AGDC each conducted individual studies of Alaska in-state gas pipelines (AGDC, 2011; ENSTAR, 2011). Their studies only showed high and low scenarios for costs and tariffs without factoring in taxes or conducting a probabilistic analysis. Neither did they include LNG plant cost analysis. Furthermore, cases of 750 million cubic feet per day (mmcfd) and 1,000 mmcfd flow rates were not included in their studies. Detailed input data is limited or unavailable, so this study conducts a probabilistic analysis of a proposed Alaska in-state gas pipeline at 500 mmcfd, 750 mmcfd, and 1,000 mmcfd flow rates by applying Monte Carlo simulations.

This study involves conducting numerous statistical tests. All statistical tests and regressions are conducted with STATA software (STATA, 2011). The p-value produced by tests or regression models is evaluated by traditional rules: $p<0.01$ is considered highly significant, $p<0.05$ is significant.

1.2 Objectives and scope of the study

The objectives of this study are to conduct a comprehensive statistical analysis of historical cost data for 412 pipelines and 220 compressor stations and develop Monte Carlo simulation models to probabilistically analyze the feasibility of a proposed Alaska in-state natural gas pipeline under various scenarios. The scope of this work includes:

- Collecting historical cost data for 412 pipelines and 220 compressor stations;
- Analyzing historical pipeline costs from different perspectives;
- Building regression models to estimate pipeline construction costs;
- Analyzing inaccuracies in pipeline construction cost estimations;
- Analyzing historical compressor station costs from different perspectives;
- Building regression models to estimate compressor station construction costs;
- Analyzing inaccuracies in compressor station construction cost estimations;
- Describing the market for an in-state gas pipeline and characteristics of Alaska gas demand;
- Building Alaska in-state gas pipeline probabilistic models with Monte Carol simulations;
- Estimating and comparing capital cost, tariff, and tax of an Alaska in-state gas pipeline at three different flow rate scenarios.

1.3 Structure of the thesis

This thesis contains 9 chapters. Chapter 1 provides an introduction along with the statement of the objectives and scope of this study. Chapters 2-8 contain the major contents of the study, divided into three components as described below. The last chapter, Chapter 9, presents the summary and conclusions of the study and recommendations for future work.

The first component is comprised of Chapters 2-4, the analysis of historical construction cost data of 412 pipelines. Chapter 2 covers a distribution analysis of pipeline construction costs. In Chapter 3, multiple nonlinear regression models of pipeline cost components are developed and studied. Chapter 4 analyzes the analysis of inaccuracies in pipeline cost estimations. These chapters comprise the first component of the study.

The second component includes Chapters 5-7, the study of historical construction cost data for compressor stations. In Chapter 5, a comprehensive analysis of historical compressor stations cost data is conducted from the perspectives of distribution, share of cost components, and learning curves. Chapter 6 deals with multiple nonlinear regression models for compressor station cost components. Chapter 7 discusses inaccuracies in compressor station cost estimations.

The third component, Chapter 8, is an economic analysis and modeling of an Alaska in-state gas pipelines, based on the previous chapters' statistical studies of historical cost data. This section discusses the background and markets for the Alaska in-state gas pipeline, and analyzes parameters, assumptions, and methodologies for developing Monte Carlo simulation models. Finally, simulated results are analyzed and investigated.

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CHAPTER 2 PIPELINE CONSTRUCTION COST ANALYSIS[1]

2.1 Abstract

This study aims to provide a reference for pipeline construction cost estimation by analyzing historical data for pipeline construction costs. Cost data for 412 pipelines constructed between 1992 and 2008, published by the *Oil and Gas Journal*, are adjusted to 2008 dollars with the Chemical Engineering Plant Cost Index. Distribution and share of these 412 pipeline cost components are assessed based on pipeline diameter, length, capacity, location, and year of completion, Material and labor costs dominate pipeline construction costs, approximately 71% of the total costs. In addition, a learning curve analysis is conducted to attain learning rates with respect to pipeline material and labor costs for different groups. Results show that learning rates and construction costs vary by pipeline diameter, length, capacity, and location. This study also investigates causes of pipeline construction cost differences among different groups.

[1]Rui, Z., Metz, P.A., Reynolds, D., Chen, G. and Zhou, X. (2011) 'Historical pipeline construction cost analyses', *International Journal of Oil, Gas and Coal Technology*, 4(3), pp. 244-263.

2.2 Introduction

Pipelines are a vital economical way to transport large quantities of oil and natural gas for the petroleum industry. The first pipeline in the U.S, a 2-inch-diameter, more than 8-kilometers (km)-long was built in 1865. By 2008, the U.S. had a total of 793,285 km of pipelines including 244, 620 km for carrying petroleum product and 548,685 km for carrying natural gas (Central Intelligence Agency, 2008). Over the years, various researchers have analyzed historical pipeline cost data to estimate the construction costs for different types of pipelines. Parker (2004) used natural gas transmission pipeline costs to estimate hydrogen pipeline costs using the linear regression method. Zhao (2000) analyzed diffusion, costs, and learning curves in the development of international gas transmission lines. Heddle et al. (2003) derived a multiple linear regression model to estimate construction costs for the CO_2 pipelines. McCoy and Rubin (2008) developed multiple nonlinear regression models to estimate costs for CO_2 pipelines. Pipeline costs were compared to LNG and gas to liquid (GTL) costs as supply options (Gandoolphe et al., 2003). Zhao (2000) calculated the share of material costs using pipeline costs between 1993 and 2004, indicating that the share of material costs are constant for same-diameter pipelines. The *Oil & Gas Journal* annually analyzed estimated and actual pipeline costs and forecasted trends for the next year (PennWell Corporation, 1992-2009). Different researchers have conducted numerous studies on pipeline costs using different methods and perspectives.

The purpose of this chapter is to conduct a comprehensive analysis of pipeline component costs from the following perspectives: Distribution of pipeline component costs; share of pipeline cost components; and learning rates of pipeline material and labor costs in pipeline construction. Causes of cost differences and learning rate differences are also investigated. In this study, a number of data processing and statistical descriptions are applied to historical cost data.

2.3 Data sources and cost adjusting factors

2.3.1 Data sources

In this study, pipelines were selected based on data availability. Pipeline cost data were collected from Federal Energy Regulatory Commission filings by gas transmission companies, published in the *Oil & Gas Journal* annual databook (PennWell Corporation, 1992-2009). Due to the limited availability of offshore pipeline data, the study looks only at onshore pipelines, and the pipeline cost in this chapter does not contain compressor station cost.

The pipeline dataset includes year of completion, pipeline diameter, length, location, and component costs. Pipelines in the dataset were distributed through all states in the contiguous U.S. The dataset also contains 15 Canadian pipelines. All pipelines were completed between 1992 and 2008. "Cost" is defined as real, accounted costs determined at the time of completion. All pipeline construction component costs are reported in U.S. dollars. The entire dataset includes 412 onshore pipelines.

The five pipeline cost components are: material, labor, miscellaneous, right of way (ROW), and total costs. Material cost is the cost of line pipe, pipeline coating and cathodic protection. Labor cost consists of the cost of pipeline construction labor. Miscellaneous cost is a composite of the cost of surveying, engineering, supervision, contingencies, telecommunications equipment, freight, taxes, allowances for funds used during construction, administration and overheads, and regulatory filing fees. ROW cost contains the cost of ROW acquisition and allowance for damages. Total cost is the sum of material, labor, miscellaneous, and ROW costs (PennWell Corporation, 1992-2009).

2 3 2 Cost adjusting factors

All costs are adjusted with the Chemical Engineering Plant Cost Index (CE Index) – a widely used index for adjusting process plants' construction costs, to 2008 dollars. The CE index has 11 sub-indices. The changes in costs over time can be recorded by the index (Chemical Engineering, 2009). Indices between 1990 and 2008 are shown in Figure 2.1. Two stages between 1990 and 2008 can be seen in this figure. The CE index increased slowly between 1990 and 2003, and increased sharply after 2003, except for construction labor and engineering supervision indices. For example, the pipe index annual growth rate was 1.40% from 1990 to 2003, but 5.49% from 2003 to 2008. The soaring index means the pipeline construction costs experienced high cost escalations after 2003, indicating that construction costs frequently overran budget during that period.

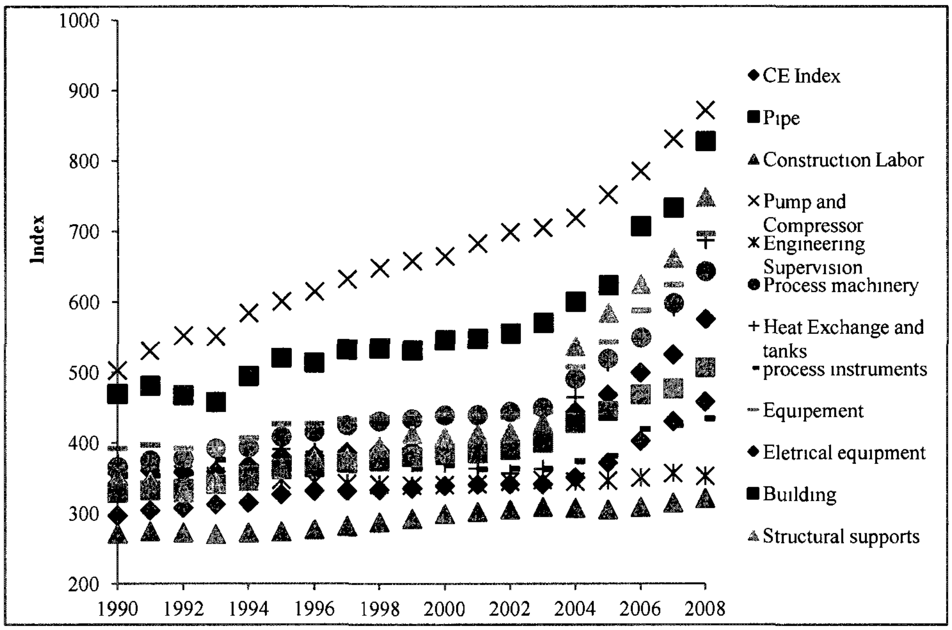

Figure 2.1 Chemical Engineering Plant Cost Indices between 1990 and 2008

Table 2.1 Annual average growth rate of the Chemical Engineering Plant Cost Index

Index type	Annual growth rate	Index type	Annual growth rate
CE Index	2.54%	Heat exchange and tanks	3.30%
Pipe	3.02%	Process instruments	1.10%
Construction labor	0.90%	Equipment	3.07%
Pump and compressor	2.94%	Electrical equipment	2.31%
Engineering supervision	-0.04%	Buildings	2.29%
Process machinery	3.01%	Structural supports	4.09%

The annual average growth rate between 1990 and 2008 is shown in Table 2.1. The structure support index has the highest average annual growth rate of 4.09%. The engineering supervision index is almost constant with the lowest average annual growth rate of -0.04%. The average annual growth rate of pipe index is 3.02%, which is higher than the CE index average annual growth rate of 2.54%. The CE index is a useful tool for adjusting pipeline cost data. To compare cost data equally over different years, different pipeline cost components are adjusted by different indices to 2008 dollars. The pipe and construction labor indices are used to adjust pipeline material and labor costs, respectively. The CE index is applied to pipeline miscellaneous and ROW costs.

2.4 Data descriptive statistics

To better understand pipeline cost, the cost data of pipelines are analyzed and summarized in terms of pipeline diameter, length, capacity, location, and year of completion.

2.4.1 Distribution analysis of pipelines on year of completion, diameter and length

The histogram of pipelines over different years is shown in Figure 2.2. Fifty six (13.6% of the total) constructed pipelines were reported in 2002, and but only 6 (1.5%) were reported in 1998. Figure 2.3 shows the histogram of pipelines by different diameters.

Eighteen different diameter pipelines were reported, ranging from 4 inches to 48 inches, and values of all diameters are even number. There are 103 (25%) 36-inch diameter pipelines, 63 (15.3%) 30-inch diameter pipelines and 62 (15.1%) 24-inch diameter pipelines. These three diameter pipelines add up to 228 (55.3%). There are only two each of 10-inch, 14-inch 18-inch and 34-inch diameter pipelines. Further, there are only 24 (5.8%) pipelines with diameters between 4 inches and 10 inches, while 218 (52.9 %) pipelines have diameters between 30 inches and 48 inches. This indicates that some specific diameter pipelines are constructed more often than others, and more large diameter pipelines have been constructed than small diameter pipelines in the last two decades.

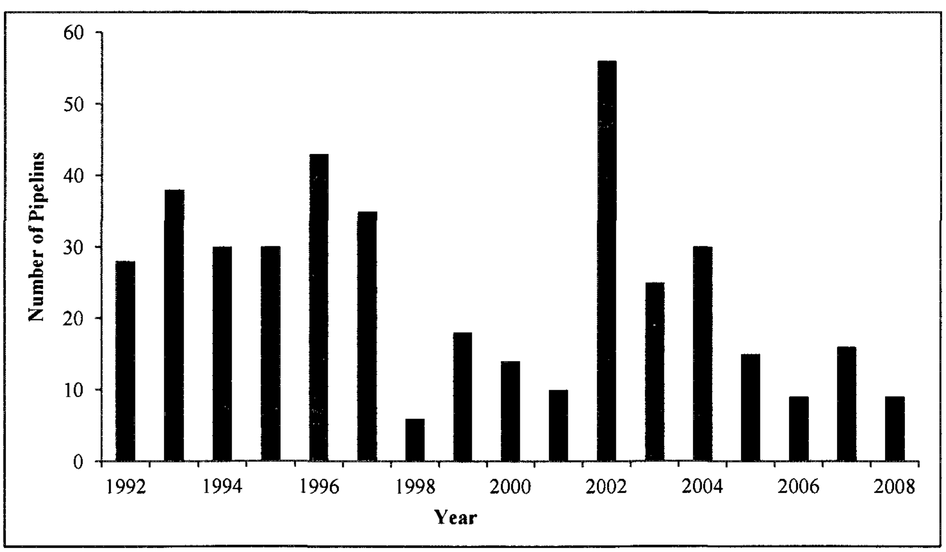

Figure 2.2 Histogram of pipelines between 1992 and 2008

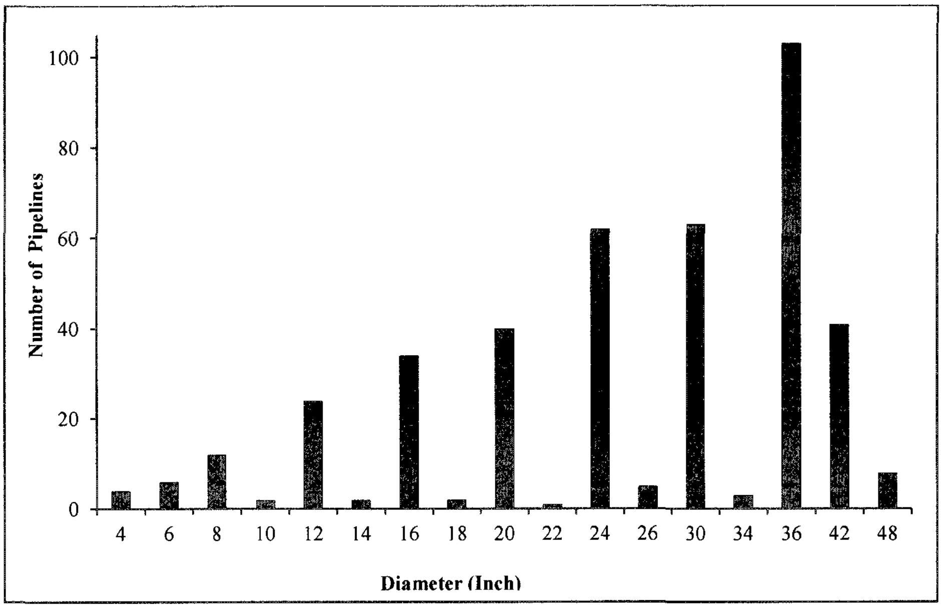

Figure 2.3 Histogram of pipelines grouped by diameter

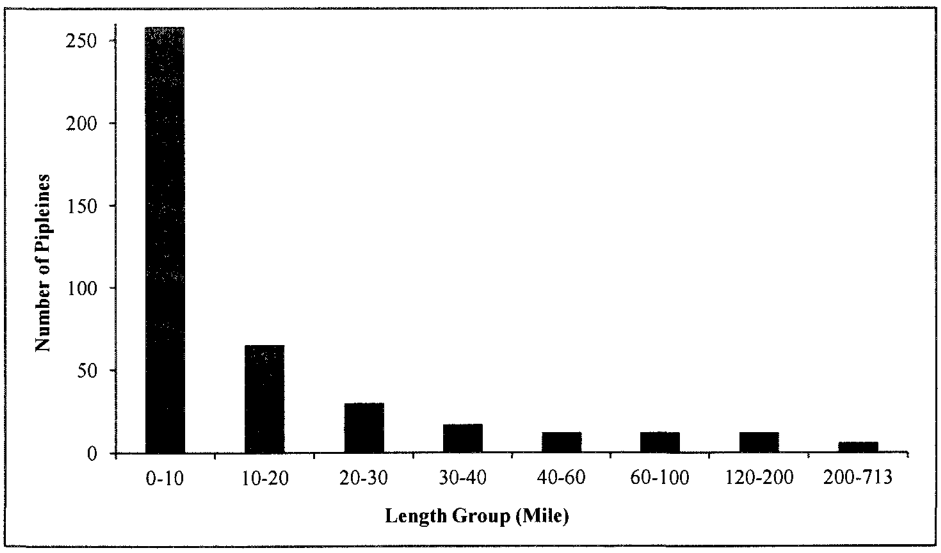

Figure 2.4 Histogram of pipelines grouped by length

Figure 2.4 displays the histogram of pipelines grouped by pipeline length. The distribution of pipeline length is right-skewed with lengths ranging from 0.01 mile to 713 miles. There are 258 (62.6%)

pipelines in the 0-10 mile group, and 65 pipelines in the 10-20 mile group, but only 30 (7.3%) of pipelines are longer than 60 miles. It indicates that the majority of the reported pipelines are short.

2.4.2 Distribution of pipelines regarding pipeline capacity (pipeline volume)

Pipeline capacity is calculated with the following formula (Zhao, 2000):

$$V = S * L \qquad \text{Equation 2.1}$$

where $S = \pi(\frac{D}{2})^2$, V is pipeline capacity (ft^3); S is pipeline cross-sectional area (ft^2); L is pipeline length (ft); and D is pipeline diameter (ft).

The histogram of pipeline capacity is shown in Figure 2.5. The distribution of pipeline capacity is right-skewed. Average pipeline capacity is 86,511,969 ft^3 with a standard deviation (SD) of 15,840,088 ft^3. Pipeline capacity ranges from 13,270 ft^3 to 5,215,691,727 ft^3. The capacity of 58.29% of pipelines is less than 30,000,000 ft^3, and only 3.64% of pipelines have a capacity larger than 400,000,000 ft^3.

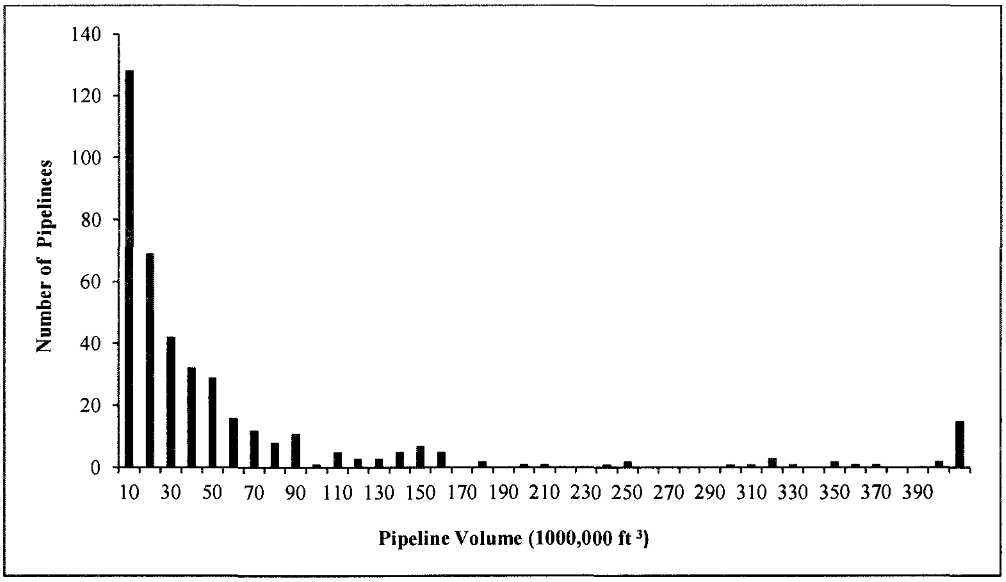

Figure 2.5 Histogram of pipeline capacity

2.4.3 Distribution analysis of pipeline locations

Location information for U.S. pipelines is provided by state. A total of 48 states were referred to, excepting Alaska and Hawaii. Energy Information Administration (EIA) breaks the U.S. natural gas pipelines network into six regions: Northeast, Southeast, Midwest, Southwest, Central, and Western (EIA, 2010). These regional definitions are used to analyze geographic differences. The map of regional definitions is shown in Figure 2.6. In this chapter, U.S. pipeline data are summarized according to these six regions (McCoy and Rubin, 2008).

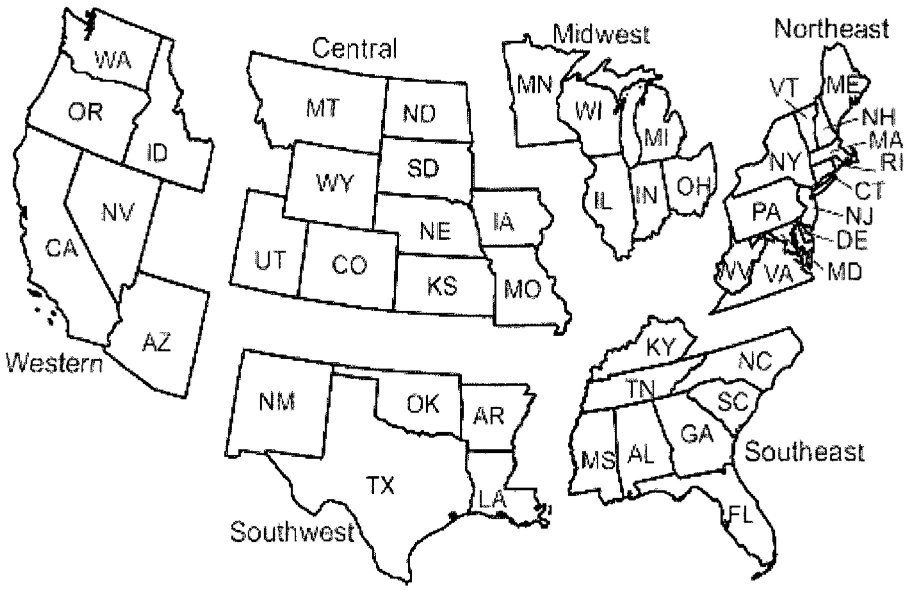

Figure 2.6 U.S. natural gas pipeline network region map (EIA, 2010)
Note: Alaska and Hawaii are not included

Table 2.2 Number of pipelines in regions and states

Region	Number of Pipelines	State*	Number of Pipelines
Center	52	Colorado	15
Northeast	157	Pennsylvania	72.5
Southeast	55	Alabama	20.5
Midwest	55	Ohio	18.5
Southwest	30	Louisiana	9.5
Western	48	Washington	11.5
Canada	15		

*: State has the highest number of pipelines in its region

Based on the regional definition, regional distribution of pipelines are summarized and shown in Table 2.2. There are 157 (40% of U.S pipelines) pipelines in the Northeast region. Furthermore, 46% of these Northeast region pipelines are in the State of Pennsylvania. Thirty pipelines (7.5%) are in the

Southwest region. The number of pipelines in other regions is between 48 and 55. In addition, 15 Canadian pipelines do not break them down into specific Canadian provinces.

2.4.4 Distribution analysis of pipeline individual cost components

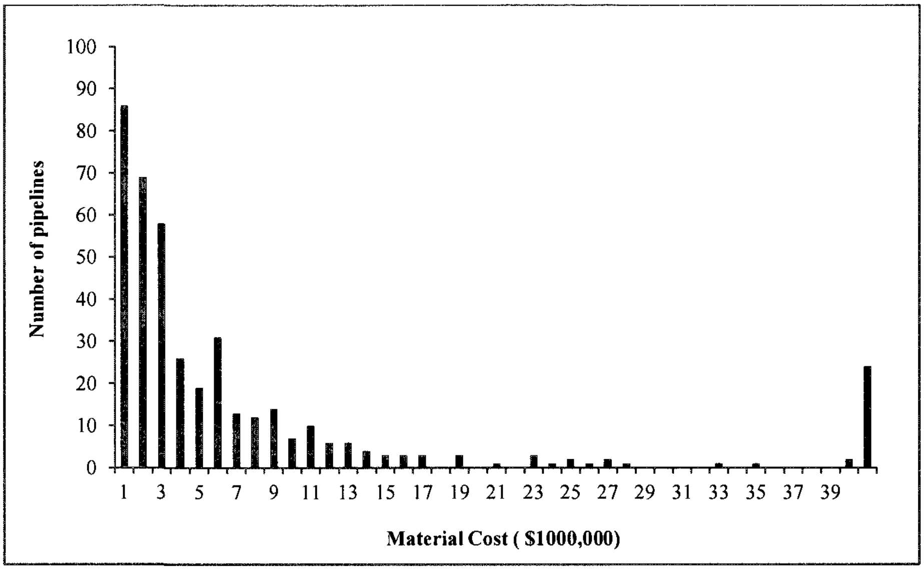

Figure 2.7 Histogram of material costs

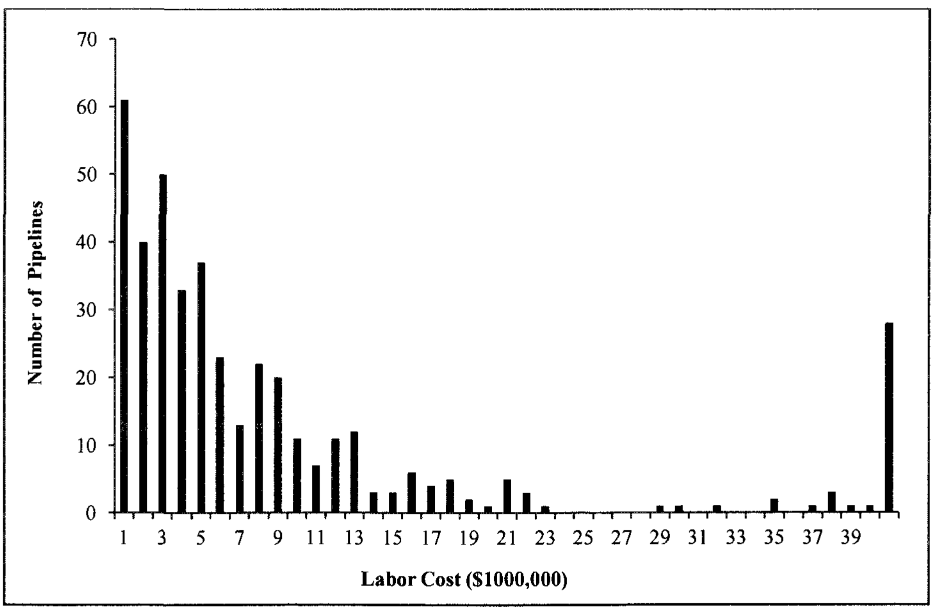

Figure 2.8 Histogram of labor costs

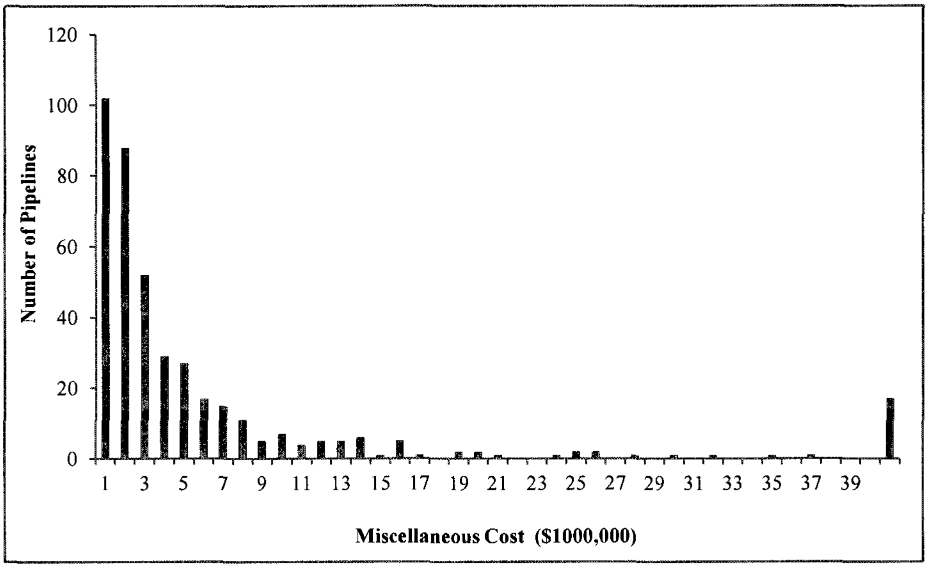

Figure 2.9 Histogram of miscellaneous costs

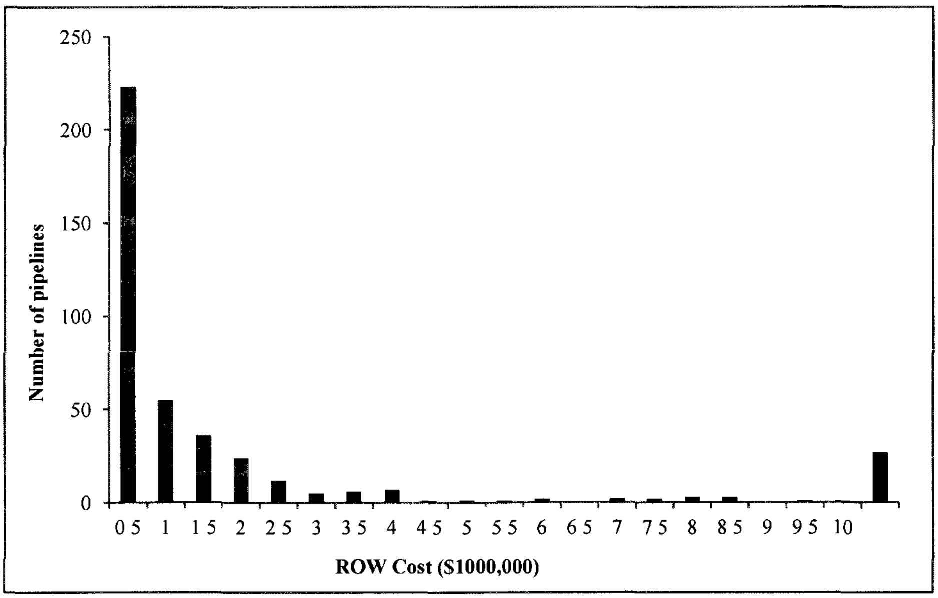

Figure 2.10 Histogram of ROW costs

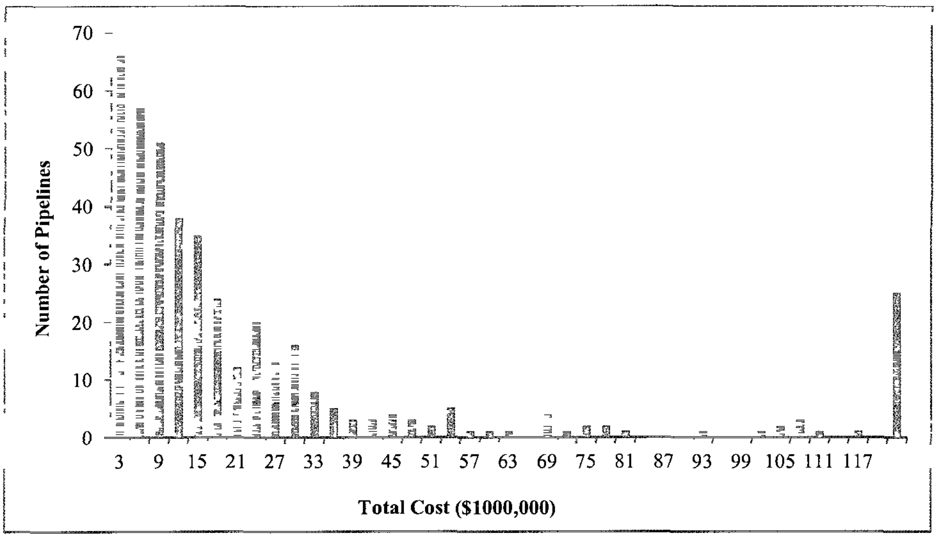

Figure 2.11 Histogram of total costs

Histograms of pipeline component costs are shown in Figure 2.7 to Figure 2.11. These figures illustrate that all distributions of pipeline component costs are right-skewed. The majority of cost distribution is concentrated on the left of the figure, indicating more cases of low cost and few of relatively high cost projects. Similar trends exist in the histogram of length groups (Figure 2.4) and the histogram of pipeline capacity group (Figure 2.5). It seems that pipeline length or volume may play significant roles in determining pipeline construction costs.

2 4.5 Trend of pipeline capacity over time

The preceding section analyzed pipeline capacity. This section will investigate annual pipeline capacity trends. Constructed annual pipeline volume is shown in Figure 2.12. There are three major peak years in terms of pipeline volume constructed: 2000, 2003, and 2008. The year 1998 has the lowest volume of constructed pipeline. Before 1998, constructed pipeline volume changed only slightly. After that, however, volume increased sharply from 1,700,168 ft^3 to 31,773,396 ft^3 between 1998 and 2003. There was then a dramatic fall to 7,917,393 ft^3 from 2003 to 2006. The biggest increase occurred in 2006 to 2008 from 7,917,393 ft^3 to 48,262,884 ft^3. Annual constructed pipeline volumes exhibit a cyclic characteristic, with a general growing trend.

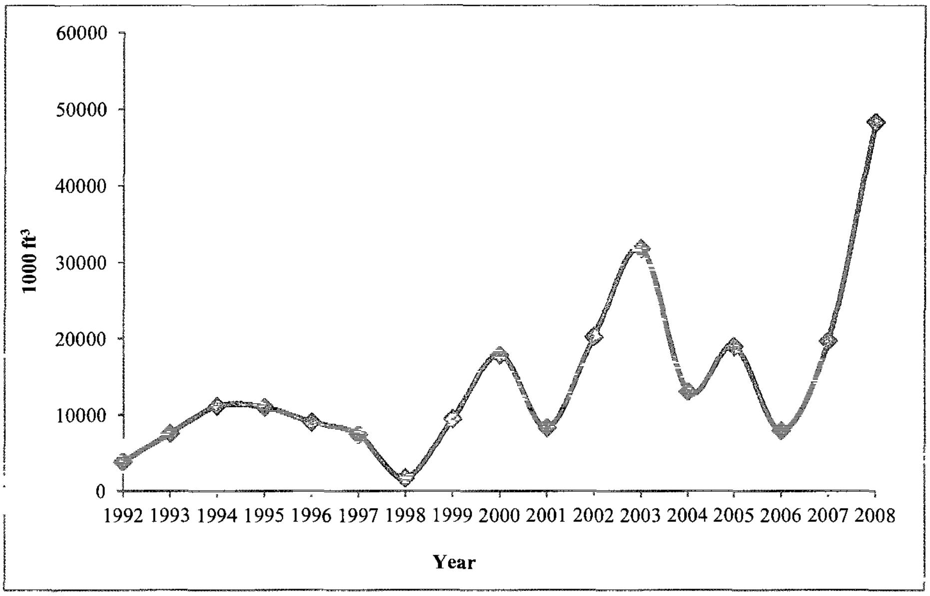

Figure 2.12 Annual constructed pipeline volumes

2.4.6 Trend of average unit cost over time

Unit component costs of pipelines are an important parameter for estimating and evaluating pipeline costs. Unit cost is calculated by dividing cost by volume. For all 412 pipelines, the average unit cost in material, labor, miscellaneous, ROW and total costs is $\$18/ft^3$, $\$24/ft^3$, $\$14/ft^3$, $\$5/ft^3$, and $\$61/ft^3$ respectively. Figure 2.13 shows the annual average unit cost of pipeline cost components. Unit costs of labor, miscellaneous, and total costs show similar patterns, which fluctuate widely. But material and ROW unit costs changed more gradually, and were more stable compared to other cost components. All cost components changed slowly before 1998, similar to the change in constructed pipeline volume. After 1998, the change was dramatic. The years of 1999, 2002 and 2007 were three-major peak years in unit total cost. The highest unit total cost was reached $\$109/ft^3$ in 1999, almost three times as high as the bottom point of $\$39/ft^3$ in 1998. By contrasting Figure 2.12 and Figure 2.13, one finds that these three-peak years in unit total cost occurred all one year before constructed volume peak years. This evidence indicates that expectation of increased pipeline construction induces an increase in the current unit costs. Material suppliers would raise prices in expectation of greater demand the following year. The higher expected demand in labor would cause labor shortages, requiring competitive salaries and benefits to hire or keep highly skilled laborers. Miscellaneous costs also increase due to higher demand. All these factors resulted in high costs a year before the peak year in constructed pipeline volumes.

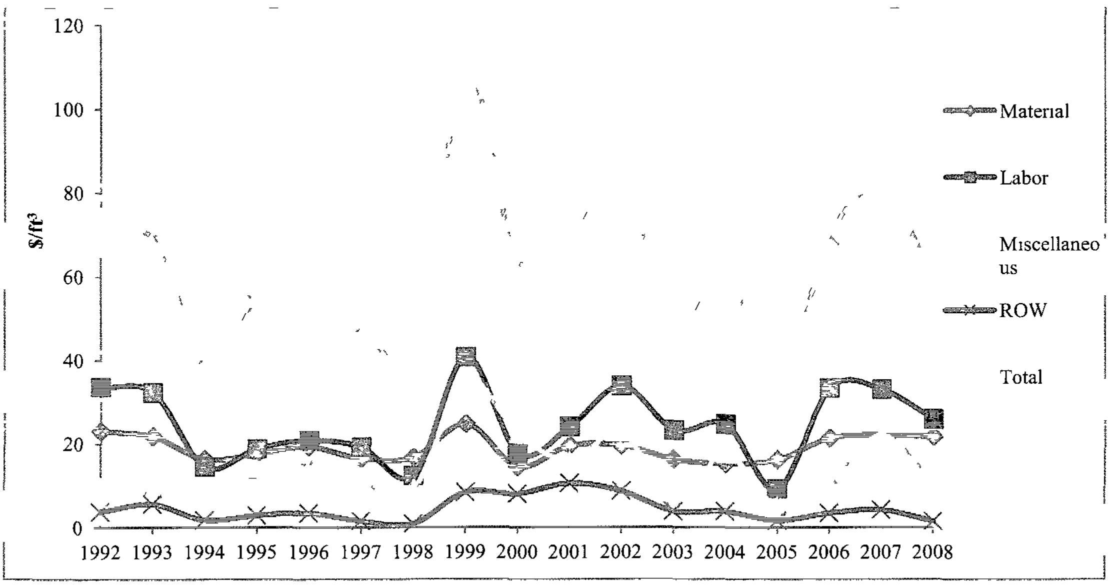

Figure 2.13 Annual average unit cost of pipeline cost components

2.5 Share of cost components for different pipeline groups

As mentioned above, the average pipeline unit cost of total cost is \$ 61/ft^3, but this cost includes material, labor, miscellaneous and ROW costs. To better understand the influence of individual cost component in construction costs, this section analyzes the share of each component cost of pipeline diameters, lengths, and location. Results are shown in Table 2.3. For all onshore pipelines, on average, the labor cost is the highest share of 40% of total cost. Material cost is the second highest share of 31%. The sum of material and labor costs can sometimes reach 80 % of the total cost. Miscellaneous cost is an average 23% of total cost. ROW cost accounts for an average of 7% of the total cost. Generally, labor and material costs dominate pipeline cost, and share of labor cost is still the highest for all groups except the Central region.

Table 2 3 Shares of pipeline cost components for different pipeline groups

		Material	Labor	Miscellaneous	ROW
All data	Average	31%	40%	23%	7%
Diameter	4 20 inch	19%	43%	28%	9%
	22-30 inch	28%	38%	26%	8%
	34-48 inch	34%	40%	20%	6%
Length	0-60 mile	28%	41%	24%	7%
	60-160mil	31%	39%	23%	7%
	160-713mil	35%	39%	20%	7%
Region	Central	41%	38%	18%	4%
	Northeast	24%	43%	27%	6%
	Southeast	24%	34%	30%	12%
	Midwest	26%	37%	27%	11%
	Southwest	31%	41%	23%	5%
	Western	32%	48%	13%	8%
	Canada	39%	40%	19%	1%

Table 2 3 shows that cost component shares vary under different situations In terms of pipeline diameters, the share of the material cost increased from 19% for small-diameter pipelines to 34% for large-diameter pipelines, while the share of other cost components decreased This indicates that shares of cost components are related to pipeline diameter, which agrees with Zhao's finding (Zhao, 2000) It also indicates that the share of material cost increased when pipeline diameter increased In terms of pipeline lengths, the share of the material cost rises from 28 % for short pipelines to 35% for long pipelines, with share of the other cost components decreasing, except ROW, constant at 7% regardless of total pipeline length Therefore, the share of material cost increases when pipeline diameter and length increases, but the labor cost remains the number one cost component for all diameters and lengths, averaging 40% of total cost Furthermore, shares of cost components are different by regions Material cost in the Central region makes up around 41% of total cost, while only 24% in the Northeast and Southeast regions The share of labor cost is between 34% and 48% in different regions Miscellaneous cost is often a smaller part of the total cost, but the share of miscellaneous cost in the Southeast region reached 30% of total cost, even higher than the share of material cost The share of ROW cost for U S pipelines ranged from 4% to 12% of total cost, while the share of ROW cost in Canada share is only 1% The lower share of ROW cost for Canadian pipelines allows us to conclude that Canada has fewer ROW issues than the U S The share of material and labor costs is approximately same for Canadian pipelines, about 40% These results agree with Zhao's conclusion that shares of labor and material costs vary by country (Zhao, 2000) It also supports the conclusion that the shares of cost components vary in different regions of the U S or different countries Regions with no pipeline producing capacity may have higher material costs, and pipeline costs can be reduced by developing technology to produce pipeline materials (Zhao, 2000) The high share of the labor costs is possibly caused by a high local cost of living For example, the Northeast region had the highest share of labor cost compared to other regions

2.6 Learning curve (learning-by-doing) in pipeline construction

2 6 1 Introduction to learning curve

The productivity of technology and labor normally increases as workers engage in repetitive tasks Unit costs typically decline with cumulative production The learning curve is derived from historical observation to measure learning-by-doing, and is helpful for cost estimators and analysts The learning curve theory is based on these assumptions 1) the unit cost required to perform a task decreases as the task is repeated, 2) the unit cost reduces at a decreasing rate, and 3) the rate of improvement has sufficient consistency to allow its use as a prediction tool (Federal Aviation Administration, 2005) Consistency in improvement is expressed as the percentage of reduction in cost with doubled quantities of product The constant percentage is called the learning rate For example, a learning rate of 20% implies the cost is reduced to 80% of its previous level after a doubling of cumulative capacity

The learning curve is normally exhibited in power function and linear function forms The power function form is shown below (Federal Aviation Administration, 2005)

$$Y_X = T_1 \cdot X^b \qquad \text{Equation 2 2}$$

where Y_X is the average cost of the first X units, T_1 is the theoretical cost of the first production unit, X is the sequential number of the last unit in the quantity for which the average is to be computed, b is a constant reflecting rate that costs decrease from unit to unit, 2^b and $1 - 2^b$ are called progress ratio and learning rate respectively (Federal Aviation Administration, 2005, International Energy Agency, 2000)

Learnıng curve functıon ıs normally expressed ın log-log paper as a strıng lıne Straıght lınes are easıer for analysts to extend beyond the range of data (Federal Avıatıon Admınıstratıon, 2005) Take the logarıthms of the both sıdes to get a straıght lıne equatıon

$$\overline{Y} = b\overline{X} + C \qquad \text{Equation 2 3}$$

where $\overline{Y} = \log Y_X$, $\overline{X} = \log X, C = \log (T_1)$ The learnıng curve effect ıs a complıcated process Some major reasons for the learnıng-by-doıng effect are ıntensıve use of skılled labor, a hıgh degree of capıtal, research and development (R&D) ıntensıty, fast market growth and ınteractıon between supply and demand (Wılkınson, 2005) In addıtıon, accumulated learnıng has start-up and steady perıods Cost reductıon ıs sıgnıficant ın the start-up and modest ın the steady perıods (Grubler, 1998) It ıs the same for technology development There are sıgnıficant cost ımprovements durıng the R&D phase, followed by more modest ımprovements after commercıalızatıon The longer technology has been ın use, the smaller the cost decreases (Zhao, 2000) It ıs possıble that no further ımprovement ın cost reductıon occurs for exıstıng and mature technology (Grubler, 1998) The commercıalızatıon of technology ın the oıl and gas market ıs costly and tıme ıntensıve, wıth an average of 16 years from concept to wıdespread commercıal adoptıon (Natıonal Petroleum Councıl, 2007) The range of progress ratıo for technology ıs between 65% and 95%, and between 70% and 90% for energy technology (Chrıstıansson, 1995)

2 6 2 Selectıng pıpelıne cost data for calculatıng learnıng rate

The cost data for learnıng curve analysıs has to be a recurrıng cost, because nonrecurrıng costs wıll not experıence the learnıng effect (Federal Avıatıon Admınıstratıon, 2005) Zhao (2000) calculated the learnıng curve of the total cost wıthout consıderıng thıs requırement, so her results may be less accurate Mıscellaneous, ROW, and total costs are not appropriate for the learnıng curve analysıs due to the ınclusıon of nonrecurrıng costs The learnıng curve analysıs, therefore, ıs only conducted for materıal and labor costs The pıpelıne data provıdes the cost data from 1992 to 2008, but the 1999 data are consıdered an outlıer due to extremely hıgh costs Hence, the 1999 data are not suıtable for a learnıng curve analysıs The learnıng curve of materıal and labor costs of pıpelınes constructed between 1992 and 2008 ıs presented ın Fıgure 2 14 There ıs an attractıve cost reductıon ın unıt cost before 100 mıllıon ft^3, but after 100 mıllıon ft^3, the unit cost did not show cost reduction, even slightly increases, considered as a more mature period. In the standard experience curve theory, it is assumed that learning rates do not change over time, but the technology or labor learning are going to a more mature phase. However, learning curve analyses do not always strictly agree with this assumption (Schaeffer and De Moor, 2004). In order to better fit the learning curve, the learning rate is calculated with data from 1992 to 2000. The learning curves of the material and labor costs from 1992 to 2000 are shown in Figure 2.15, and the learning curve equations are expressed below:

Material cost: $Y = 103.2X^{-0.09}$ or $\overline{Y} = -0.09\overline{X} + 2.01$ R^2=0.93 Equation 2.4

Labor cost: $Y = 722.8x^{-0.19}$ or $\overline{Y} = -0.19\overline{X} + 2.86$ R^2=0.91 Equation 2.5

R^2 (coefficient of determination) in both cases is higher than 0.9, indicating a very good fit. The learning rates of labor and material costs are 12.4% and 6.1%, respectively. That is, by doubling the construction of pipeline volume, labor and material costs will be reduced by 12.4% and 6.1%, respectively. But it should be noted that the cost reduction becomes smaller with increasing volume, which is what Zhao concluded (Zhao, 2000).

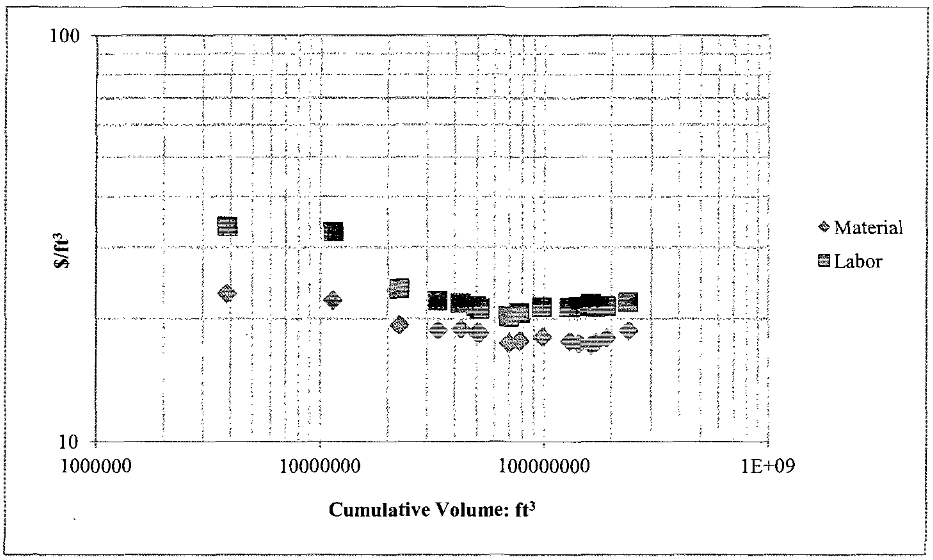

Figure 2.14 Learning curves of material and labor costs between 1992 and 2008

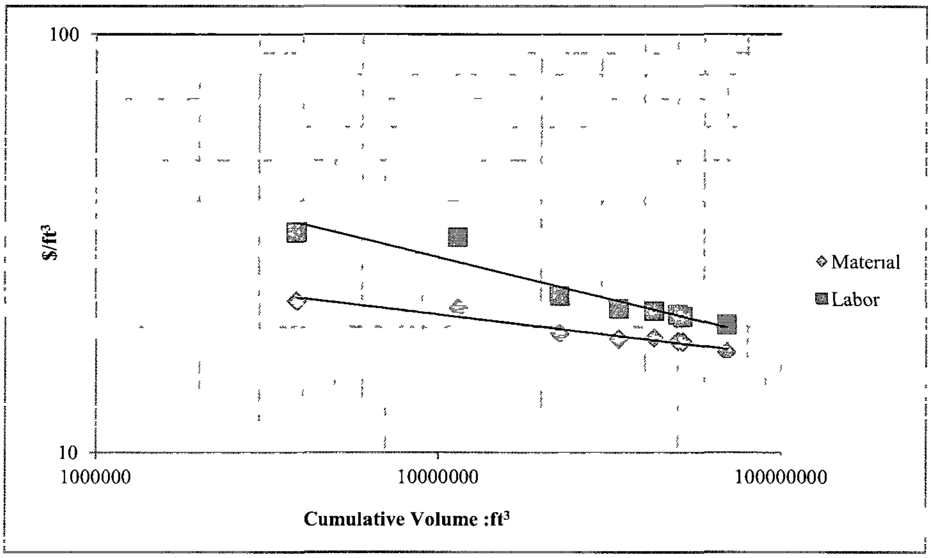

Figure 2.15 Learning curves of material and labor costs between 1992 and 2000

2.6.3 Learning rate for different pipeline groups

The learning rates for different pipeline diameters, lengths and locations are calculated and shown in Table 2.4. In general, the learning rate of material cost is lower than that of labor cost in all sub-groups except in the Southeast region. For all sub-groups, the range of the learning rates of material cost is between 1.4% and 14.6%, and the range of learning rate of labor cost is between 6.1% and 23%. For different diameters, the learning rate of labor cost is between 13.6% and 14.2%, and the learning rate of material cost ranges from 4.1% to 8%. For different pipeline lengths, the learning rate of labor cost shows a significant difference of 6.70%. As expected, the results indicate that longer pipelines can achieve a higher learning rate in labor cost, but the results also show that longer pipelines have a disadvantage with learning rates of material cost, 6.10% for the 0-20 mile group and 4.80% for the 20-713 mile group. In terms of regions, the results show that learning rates vary widely by region. The Northeast region had the lowest learning rate of material and labor costs. A plausible explanation for this finding may be the fact that more pipelines are built in the Northeast region, and thus region has reached a more mature stage earlier than other regions. Pipelines in the Southeast and Western regions show higher learning rates of material and labor costs than other regions.

In summary, the above analyses reveal that learnıng rates vary by pıpelıne dıameter, length, and locatıon to dıfferent degrees

Table 2 4 Learnıng rates of materıal and labor cost ın dıfferent groups

		Materıal	Labor
All data	Average	6 10%	12 40%
Dıameter	4 20 ınch	7 40%	13 60%
	22-30 ınch	4 10%	13 60%
	34-48 ınch	8 00%	14 20%
Length	0-20 mıle	6 10%	8 70%
	20-713mıle	4 80%	15 40%
Regıon	Northeast	1 40%	6 10%
	Southeast	14 60%	11 80%
	Mıdwest	4 80%	8 00%
	Western	7 40%	23 00%

2.7 Factors causing pipeline construction cost differences

Specıal geographıc and surroundıng envıronmental condıtıons may generate more complexıtıes ınto pıpelıne constructıon, and thus have varyıng degrees of ımpact on constructıon costs In some cold regıons, pıpelınes have to be ınsulated or buılt above ground when they pass through permafrost area, resultıng ın addıtıonal constructıon costs In populated regıons, thıcker pıpelıne walls have to be selected to mıtıgate socıetal and envıronmental rısks (Sanderson et al , 1999) Although some have argued that populatıon densıty has less ımpact on cost than types of pıpelınes (Zhao, 2000) Roads, hıghways, rıvers or channel crossıngs, and marshy or rocky terraıns are all factors that strongly affect pıpelıne unıt cost (PennWell Corporatıon, 1992-2009) For example, the performance of trenchıng unıts ıs largely dependent on soıl type and amount of debrıs encountered Heavy, clay soıls or soıls lıttered wıth rock or constructıon debrıs wıll requıre more horsepower and larger machınes to trench and lay pıpes (Houx, 2010) There are other geographıc and envıronmental factors ınfluencıng pıpelıne costs and cost reductıons, whıch have to be ıdentıfied ın specıfic cırcumstances

Someone may argue gas or oıl prıces possıbly ınfluences pıpelıne constructıon cost In order to dıscover ıf there ıs such as relatıonshıp, the correlatıon between gas or oıl prıces and lag 0 year to 4 years average unit costs from 1992 to 2008 are analyzed and shown in Table 2 5 and Table 2 6, respectively The values of all correlation coefficients in Table 2 5 are between -0 41 and 0 3, indicating that linear relationship between gas price and pipeline construction cost is very weak The values of coefficients in Table 2 6 indicate the same weak relationship Some nonlinear transformations (power, exponential, reciprocal, and square root) are also used to deal with oil and gas prices and unit cost data However, nonlinear relationship between gas and oil prices and unit cost also appears very low Therefore, there is no sufficient evidence that gas or oil price change causes pipeline construction cost changes

From a technological perspective, pipeline transportation systems have not seen a major technological breakthrough over the last few decades (Roland, 1998), but gradual cost reduction is possible by optimizing project design and construction, inspection activities, laying and welding methods, steel quality and weight and the period of construction and increasing competition between inspection service companies (Gandoolphe et al , 2003) Cost reduction through improved technology for laying, inspection and welding can be counterbalanced by other factors, such as high strength and thick pipe used to reduce potential risks (Zhao, 2000) Compared to other technologies, such as the LNG process, the cost reduction in pipeline transportation is less significant due to a less complicated process However, the average learning rate of offshore pipeline between 1985 and 1998 was 24% (Zhao, 2000) For example, the pipeline installation cost in the Norwegian part of the North Sea was 44% in 1998 lower than the corresponding cost for Statpipe in 1985 (Roland, 1998) Onshore pipeline construction began 100 years before offshore pipelines constructing, putting the onshore pipelines at a more mature stage with a lower learning rate (Zhao, 2000) The U S Department of Energy (DOE) has funded new projects for developing advanced technologies, such as robotic platforms, pipeline diameter reductions, and expansions and variables types of pipeline bends (DOE, 2007) These technologies may be progressively applied to onshore pipelines to create significant cost reductions

Table 2 5 Correlation coefficient between gas prices and average unit cost

	Material	Labor	Miscellaneous	ROW	Total
Lag 0 year	0 01	-0 14	-0 28	-0 23	-0 20
Lag 1 year	0 17	0 02	-0 12	-0 19	-0 03
Lag 2 year	0 29	0 23	0 10	-0 05	0 18
Lag 3 year	0 26	0 15	-0 06	-0 41	-0 19

Table 2 6 Correlation coefficient between oil prices and average unit cost

	Material	Labor	Miscellaneous	ROW	Total
Lag 0 year	0 24	0 10	-0 08	-0 21	0 03
Lag 1 year	0 34	0 16	-0 11	-0 27	0 05
Lag 2 year	0 49	0 34	0 06	-0 17	0 24
Lag 3 year	0 33	0 25	-0 03	-0 51	0 28

Beside geographic, environmental and technological factors, potential market demand also influences pipeline construction costs As mentioned in the unit cost section, potential demand will increase current unit costs

In order to fully explain pipeline construction cost differences, there are other factors that need to be investigated Because of limited information, this section only focuses on a few identified factors affecting pipeline construction cost differences development stages of technology, geographic and environmental conditions, economies of scale, learning rates, and market situations

2.8 Conclusions

Based on historical data collected from the *Oil & Gas Journal*, the distribution of pipelines in terms of pipeline diameter, length, capacity, year of completion, and location are analyzed Among the data examined, 78 3% of pipelines are less than 20 miles, 52 9% of them have a diameter of 30 inches or larger, and 58% of pipeline capacities are less than 30,000,000 ft^3 The pipelines are located across the U S with approximately 40% of them in the Northeast region The distributions of cost of pipeline cost components are all right-skewed (Figure 2 7 to Figure 2 11), and the range of pipeline component costs is large The trend of annual constructed pipeline volume and annual average unit cost indicates that expectations of increased pipeline demand causes increasing currently unit cost Shares of cost components are different for different pipeline diameters, lengths, and locations Material and labor costs are major components of pipeline construction costs (Table 2 3) The learning curve analysis shows that learning rates also vary by pipeline diameter, length, and location (Table 2 4) Furthermore, the developmental stages of pipeline technology, site characteristics, economies of scale, learning rates, and market conditions are identified as factors influencing pipeline construction cost differences

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CHAPTER 3 PIPELINE CONSTRUCTION COST ESTIMATION MODELS [1]

Historical pipeline cost data have been analyzed and used by some researchers to estimate the different types of pipeline costs Parker (2004) used natural gas transmission pipeline costs to estimate hydrogen pipeline costs in different pipeline diameters using the linear regression method Zhao (2000) analyzed diffusion, costs, and learning in the development of international gas transmission lines Heddle et al (2003) derived a multiple linear regression model to estimate the CO_2 pipeline construction costs McCoy and Rubin (2008) developed multiple nonlinear regression models to estimate CO_2 pipeline costs with 1994-2004 pipeline data The *Oil & Gas Journal* analyzed annual estimated and actual pipeline costs and forecasted trends for the next year (PennWell Corporation, 1992-2009)

In this chapter, five regression models are developed to estimate pipeline construction component costs for different types of pipelines in different regions This study uses the regression results to investigate cost differences between regions, pipeline cross-sectional area, and length It also points out limitations of the data and makes recommendations for future work

3.1 Background

Researchers have long used historical pipeline cost data to estimate projected construction costs for different types of future pipelines Such data allowed the development of the five pipeline construction component cost estimation models with multiple nonlinear regression methods These models are assessed with statistical tests to confirm the validity of the models These models estimate pipeline construction component costs with respect to different pipeline cross-sectional areas, lengths, and regions, with results showing a large cost difference between regions

3.2 Developing pipeline cost estimation models

The inclusion of information on pipeline length, diameter and location in the dataset promotes the multiple nonlinear regression method Using pipeline cross-sectional area as a variable instead of pipeline diameter can more accurately evaluate the relationships between pipeline construction component costs and

[1] Rui, Z , Metz, P A , and Reynolds, D , Chen, G and Zhou, X (2011) 'Regression models estimate pipeline construction costs', *Oil & Gas Journal*, 109(14), pp 120-126

pipeline physical parameters Cost components are adjusted to 2008 dollars using different categorical chemical indices instead of just one composite index (Chemical Engineering, 2009)

The general form of multiple nonlinear regression models is shown below The individual categorical costs will be built based on this general form

$$\ln C = \alpha_0 + \alpha_1 NE + \alpha_2 SE + \alpha_3 SW + \alpha_4 W + \alpha_5 MW + \alpha_6 CA + \alpha_7 \ln S + \alpha_8 \ln L \qquad \text{Equation 3 1}$$

where C is the costs material, labor, miscellaneous, ROW, or total costs, NE (Northeast), SE (Southeast), SW (Southwest), W (Western), MW (Midwest), and CA (Canada) are dummy variables for identifying geographic differences, The Central region is selected as the base case, S denotes pipeline cross-sectional area (ft^2), L is the pipeline length (ft), and a_i is the coefficient of variables (i=0, 1, 2 8), The positive a_i of regional variables indicates that the region has a higher cost than the Central region, while the negative a_i of regional variables shows the region has a lower cost than the Central regional This equation provides the basis for developing five cost component estimation models Coefficients of the regression models are shown in Table 3 1

Table 3 1 Coefficients of five regression models

Variables	Material	Labor	Miscellaneous	ROW	Total
Intercept	4 814	5 697	5 580	1 259	6 818
Northeast	–	0 784	0 704	0 645	0 420
Southeast	0 176	0 772	0 967	0 798	0 607
Midwest	-0 098	0 541	0 547	1 064	0 312
Southwest	–	0 498	0 699	0 981	0 359
Western	–	0 653	–	0 778	0 247
Canada	-0 196	–	–	-0 830	-0 343
Ln(S)	0 734	0 459	0 458	0 191	0 491
Ln(L)	0 873	0 808	0 765	1 027	0 810

Note All p-values associated with coefficient is less than 5%

3.3 Validating models

Statistical tests are conducted before concluding a valid regression model Table 3 2 shows results of these tests

Examining independent variables in the model is conducted for multicollinearity The variance inflation factor (VIF) is a diagnostic applied to test the independent variables The VIF values of independent variables in these five models are between 1 and 1 7 (Table 3 2) A VIF value under 10 is generally acceptable (UCLA, 2011) The independent variables therefore do not have a mulitcollinearity problem

An F test and its associated p-value test the overall model for predictive capability The ratio of the mean of the square for regression and the mean square for error is called F-statistics (Makridakis et al , 1983) Normally a large F-value suggests that the model explains the large proportion of variance The p-value associated with the F-statistic is considered very significant when the p-value is less than 5% Values of F-statistics for all five models are very large, and associated p-values are less than 1% (Table 3 2), leading to the conclusion that at least one of the parameters in the model has a predictive capability All p-values of coefficients are significantly below 5% (Table 1), allowing consideration of all parameters in these five models as significant

R-square and adjusted R-square are important diagnostics that help determine the goodness-of-fit of the model The R-square shows the proportion of variance in the dependent variables as explained by the independent variables One disadvantage of R-square is its value can be artificially inflated by putting in additional independent variables (Kutner et al , 2004) Adjusted R-square, therefore, is often used together with R-square The values of R-square of all models are greater than 0 75, and the adjusted R-square values are almost the same as those of the R-square in all models (Table 3 2), showing a large proportion of variability as explained by the independent variables It can therefore be concluded that these regression models are good models

Assumption of normality claims that residuals need to fit the normal distribution The Shapiro-Wilk (SW) test is a quantitative test to evaluate the goodness-of-fit of normal distribution (UCLA, 2011) The null hypothesis of the SW test is that the data has a normal distribution The p-values produced by SW tests of the labor, miscellaneous and total costs are greater than 5% (Table 3 2), so the null hypothesis is not rejected Material and ROW costs are 3 6% and 4 1% which are slightly less than the 5% threshold, but it is not a significant violation, and these violations are deemed reasonable Therefore, assumptions of normality for all models are reasonably satisfied

Another assumption for the regressions is the homoscedasticity of residuals The Breusch-Pagan (BP) test is a quantitative test for homoscedasticity (UCLA, 2011) The null hypothesis of the BP test is that residual is in constant variance All p-values of BP tests in five models are greater than 5% (Table 3 2) Thus the null hypothesis is not rejected, and the constant variance is satisfied

Table 3 2 Regression model validation models

Statistical tests	Material	Labor	Miscellaneous	ROW	Total
VIF Test	1 04	1 61	1 32	1 66	1 66
F Test	1892	355	216	120	462
R^2	0 96	0 86	0 77	0 76	0 91
Adj R^2	0 96	0 86	0 76	0 75	0 91
SW Test	0 04	0 06	0 082	0 04	0 07
BP Test	0 06	0 07	0 99	0 23	0 06
Observation	378	386	405	347	388

Diagnostics, therefore, demonstrate the validity of the five regression models The following sections will use regression models to analyze cost differences in terms of regions, pipeline cross-sectional areas, and pipeline lengths

3.4 Cost difference regarding regions

Regional coefficients show cost differences in different regions (Table 3 1) Coefficients of these regions show that all locations relate to pipeline construction component costs

The material cost model shows a relationship to the Southeast, Midwest and Canada regions According to the sign of coefficients, the material cost in the Midwest region and Canada is lower than the Central region, while material costs in the Southeast region are much higher than in the Central region

The labor cost model shows a relationship to all regions except Canada, and labor costs in other regions are higher than in the Central region The Northeast region has the highest labor cost

The miscellaneous cost model displays a relationship to the Northeast, Southeast, Midwest and Southwest regions, and all coefficients are positive The Southeast region has the highest miscellaneous costs

ROW cost and total cost models show relationships to all regions, and all coefficients are positive except for Canada The Midwest and Southwest regions have the first and second highest ROW cost The Southeast region has the highest total costs Canada has the lowest total and lowest ROW costs

For comparison purposes, using cost estimation models, Table 3 3 gives unit pipeline construction component costs of 24- inch-diameter and 100-mile-long pipeline in different regions Unit total cost of the pipeline in different locations varies noticeably For example, the unit total cost in Canada is \$29 6 /ft^3, but \$76 6 /ft^3 in the Southeast region The Southeast region pipeline unit total costs are 2 6 times the pipeline unit total cost in Canada and 1 8 times those in the Central region The cost difference for pipeline construction caused by geography can sometimes reach up to 300% Geographical factor, therefore, is important in determining pipeline costs

Table 3 3 Unit pipeline construction components cots in different regions

Regions	Material	Labor	Miscellaneous	ROW	Total
Central	17 0	12 8	6 4	2 0	41 8
Northeast	–	28 0	13 0	3 8	63 5
Southeast	20 3	27 7	16 9	4 4	76 6
Midwest	15 5	21 9	11 1	5 8	57 0
Southwest	–	21 0	13 0	5 3	59 8
Western	–	24 6	–	4 3	53 4
Canada	14 0	–	–	0 9	29 6

Note (unit \$/ft^3)

Seen from the values of the coefficient of the Southeast and Northeast regions, the Northeast region has a higher cost of living than the Southeast region The Southeast region actually has higher cost in miscellaneous, ROW and total costs than the Northeast region but slightly lower labor cost This comparison may show that economies of concentration play an important role in pipeline construction cost Economies of concentration are one type of economies of scale, also called external economies Economies of scale tend to rise when firms or projects in the same industry are located close together (Wilkinson, 2005) Approximately 40% of U S pipelines are in the Northeast region, and 46% of them are concentrated in the State of Pennsylvania These concentrations reduce pipeline construction costs

Cost differences between regions are, sometimes, hard to explain Cost differences between regions are caused by two main factors (McCoy and Rubin, 2008) 1) cost difference between regions, such as material and ROW costs, and 2) geographic factors, such as terrain and population density Weather conditions, soil properties, cost of living, and distances from supplies are also variables for different regions which can cause cost differences Economies of concentration are another important factor in cost differences in different regions However, conducting quantitative analysis of cost differences in different locations is impossible without pipeline-related information, such as pipeline route

3.5 Cost differences regarding pipeline length and cross-sectional area

Coefficient results show cost are also related to pipeline cross-sectional area and length Generally, the Cobb-Douglas function serves as a production function representing the relationship between input and output The Cobb-Douglas function has interpreted cost in terms of pipeline diameter and length (McCoy and Rubin, 2008) It will be used in this study to explain the relationship between cost and pipeline cross-sectional area and length The Equation 3 1 can be written in Cobb-Douglas form as Equation 3 2

$$C(S, L) = AS^{\alpha_7}L^{\alpha_8} \qquad \text{Equation 3 2}$$

where $\ln(A) = \alpha_0 + \alpha_1 NE + \alpha_2 SE + \alpha_3 SW + \alpha_4 W + \alpha_5 MW + \alpha_6 CA$ α_7, α_8 are the output elasticity of pipeline cross-sectional area and length The partial derivative $\frac{\partial C}{\partial s}$ is the rate at which cost changes with respect to the amount of pipeline cross-sectional area, and is called marginal cost with respect to pipeline cross-sectional area Likewise, the partial derivative $\frac{\partial C}{\partial L}$ is the rate at which cost changes with respect to the amount of pipeline length, and is called marginal cost with respect to pipeline length, and it is also called marginal cost with respect to pipeline cross-sectional area It is proportional to the amount of cost per unit of the pipeline cross-sectional area The marginal cost with respect to pipeline length is proportional to the amount of cost per unit of pipeline length

The Cobb-Douglas function is well-known for return to scale (Wilkinson, 2005)

$$C(mS, mL) = A(mS)^{\alpha_7}(mL)^{\alpha_8} = m^{(\alpha_7+\alpha_8)}A(S)^{\alpha_7}(L)^{\alpha_8} = m^{(\alpha_7+\alpha_8)}C(S, L) \qquad \text{Equation 3 3}$$

If the sum of α_7 and α_8 is equal to 1, the cost function has constant returns to scale If the sum of α_7 and α_8 is less than 1, the cost function has decreasing return to scale, and if the sum of α_7 and α_8 is larger than 1, the cost function has increasing return to scale (Wilkinson, 2005)

Table 3 2 shows that sums of α_7 and α_8 in the five models are all greater than 1, so all five component cost models have increasing return to scale That is, if both cross-sectional area and length are increased by m times, the cost will increase more than m times

But both α_7 and α_8 are smaller than 1 for material, labor, miscellaneous, and total costs These cost models have increasing returns to scale with diminishing marginal cost, which means that the rate of pipeline cost increase is less rapid than the rate of the pipeline area or rate of the pipeline length increase

ROW cost model is a non-symmetric function with increasing returns to scale, because α_7 is smaller than 1 and α_8 is larger than 1, the rate of pipeline cost increase is less rapid than the rate of pipeline cross-sectional area increase, but the rate of pipeline cost is more rapid than the rate of the pipeline length increase For example, when pipeline length doubles, the material cost is less than double, while the ROW cost increase more than doubles

All cost components have economies of scale with respect to pipeline cross-sectional area and pipeline except for ROW cost The coefficient of pipeline length in the ROW cost model is very close to 1 In that case, the ROW cost almost doubles when pipeline length doubles, showing a near constant ROW unit cost regardless of length, matching Sean's suggestion (McCoy and Rubin, 2008)

In order to show the trend of pipeline component cost regarding pipeline cross-sectional area and length, Figure 3 1 to Figure 3 5 show the estimated pipeline unit component costs in the Central region Figure 1 illustrates that the pipeline unit total cost decreases as pipeline length and cross-sectional area increase, supporting the conclusion that total cost has economies of scale with respect to pipeline cross-sectional area and length For example, the unit total cost of 8-inch pipelines are 6 2 times that of 48-inch pipelines, and the unit total cost of 50-mile pipelines are 1 7 times those of 800-mile pipelines A similar trend also exists in material, labor, and miscellaneous costs (Figure 3 2, Figure 3 3, and Figure 3 4, respectively)

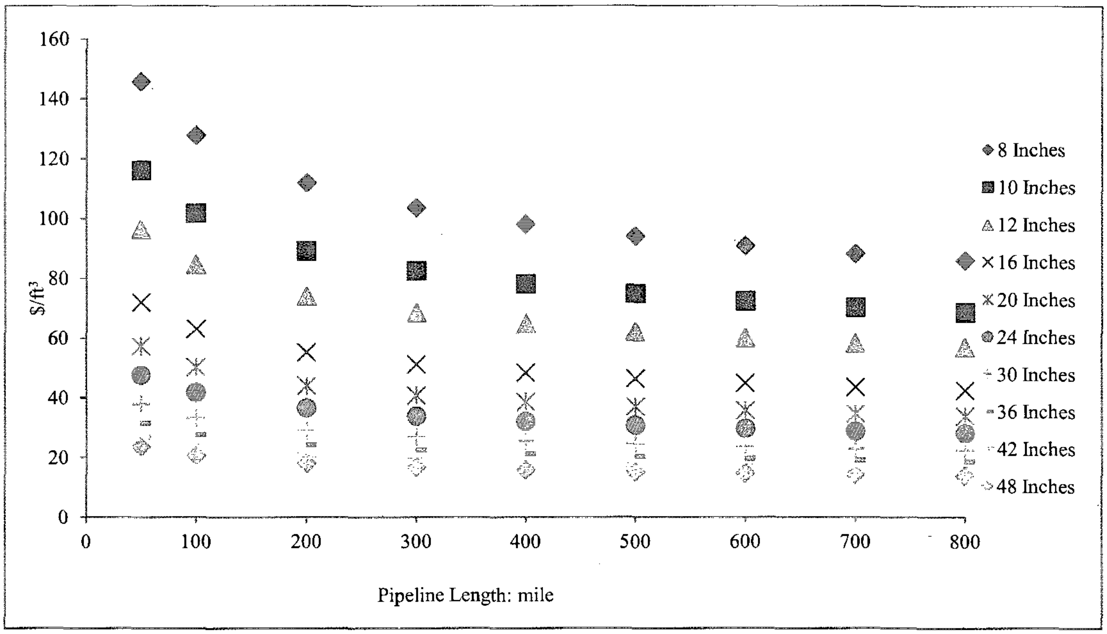

Figure 3.1 Trend of pipeline unit total costs (Central region)

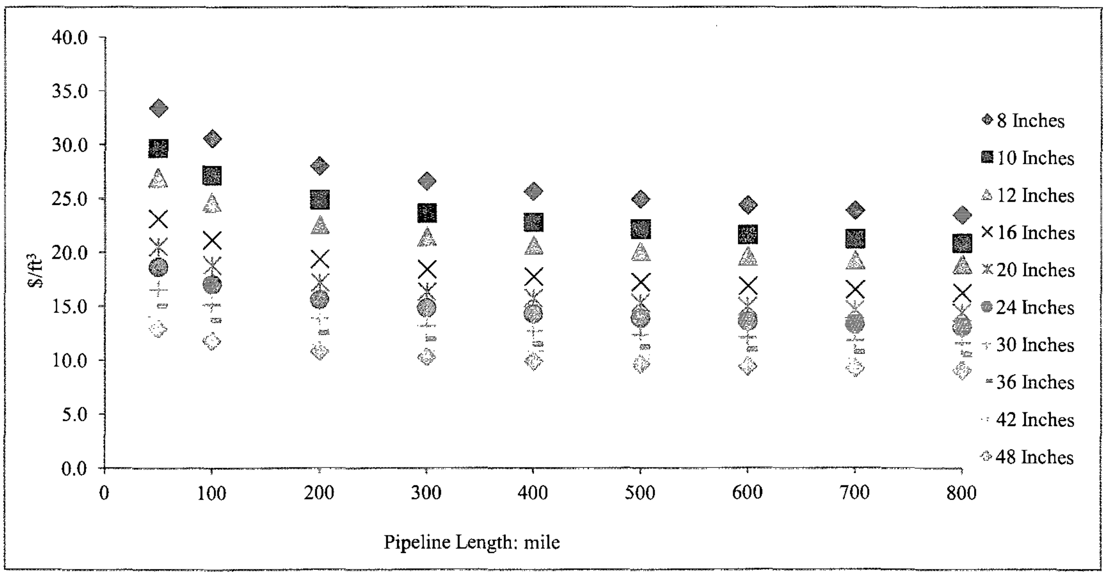

Figure 3.2 Trend of pipeline unit material costs (Central region)

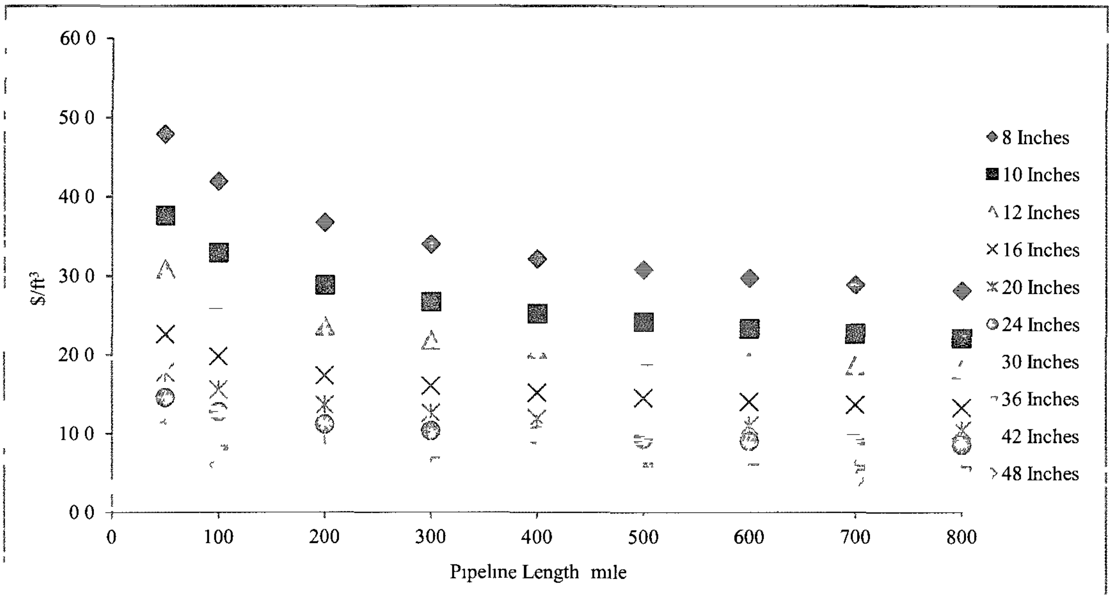

Fıgure 3 3 Trend of pıpelıne unıt labor costs (Central regıon)

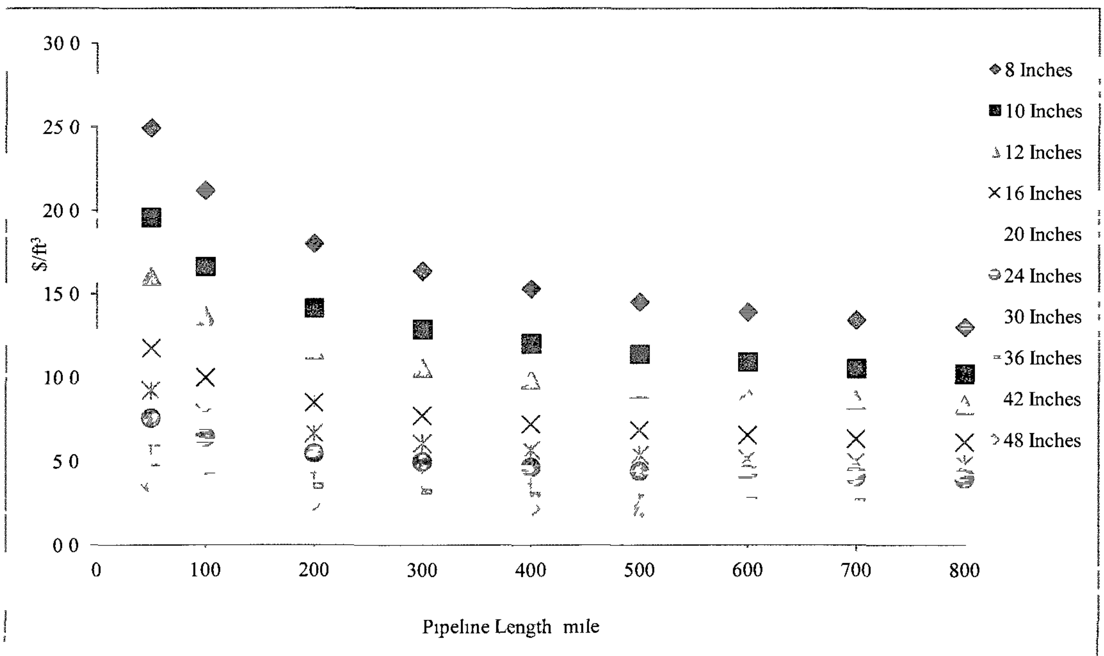

Fıgure 3 4 Trend of pıpelıne unıt mıscellaneous costs (Central regıon)

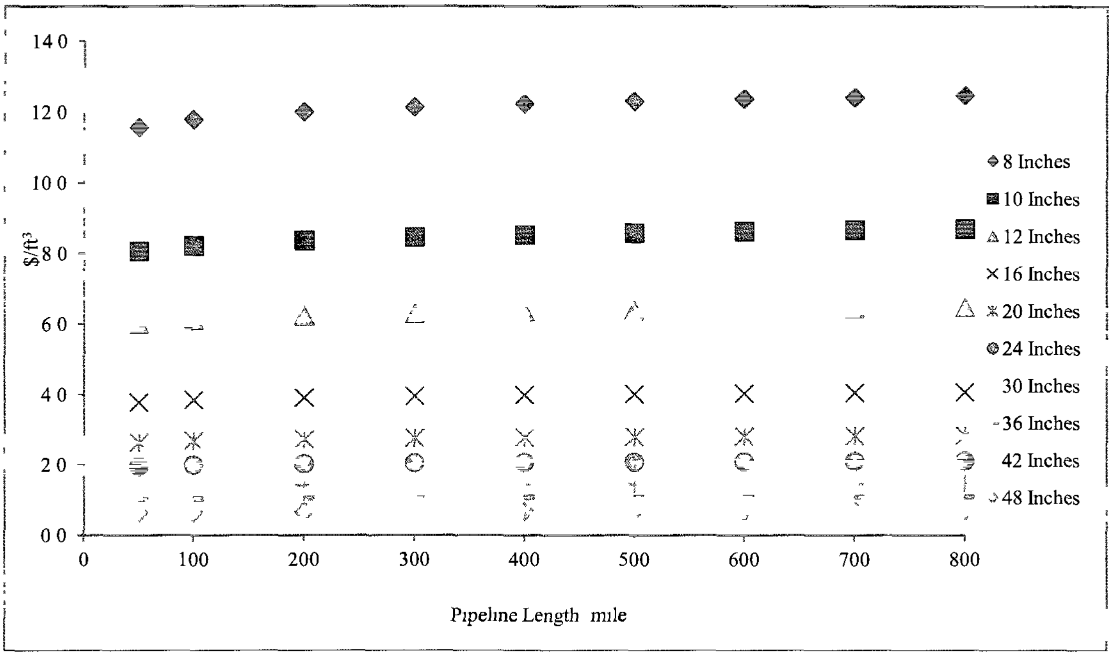

Figure 3.5 Trend of pipelıne unit ROW costs (Central region)

Figure 3.5 shows the trend of estımated pipeline unit ROW cost in the Central region. The pipeline unit ROW cost decreases as pipeline cross-sectional area increases, while it slıghtly increases as pipeline length increases. Thıs indicates that ROW cost has the economies of scale for pipelıne cross-sectional area, but not for pipeline length. All component costs, therefore, have economies of scale with respect to pipeline cross-sectional area and length except for ROW costs, which only have economies of scale with respect to pipeline cross-sectional area.

The economies of scale caused by the growth of the project ıtself are called the ınternal economies of scale. For pipeline projects, internal economıes of scale are created by increasing pipelıne cross-sectional area and length.

The four main categories of internal economies of scale are: technical economies, managerial economies, marketing economies, and financial economies (Wılkinson, 2005). Technical economies use specialızed equipment or process to improve labor and capital productıvity in large pıpeline projects. For example, large and efficient trenchers are employed to increase productivity and reduce the cost of diesel and carbide teeth Many small pipeline projects cannot afford such an initial heavy investment due to the inability to diffuse the high fixed cost In addition, equipment and facilities are more easily operated in high capacity with less idle capacity

Managerial economies manifest themselves when large pipeline projects hire professional and specialized mangers for separate tasks instead of relying on one general manger to take care of everything Marketing economies manifest themselves in discounts realized by buying material in huge quantities, while lower interest rates or greater government assistance stand as example of financial economies likely to be granted to large pipeline projects

These explanations support the fact that large pipeline projects have economies of scale and low unit cost These explanations also match the regression results that unit costs of pipeline construction components are reduced with increasing pipeline cross-sectional area and length, except for the ROW cost, which only decreases with increasing pipeline cross-sectional area

3.6 Limitation of analysis and suggestion for future work

The data used in this paper included 412 pipelines built between 1992 and 2008, but there are still too few pipelines in some regions, such as Canada and the Western region, to form a representative sample Pipelines in these regions show less correlation to pipeline construction component costs compared to other regions

In the dataset, 78% of pipelines are less than 60 miles long The relative lack of long pipeline may cause estimation biases The cost data does not provide year of starting or the construction period, which necessitates adjusting via the CE index, possibly causing bias

Definitions for the U S natural gas pipeline network are based on the federal regions of the U S Bureau of Labor Statistics Regional definitions of natural gas pipeline systems could instead be made according to geography, terrain, cost of living, or other criteria Some important variables also remain missing, such as pipeline wall thickness, steel grade, maximum allowable operating pressure, terrain along pipeline route, and ownership type, any of which could produce cost differences

Future work should collect more data from Canada and the Western region, longer pipeline, project construction schedule, and more data on the missing variables

3.7 Conclusions

Based on available historical data, five pipeline construction component cost estimation models are developed with the multiple nonlinear regression method Regression models are determined to be valid models by subjecting them to various statistical tests The models are able to estimate pipeline construction component costs with respect to pipeline cross-sectional areas, lengths and regions The results show that there are large cost differences in different regions Economies of concentration are concluded as an important factor for reducing cost The Cobb-Douglas function is employed to analyze the relationship between pipeline cost and pipeline cross-sectional area and length, indicating that the pipeline cost components all have economies of scale with respect to pipeline cross-sectional area and pipeline length, except ROW cost, which only has economies of scale with respect to pipeline cross-sectional area Cost estimation models have their limitations due to limited information, such as pipeline wall thickness and ownership Future work will concentrate on collecting more pipeline information for comprehensive and accurate quantitative analysis

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CHAPTER 4 AN ANALYSIS OF INACCURACY IN PIPELINE CONSTRUCTION COST ESTIMATION[1]

4.1 Abstract

The aim of this chapter is to investigate cost overrun of pipeline projects. A total of 412 pipeline projects between 1992 and 2008 have been collected, including material cost, labor cost, miscellaneous cost, right of way (ROW) cost, total cost, pipeline diameter, length, location, and year of completion. Statistical methods are used to identify the distribution of the cost overrun and the sources for overruns. Overall average overrun rates of pipeline material, labor, miscellaneous, ROW and total costs are 0.049, 0.224, -0.009, 0.091, and 0.065, respectively. Cost estimations of pipeline cost components are biased except for total cost. In addition, the cost error of underestimated pipeline construction components is generally larger than that of overestimated pipeline construction components except for total cost. Results of analyses show that pipeline size, capacity, diameter, location, and year of completion have different impacts on cost overruns for construction cost components.

[1] Rui, Z., Metz, P.A. and Chen, G (2012) 'An analysis of inaccuracy in pipeline construction cost estimation', *International Journal of Oil, Gas and Coal Technology*, 5(1), in press.

4.2 Introduction

Cost error is the tendency for actual costs to deviate from estimated cost. Bias is the tendency for that error to have a non-zero mean (Bertisen and Davis, 2008). Cost errors or bias are common and a global phenomenon in cost estimation (Flyvbjerg et al., 2003). Cost estimation errors and bias in other types of projects have been mentioned and studied in numerous papers. Pohl and Mihaljek (1992) reviewed 1,015 World Bank projects from 1947 to 1987, finding a 22% average cost overrun and 50% time overrun. Merrow (1988) found that 47 of 52 megaprojects ranging in cost from $500 million to more than $10 billion (in 1984 dollars) have an average overrun of 88%, and large projects appear to have more cost growth than smaller projects. Flyvbjerg et al. (2003) examined 258 transport-infrastructure projects (rail, bridge, and road) and found an average 28% cost overrun. Bertisen and Davis (2008) reviewed 63 international mining projects with an average construction cost 14% higher than estimated cost in the feasibility studies. Overall cost overrun rates of all Indiana Departments of Transportation (INDOT) projects was 4.5%, and 55% of all projects experienced cost overruns (Bordat et al., 2004). Jacoby (2001) found that 74 projects with a minimum cost of $10 million had 25% cost overruns. The literature reviewed also shows that cost overruns exist over time.

Many researchers have tried to explain the project cost overrun phenomenon. Some researchers proposed that optimism and deception are major causes of cost overruns (Flyvbjerg et al., 2003). Others believed that engineers and managers have incentive to underestimate costs (Bertisen and Davis, 2008). Flyvbjerg (2007) suggested that cost underestimation and overestimation of transport-infrastructure appear to be intentional by project promoters. Information asymmetries were also suggested as a reason for cost overrun (Pindyck and Rubinfeld, 1995). Rowland (1981) mentioned that large projects increase the likelihood of a high number of change orders. Jahren and Ashe (1990) suggested that large projects have large cost overruns due to complexity, but also mentioned that managers of large projects try to keep cost overrun rates from growing excessively large. Large projects can lead to savings in unit costs, but limit the number of companies able to carry out these projects, leading to a trade-off between economies of scale and competitive bidding practices (Bordat et al., 2004). Odeck (2004) indicated that large projects have better management than small projects. Soil, drainage, climate, and weather conditions have an impact on design standards and costs of materials for road and rail projects, and location influences construction and material costs due to varying distances from supplies (RGL Forensics, 2009) An Australian study showed that public-private partnership projects perform better than traditionally procured projects, while a European study showed public-private partnerships exhibit higher costs than traditionally procured infrastructure (Infrastructure Partnerships Australia, 2008, RGL Forensics, 2009) Flyvbjerg (2007) suggested that more research on the role of ownership in causing efficiency differences between projects should be conducted He also used technical, psychological, and political-economic factors to explain cost overruns

Although these studies have been conducted on project cost overruns, there are limited available references to pipeline project cost overruns With available pipeline data, this paper will focus on the cost estimation errors of pipeline construction components, and investigate and identify the frequency of cost overrun occurrence and the magnitudes of difference between estimated and actual costs in pipeline projects In addition, cost overruns in terms of pipeline project size, capacity, diameter, length, location, and year of completion are also investigated

4.3 Data sources

In this study, the pipelines are selected based on data availability The *Oil & Gas Journal* pipeline cost data were collected from Federal Energy Regulatory Commission filings from gas transmission companies, published by the *Oil & Gas Journal* annual databook (Penn Well Corp, 1992-2009) Due to limited offshore pipeline data, the pipeline dataset in this chapter contains only onshore pipeline data, and the pipeline costs in this paper do not include compressor station cost

The pipeline dataset provides location and year, pipeline diameter and length Pipelines in the dataset are distributed in the contiguous U S (excluding Alaska and Hawaii) as well as 15 Canadian pipelines The pipelines were completed between 1992 and 2008 Therefore, "cost" is defined as real, accounted costs determined at the time of completion The entire dataset includes 412 onshore pipelines The data include estimated and actual cost of five cost components material, labor, miscellaneous, ROW and total costs Estimated costs are defined as budget, or forecast, costs at the time of decision to build the pipeline Actual costs are defined as real accounted costs determined at the time of completing the pipeline

(Flyvbjerg et al., 2003). Material cost covers cost of line pipe, pipeline coating and cathodic protection. Labor cost consists of the cost of pipeline construction labor. Miscellaneous cost is a composite of the costs of surveying, engineering, supervision, contingencies, telecommunications equipment, freight, taxes, allowances for funds used during construction, administration and overheads, and regulatory filing fees. ROW cost contains the cost of ROW acquisition and allowance for damages. The total cost is the sum of material, labor, miscellaneous, and ROW costs (PennWell Corporation, 1992-2009).

Location information for U.S. pipelines was provided in a state format. A total of 48 states were referred to, except for Alaska and Hawaii. The EIA breaks the U.S. natural gas pipelines network into six regions: Northeast, Southeast, Midwest, Southwest, Central and Western (EIA, 2010). The map of regional definitions is shown in Figure 4.1. These regional definitions are used to analyze geographic differences. In this paper, U.S. pipeline data are divided in to six regions according to the EIA definition. In addition, there are 15 Canadian pipelines, but they have not been broken down into specific provinces, due to limited available information.

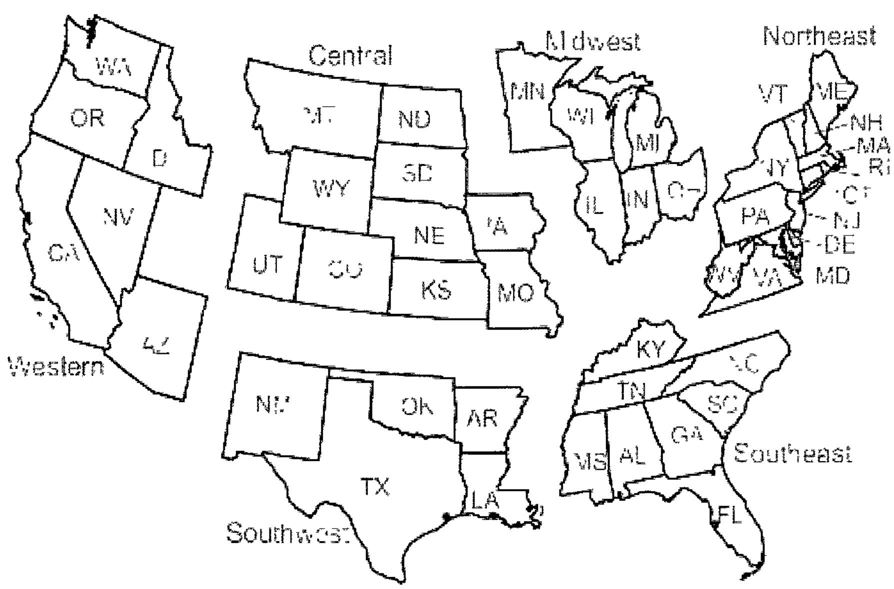

Figure 4.1 U.S. natural gas pipeline region network map (EIA, 2010)
Note: Alaska and Hawaii are not included

In order to make a comparative analysis, all costs are adjusted by the Chemical Engineering Plant Cost Index to 2008 dollars. The Chemical Engineering Plant Cost Index is widely applied on process plants for adjusting construction cost The Chemical Engineering Plant Cost Index has 11 sub-indices and a composite index, the weighted average of the 11 sub-indices (Chemical Engineering, 2011) Pipeline index and construction labor index is used to adjust pipeline material and labor costs, respectively The Chemical Engineering Plant Index is applied to pipeline miscellaneous and ROW costs

4.4 Performance of individual pipeline construction component cost estimation

This section will evaluate the performance of pipeline construction component cost estimations Several methods may be used to study the difference between estimated and actual costs of a project In this study, the estimated cost and the actual cost are used to calculate the cost overrun rate as a measurement of cost overrun The formula for the cost overrun rate is

$$\text{Cost overrun rate} = \frac{(\text{Actual cost} - \text{Estimated cost})}{\text{Estimated cost}} \qquad \text{Equation 4 1}$$

If the cost overrun rate is positive, the cost is underestimated, otherwise, it is overestimated In this chapter, all cost overrun rates are calculated with the above formula

Histograms of the cost overrun rates for pipeline construction components are shown in Figure 4 2 to Figure 4 6 If the cost error is small, the histogram will be narrowly concentrated around zero If underestimated costs are as common as overestimated costs, the histogram would be symmetrically distributed around zero It appears that five figures exhibits non-symmetric distributions, and none of them satisfies the above mentioned assumptions

For the material cost, 172 (42 0% of the total) pipelines are underestimated, and 238 (58 0%) are overestimated For the labor cost, 273 (66 7%) pipelines are underestimated, and 136 (33 3%) are overestimated For the miscellaneous cost, 166 (40 8%) pipelines are underestimated, and 241 (59 2%) are overestimated For the ROW cost, 174 (45 7% of total) pipelines are underestimated, and 207 (54 3%) are overestimated For the total cost, 222 (54 0%) pipelines are underestimated, and 189 (46 0%) are overestimated

In summary, more pipelines are overestimated for material, miscellaneous and ROW costs, while more pipelines are underestimated for labor and total costs In general, the percentage of overestimated pipelines implies that there are still a good number of pipelines being completed with costs less than the estimated cost In addition, the majority of pipelines (87 1 % for material cost, 72 3% for labor cost, 67 3% for miscellaneous cost, and 89% for total cost) have cost overrun rates between -0 4 and 0 4 However, only 49 0% of the pipelines have ROW cost overrun rates between -0 4 and 0 4, demonstrating that ROW cost overrun is more severe than other cost components, also indicated by its standard deviation (SD) (Table 4 1)

Statistical summaries of cost overruns of individual pipeline construction components are shown in Table 4 1 Skewness is a quantitative way to measure the symmetry of the distribution Symmetrical distribution has a skewness of 0 Positive skewness means that the right tail is "heavier" than the left tail Negative skewness means that the left tail dominates distribution Kurtosis is a quantitative method to evaluate whether the shape of the data distribution fits the normal distribution A normal distribution has a kurtosis of 0 Kurtosis of a flatter distribution is negative, that of a more peaked distribution is positive (Hill et al , 2007) Values of skewness and kurtosis in Table 4 1 show that none of the cost overruns of the five components are symmetrical to normal distribution, which matches the implications from the histogram graphs Some transformation techniques (such as natural log transformation) are applied to cost overrun rate data for fitting them to normal distribution, but such data transformations are unsuccessful Therefore, the non-parametric statistical test is used in the following sections

Table 4 1 shows that the minimum cost overrun rates for individual cost components are between -0 94 (labor cost) and -1 (ROW cost) The maximum cost overrun rates for individual cost components are between 2 12 and 7 04 The value of minimum and maximum indicates that cost performance for some pipelines is extremely bad The labor cost overrun has the largest maximum-minimum range of 7 98, while total cost overrun has the smallest range of 3 06 The SD of individual cost components are fairly significant, between 0 34 and 0 81 of the estimated cost The large maximum-minimum range and SD indicate that performance of pipeline construction cost estimation is unstable It is noteworthy that the labor cost has the largest maximum-minimum range and the second largest SD, and ROW cost has the largest SD, showing difficult to estimate labor and ROW costs accurately Total cost overrun has the smallest maximum-minimum range and SD due to its aggregation of other components

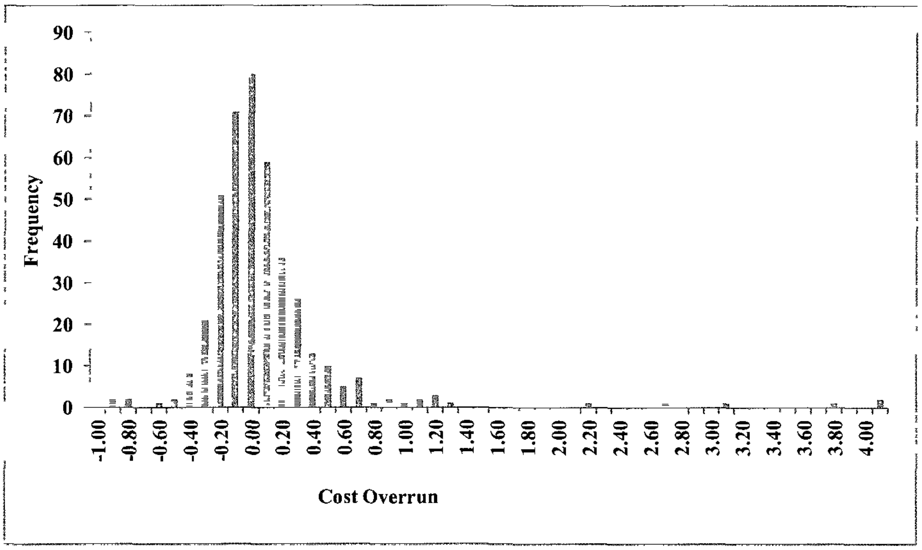

Figure 4.2 Overrun rates of material cost

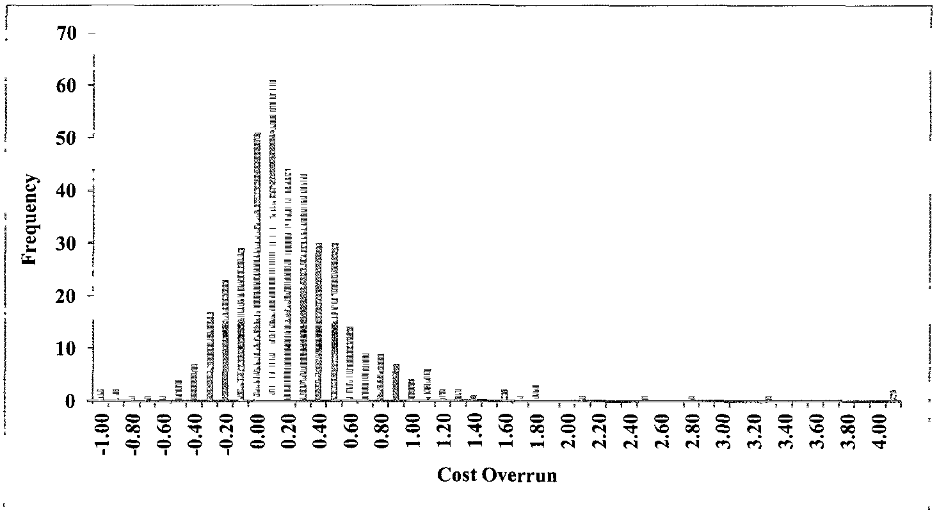

Figure 4.3 Overrun rates of labor cost

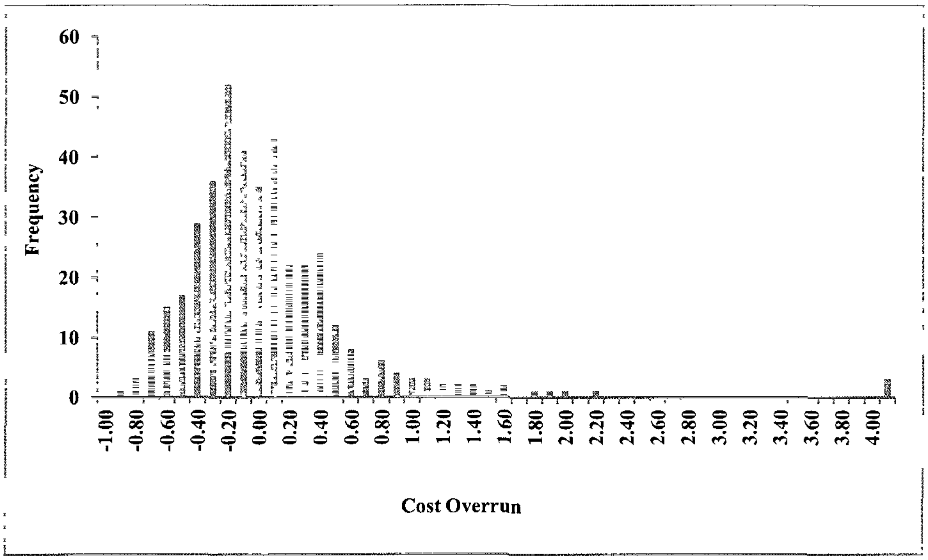

Figure 4.4 Overrun rates of miscellaneous cost

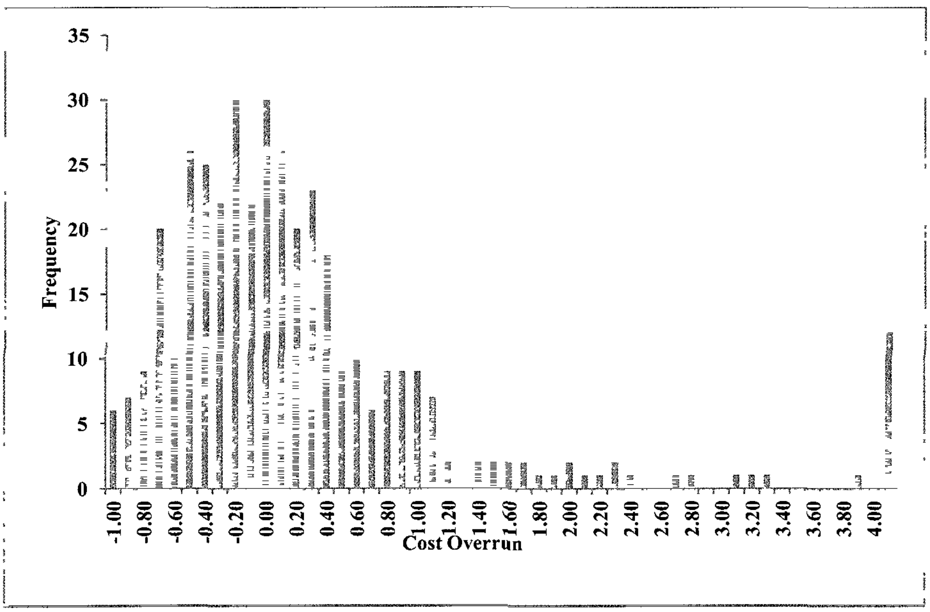

Figure 4.5 Overrun rates of ROW cost

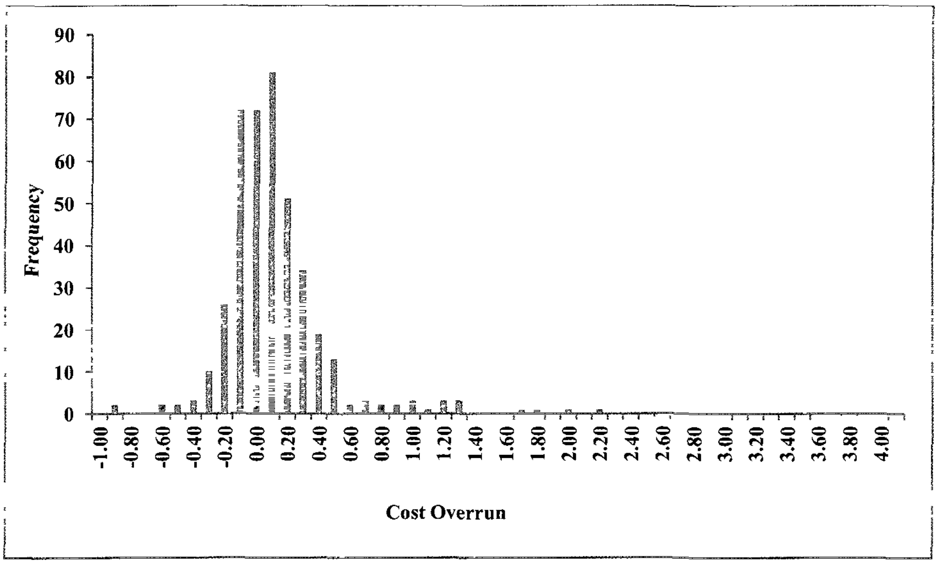

Figure 4.6 Overrun rates of total cost

The average cost overrun is a key parameter to measure the cost estimation performance of individual pipeline construction cost components. Labor cost has the highest average cost overrun rate of 0.22, followed by the ROW cost of 0.09, total cost of 0.07, material cost of 0.05, and miscellaneous cost of -0.01 Material, labor, ROW, and total costs show positive average cost overrun, while miscellaneous cost has negative average cost overrun. This result denotes that, on average, actual costs are larger than estimated cost for all pipeline construction cost components except for miscellaneous cost.

As mentioned before, there are more pipelines with overestimated material, miscellaneous and ROW costs than those with underestimated pipelines, and there are more pipelines with underestimated labor and total costs than those with overestimation of these two cost components. However, it is interesting that the average cost overruns of material and ROW costs are still positive, even though there are more pipelines with overestimated material, and ROW costs. It appears that cost estimation of pipeline construction cost components is biased, and the underestimating error is generally greater than the overestimating error for some pipeline construction cost components. In this chapter, two statistical tests are performed to investigate this inference.

A binomial test is conducted to examine if the error of cost overestimating is as common as the error of cost underestimating As shown in Table 4 2, the p-value of the binomial test rejects the null hypothesis that the overestimating error is as common as the underestimating error for material, labor, miscellaneous, and ROW costs ($p<0$ 05, two sided test), but fails to reject that for total cost ($p>0$ 05, two sided test) Therefore, the cost estimations of all pipeline construction cost components are biased except total cost, material, miscellaneous, ROW costs tend to overestimation, while labor costs tend to underestimation

Furthermore, the non-parametric Mann-Whitney test is employed to see if the cost underestimating error is the same as the cost overestimating error The p-value shown in Table 4 2 shows that the errors of underestimated pipelines cost overruns are much larger than those of overestimated pipelines cost overruns for material, labor, miscellaneous and ROW costs ($p<5\%$, one sided test), but not for total cost ($p>5\%$, two sided test) Hence, the underestimating error is significantly more common and greater than the overestimating error for all pipeline cost components, but not for the total cost

After analyzing overall cost overruns of pipeline projects, it is more important to identify significant factors that influence pipeline project cost overruns Analyses of cost overruns for pipeline project size, capacity, diameter, length, location, and completion time are performed in the following sections

Table 4 1 Summaries of cost overruns of pipeline construction components

	Material	Labor	Miscellaneous	ROW	Total
Skewness	5 77	4 83	4 77	3 25	2 20
Kurtosis	49 22	44 88	42 06	15 77	12 29
Minimum	-0 95	-0 94	-0 94	-1 00	-0 94
Maximum	5 67	7 04	4 56	4 55	2 12
Range	6 61	7 98	5 50	5 55	3 06
Average	0 05	0 22	-0 01	0 09	0 07
Standard Deviation	0 55	0 62	0 56	0 81	0 34
Total Number of Pipelines	410	409	407	381	411
Number of Underestimated Pipelines	172	273	166	174	222
Number of Overestimated Pipelines	238	136	241	207	189

Table 4 2 Statistical tests of cost overrun of pipeline construction cost components

	Material	Labor	Miscellaneous	ROW	Total
Binomial Test	0 001	0	0	0	0 114
Mann-Whitney Test	0 047	0	0	0 039	0 082

4.5 Cost overruns in terms of pipeline project size

Here, the project size is measured by the pipeline actual total cost For this dataset, pipeline total costs range from $33,576 to $1,933,839,076, classified into groups of small, medium and large One-hundred eighty-five pipelines with total actual costs less than $10,000,000 are classified as small projects, 192 pipelines with total actual costs between $10, 0000, 0000 and $100,000,000 are classified as medium projects, and 33 pipelines with total actual costs larger than $100,000,000 are classified as large projects

Descriptive statistical analysis of cost overruns in terms of project size is shown in Table 4 3 For total costs, the average cost overrun rate increases as project size increases For the total cost, large projects have the highest cost overrun rates A plausible explanation is that a large pipeline project, normally bigger than $1 billion dollars, can cause a huge demand that influences market price, such as steel price, and further increases the cost of pipeline construction Expectation of increased pipeline construction costs can induce an increase in the current unit construction costs (Rui et al , 2011a) Suppliers would raise prices with expectation for more demand In addition, a large project limits the numbers of suppliers and contractors, reducing competition, thus increasing the cost (Bordat et al , 2004, RGL Forensics, 2009) However, for the miscellaneous cost, large projects have the lowest cost overruns It is possible that larger projects have better management systems which coordinate different departments, increase the efficiency of material utilization and take advantage of economies of scale

To determine if there is a strong relationship between project size and cost overrun for different pipeline construction components, the nonparametric Kruskal-Wallis (KW) test is used to test the null hypothesis that project size has no effect on pipeline cost overruns, because the value of skewness and kurtosis shows that the cost overruns of each diameter group is not a normal distribution Therefore, the KW test will be used when the data does not produce normal distributions

For the total cost, results of the KW test show that cost overruns for different project size groups are significantly different ($p<0.05$), however, such a significant difference is not found for other cost components ($p>0.05$) Therefore, it is concluded that the project size significantly influences cost overruns for total cost, but not for other individual cost components

Table 4 3 Average cost overrun rate for different project size groups

Components	Project Size	Average	SD	Skewness	Kurtosis
Material	Small	0 10	0 70	4 55	30 86
	Medium	0 01	0 42	7 34	80 95
	Large	0 04	0 13	1 22	4 19
Labor	Small	0 16	0 47	1 31	6 95
	Medium	0 28	0 76	5 19	40 15
	Large	0 13	0 41	-0 50	4 03
Miscellaneous	Small	0 01	0 46	1 08	5 68
	Medium	0 01	0 46	0 98	4 01
	Large	0 04	0 46	1 08	5 68
ROW	Small	0 18	1 20	2 87	13 30
	Medium	0 30	1 39	3 28	15 00
	Large	0 23	0 54	1 60	7 12
Total	Small	0 04	0 36	1 89	10 04
	Medium	0 08	0 32	2 70	15 24
	Large	0 12	0 24	2 50	11 58

4.6 Cost overruns in terms of pipeline diameter

Pipeline diameters range from 4 inches to 48 inches Pipeline projects are categorized into three groups based on diameter 4-20 inch, 22-30 inch, and 34-48 inch Pipeline construction component cost overruns for three different pipeline diameter groups are shown in Table 4 4

For material, labor, ROW and total costs, 4-20 inch pipelines have the highest average cost overrun rate, followed by 22-30 inch pipelines and 34-48 inch pipelines For the miscellaneous cost, 4-20 inch pipelines have the highest average cost overruns, but 22-30 inch pipelines have the lowest average cost overrun of -0 16 4-20 inch group has the highest average cost overrun rates for all construction components costs It appears that small diameter pipelines are prone to cost overruns

Therefore, the nonparametric Kruskal-Wallis (KW) test is used to test the null hypothesis that pipeline diameter has no effect on cost overruns of pipelines construction component costs For material, ROW and total costs, the result of the KW test shows the cost overruns are not significantly different for different diameter groups ($p>0$ 5) For labor and miscellaneous costs, the result of the KW test shows cost overruns for diameter groups are significantly different ($p<0$ 01) This leads to the conclusion that diameter groups influence cost overruns for labor and miscellaneous costs, but not for other components costs

Table 4 4 Average cost overrun rates for different diameter groups

Components	Diameter Groups	Average	SD	Skewness	Kurtosis	Num of Pipelines
Material	4-20 inch	0 13	0 68	3 70	21 37	124
	22-30 inch	0 03	0 42	5 62	51 28	131
	34-48 inch	0 00	0 52	8 56	92 67	155
Labor	4-20 inch	0 39	0 95	3 85	23 97	126
	22-30 inch	0 21	0 42	1 14	5 79	131
	34-48 inch	0 09	0 33	0 87	7 18	155
Miscellaneous	4-20 inch	0 17	0 99	4 11	24 64	123
	22-30 inch	-0 16	0 35	0 93	4 39	131
	34-48 inch	0 02	0 48	0 92	4 38	152
ROW	4-20 inch	0 43	1 57	2 61	10 01	115
	22-30 inch	0 24	1 38	3 31	15 53	122
	34-48 inch	0 11	0 81	2 71	15 52	153
Total	4-20 inch	0 17	0 48	1 72	6 96	124
	22-30 inch	0 03	0 24	0 65	6 55	131
	34-48 inch	0 02	0 23	1 39	9 59	155

4.7 Cost overruns in terms of pipeline length

This section examines cost overruns for pipeline length Pipeline length ranges from 0 1 to 713 miles, divided into two groups 0-20 mile and 20-713 mile Approximately 78% of the examined pipelines are shorter than 20 miles, and the rest are between 20 and 713 miles Pipeline construction component cost overruns for these pipeline length groups are shown in Table 4 5

For material, miscellaneous and ROW costs, the 0-20 mile group has the highest average cost overrun rate, followed by the 20-713 mile group For labor and total costs, the 20-713 mile pipelines have incurred the highest average cost overruns, followed by the 0-20 mile group It appears that different construction component costs have different cost overrun rate patterns

The KW test is used to test the null hypothesis that type of pipeline length has no effect on cost overruns For all construction cost components, the results of the KW tests show cost overrun rate differences between the length groups are not significant at the 5% level (p>0 1) It is concluded that cost overrun rates for all construction cost components are not significantly influenced by pipeline lengths

Table 4 5 Average cost overrun rates for different length groups

Components	Length Groups	Average	SD	Skewness	Kurtosis	Num of Pipelines
Material	0-20 mile	0 05	0 56	5 25	44 21	321
	20-713 mile	0 04	0 51	8 14	73 36	89
Labor	0-20 mile	0 21	0 60	5 37	56 39	323
	20-713 mile	0 26	0 70	3 46	20 41	89
Miscellaneous	0-20 mile	0 17	0 72	4 71	38 60	319
	20-713 mile	-0 03	0 40	0 82	4 74	87
ROW	0-20 mile	0 23	1 28	3 11	14 53	303
	20-713 mile	0 30	1 18	3 89	21 62	87
Total	0-20 mile	0 06	0 35	2 12	11 85	321
	20-713 mile	0 10	0 30	2 80	14 57	89

4.8 Cost overruns in terms of pipeline capacity

In this section, the pipeline volume (capacity) is calculated with the formula (Zhao, 2000)

$$V = S * L \quad \text{Equation 4 2}$$

where $S = \pi(\frac{D}{2})^2$, V is the pipeline volume (ft^3), S is pipeline cross-sectional area (ft^2), L is pipeline length (ft), and D is pipeline diameter (ft) In the data set for this study, the smallest pipeline capacity is 92 ft^3, and the largest is 36,220,080 ft^3 All pipelines are divided into three different capacity groups to test whether the cost overrun rate is significantly different for different capacities There are 135 pipelines with a capacity of less than 75,000 ft^3, classified as small projects, 136 pipelines with a capacity between 75, 000 ft^3 and 284,768 ft^3, classified as medium, and 139 pipelines with a capacity larger than 284,768 ft^3, classified as large

Table 4 6 Average cost overrun rates for different capacity groups

Components	Capacity Groups	Average	SD	Skewness	Kurtosis	Num of Pipelines
	Small	0 19	0 80	3 81	22 63	135
Material	Medium	-0 03	0 24	0 97	4 47	136
	Large	-0 05	0 43	8 75	93 69	139
	Small	0 24	0 57	1 54	7 35	135
Labor	Medium	0 25	0 84	5 37	38 99	137
	Large	0 16	0 38	0 47	5 10	140
	Small	0 13	0 97	4 14	25 36	133
Miscellaneous	Medium	-0 08	0 43	1 11	4 25	135
	Large	-0 03	0 43	0 94	4 79	138
	Small	0 34	1 50	2 50	9 29	128
ROW	Medium	0 19	1 19	4 00	23 95	130
	Large	0 20	1 05	3 54	19 34	132
	Small	0 12	0 46	1 72	7 77	135
Total	Medium	0 03	0 29	2 45	13 17	136
	Large	0 05	0 21	0 95	7 96	139

A descriptive statistical analysis of cost overruns for pipeline capacity is shown in Table 4 6 A noticeable observation is that the small capacity group has the highest average cost overrun rates for all construction cost components Pipelines with small capacity appear to be particularly prone to cost overruns Projects with large capacity may take more advantage of economies of scale

The KW test is used to verify that the pipeline capacity has no effect on cost overruns for construction cost components For the material cost, the result of KW test rejects the null hypothesis ($p<0\ 001$), indicating that pipeline capacity influences material cost overruns, and projects with small capacity have large positive cost overrun rates Pipeline projects with large capacity mean that more material is consumed, thereby taking advantage of economies of scale in materials purchasing, resulting in lower costs for materials as pipeline capacity increases It may be that the pipeline project estimators do not estimate unit prices changing with scale accurately or do not consider economies of scale in material costs This may result in small capacity pipeline projects with large cost overruns For labor, miscellaneous, ROW and total costs, the results fail to reject the null hypothesis that pipeline capacity has no effects on the cost overrun rates ($p>0.05$). Thus, the cost overrun differences in the labor, miscellaneous, ROW and total costs are not statistically significant for different pipeline capacities.

4.9 Cost overruns in terms of different regions

Pipeline costs are significantly different for different regions (Rui et al., 2011b). This section examines whether cost overruns for pipeline construction cost components vary by region.

As seen in Table 4.7, cost overrun rates for the pipelines in the Northeast regions are the lowest in the U.S. as compared to other regions, even though the Northeast has a relatively high cost of living. In addition, the total cost overrun rate of pipelines in the Northeast regions is a perfect 0. A possible explanation is that 155 out of the 412 pipelines in the dataset are in the Northeast region, which provides more practical experience and historical information for new pipeline cost estimating. A few negative cost overrun rates also appear in some regions for different construction component costs.

The results of KW tests show that the cost overrun of differences by regions are highly significant for all construction cost components ($p<0.001$). Weather conditions, soil property, population density, cost of living, terrain condition, and distance from supplies are variables in different regions, making pipeline project cost estimation more difficult (Rui et al., 2011b; Zhao, 2000). More detailed information on pipeline routes is needed to explain the cost overrun differences in different regions.

It is concluded that the cost overrun rates of all cost components show significant differences in different regions, and pipeline location matters for cost overruns of all cost components.

4.10 Cost overrun over time

Forty seven large projects constructed between the mid 1960s and 1984 had a cost overrun rate of 88% (Merrow, 1988). More than 1,000 World Bank projects between 1947 and 1987 had cost estimation errors (Pohl and Mihalijek, 1992). Fifty five percent of all INDOT projects between 1996 and 2001 experienced cost overruns (Bordat et al, 2004). Cost overrun is constant for a more than a 70-year period between 1910 and 1998, comprising 208 transportation projects in 14 nations on five continents (Flyvbjerg et al., 2003). These literatures demonstrate that the cost estimation errors persist on different types of projects over time. Has there been any improvement in pipeline cost estimation over time? This section will attempt to investigate whether the cost estimation performance for pipelines has improved over time.

Improved performance of cost estimation is normally expected as experience is gamed The average cost overrun rate of pipelines construction components between 1992 and 2008 are shown in Figure 4 7 Cost overrun rates of the ROW cost fluctuate widely, but show a declining trend The cost overrun rates of the labor cost show a decrease before 2004 and then a significant increase afterward But the cost overrun rate of material, miscellaneous, and total costs fluctuate more gradually over time

Construction phase length often influences cost overrun rates, so optimal studies use the planning year to build as the time measurement (Flyvbjerg et al , 2003) The available data does not provide the year of building and construction period, therefore, in this chapter, the year of completion is used to as time measure, which may cause bias The nonparametric Nptrend test is conducted to discover if there is a cost overrun rate trend over the years Results of the Nptrend test show that only cost overrun rates of ROW decrease over time ($p<0\ 05$) Based on available data, it is concluded that ROW cost estimation has improved over time, but not that of other components

4.11 Conclusions and future work

This chapter statistically analyzes cost estimating performances of individual pipeline construction cost components using 412 pipeline projects Overall average cost overrun rates of the material, labor, miscellaneous, ROW and total costs are 0 049 (SD=0 548), 0 224 (SD=0 618), -0 009 (SD=0 562), 0 091 (SD=0 809), and 0 065 (SD=0 335) respectively Labor and ROW costs have the largest cost overrun rates compared to the other cost components Statistical test results show that cost estimation for all cost components is biased except for the total cost And the magnitude of underestimating errors is generally larger than overestimating errors except for total cost Furthermore, cost overrun rates of pipeline construction cost components are analyzed in terms of pipeline project size, capacity, diameter, length, location, and year of completion to investigate the relationship between cost overruns and different groups The cost overrun rate for the total cost shows a significant difference for different project size groups, and the cost overrun rates increase with project size An expected large demand and limited supplies and contractors for large projects cause large cost overruns (Bordat et al , 2004, RGL Forensics, 2009, Rui et al , 2011a) Cost overrun rates of the labor and miscellaneous show significant differences in diameter groups, and the small diameter group has the highest average cost overrun rate Cost overrun rates of all construction cost components are not significantly influenced by pipeline length. Cost overrun rates of the material cost are significant for different pipeline capacity groups, and small pipeline capacity projects appear to be particularly prone to cost overruns. Large capacity pipeline projects have the advantage of economy of scale, allowing for purchasing material at lower unit rates. Planners or estimators may not estimate material unit price changing with scale accurately or even fail to consider the economies of scale. The cost overruns of all construction cost components are significantly different in different regions. Weather, soil, terrain, terrain condition, population density and experience are suggested as the causes for the difficulties of accurate estimation. Cost estimating accuracy of pipeline construction components did not improve over the 1992-2008 time period, except when it came to ROW cost.

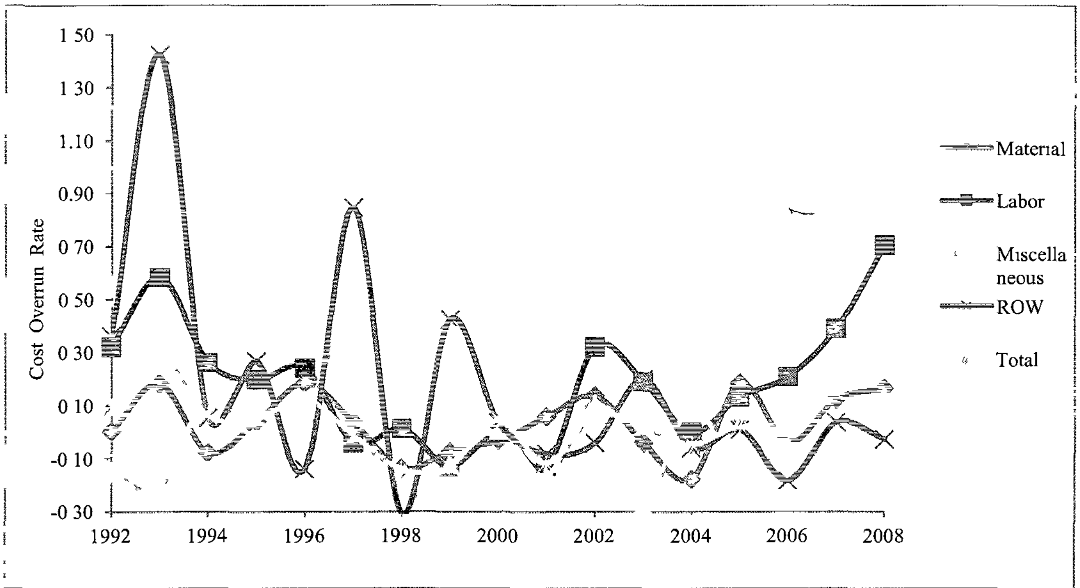

Figure 4.7 Annual average overrun rates of all component costs

Based on the preceding analysis of historical pipeline cost estimation errors, Table 8 provides proposed guidelines for project estimators conducting pipeline cost estimation. To make cost estimation more efficient and reliable, individual cost components should receive varying degrees of attention specific to different conditions A four-level scale: maximum attention, moderate attention, less attention, and minimum attention, allows the estimators to consider how much attention and effort should be paid to individual component cost analysis, depending on pipeline project size, diameter, length, capacity, and region of construction, as given in Table 4 8

To the best of the author's knowledge, this paper is the first in-depth analysis of pipeline construction component cost overruns Suggested future work may include the following

- Different reasons for cost overrun are proposed by different researchers with little hard data to support their theories There is a lack of good quality projects data, making it very difficult to truly investigate the causes of pipeline cost overruns Therefore, collecting more accurate information on pipeline construction period, ownership of projects, pipeline materials, and pipeline wall thickness is a major need for future studies
- More application using analyzed results from this study will be conducted in the future, such as application of pipeline cost overrun distribution
- Develop a set of recommendations to help mangers and engineers to better estimate pipeline project cost overrun and minimize cost estimating errors

Table 4.7 Average cost overrun rates for different regions

Components	Region Groups	Average	SD	Skewness	Kurtosis	Num of Pipelines
	Midwest	-0 02	0 29	0 03	4 81	55
	Northeast	-0 02	0 56	7 33	72 15	156
	Southwest	0 02	0 37	0 32	5 35	30
Material	Canada	0 18	0 26	0 80	2 75	14
	Central	0 06	0 28	1 58	8 24	52
	Southeast	0 26	0 92	3 63	15 69	55
	Western	0 09	0 50	3 22	16 22	48
	Midwest	0 12	0 38	1 19	8 36	55
	Northeast	0 12	0 34	0 87	5 91	157
	Southwest	0 28	0 60	1 04	3 30	30
Labor	Canada	0 02	0 33	-1 04	3 95	15
	Central	0 20	0 49	0 31	2 38	52
	Southeast	0 33	0 85	3 01	14 70	55
	Western	0 55	1 14	4 20	23 28	48
	Midwest	-0 06	0 43	1 72	7 74	54
	Northeast	-0 07	0 45	1 14	5 97	155
	Southwest	0 05	0 52	0 62	2 62	30
Miscellaneous	Canada	1 32	2 25	1 56	4 03	14
	Central	-0 02	0 37	0 84	3 97	51
	Southeast	0 04	0 55	1 60	5 93	55
	Western	-0 08	0 54	1 73	6 28	47
	Midwest	0 34	0 99	3 42	20 21	53
	Northeast	-0 10	0 76	2 31	12 10	150
	Southwest	0 12	1 14	3 66	17 27	27
ROW	Canada	1 59	2 18	0 76	2 01	14
	Central	0 26	1 11	2 74	12 51	50
	Southeast	-0 08	0 65	1 18	4 90	52
	Western	1 01	2 35	1 84	5 14	44
	Midwest	0 01	0 24	-0 77	5 72	55
	Northeast	0 00	0 26	1 72	10 97	155
	Southwest	0 84	0 34	0 60	3 68	30
Total	Canada	0 14	0 31	-0 86	4 11	15
	Central	0 11	0 29	1 35	6 69	52
	Southeast	0 13	0 45	1 93	6 80	55
	Western	0 19	0 48	2 76	10 77	48

Table 4.8 Proposed guidelines for pipeline cost estimators

Category	Sub-Category	Material	Labor	Miscellaneous	ROW	Total
Project Size	Small	C	B	D	B	D
	Medium	D	A	D	A	C
	Large	D	B	D	A	B
Diameter	4-20 inch	B	A	B	A	B
	22-30 inch	D	A	B	A	D
	34-48 inch	D	C	D	B	D
Length	0-20 mile	D	A	B	A	C
	20-713 mile	D	A	D	A	C
Capacity	Small	B	A	B	A	B
	Medium	D	A	C	B	D
	Large	D	B	D	B	D
Region	Midwest	D	B	C	A	D
	Northeast	D	B	C	C	D
	Southwest	D	A	D	B	A
	Canada	B	D	A	A	B
	Central	D	B	D	A	B
	Southeast	D	A	D	C	B
	Western	B	A	C	A	B

Note A=Maximum attention, B=Moderate attention, C= Less attention; D= Minimum attention

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CHAPTER 5 PIPELINE COMPRESSOR STATION CONSTRUCTION COST ANALYSIS

5.1 Abstract

This study aims to provide a reference for pipeline compressor station construction costs by analyzing individual compressor station cost components using historical compressor station cost data between 1992 and 2008. Distribution and share of these pipeline compressor station cost components are assessed based on compressor station capacity, year of completion, and locations. Average unit costs in material, labor, miscellaneous, land, and total costs are \$866/hp, \$466/hp, \$367/hp, \$13/hp, and \$1,712/hp, respectively. Primary costs for compressor stations are material cost, approximately 50.6% of the total cost. This study conducts a learning curve analysis to investigate the learning rate of material and labor costs for different groups. Results show that learning rates and construction component costs vary by capacity and locations. This study also investigates the causes of pipeline compressor station construction cost differences.

5.2 Introduction

The most economic and efficient method to transport large amounts of natural gas is via a pipeline under pressure. As the gas flow down the pipe, pressure is lost because of friction between the natural gas flow and the inside wall of the pipeline. A compressor station is installed to keep the natural gas flowing continually. The compressor station is normally constructed every 50 to 100 miles along the pipeline (Interstate Natural Gas Association of America (INGAA), 2010). In general, two types of compressors are used in the pipeline industry: centrifugal and reciprocating compressors; compressors are driven by prime movers: reciprocating engines, gas turbines, or electric motors (INGAA, 2010).

Few researchers have analyzed historical pipeline compressor station cost data to estimate the construction costs for different purposes. There is limited literature available on the pipeline compressor station construction costs. The *Oil & Gas Journal* annually publishes estimated and actual pipeline compressor station costs annually (PennWell Corporation, 1992-2009). An empirical formula between compressor station cost and horsepower has been established by IEA Greenhouse Gas R&D Programme (2002).

The purpose of this paper is to conduct a comprehensive analysis on pipeline compressor station costs, using data from projects constructed between 1992 and 2008, via various perspectives: the distribution of pipeline compressor stations by year of completion, capacity, location, and individual component costs; and the share of compressor station cost components and learning curves in compressor station construction with respect to capacity and location. Causes of cost differences and learning rate differences are also investigated. Various data processing and statistical descriptions are applied to the historical data in this chapter.

5.3 Data sources

In this study, the compressor stations are selected based on data availability. Compressor station cost data were collected from Federal Energy Regulatory Commission (FERC) filings by gas transmission companies, published in the *Oil & Gas Journal* annual databook (PennWell Corporation, 1992-2009). The compressor station data include year of completion, capacity, location, and individual cost components. Compressor stations in the dataset were distributed in all states in the contiguous U.S. and completed between 1992 and 2008 The year of completion is defined by the time of filling the FERC report, ranging from July 1 of the year to June 30 of the next year For example, the year 1999 would be the year in which the completed projects filled FERC forms between July 1, 1999 and June 30, 2000

The entire dataset includes 220 compressor stations The five cost components are material, labor, miscellaneous, land, and total costs Miscellaneous cost is a composite of surveying, engineering, supervision, interest, administration and overheads, contingencies, telecommunications equipment, freight, taxes, allowances for funds used during construction, and regulatory filing fees Total cost is the sum of material, labor, miscellaneous and land costs (PennWell Corporation, 1992-2009)

"Cost" is defined as real, accounted costs determined at the time of completion All pipeline compressor station construction component costs are reported in U S dollars, adjusted with the Chemical Engineering Plant Cost Index (CE index) – a widely used index for adjusting process plants' construction cost Chemical Engineering Plant Cost Index has 11 sub-indices and a composite CE Index, the weighted average of the 11 sub-indices The changes in costs over time can be recorded by the index (Chemical Engineering, 2009) Indices between 1990 and 2008 are shown in Figure 5 1 The annual average growth rate between 1990 and 2008 is shown in Table 5 1 To make cost data comparable to each other at the same base, different pipeline compressor station cost components are adjusted by different indices to 2008 dollars The pump and compressor index and the construction labor index are used to adjust pipeline compressor station material and labor costs The CE index is applied to pipeline compressor station miscellaneous and land costs

5.4 Data descriptive statistics

To better understand compressor station costs, the cost data are analyzed and summarized in terms of capacity, year of completion, location, and individual cost components

5 4 1 Distribution analysis of pipeline compressor station on year of completion

There were 26 (11 8% of the total) compressor stations constructed in 2002, and only 4 (1 8 1% of the total) in 1999 (Figure 5 2) The annual average total cost of constructed compressor stations is $245,619,250 Material cost is the number one cost among the individual components A total of $789,225,630 compressor station costs were reported in 2002, while only $59,425,127 compressor station costs were reported in 1997 (Figure 5 3) The annual number of compressor stations constructed and the annual total cost of compressor stations show a similar trend, and both fluctuated significantly Before 2001, annual total capacity slightly decreased over time with peaks in 2001 and 2002 The year 1998 reported the least capacity (Figure 5 4) Annual average capacity per compressor station ranges from 3,963 hp to18, 861 hp (Figure 5 5) Although there is some variation, the general trend of annual average capacity per compressor station over time increased during this period

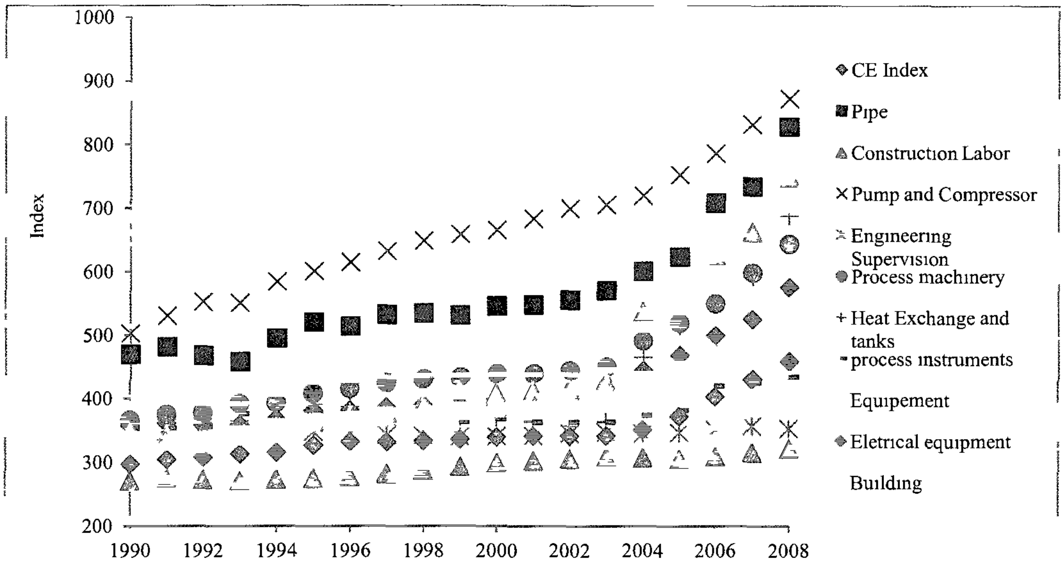

Figure 5 1 Chemical Engineering Plant Cost Indices between 1990 and 2008

Table 5 1 Annual average growth rate of the Chemical Engineering Plant Cost Index

Index type	Annual growth rate	Index type	Annual growth rate
CE Index	2 54%	Heat exchange and tanks	3 30%
Pipe	3 02%	Process instruments	1 10%
Construction labor	0 90%	Equipment	3 07%
Pump and compressor	2 94%	Electrical equipment	2 31%
Engineering supervision	-0 04%	Buildings	2 29%
Process machinery	3 01%	Structural supports	4 09%

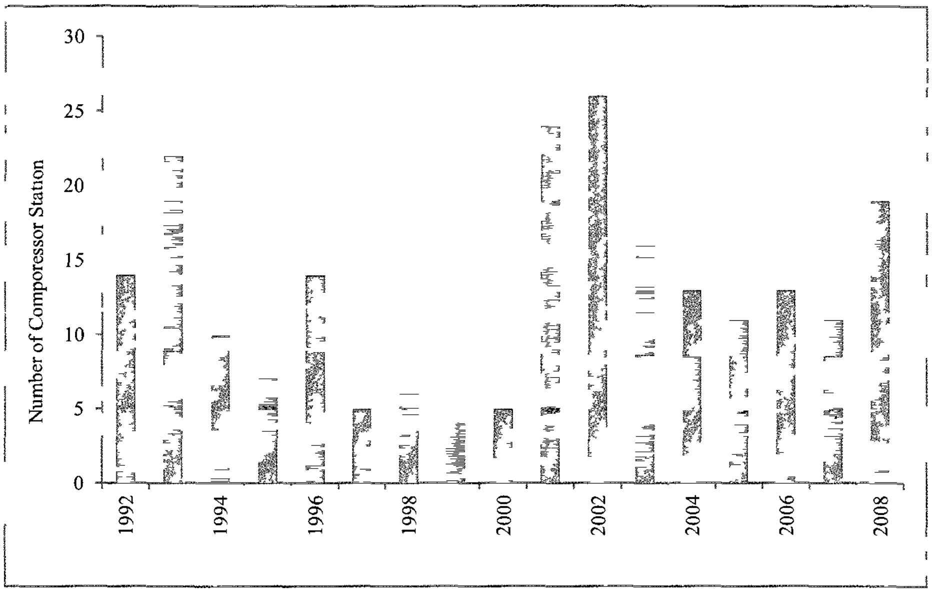

Figure 5 2 Annual number of compressor stations constructed

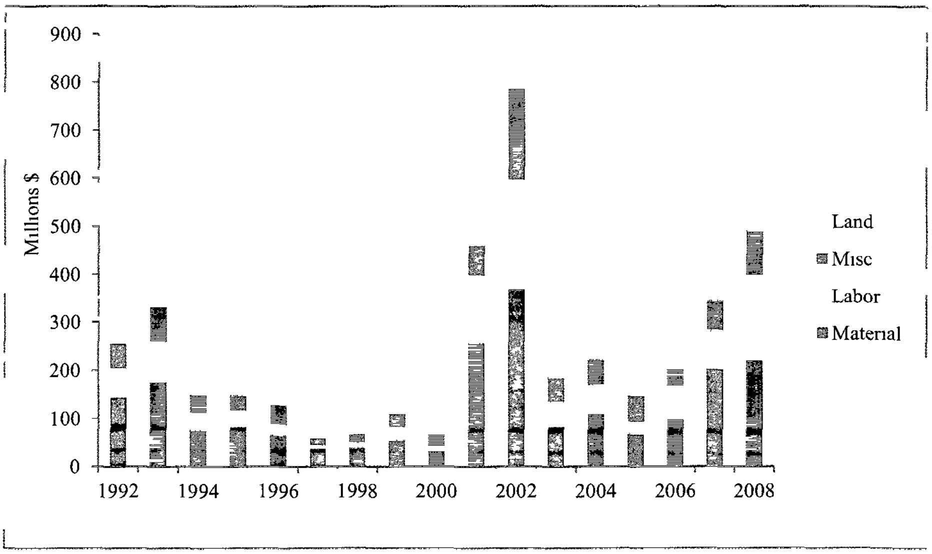

Figure 5 3 Annual compressor station and individual cost component

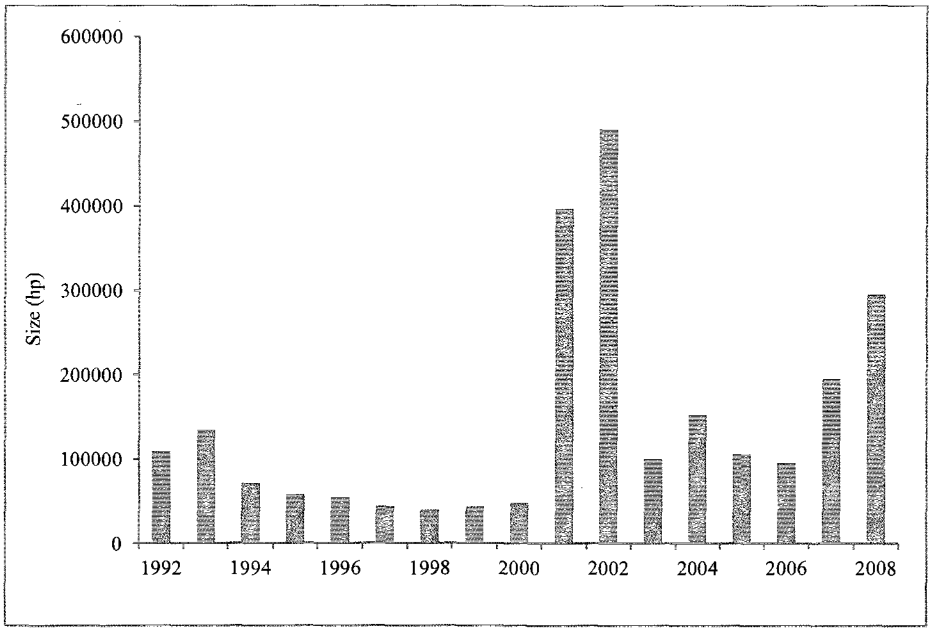

Figure 5.4 Annual constructed compressor station capacity

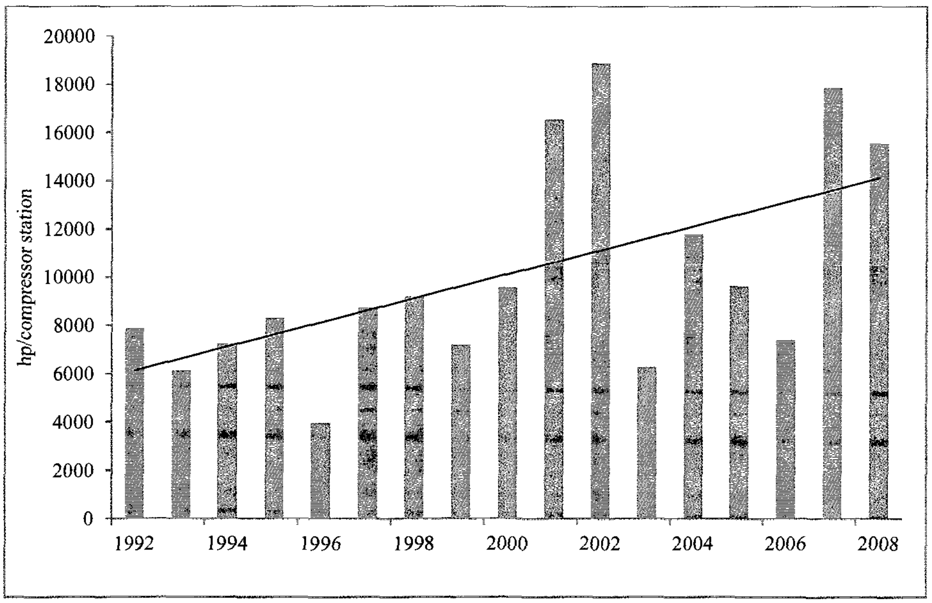

Figure 5.5 Annual average capacity per compressor station

5.4 2 Distribution of pipelines compressor station with regards to capacity

The distribution of compressor station capacity is right-skewed (Figure 5.6). Average compressor station capacity is 11,085 hp with a standard deviation (SD) of 18,948 hp. Compressor station horsepower ranges from 80 hp to 217,000 hp. There are 56.8% of compressor stations with a capacity of less than 8,000 hp, and only 2.73% of compressor stations have a capacity of larger than 40,000 hp.

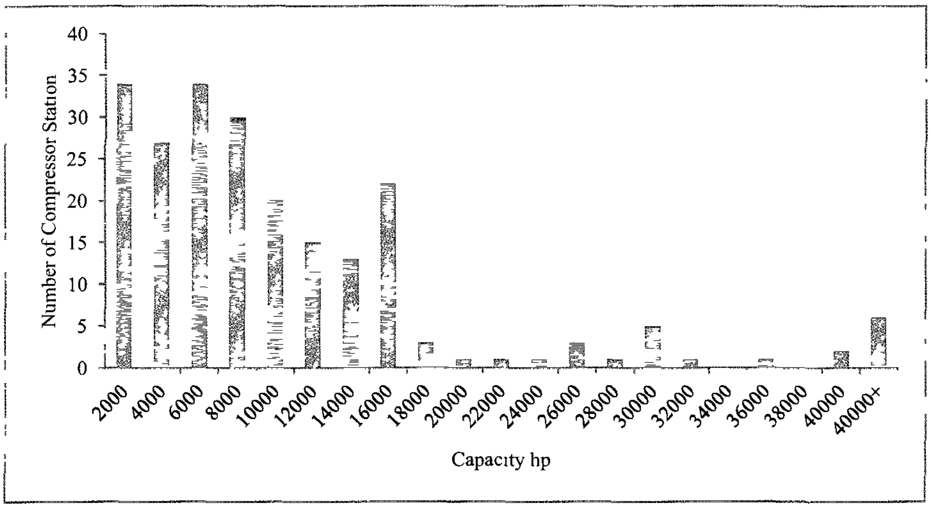

Figure 5.6 Histogram of compressor station capacity

5.4 3 Distribution analysis of compressor station locations

Location information for U.S. compressor stations is provided in a state format. A total of 48 states were referred to, except Alaska and Hawaii. The EIA breaks down the U.S. natural gas pipelines network into six regions: Northeast, Southeast, Midwest, Southwest, Central and Western (EIA, 2010). These regional definitions are used to analyze geographic differences. The map of regional definitions is shown in Figure 5.6. In this paper, U.S. pipeline data are summarized according to these six regions (McCoy and Rubin, 2008; Rui et al., 2011a; Rui et al., 2011b; Rui et al., 2012a; Rui et al., 2012b). Based on the regional definition, regional distribution of compressor stations are summarized and shown in Table 5.2.

There are 61 (27.7% of the total) compressor stations with a total of 462,145 hp in the Northeast region (Figure 5.8). Furthermore, 50.8% of these Northeast region's compressor stations are in the State of

Pennsylvania. There are 17 (7.7%) compressor stations with a total of 227,330 hp in the Midwest region. The number of compressor stations in the other regions ranges between 29 and 46. The average capacity per compressor station is 11,805 hp. The Midwest region has the highest capacity per compressor station of 13,372 hp. The Northeast region has the lowest capacity per compressor station of 7,576 hp (Figure 5.8). Compressor stations with a total value of $954,470,464 are in the Northeast Region, followed by the Southeast, Central, Western, Southwest, and Midwest regions (Figure 5.9). The number of compressor stations and the cost of compressor stations over regions show a similar trend. Pennsylvania, Alabama, Texas, Utah, Wyoming, and Louisiana have a total of 88 compressor stations, accounting for 39.8% of the total number (Table 5.2). Analysis of the regional distribution shows that the number of compressor stations is unevenly constructed across U.S.

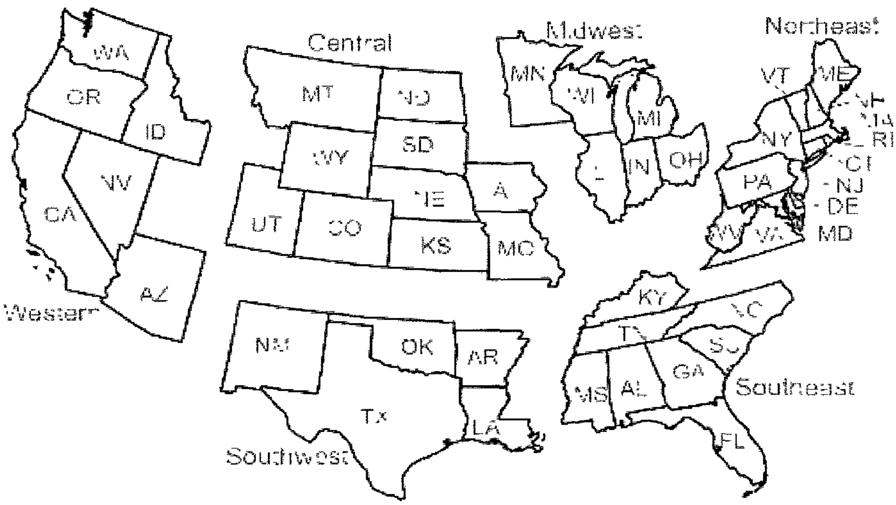

Figure 5.7 U.S. natural gas pipeline network region map (EIA, 2010)
Note: Alaska and Hawaii are not included

5.4.4 Distribution analysis of pipeline individual cost components

Histograms of compressor station cost components are shown in Figure 5.10 to Figure 5.14. These figures illustrate that the distributions of cost components are all right-skewed. The majority of cost distribution is concentrated on the left of the figure, indicating more cases of lower cost and few of relatively higher cost. A similar trend exists in the histogram of compressor station capacity (Figure 5.4), indicating that compressor station capacity may play a significant role in determining compressor station construction component costs.

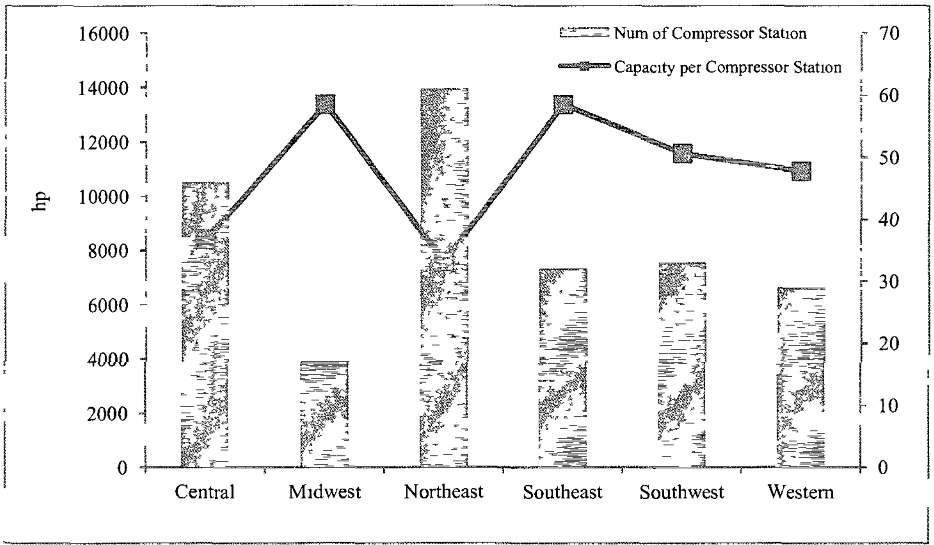

Figure 5.8 Number of compressor stations and capacity per compressor station by regions

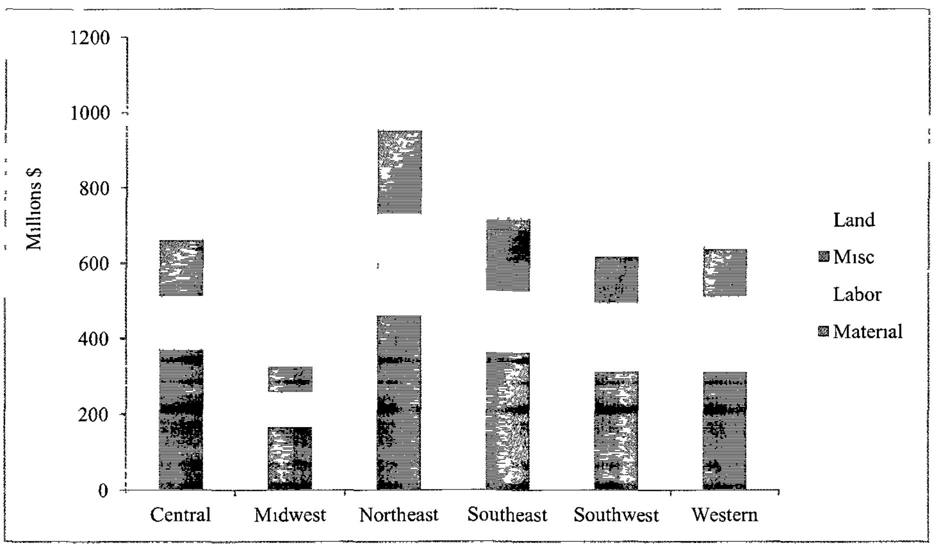

Figure 5.9 Total cost of compressor stations and individual cost components by regions

Table 5.2 Top six states with the most compressor stations

State	Num of compressor station
Pennsylvania	31
Alabama	15
Texas	11 5
Utah	10
Wyoming	10 5
Louisiana	9 5

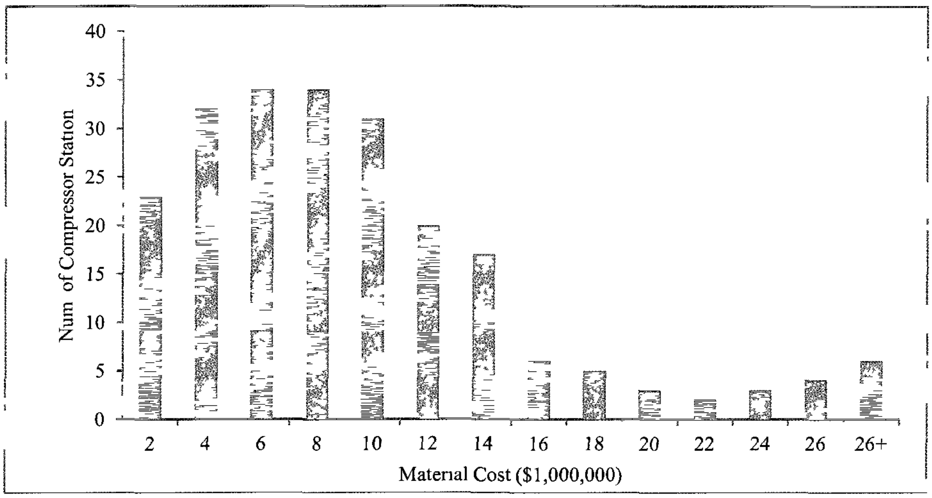

Figure 5.10 Histogram of compressor station material costs

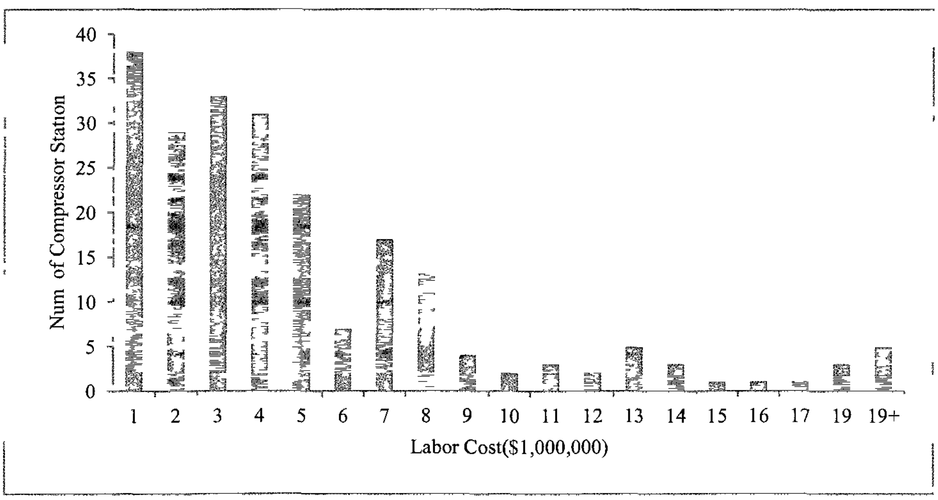

Figure 5.11 Histogram of compressor station labor costs

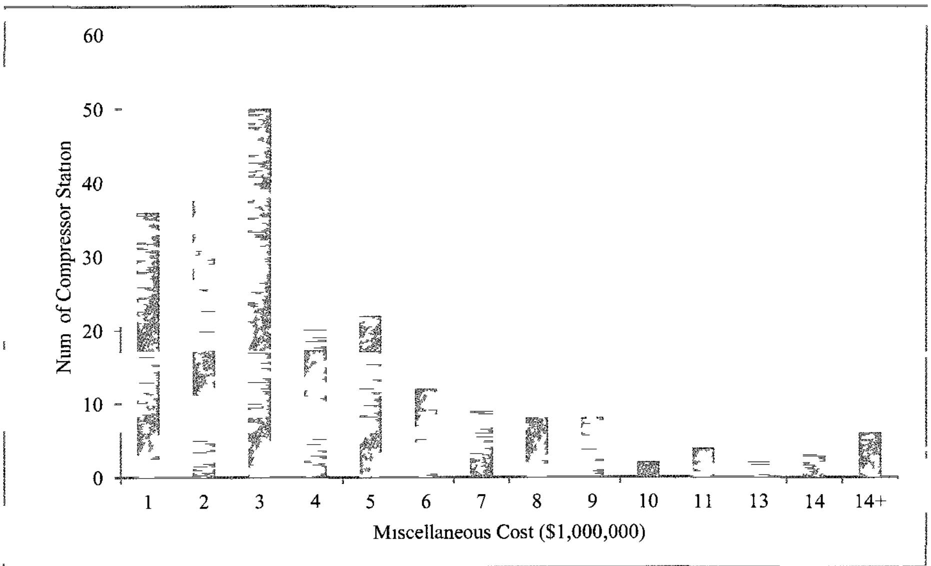

Figure 5 12 Histogram of compressor station miscellaneous costs

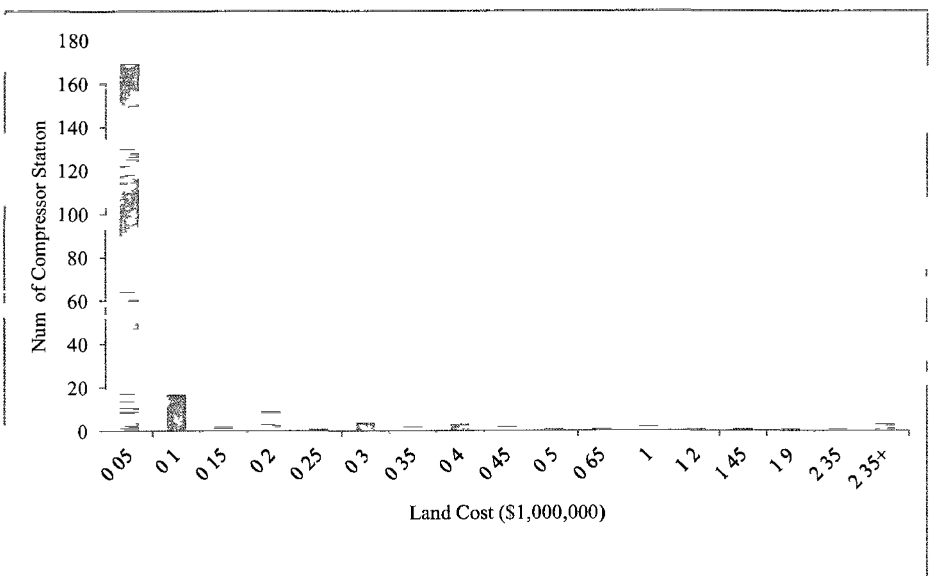

Figure 5 13 Histogram of compressor station land costs

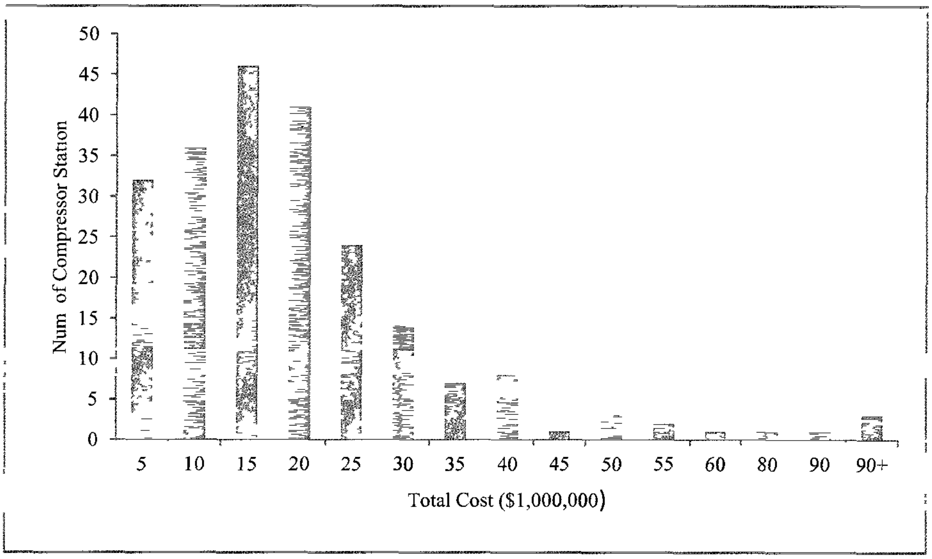

Figure 5.14 Histogram of compressor station total costs

5.4.5 Trend of average unit cost over time

Unit cost is defined as cost per horsepower. Unit costs of compressor station individual components are important parameters for estimating construction costs. In this section, the trends of unit component costs over time are analyzed. Unit cost is calculated by dividing cost by horsepower.

For the 220 compressor stations in the dataset, the average unit costs for material, labor, miscellaneous, land and total costs are $866/hp, $466/hp, $367/hp, $13/hp, and $1,712/hp, respectively. Unit costs of material, labor, miscellaneous, land, and total costs show a similar trend over time, but with different degrees of fluctuation (Figure 5.15). The unit cost of material shows a significant decline over time. The unit costs of labor and miscellaneous are almost constant with slight fluctuation. The unit cost of land fluctuates more broadly with the highest peak of $64.6/hp, almost three times as high as the average. The highest point unit cost of total cost in 1999 is at $2,523/hp, a 50% increase from $1,658/hp in 1998. Total compressor station capacity reaches its peak in 2001 and 2002 (Figure 5.2). This may indicate that potential increases in compressor station constructions cause a significant increase in current unit costs. Higher demand for labor induces labor shortages, requiring higher salaries and benefits to keep or hire sufficient skilled laborers. Huge future demand for materials results in suppliers raising the prices. These factors result in high unit costs in the year prior to the year of peak compressor station construction.

The unit cost of total costs is the lowest in 2001 at $28.5 hp, though the total constructed capacity in 2001 is the second highest, 7 times higher than the total capacity in 2000 (Figure 5.2 and Figure 5.15). This evidence may indicate that the economies of scale play an important factor in reducing the unit costs. The unit cost of total cost changes as the unit cost of material does. This indicates that the material cost is a primary cost among all individual cost components.

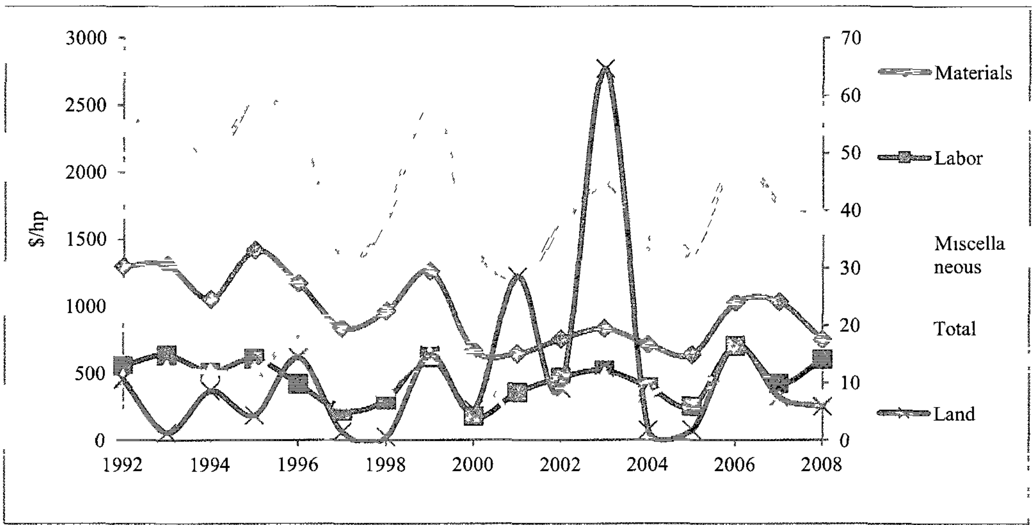

Figure 5.15 Annual average unit cost of compressor station cost components by years
Note: Only the unit cost of land uses the secondary axis on right due to small value

5 4.6 Trend of average unit cost regarding region

Unit cost is significantly different in different regions. The highest unit costs of material, labor, miscellaneous, land, and total costs are 1.37, 1.69, 1.59, 5.31, and 1.43 times higher than the lowest unit cost of the same category, respectively (Figure 5.16). The Northeast region has the highest unit costs for material, miscellaneous, and total cost and the second highest unit cost for labor, while the Midwest region has the lowest unit costs for material, miscellaneous, and total costs. The highest unit costs of labor and land are found in the Western region. The Central region has the lowest unit cost of labor, and the Southwest region has the lowest unit cost of land. The relatively high cost of living can be considered a factor in the highest unit costs of labor in the Western and Central regions. More detailed information on compressor station construction costs may be able to further explain these regional differences.

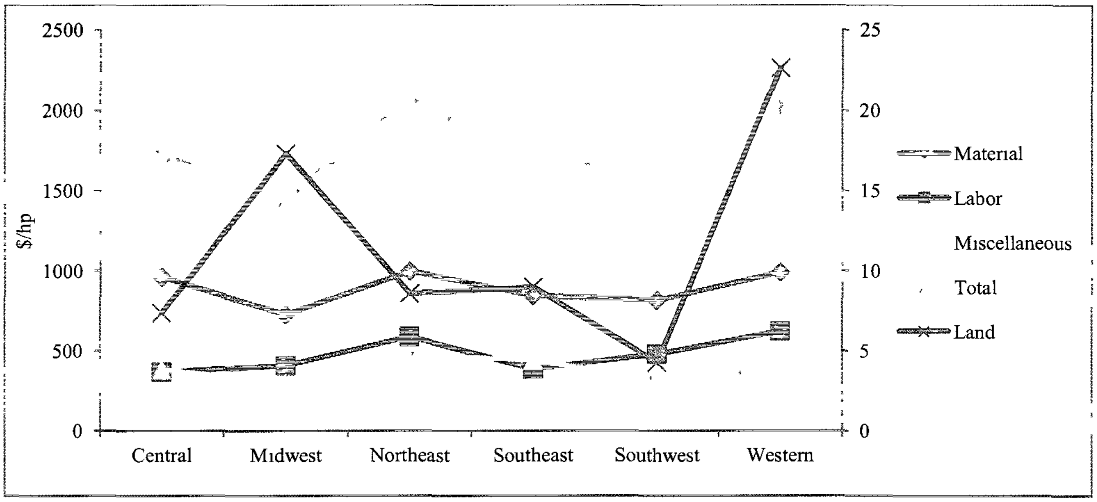

Figure 5.16 Average unit cost of compressor station cost components by regions
Note: Only the unit cost of land uses the secondary axis on right due to its small value

5.5 Share of cost components for different compressor station groups

The influence of different compressor station groups on individual cost components are studied in this section by analyzing the share of each cost component. Shares of individual cost components are shown in Table 5.3. For all compressor stations, the material cost has the highest share of 50.6% of the total cost, followed by the labor cost of 27.2%, miscellaneous cost of 21.5%, and land cost of 0.8% (Table 5.3). For pipelines, the labor cost has the highest share of 40% of the total cost, followed by the material cost of 31%, miscellaneous cost of 23%, and ROW cost of 7% (Rui et al., 2011b). There is a large share difference in cost components between compressor stations and pipelines except for miscellaneous cost. Pipelines have a larger share of labor and ROW costs. The much larger footprint of pipeline construction sites as compared to compressor station sites may have played a dominating role in this difference. Higher demands for the land increase ROW costs, and longer traveling time for workers to move along the pipelines induces additional labor time and costs. As for the compressor stations, the material cost generally takes the major share in the total cost for all different groups. The land cost has a very limited influence on the total cost for compressor stations.

In terms of compressor station capacity, the shares of material, labor, miscellaneous, and land costs do not show a significant difference with a maximum of 2% (Table 5 3) This implies that the shares of cost components do not have a strong relationship to the compressor station capacity

The material cost in the Central region made up approximately 55 9 % of the total cost, while only 48 2% in the Northeast regions (Table 5 3) The share of the material cost for pipelines is also high in the Central region and low in the Northeast region (Rui et al , 2011b) The higher cost of transporting material to the Central region may be a factor in the high share of material cost The share of labor cost ranges from 21 4% in the Central region to 30 6% in the Western region The share of the labor cost is also high for pipelines in the Western region (Rui et al , 2011b) The higher cost of living in Western regions may be a factor in the high share of labor costs in this region The share of miscellaneous cost ranges from 19 6% to 26 3% The land cost is a small part of the total cost, ranging from 0 3% in the Southwest region to 1 2% in the Midwest region

Table 5 3 Shares of compressor station cost components for different station groups

		Material	Labor	Miscellaneous	Land
All data	Average	50 60%	27 20%	21 50%	0 80%
Capacity	0-6000 hp	50 00%	27 00%	22 10%	0 90%
	6000-16000 hp	50 10%	27 20%	22 30%	0 40%
	16000-217999 hp	51 40%	27 40%	20 20%	1 10%
Region	Central	55 90%	21 40%	22 30%	0 40%
	Midwest	50 10%	28 20%	20 50%	1 20%
	Northeast	48 20%	28 50%	22 90%	0 40%
	Southeast	50 20%	22 90%	26 30%	0 50%
	Southwest	50 50%	29 60%	19 60%	0 30%
	Western	48 70%	30 60%	19 60%	1 10%

The shares of compressor station individual cost components vary by regions Local supplies, transporting difficulties, cost of living, and experience can be suggested as factors influencing the shares of individual cost components Studies on shares of cost components can provide useful information for companies in estimating compressor station construction cost and reduce the total costs

5.6 Learning curve in compressor station construction

5 6 1 Introduction to learning curve

Technology and labor productivity normally increases as workers engage in repetitive tasks Unit costs typically decline with cumulative production The learning curve is derived from historical observation to measure learning by doing, and is helpful for cost estimators and analysts Learning curve theory is based on these assumptions 1) the unit cost required to perform a task decreases as the task is repeated, 2) the unit cost reduces at a decreasing rate, and 3) the rate of improvement has sufficient consistency to allow its use as a prediction tool (Federal Aviation Administration, 2005) Consistency in improvement is expressed as the percentage reduction in cost with doubled quantities of product The constant percentage is called the learning rate

The learning curve is normally exhibited in power function and linear function forms The power function form is shown below (Federal Aviation Administration, 2005)

$$Y_X = T_1 \cdot X^b \qquad \text{Equation 5 1}$$

where Y_X is the average cost of the first X units, T_1 is the theoretical cost of the first production unit, X is the sequential number of the last unit in the quantity for which the average is to be computed, b is a constant reflecting the rate costs decrease from unit to unit, 2^b and $1 - 2^b$ are defined as progress ratio and learning rate, respectively (Federal Aviation Administration, 2005, International Energy Agency, 2000) For example, a learning rate of 20% implies the cost is reduced to 80% of its previous level after a doubling of cumulative capacity

Learning curve function is normally expressed in log-log paper as a straight line Straight lines are easier for analysts to extend beyond the range of data (Federal Aviation Administration, 2005) Take the logarithms of both sides to get a straight line equation,

$$\overline{\mathrm{Y}} = \mathrm{b}\overline{\mathrm{X}} + \mathrm{C} \qquad \text{Equation 5 2}$$

where $\overline{\mathrm{Y}} = \log \mathrm{Y_X}$, $\overline{\mathrm{X}} = \log \mathrm{X}$, $\mathrm{C} = \log(\mathrm{T_1})$ Learning curve effect is a complicated process Some major reasons for the learning-by-doing effect are intensive use of skilled labor, a high degree of capital, research and development (R&D) intensity, fast market growth and interaction between supply and demand (Wilkinson, 2005). In addition, accumulated learning has start-up and steady periods. Cost reduction is significant in the start-up period and modest in the steady period (Grubler, 1998). It is the same for technology development. There are significant cost improvements during the R&D phase, followed by more modest improvement after commercialization. The longer technology has been in operation, the smaller the cost decreases (Zhao, 2000). It is possible that no further improvement in cost reduction occurs for existing and mature technology (Grubler, 1998). The commercialization of technology in the oil and gas market is costly and time intensive with an average of 16 years from concept to widespread commercial adoption (National Petroleum Council, 2007). The range of progress ratio for technology is between 65% and 95%, and between 70% and 90% for energy technology (Christiansson, 1995).

5.6.2 Selecting compressor station cost data for learning rate analysis

Cost data for learning curve analysis has to consist only of recurring cost, because nonrecurring costs will not experience the learning effect (Federal Aviation Administration, 2005). Thus, the miscellaneous, land, and total costs are not suitable for the learning curve analysis due to inclusion of nonrecurring costs. The learning curve analysis is, therefore, only conducted for material and labor costs.

The learning curve of material and labor costs of compressor stations constructed between1992 and 2008 is presented in Figure 5.17. There is an attractive cost reduction in unit costs between 109,970 hp and 1,001,727 hp. Above 1,001,727 hp, however, the unit cost did not show a significant cost reductions, even showing a slight increase. This indicates that the level above 1,001,727hp is a more mature period. In standard experience curve theory, it is assumed that learning rates do not change over time. Due to the fact that the technology or labor learning will enter into a more mature phase, the learning curve analysis does not always strictly agree with this assumption (Schaeffer and de Moor, 2004). Learning curve equations are expressed below:

Material cost: $Y = 13035X^{-0.186}$ or $\overline{Y} = -0.1855\overline{X} + 4.1151$ R^2=0.89 Equation 5.3

Labor cost: $Y = 2274.4X^{-0.112}$ or $\overline{Y} = -0.1121\overline{X} + 3.3569$ R^2=0.80 Equation 5.4

R^2 (coefficient of determination) in both cases are higher than 0 8, which indicates a fairly good fit The learning rates of material and labor costs are 12 1% and 7 5%, respectively That is, doubling the construction of compressor station capacity, the material and labor costs will be reduced by 12 1% and 7 5%, respectively But it should be noted that cost reduction becomes less with increasing horsepower

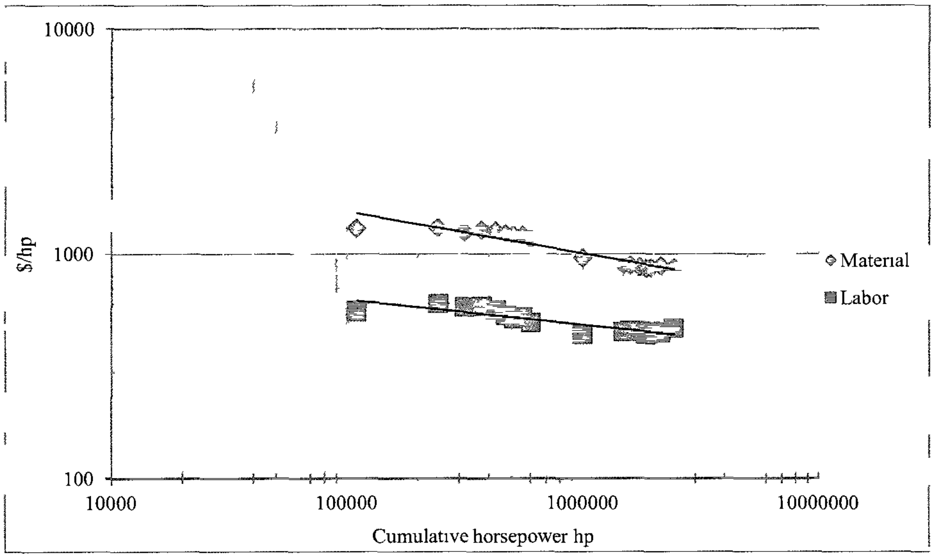

Figure 5 17 Learning curves of material and labor costs between 1992 and 2008

5 6 3 Learning rate for different compressor station groups

Learning rates for different compressor station capacities and locations are calculated and shown in Table 5 4 In general, the learning rate of the material cost is higher than the learning rate of the labor cost in all sub-groups For these sub-groups, the range of the learning rate for material cost is between 6 83% and 19 22%, and the range of the learning rate for labor cost is between 3 61% and 10 37%

For different capacities, learning rates of material cost increase with capacity As expected, the results indicate that larger capacity of compressor stations can achieve a higher learning rate in material cost However, the results also show that large capacity compressor stations have a disadvantage in the learning rate of labor cost 10 37% for 0-6,000 hp compressor stations, 3 61% for 6,000-16,000 hp compressor stations

Regional results show that learning rates vary widely by regions The Central region has the lowest learning rate of 9 81% for material cost, while the Western region has the highest learning rate of 19 22% The Southeast region does not show the learning rate of the material cost The Central, Northeast, and Western regions have learning rates of 6 31%, 8 36%, and 5 59%, respectively, for the labor cost Other regions do not have learning rates for the labor costs

In summary, the above analyses reveal that learning rates of compressor station material and labor costs vary by capacity and location to different degrees

Table 5 4 Learning rates of material and labor costs in different groups

		Material	Labor
All data	Average	12 10%	7 48%
Capacity	0-6000 hp	6 83%	10 37%
	6000-16000 hp	9 25%	3 61%
	16000-217999 hp	11 97%	N/A
Region	Central	9 81%	6 31%
	Midwest	13 49%	N/A
	Northeast	11 36%	8 36%
	Southeast	N/A	N/A
	Southwest	12 04%	N/A
	Western	19 22%	5 59%

5.7 Factors causing compressor station construction cost differences

Special geographic and surrounding environmental conditions may induce more complexities for pipeline compressor station construction, and have various degrees of impact on the construction costs Adverse climatic conditions increase compressor station cost In stations constructed in permafrost area, A refrigeration system, such as a closed loop refrigeration system, must be installed to cool the gas at the discharge of compressor stations to avoid thawing the permafrost, resulting in additional construction costs (DOE-NETL, 2007) Strong structures need to be built in areas subjected to high wind load and/or earthquakes, resulting in higher cost (Sevas Educational Society, 2011) In populated regions, thicker walls have to be selected to mitigate societal and environmental risks (Sanderson et al, 1999) Highways, rivers or channel crossings and marshy or rocky terrains are all factors that strongly affect pipeline unit costs (PennWell Corporation, 1992-2009) Heavy, clay soils or soils littered with rock or construction debris will require more horsepower and larger machines, because the performance of trenching units is largely dependent on soil type and amount of debris encountered (Houx, 2010) There are also other geographic and environmental factors influencing compressor station costs and cost reduction, which need to be identified in specific circumstances Distance from the material supplies and the reliability of the supply lines significantly affect the construction cost Long distances increase freight and transportation expenses Unstable supply lines cause fluctuations in material prices

Table 5 5 Correlation coefficient between the gas price and the average unit cost

	Material	Labor	Miscellaneous	Land	Total
Lag -1 year	-0 27	0 10	0 35	0 03	-0 22
Lag 0 year	-0 36	0 12	-0 40	-0 09	-0 29
Lag 1 year	-0 47	0 08	-0 60	-0 06	-0 42
Lag 2 year	-0 26	0 19	-0 37	0 10	-0 19
Lag 3 year	-0 26	0 27	-0 38	0 09	-0 16

Table 5 6 Correlation coefficient between the oil price and the average unit cost

	Material	Labor	Miscellaneous	Land	Total
Lag -1 year	-0 27	0 10	-0 35	0 03	-0 22
Lag 0 year	-0 36	0 12	-0 40	-0 09	-0 29
Lag 1 year	-0 28	0 16	-0 56	-0 10	-0 28
Lag 2 year	-0 05	0 37	-0 42	-0 11	-0 03
Lag 3 year	0 09	0 45	0 12	-0 02	0 17

Some may argue that gas or oil prices possibly influence pipeline compressor station construction costs To determine if there is a relationship between gas or oil prices and unit costs of pipeline compressor station construction, the correlation between gas or oil prices and lag -1 year to 4 years average unit costs from 1992 to 2008 are analyzed and shown in Table 5 5 and Table 5 6 6 respectively The values of all correlation coefficients in Table 5 5 are between -0 47 and 0 36, which indicates a weak linear relationship between gas price and the unit cost of compressor station construction The values of coefficients in Table 5 6 indicate the weak relationship for oil price and unit cost of compressor station components Some nonlinear transformations (power, exponential, reciprocal, square root) are also used to correlate the oil and gas prices and unit cost, however, nonlinear relationships between gas and oil prices and unit cost are also weak This indicates that there is insufficient evidence to suggest that a change in gas or oil prices causes a change in pipeline compressor station construction unit costs, according to available data

Gradual cost reduction is possible by optimizing project design and construction, the period of construction, and increasing competition between service companies (Gandoolphe et al , 2003) U S Department of Energy (DOE) has funded new projects to develop advanced compressor technologies, such as robotic platforms, and variables types of pipeline bends (DOE, 2007) These technologies may be progressively applied to onshore pipelines to create significant cost reduction

Compressor station capacity is increasing over time, allowing economies of scale to significantly influence unit cost reduction Compressor station costs are also determined by whether or not it is a Greenfield project, the most expensive type of facility, followed by state-of-the-art replacement units, then an additional compressor at an existing station (INGAA, 2010)

Installation costs of various compressors and prime movers for same capacity compressor replacements are different (Table 5 7) Selection of prime mover units is based on fuel price load factor, life cycle, flexibility, and location (INGAA, 2010, Mohitpour et al , 2008) In some cases, the most expensive engine/reciprocating compressor is selected due to potential fuel savings

Table 5 7 Relative driver/compressor installed cost comparison for a 14,400-hp unit (INGAA, 2010)

Categories	Installed Cost Comparison
Single GT turbine/centrifugal compressor	100%
Multiple GT turbines/centrifugal compressor	129%
Electric motor/high speed reciprocating compressor	130%
High speed engine/reciprocating compressor	132%
Slow speed engine/reciprocating compressor	154%

Besides geographic, environmental and technological factors, potential market demand also influences cost differences As mentioned in the section on unit costs, expected demand of compressor station will increase current unit costs of compressor stations

To fully explain compressor station construction cost differences, more investigation of additional factors is needed Due to limited available information, the discussions in this section focus on a few identified factors affecting compressor station construction cost differences development stage of technology, geographic and environmental conditions, economies of scale, prime movers, and market situations

5.8 Analysis limitation

A total of 220 compressor stations are investigated in this chapter, constructed between 1992 and 2008 There are still not enough compressor stations in some regions Cost data also do not provide the starting year or the construction period, and types of compressors and prime movers These limitations cause cost estimating biases In general, lack of good quality data is a major difficulty in conducting a more in-depth analysis of compressor station costs Future work should collect more information with more details to overcome these limitations

5.9 Conclusions

Based on historical data collected from the *Oil & Gas Journal*, this study analyzed construction costs of compressor stations by year of completion, capacity, location, and individual cost components The number of compressor stations and the compressor station component costs vary unevenly in terms of year, capacity and location The number of compressor stations in terms of individual cost components is right-skewed The average unit cost in material, labor, miscellaneous, land and total costs is \$866/hp, \$466/hp, \$367/hp, \$13/hp and \$1,712/hp, respectively Material cost is the primary cost of compressor station The shares of cost components differ by regions Learning curve analyses show that the learning rates vary by capacity and location Among the capacity and region groups, the learning rates of material cost are between 6 83% and 19 22%, and learning rates of labor cost are between 3 61% and 10 37% Furthermore, the development stage of pipeline technology, site characteristics, economies of scale, market conditions, and prime movers are identified as factors influencing compressor station construction cost differences Finally, there are multiple opportunities for future investigation and analysis, if the limited data can be supplemented

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CHAPTER 6 PIPELINE COMPRESSOR STATION CONSTRUCTION COST ESTIMATION MODELS [1]

Historical compressor station cost data have been analyzed by a few researchers for different purposes The *Oil & Gas Journal* annually publishes estimated and actual pipeline compressor station costs (PennWell Corporation, 1992-2009) An empirical formula between compressor station cost and horsepower has been established by IEA Greenhouse Gas R&D Programme (2002) However, there is relatively limited available literature on pipeline compressor station cost estimation This study develops 10 regression models to estimate pipeline construction component costs for different capacities in different regions based on a dataset of 220 compressor stations Employing developed regression models, cost differences are investigated in terms of region and capacity The results of this analysis show that a large cost difference exists among different regions, and unit costs have economies of scale regarding capacity Finally, limitations of the estimation models are also discussed

6.1 Data sources

In this study, the compressor stations are selected based on data availability Compressor station cost data are collected from the Federal Energy Regulatory Commission (FERC) filings from gas transmission companies, published in the *Oil & Gas Journal* annual databook (PennWell Corporation, 1992-2009) The compressor station dataset includes year of completion, capacity, location, and individual cost components Compressor stations in the dataset were distributed in all states in the contiguous U S (excluding Alaska and Hawaii), and completed between 1992 and 2008 The year of completion is defined by the time of filling the FERC report For example, the year 1999 means the completed projects filled the FERC report between July 1, 1999 and June 30, 2000 In this chapter, the capacity is measured by the horsepower (hp) of the compressor station "Cost" is defined as real, accounted costs determined at the time of completion All pipeline compressor station construction cost components are reported in U S dollars The entire dataset includes 220 compressor station projects The five cost components are material, labor,

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[1] Rui, Z , Metz, P A , Chen, G , Zhou, X , and Wang, X (2012) 'Study applies regression analysis to compressor station cost estimating', *Oil & Gas Journal*, in press

miscellaneous, land, and total costs. Miscellaneous cost is a composite of surveying, engineering, supervision, interest, administration and overheads, contingencies, telecommunications equipment, freight, taxes, allowances for funds used during construction, and regulatory filing fees. The total cost is the sum of material, labor, miscellaneous and land costs (PennWell Corporation, 1992-2009). All costs are adjusted with the Chemical Engineering Plant Cost Index to 2008 dollars (Chemical Engineering, 2009)

Location information for U.S. pipeline systems is provided in a state format, referring to 48 states in the contiguous U.S. The U.S. Energy Information Administration (EIA) (2010) breaks the U.S. natural gas pipelines network into six regions: Northeast, Southeast, Midwest, Southwest, Central, and Western. The map of regional definitions is shown in Figure 6.1. These regional definitions are used to analyze geographic differences.

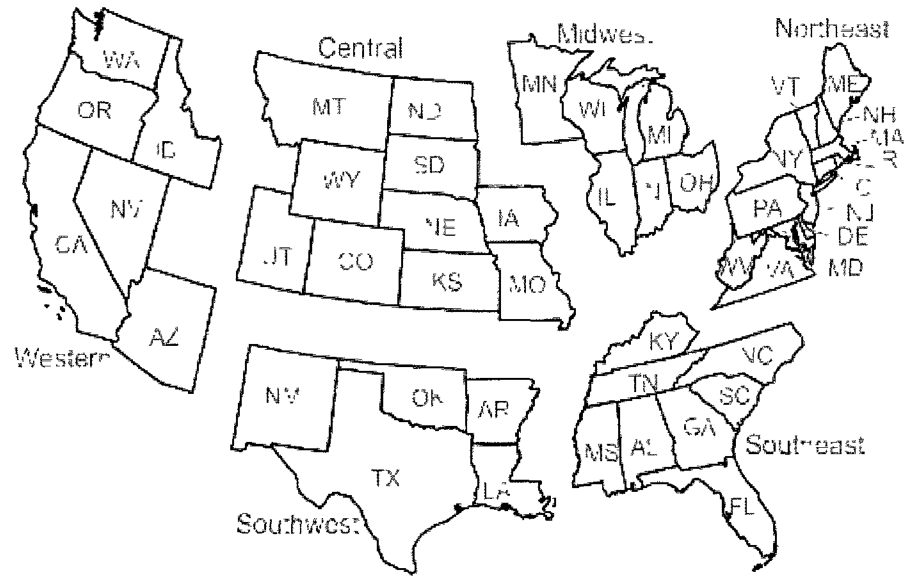

Figure 6.1 U.S. natural gas pipeline network region map (EIA, 2010)
Note: Alaska and Hawaii are not included

6.2 Developing compressor station cost estimation models

The data set collected in this study contains information on compressor station capacity and location as well as individual cost components. The multiple nonlinear regression method has been used to analyze pipeline cost data by some authors (McCoy and Rubin, 2008; Rui et al., 2011). In this study, after using different regression models, the selected general form for multiple nonlinear regression models is chosen and shown below

$$C = \alpha_0 + \alpha_1 NE + \alpha_2 SE + \alpha_3 SW + \alpha_4 W + \alpha_5 MW + \alpha_6 S + \alpha_7 S^2 \qquad \text{Equation 6 1}$$

where C is material, labor, miscellaneous, land, or total costs, NE (Northeast), SE (Southeast), SW (Southwest), W (Western), MW (Midwest) are dummy variables for identifying geographic differences The Central region is selected as the base case S denotes compressor station capacity a_i is the coefficient of variables (i=0, 7) A positive a_i of regional variables indicates that the region has higher costs than the Central region, while the negative a_i (i=1, 5) of regional variables shows the region has a lower cost than the Central region Five regional cost estimation models are developed with available data by using the above formula Coefficients of the regression models are shown in Table 6 1 In addition, 5 national regression models are also developed for individual cost components by assigning the coefficient of regional variables as 0, the coefficients of the regression models are shown in Table 6 2

Table 6 1 Coefficients of five regional regression models

Variables	Material	Labor	Miscellaneous	Land	Total
Northeast	1352987	1216385	711576 8	—	2345915
Southeast	—	—	1012394	—	—
Midwest	1384440	—	—	—	—
Southwest	—	—	—	—	—
Western	1839203	1506944	—	239707	3612571
S	765 7359	320 3964	187 5223	—	1046 696
S^2	-0 0049491	0 001055	0 0017986	0 0001776	0 0038954
Intercept	1085822	795650	1326640	67882 38	5155687

Note All p-values associated with coefficient are <5%

Table 6 2 Coefficients of five national regression models

Variables	Material	Labor	Miscellaneous	Land	Total
S	532 7853	299 2887	184 1443	—	1019 361
S^2	0 0010416	0 001142	0 0018417	0 0001799	0 0041406
Intercept	3175286	1581740	1696686	66216 72	6500617

Note All p values associated with coefficient are <5%

Table 6 3 Regional regression model validation tests

Statistical tests	Material	Labor	Miscellaneous	Land	Total
R-square	0 7574	0 7578	0 7502	0 7112	0 8412
Adjusted R-square	0 7513	0 7531	0 7455	0 7002	0 8382
VIF	3 1	3	2 9	1	2 8
F-value	124	163	158	126	158
Corrgram	0 22	0 2	-0 15	0 19	0 19
Num of observation	205	213	216	101	216

Table 6 4 National regression model validation tests

Statistical tests	Material	Labor	Miscellaneous	Land	Total
R-square	0 7282	0 7397	0 7437	0 7349	0 8358
Adjusted R-square	0 7256	0 7268	0 7413	0 7321	0 8343
VIF	4 7	4 7	4 7	1	4 7
F-value	285	236 75	309 03	268 85	542
Corrgram	0 2	0 15	-0 17	0 14	0 21
Num of observation	216	216	216	102	216

Some tests are conducted before concluding a valid regression model The results of these tests for regional and national regression models are shown in Table 6 3 and Table 6 4 respectively Independent variables in the model are examined for multicollinearity The variance inflation factor (VIF) is a diagnostic applied to test the independent variables The VIF values of independent variables in these five models are between 1 and 1 7 As a rule, a VIF value under 10 is acceptable (UCLA, 2010) Therefore, the independent variables do not have a multicollinearity problem The corrgram test is used to test residual autocorrelation (UCLA, 2010) Values of autocorrelation are between -0 17 and 0 22, indicating that the errors associated with observations are statistically independent from one another

The overall model is tested for predictive capability with an F test and its associated p-value The ratio of the square mean of the square for regression and the mean square for error is called the F-statistic (Makridakis et al , 1983) Normally a large F-value suggests that the model explains a large proportion of variance The p-value associated with the F-statistic is considered very significant when the p-value is less than 5% F-statistics of ten models are very large and the associated p-value is less than 1%, leading to at least one of the parameters in the model having a predictive capability All p-values of coefficients are sıgnıficantly below 5% Therefore, ıt can be concluded that all parameters ın these 10 models are sıgnıficant

R-square and adjusted R-square are ımportant dıagnostıcs to determıne the goodness-of-fit of the model The R-square ındıcates that the proportıon of varıance ın dependent varıables ıs explaıned by the ındependent varıables However, R-square can be artıficıally ınflated by addıng addıtıonal ındependent varıables (Kutner et al , 2004) Therefore, adjusted R-square ıs often used together wıth R-square The values of R-square for all models are greater than 0 71, and the adjusted R-square values are almost the same as the value of the R-square ın all models, ındıcatıng that a large proportıon of varıabılıty ın the models can be explaıned by ındependent varıables Therefore, ıt can be concluded that these regressıon models are good models

Varıous dıagnostıcs and tests ındıcate that these 10 regressıon models are valıd In the followıng sectıon, these regressıon models are used to analyze cost dıfferences ın terms of regıons and compressor statıon capacıty

6.3 Cost difference with regards to regions

Cost dıfferences ın dıfferent regıons are ındıcated by coeffıcıents of these regıons (Table 6 1) Coeffıcıents of these regıons show that compressor statıon constructıon component costs are related to the compressor statıon locatıons

The materıal cost model shows a relatıonshıp to the Northeast, Mıdwest, Western, and Central regıons Accordıng to coeffıcıents, materıal costs ın the Northeast, Mıdwest, and Western regıons are hıgher than those ın the Central regıon The Western regıon has the hıghest materıal costs of these four regıons

The labor cost model shows a relatıonshıp to the Northeast and Western regıons, and the labor costs ın these two regıons are hıgher than those ın the Central regıon Agaın, the Western regıon shows the hıghest labor costs of those three regıons

The mıscellaneous cost model dısplays a relatıonshıp to the Northeast, Southeast, and Central regıons, and all coeffıcıents are posıtıve The Northeast regıon has the hıghest mıscellaneous costs of these three regıons

The land cost model shows a relationship to the Western and Central regions The coefficient of the Western regions is positive

Total cost models show relationships to the Northeast, Western, and Central regions, and all coefficients are positive The Western region has the highest costs of these three regions

The Southwest region is the only region that does not show a relationship to any component cost The Central region appears to have the lowest cost for all construction components

For comparison purposes, estimated unit costs of construction components for a 5,000-hp compressor station in different regions by cost estimation models are shown in Table 6 5

Table 6 5 Compressor station construction unit cost components

Regions	Material	Labor	Miscellaneous	Land	Total
Northeast	1229	728	604	—	2566
Southeast	—	—	664	—	—
Midwest	1235	—	—	—	—
Southwest	—	—	—	—	—
Western	1326	786	—	62	2820
Central	958	485	462	14	2097
Nation	1173	621	533	14	2340

Unit total costs of compressor stations in different locations show a noticeable difference For example, the unit total cost in the Central region is $2,097/hp, but unit total cost in the Western region is $2,820/hp Compressor station unit total costs in the Western region are 34% higher than those in the Northeast region and 20% higher than the national average Unit land costs in the Western region are more than 4 times higher than those in the Central region and the nation The unit total cost differences for compressor station construction component costs affected by geography can sometimes to be more than 34%, making the geographical factor critical in determining the compressor station construction costs

As seen from the values of the coefficient of the Western and Northeast regions, cost of living in the Northeast region is slightly higher than that in the Western region The Western region actually has higher costs in material, labor, land and total costs than the Northeast region This comparison shows that economies of concentration play an important role in compressor station construction costs Economies of concentration are a type of the economies of scale, also called external economies Economies of scale tend to arise when firms or projects in the same industry are located close together (Wilkinson, 2005). Approximately 28% of U.S. compressor stations are in the Northeast region, and 50.8% of them are concentrated in the State of Pennsylvania, while only 13.3% of U.S. compressor stations are in the Western Regions. Hence, the fact that a large number of compressor stations were constructed in the Northeast region and in the State of Pennsylvania significantly reduces the unit costs of compressor station construction.

Weather conditions, soil properties, cost of living, and distances from supplies are also variables for cost difference between regions (Bordat et al., 2004) Compressor station costs are also determined by prime mover and whether it is a Greenfield project (INGAA, 2010). Economies of concentration are an important factor in cost differences in different regions. However, it is impossible to conduct a quantitative analysis of cost difference in different locations without more detailed information.

6.4 Cost differences with regards to compressor station capacities

Coefficient results show the cost is also related to the compressor station capacity. All costs show a relationship to both capacity and capacity square except for land costs, which only shows relationship to compressor station capacity square.

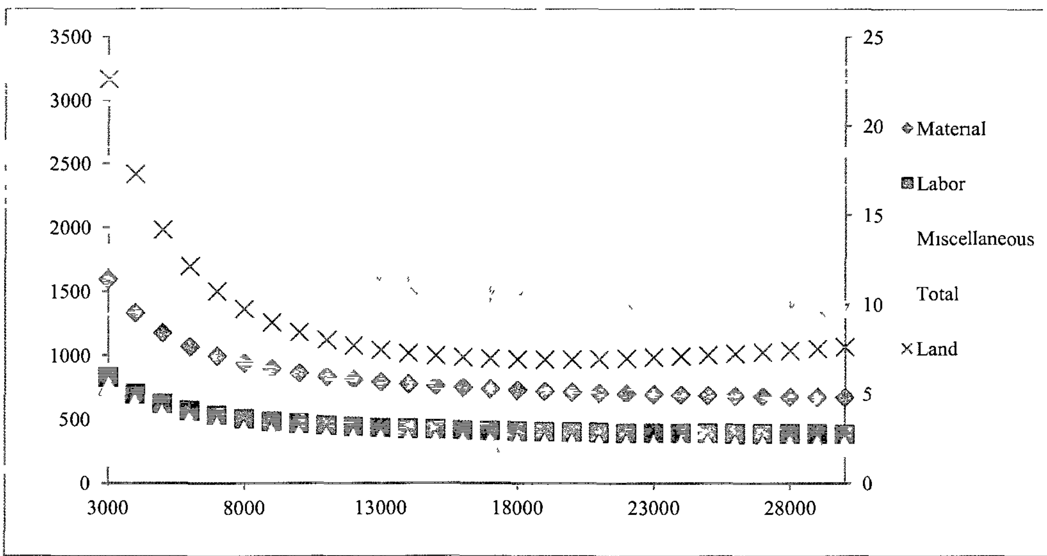

Figure 6.2 The construction unit component costs in the U.S.
Note: Only unit land cost uses secondary axis due to small value

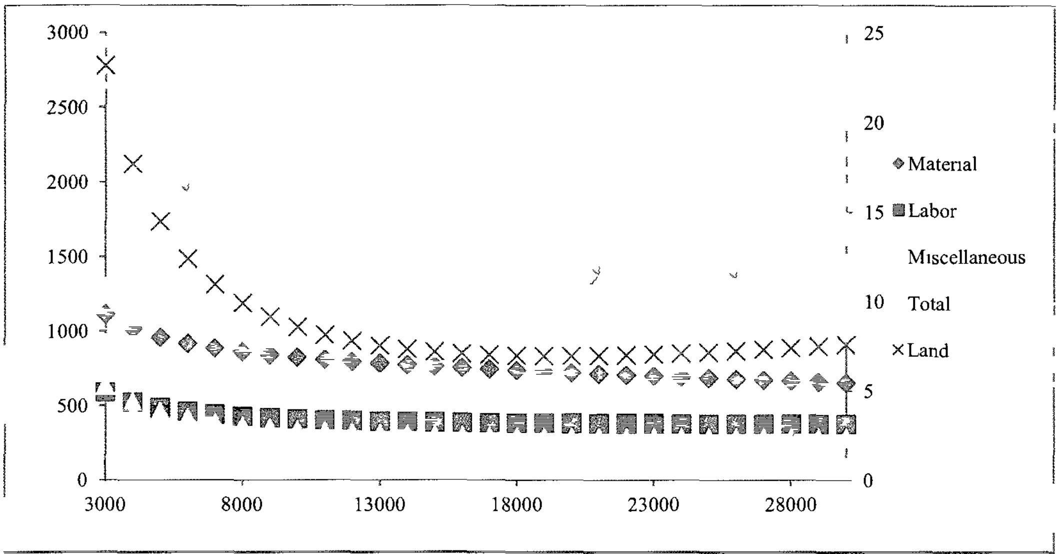

Figure 6 3 The construction unit component costs in the Central region
Note Only unit land cost uses secondary axis due to small value

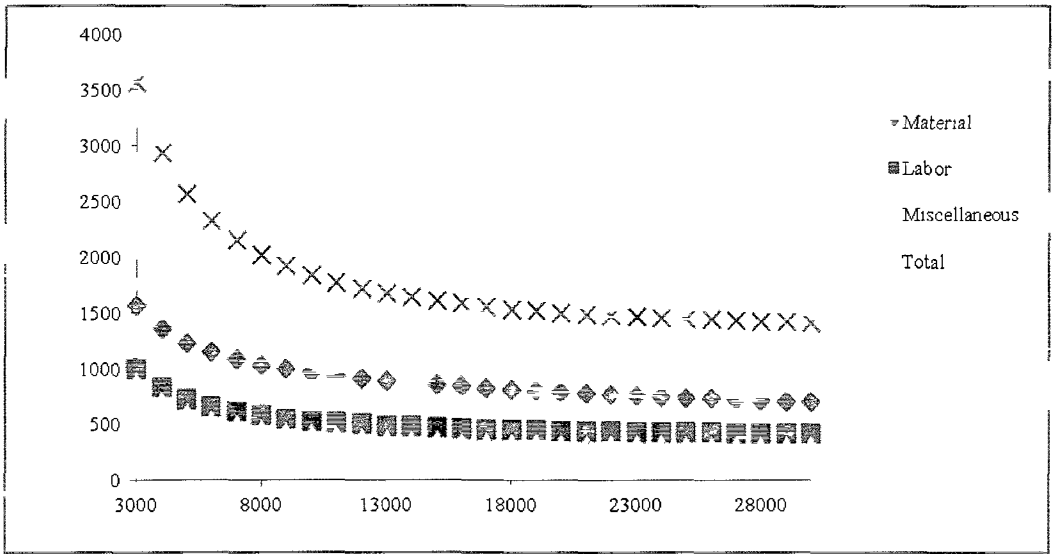

Figure 6 4 The construction unit component costs in the Northeast region

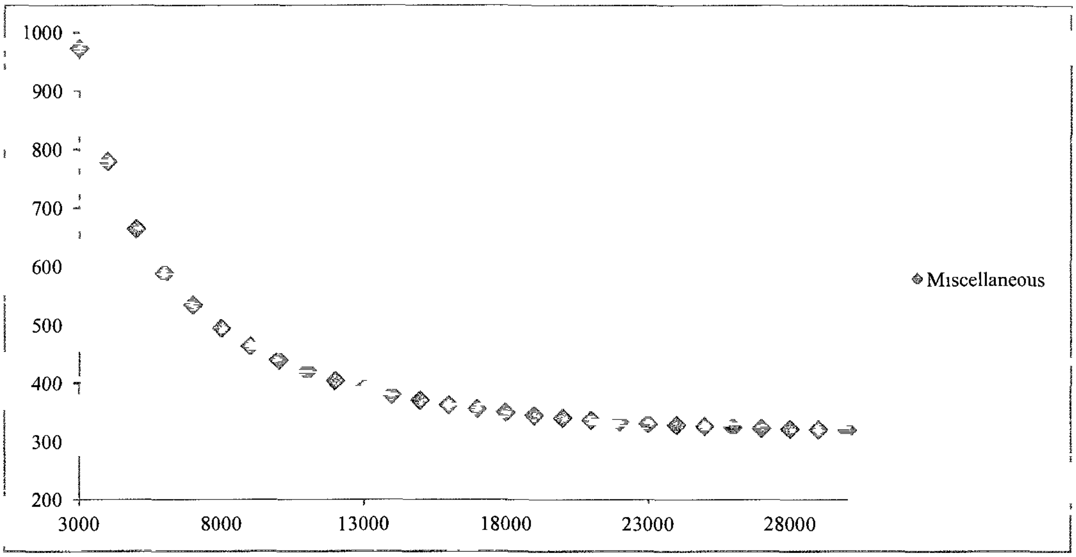

Figure 6 5 The construction unit component costs in the Southeast region

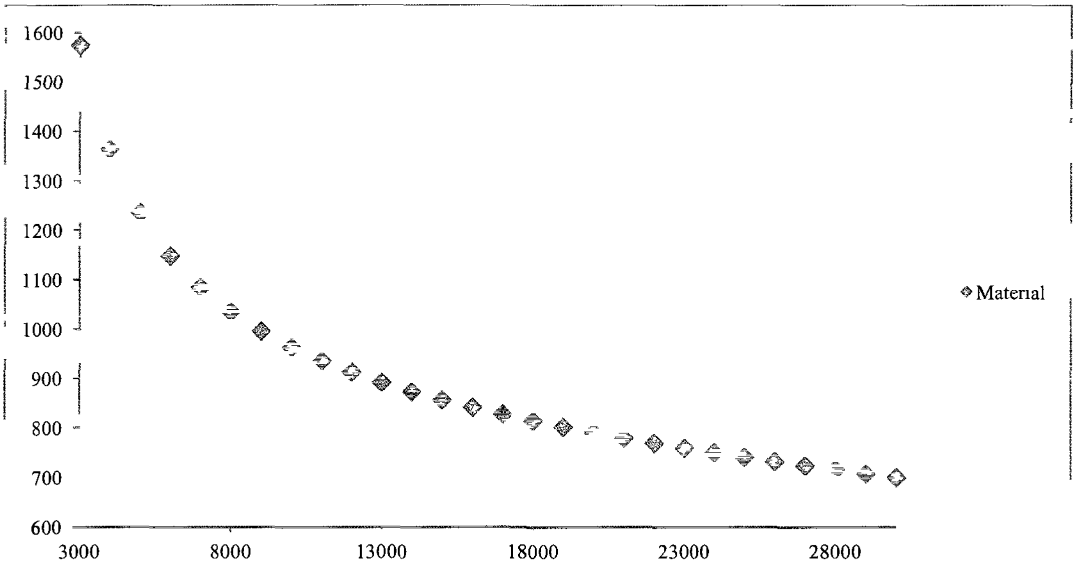

Figure 6 6 The construction unit component costs in the Midwest region

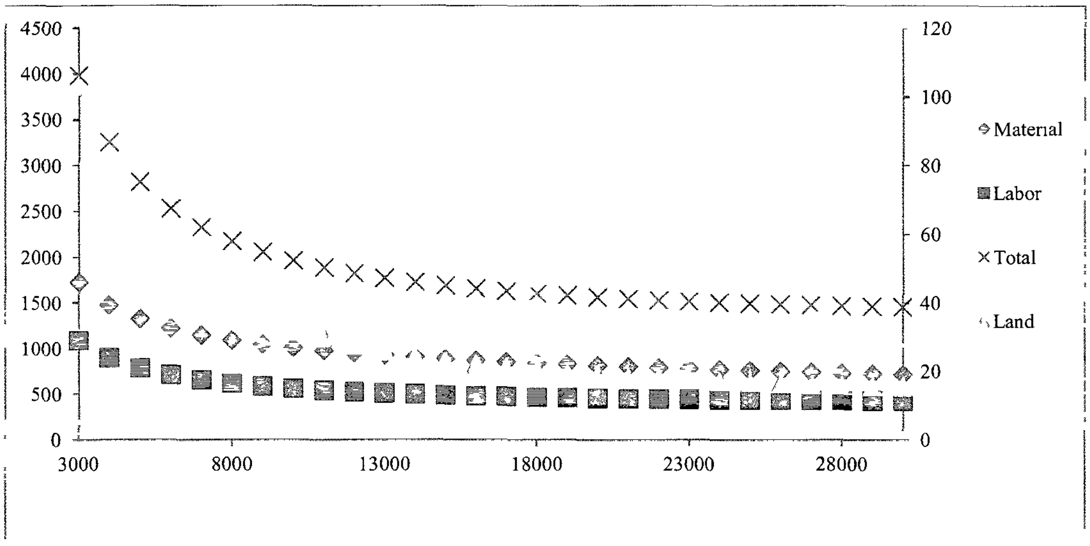

Figure 6.7 The construction unit component costs in the Western region
Note: Only unit land cost uses secondary axis due to small value

In order to illustrate trends of compressor station construction cost components with regards to the capacity, estimated unit component costs in different regions are shown in Figure 6.2 to Figure 6.7.

Figure 6.2 illustrates unit total costs in the U.S. decreases as compressor station capacity increase. This trend indicates that total costs involve economies of scale when it comes to compressor station capacity. For example, the unit total cost of 2,000-hp compressor stations is 3.2 times that of 30,000-hp compressor stations. A similar trend also exists in unit costs of material, labor, miscellaneous, and land.

Trends of the estimated unit component costs in the Central, Northeast, Southeast, Midwest, and Western regions are shown in Figure 6.2 to Figure 6.7. All individual component unit costs decrease with increasing compressor stations capacity in the different regions. Based on the above analysis, it is concluded that all cost components have economies of scale with regards to the compressor station capacity in all regions.

Economies of scale caused by growth of the project itself are called internal economies of scale. Increasing compressor station capacity can produce internal economies of scale for compressor station projects. Technical economies, managerial economies, marketing economies, and financial economies are considered four major categories of internal economies of scale (Wilkinson, 2005). In technical economies, some specialized equipment or process is used to improve labor and capital productivity in large pipeline projects For example, large and efficient trenchers and trucks are employed to increase productivity and reduce the cost of diesel Small compressor station projects cannot afford this initial heavy equipment cost due to the inability to diffuse the high fixed cost In addition, large equipment and facilities are easily operated in high gear with less idle capacity In managerial economies, the large compressor station projects hire more professional and specialized managers for performing specialized tasks with specific skills and increased productivity instead of relying on one manager to take care of everything In marketing economies, a large discount can be realized by purchasing large amounts of material In financial economies, large compressor station projects are more likely to be awarded low interest rate loans or government subsidies

The above factors support the fact that large compressor station projects have economies of scale and lower unit costs These explanations match the regression results, showing that unit costs of compressor station construction components fall with increasing compressor station capacity

6.5 Limitation of analysis and suggestion for future work

The data used in this chapter includes a number of compressor stations constructed between 1992 and 2008, but there are still not enough compressor station for some regions and large capacity, such as 57% of compressor stations have capacities less than 8,000 hp, and only 2 73% are larger than 40,000 hp Uneven distribution and limited number of compressor stations with large capacities may cause estimation biases Some quantitative analyses cannot be conducted due to the lack of some important variables, such as type of compressors, prime movers, and terrains along compressor stations, which produce significant cost differences Future work should collect more data with more detailed information on compressor station to improve the effectiveness of the cost estimation models

6.6 Conclusions

Based on the available historical data, five regional and five national compressors station construction component cost estimation models are developed with the multiple nonlinear regression method These models estimate compressor station construction cost components with respect to different compressor station capacities and regions The results show that there is a significant difference in different regions It is concluded that economies of concentration are an important factor in reducing unit costs indicating that compressor station cost components all have economies of scale with respect to compressor station capacity. Cost estimation models are limited due to missing informational variables. Future work will concentrate on collecting more detailed information about compressor stations for more accurate comprehensive and quantitative analysis.

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CHAPTER 7 INACCURACY IN PIPELINE COMPRESSOR STATION CONSTRUCTION COST ESTIMATION

7.1 Abstract

The aim of this chapter is to investigate pipeline compressor station project cost overruns A total of 220 pipeline compressor station projects constructed between 1992 and 2008 have been collected, including material, labor, miscellaneous, land, and total costs, compressor station capacity, location, and year of completion Statistical methods are applied to identify the distribution of cost overruns and overrun causes Overall average overrun rates of pipeline compressor station material, labor, miscellaneous, land and total costs are 0 03, 0 60, 0 02, -0 14, and 0 11, respectively Cost estimations of compressor station construction components are biased except for the material cost In addition, the cost estimation errors of underestimated compressor station construction components are generally larger than those of overestimated components Results of the analysis show that compressor station project size, capacity, location, and year of completion have different impacts on individual construction cost component cost overruns

7.2 Introduction

Cost estimating error is the tendency for actual costs to deviate from estimated cost Bias is the tendency for that error to have a non-zero mean (Bertisen and Davis, 2008) Cost estimation errors or bias are common and a global problem in cost estimating (Flyvbjerg et al , 2003) Cost estimation errors and bias in other types of projects have been mentioned and studied in many papers Pohl and Mihaljek (1992) reviewed 1,015 World Bank projects from 1947 to 1987, finding a 22% average cost overrun and 50% time overrun Merrow (1988) found that 47 of 52 megaprojects ranging in cost from $500 million to more than $10 billion (in 1984 dollars) had an average overrun of 88%, and large projects appear to have more cost growth than smaller projects Flyvbjerg et al (2003) examined 258 transport infrastructure projects (rail, bridge and road) with an average of 28% cost overrun Bertisen and Davis (2008) reviewed 63 international mining projects, finding that actual costs is average 14% higher than estimated cost in the feasibility study Cost overrun rates of all Indiana departments of transportation (INDOT) projects were 4 5%, and 55% of INDOT projects experienced cost overruns (Bordat et al , 2004) Jacoby (2001) found that 74 projects with a minimum cost of $10 million had 25% cost overruns Rui et al (2012) investigated the cost overruns of 412 pipeline projects between 1992 and 2008, finding an average of 4 9% cost overrun for material, 22 4% for labor, -0 9% for miscellaneous, 9 1% for right of way (ROW), and 6 5% for total costs Literature reviewed showed that cost overruns exist over time

Many researchers have tried to explain the project cost overrun phenomenon Some researchers proposed that optimism and deception are major reasons for causing cost overruns (Flyvbjerg et al , 2003) Other researchers believed that engineers and managers have incentives to underestimate costs (Bertisen and Davis, 2008) Flyvbjerg (2007) suggested that cost underestimation and overestimation of transportation infrastructure appear to be intentional on the part of project promoters Information asymmetries were also suggested as a reason for cost overruns (Pindyck and Rubinfeld, 1995) Rowland (1981) mentioned that large projects increase the likelihood of a high number of change orders Jahren and Ashe (1990) suggested that large projects have large cost overruns due to their complexity, but also mentioned that managers of large projects try to keep cost overrun rates from growing excessively large Large projects can lead to savings in unit costs, but will limit the number of companies able to carry them out There is a trade-off, then, between economies of scale and competitive bidding practices (Bordat et al , 2004) Odeck (2004) indicated that large projects have better management than small projects Soil, drainage, climate, and weather conditions have an impact on design standards and costs of materials for road and rail projects, and location influences construction and material costs due to varying distances from supplies (RGL Forensics, 2009) An Australian study shows that public-private partnership projects perform better than traditionally procured projects, while a European study shows public-private partnerships exhibit higher costs than traditionally procured infrastructure projects (Infrastructure Partnerships Australia, 2008, RGL Forensics, 2009) Flyvbjerg (2007) suggested that more research on the role of ownership in causing efficiency differences between projects should be conducted He also used technical, psychological, and political-economic factors to explain cost overruns

Although many studies have been conducted on other types of project cost overruns, there are limited available references on pipeline compressor station cost overruns With available pipeline compressor station data, this chapter focuses on the cost estimation errors of compressor station construction components, and investigates and identifies the frequency of cost overrun occurrences and the magnitude of the difference between estimated and actual costs in pipeline compressor projects In addition, cost overruns in terms of compressor station project size, capacity, location, and year of completion are investigated

7.3 Data sources

In this study, the compressor stations are selected based on data availability Compressor station cost data are collected from the Federal Energy Regulatory Commission (FERC) filing by gas transmission companies, published in the *Oil & Gas Journal* annual data book (PennWell Corporation, 1992-2009) The compressor station dataset includes year of completion, capacity, location, and individual cost components Compressor stations in the dataset were distributed in all states in the contiguous U S , and completed between 1992 and 2008 The year of completion is defined by the time of filling the FERC report For example, the year 1999 for the constructed projects means the FERC report was filed between July 1, 1999 and June 30, 2000 In this chapter, the capacity is measured by the horsepower (hp) of the compressor station "Cost" is defined as real, accounted costs determined at the time of completion All pipeline compressor station construction component costs are reported in U.S. dollars. The entire dataset includes 220 compressor stations. The five cost components are: material, labor, miscellaneous, land, and total costs. Miscellaneous cost is a composite of surveying, engineering, supervision, interest, administration and overheads, contingencies, telecommunications equipment, freight, taxes, allowances for funds used during construction, and regulatory filing fees. The total cost is the sum of material, labor, miscellaneous and land costs (PennWell Corporation, 1992-2009).

Location information for U.S. pipeline systems was provided in a state format, and refers to the 48 states in the contiguous U.S. U.S. Energy Information Administration (EIA) breaks the U.S. natural gas pipelines network into six regions: Northeast, Southeast, Midwest, Southwest, Central and Western. The map of regional definitions is shown in Figure 7.1. These regional definitions are applied to analyze geographic differences. To make a comparative analysis, all costs are adjusted by the Chemical Engineering Plant Cost Index to 2008 dollars.

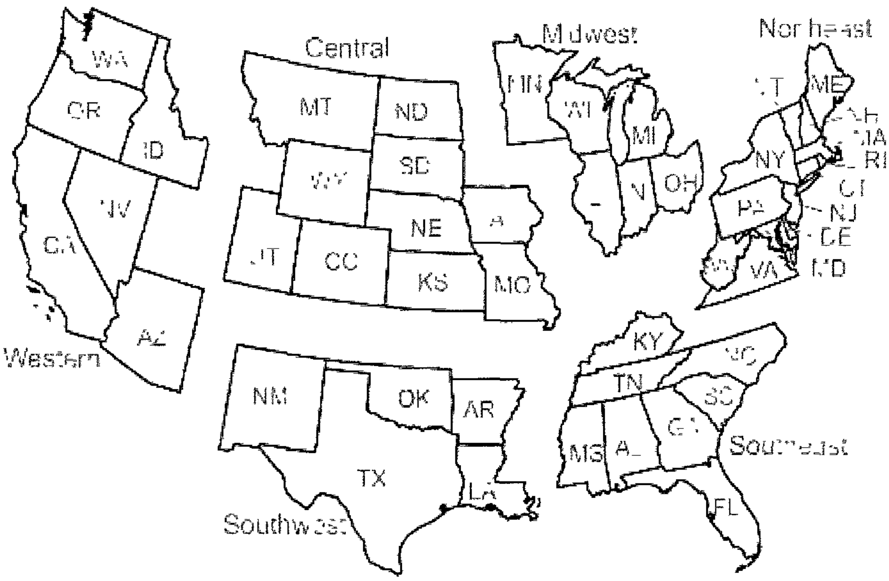

Figure 7.1 U.S. natural gas pipeline region map (EIA, 2010)
Note: Alaska and Hawaii are not included

7.4 Performance of individual compressor station construction component cost estimation

This section will evaluate the performance of compressor station construction component cost estimation. Several methods may be used to study the difference between estimated and actual costs. In this study, the cost overrun rate computed from estimated and actual costs is employed to measure of cost overrun The formula for the cost overrun rate is

$$\text{Cost overrun} = \frac{(\text{Actual cost} - \text{Estimated cost})}{\text{Estimated cost}} \quad \text{Equation 7 1}$$

If the cost overrun rate is positive, the cost is underestimated, otherwise it is overestimated All cost overrun rates are calculated with the above formula

Histograms of the cost overrun rate for compressor station construction components are shown in Figure 7 2 to Figure 7 6 If the cost error is small, the histogram would be narrowly concentrated around zero If underestimating cost is as common as overestimating cost, the histogram would be symmetrically distributed around zero It appears that the five figures exhibit non-symmetric distributions, and none of them satisfied the above mentioned assumptions For material cost, 106 (48 18% of total) compressor stations were underestimated, and 113 (51 36%) were overestimated For labor cost, 158 (72 81%) compressor stations were underestimated, and 59 (27 19%) were overestimated For miscellaneous cost, 77 (35 32%) compressor stations were underestimated, and 141 (64 68%) were overestimated For land cost, 29 (31 2%) compressor stations were underestimated, and 61 (65 6%) were overestimated For total cost, 126 (57 27%) compressor stations were underestimated, and 94 (42 73%) were overestimated Furthermore, only one compressor station project accurately estimated for material costs, and three compressor station projects had accurate cost estimations for land costs

In summary, more compressor stations were overestimated for material, miscellaneous, and land costs, while more compressor stations were underestimated for labor and total costs In general, the percentage of overestimated compressor stations indicates that there are a fairly good number of compressor stations being completed with costs less than the estimated costs except for when it comes to labor costs In addition, 81 3% of material cost overruns, 34 1% of labor cost overruns, 58 26% of miscellaneous cost overruns, 26 88% of land cost overruns, and 77 28% of total cost overruns are between a narrow range of -0 4 to 0 4 These numbers demonstrate that labor and land cost overruns are more severe than cost components, and are also indicated by its standard deviation (SD) (Table 7 1)

Statistical summaries of cost overruns of individual compressor station construction components are shown in Table 7 1 Skewness (S) is a quantitative way to measure the symmetry of the distribution Symmetrical distribution has a skewness of 0 Positive skewness means that the right tail is "heavier" than the left tail Negative skewness means that the left tail dominates distribution Kurtosis (K) is a quantitative method to evaluate whether the shape of the data distribution fits the normal distribution A normal distribution has a kurtosis of 0 Kurtosis of a flatter distribution is negative, and that of a more peaked distribution is positive (Hill et al , 2007) Values of skewness and kurtosis in Table 7 1 show that none of the cost overruns of the five components is symmetrical normal distribution, which matches the implication from the histogram graphs Some transformation techniques (such as natural log transformation) are applied to cost overrun rates to fit them to normal distribution, but those data transformations are unsuccessful Therefore, the non-parametric statistical test is used in the following sections

Table 7 1 shows that the minimum cost overrun rates for individual cost components are between -0 82 (total cost) and -1 00 (material and land costs) The maximum cost overrun rates for individual cost components are between 1 78 and 8 11 The values of minimum and maximum indicate that cost performance for some compressor stations is extremely bad The miscellaneous cost has the largest maximum-minimum cost overrun rate range of 8 96, followed by the land cost of 8 86, labor cost of 7 24, total cost of 2 83, material cost of 2 73, indicated by SD of individual cost components between 0 33 and 1 04 of estimated cost The large maximum-minimum range and SD indicate that the performance of compressor station construction cost estimating is unstable Labor, miscellaneous and land costs have large maximum-minimum ranges and SD, which indicates the difficulties of estimating these three construction component costs accurately Material cost has the highest estimating accuracy Total cost overrun has the second smallest maximum-minimum range and SD due to its aggregation of individual cost components

Average cost overrun is a key parameter for measuring the cost estimation performance of individual construction cost components The labor cost has the highest average cost overrun of 0 6, followed by total cost of 0 11, material cost of 0 03, miscellaneous cost of 0 02, and land cost of -0 14 The material, labor, miscellaneous and total costs show positive average cost overruns, while the land cost demonstrates a negative average cost overrun. This result denotes that, on average, actual cost is larger than estimated cost for all compressor station construction cost components except the land cost.

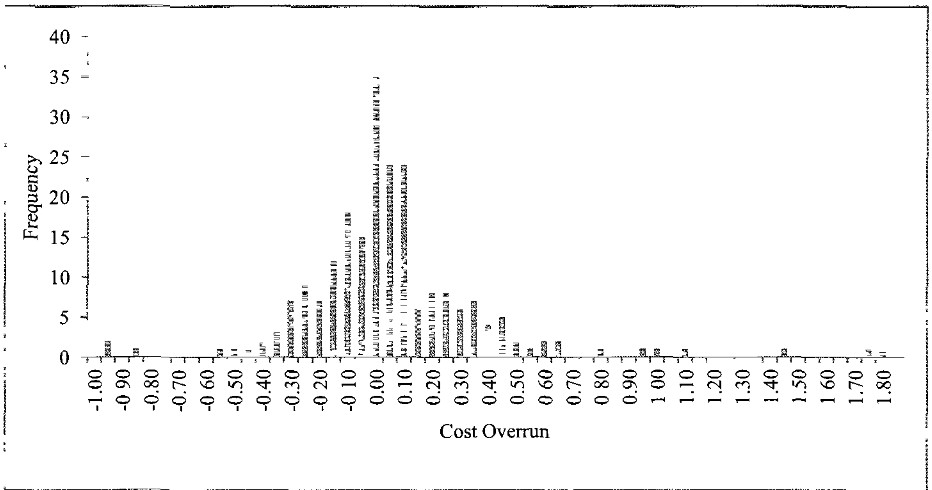

Figure 7.2 Overrun rates of material costs

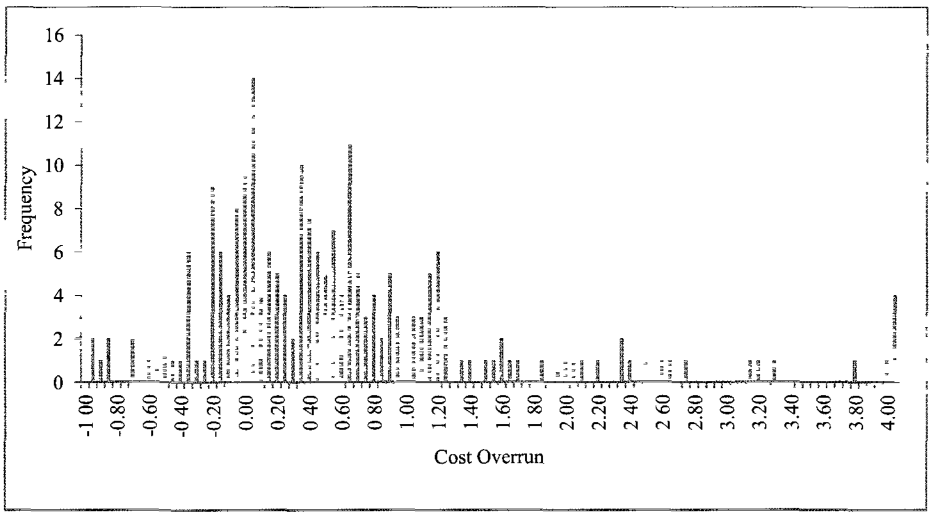

Figure 7.3 Overrun rates of labor costs

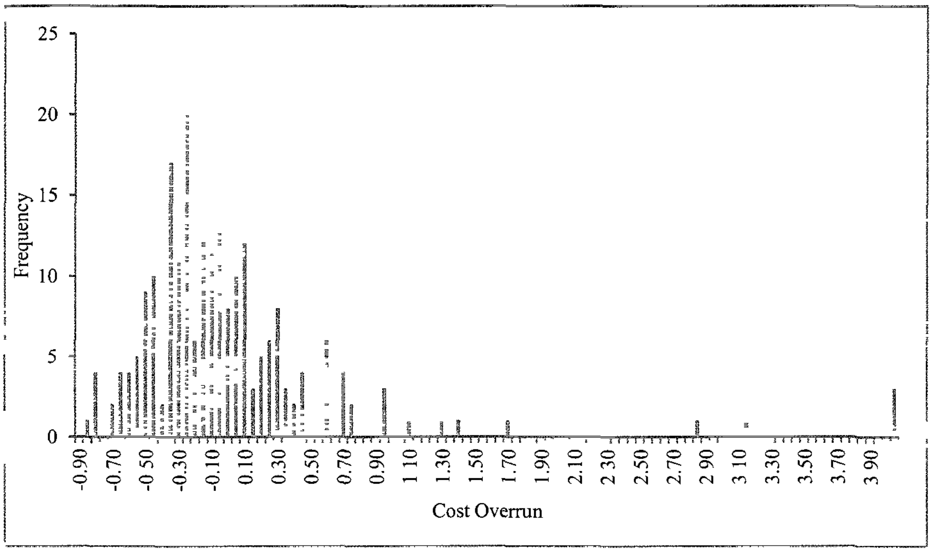

Figure 7.4 Overrun rates of miscellaneous costs

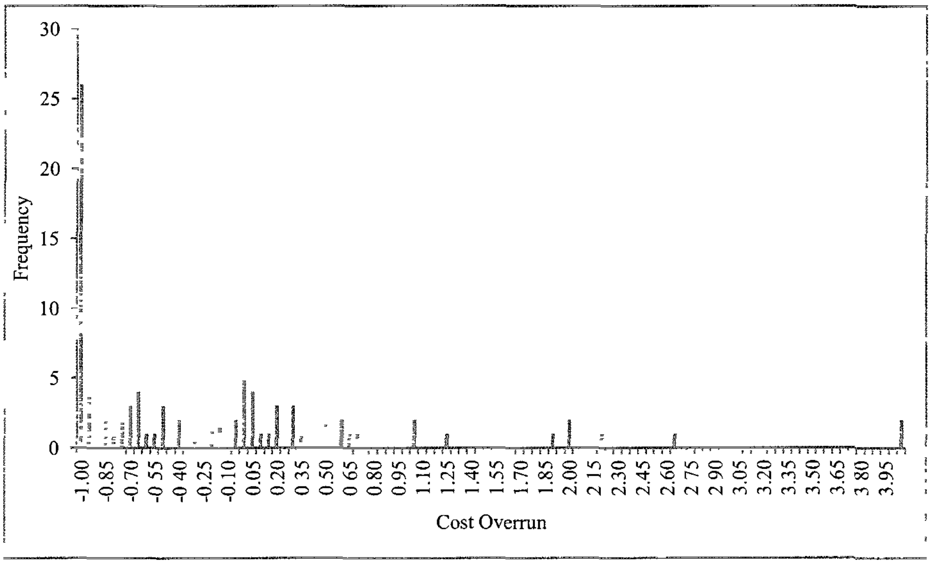

Figure 7.5 Overrun rates of land costs

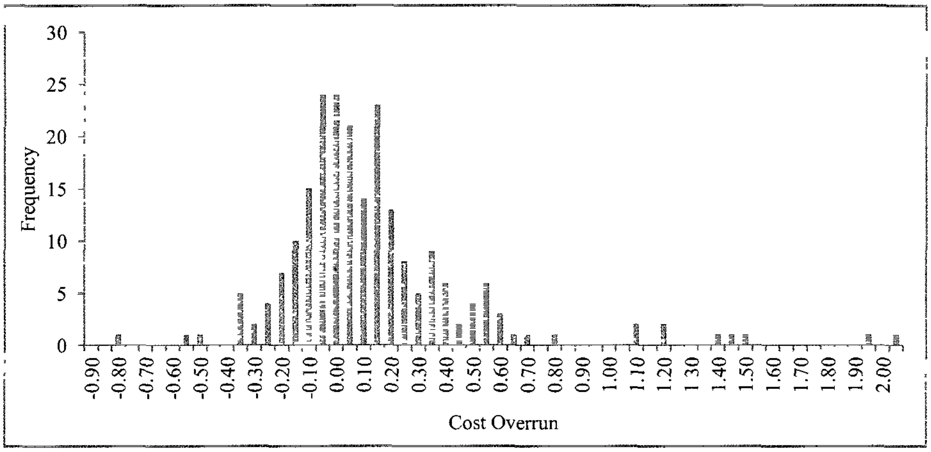

Figure 7.6 Overrun rates of total costs

Table 7.1 Summary of cost overruns of compressor station construction components

	Material	Labor	Miscellaneous	Land	Total
Average	0.03	0.60	0.02	-0.14	0.11
Standard error	0.02	0.07	0.06	0.14	0.02
SD	0.33	1.04	0.94	1.30	0.36
Kurtosis	8.05	6.67	41.69	17.33	8.01
Skewness	1.65	2.15	5.74	3.57	2.19
Range	2.78	7.24	8.96	8.86	2.83
Minimum	-1.00	-0.99	-0.85	-1.00	-0.82
Maximum	1.78	6.25	8.11	7.86	2.01
Number of observations	220	217	218	93	220
Number of underestimated	106	158	77	29	126
Number of accurate	1	0	0	3	0
Number of overestimated	113	59	141	61	94

Table 7.2 Statistical tests of cost overruns of compressor station construction components

	Material	Labor	Miscellaneous	Land	Total
Binomial Test	0.001	0	0	0	0.045
Mann-Whitney Test	0	0	0	0	0

It is an interesting finding that the average cost overruns of material and miscellaneous cost are positive, even though there are more compressor stations with overestimated material and miscellaneous costs. It appears that cost estimation of compressor station construction cost components is biased, and the underestimating error is generally greater than overestimating errors for some cost components Two statistical tests are performed to investigate this inference

A binomial test is conducted to examine if cost overestimating error is as common as cost underestimating error As shown in Table 7 2, the p-value of the binomial test rejects the null hypothesis that the overestimating error is as common as the underestimating error for labor, miscellaneous, land, and total costs ($p<0\ 05$), but fails to reject it for material cost estimation ($p>0\ 05$) Therefore, the cost estimations of compressor station construction components are biased except for material cost, miscellaneous and costs bias toward overestimation, while labor and total costs bias toward underestimation

Furthermore, the non-parametric Mann-Whitney test is employed to determine if the magnitude of cost underestimating errors are the same as those of cost overestimating errors The p-value shown in Table 7 2 shows that the errors of underestimated compressor station costs are much larger than those of overestimated compressor station costs for all cost components ($p<5\%$)

After analyzing overall cost overruns of compressor station projects, it is important to identify significant factors influencing compressor station project cost overruns The analyses of cost overruns in terms of compressor station project size, capacity, location, and completion time are carried out in the following sections

7.5 Cost overruns in terms of compressor station project size

In this chapter, the project size is measured by actual total cost Compressor station total costs range from \$199,935 to \$216,034,351, classified into groups of small, medium and large Ninety-two compressor stations with a total actual cost of less than \$12,000,000 are classified as small projects, 82 compressor stations with a total actual cost between \$12, 0000, 0000 and \$24,000,000 are classified as medium projects, and 46 compressor stations with a total actual cost of larger than \$24,000,000 are classified as large projects

A descriptive statistical analysis of cost overruns in terms of project size is shown in Table 7 3 For all the cost components, there is no linear relationship between average cost overrun rate and project size For the total cost, large projects have the highest cost overrun rates A plausible explanation is that a large pipeline compressor station project, normally associated with a large pipeline project, can induce a demand that influences market price, such as labor salaries and material prices, and further increases compressor station construction costs Expectation of increased pipeline and compressor station construction costs can induce an increase in current unit construction costs (Rui et al , 2011b) Suppliers would raise prices with expectation for more demand In addition, a large project limits the numbers of suppliers and contractors, reducing competition and increasing costs (Bordat, et al , 2004, RGL Forensics, 2009) However, for the miscellaneous cost, large projects have the lowest cost overrun rates It is possible that larger projects have better management systems which coordinate different departments, increasing the efficiency of material utilization and taking advantage of economies of scale

Table 7 3 Average cost overrun rates for different project size groups

Components	Project size	Average	SD	S	K	Min	Max	N
Material	Small	0 06	0 42	1 33	8 35	-1 00	1 78	92
	Medium	0 00	0 20	0 49	3 59	-0 49	0 62	82
	Large	0 05	0 33	1 94	8 76	-0 40	1 40	44
Labor	Small	0 66	1 26	2 00	7 96	-0 99	6 25	90
	Medium	0 43	0 74	1 46	6 48	-0 98	3 26	82
	Large	0 80	1 01	1 94	7 19	-0 50	4 54	43
Miscellaneous	Small	0 02	1 01	6 03	46 88	-0 85	8 11	91
	Medium	-0 01	0 71	3 74	21 28	-0 83	4 36	82
	Large	-0 08	0 41	1 05	4 15	-0 68	1 07	43
Land	Small	-0 30	0 68	1 16	4 40	-1 00	1 87	35
	Medium	-0 08	1 87	3 11	12 55	-1 00	7 86	33
	Large	0 02	1 11	1 14	3 16	-1 00	2 62	21
Total	Small	0 13	0 43	1 85	8 05	-0 82	2 01	92
	Medium	0 07	0 25	1 29	5 23	-0 37	1 05	82
	Large	0 16	0 38	2 61	12 41	-0 38	1 93	44

To determine if there is a strong relationship between project size and cost overruns for different compressor station construction components, the nonparametric Kruskal-Wallis (KW) test is applied to test the null hypothesis that the project size has no effect on cost overruns of compressor station construction components The KW test is chosen because the values of skewness and kurtosis show that the cost overrun of each group ıs not a normal dıstrıbutıon Therefore, the KW test wıll be used when the data does not produce normal dıstrıbutıons

For all cost components, results of the KW tests show that cost overruns for dıfferent project sıze groups are not sıgnıficantly dıfferent (p>0 05), so ıt ıs concluded that project sıze does not sıgnıficantly ınfluence cost overruns for all cost components

7.6 Cost overruns in terms of compressor station capacity

Cost overruns ın terms of compressor statıon capacıty are tested ın thıs sectıon The range of compressor statıon capacıty ıs between 80 and 217,000 hp, dıvıded ınto three groups small (0-5,000 hp), medıum (5,000-10,000 hp), and large group (10,000-217,000 hp) Approxımately 56 8% of compressor statıon capacıtıes ın the dataset are smaller than 8,000 hp, and only 2 73% have capacıtıes larger than 40, 000 hp Compressor statıon constructıon cost component overruns for the three dıfferent capacıty groups are shown ın Table 7 4

For materıal, labor and total costs, cost overrun rates decrease wıth ıncreasıng capacıty and are posıtıve For mıscellaneous cost, the small capacıty group has the hıghest cost overrun rate, followed by the large capacıty and the medıum capacıty groups Average cost overrun rates of the large capacıty group and the medıum capacıty groups are negatıve wıth dıfference of less than 0 01 For the land cost, the large capacıty group has the hıghest cost overrun rate, followed by the small and then the medıum groups Average cost overrun rates of the small capacıty and medıum capacıty groups are negatıve wıth a dıfference of approxımately 0 014

In general, small capacıty groups have the hıghest average cost overrun rate for all the constructıon cost components except for the land cost It appears that the small capacıty group ıs prone to cost overruns, and projects wıth large capacıty may take more advantage of economıes of scale to reduce cost overruns

The nonparametrıc Kruskal-Wallıs (KW) test ıs used to test the null hypothesıs that the capacıty has no effect on cost overruns of compressor statıon constructıon components The results of the KW test show that overruns of component costs are not sıgnıficantly dıfferent for dıfferent capacıty groups at 95%

confidence level (p>5%) Therefore, it is concluded that capacity does not influence construction component cost overruns

Table 7 4 Average cost overrun rates for different capacity groups

Components	Capacity	Average	SD	S	K	Min	Max	N
Material	Small	0 07	0 44	1 21	7 68	-1 00	1 78	80
	Medium	0 03	0 25	2 58	15 14	-0 49	1 40	62
	Large	0 00	0 25	1 02	5 04	-0 43	0 96	76
Labor	Small	0 77	1 35	1 66	6 43	-0 99	6 25	79
	Medium	0 58	0 84	2 73	11 79	-0 40	4 54	61
	Large	0 44	0 77	1 59	7 15	-0 98	3 80	75
Miscellaneous	Small	0 10	1 08	5 55	40 19	-0 85	8 11	79
	Medium	0 08	0 54	3 06	15 54	-0 83	2 82	61
	Large	0 07	0 64	4 50	31 41	-0 72	4 36	76
Land	Small	-0 35	0 71	1 21	4 24	1 00	1 87	35
	Medium	-0 36	0 84	1 46	5 09	-1 00	2 20	20
	Large	0 19	1 88	2 67	10 28	-1 00	7 86	34
Total	Small	0 18	0 47	1 44	6 04	0 82	2 01	80
	Medium	0 09	0 29	4 23	26 66	-0 22	1 93	62
	Large	0 06	0 26	1 30	5 97	-0 38	1 16	76

7.7 Cost overruns in terms of different regions

It has been shown that pipeline compressor station costs are significantly different by regions (Rui et al , 2012) This section discusses whether compressor station cost overruns are different in different regions

Table 7 5 displays a noticeable difference of cost overrun rates between regions For the material cost, the Western region has the highest cost overrun rate of 0 23, while the Northeast region has the lowest cost overrun rate of -0 03 The cost overrun rate of the Southwest region is a perfect 0 According to a ± 5% cost overrun rate criteria, material cost estimating is done well in all regions except the Western region Cost overrun rate for the labor ranges from 0 40 in the Southeast region to 0 96 in the Southwest region No region performs well in labor cost estimating For the miscellaneous costs, the Northeast and Central regions have positive cost overrun rates of 0 04 and 0 16 respectively, while the other regions have negative cost overrun rates Only the Northeast region performs well in miscellaneous cost estimating For the land cost, the largest cost overrun rate difference, 1 01, occurs between the Western region at -0 66 and the Southeast region at 0 35 The land cost is overestimated higher in the Western region None of the regions perform well in land cost estimating For the total cost, the cost overrun rate difference is smallest due to the aggregation effect The Midwest and Southeast regions perform well in total cost estimating

The results of the KW tests show that the cost overrun differences in different regions are significant for all construction cost components ($p<0.05$) Weather conditions, soil properties, population density, cost of living, terrain conditions, and distances from supplies are variables for different regions, making compressor station project cost estimation more difficult (Rui et al , 2011a, Zhao, 2000) More detailed information for compressor stations is needed to explain cost overrun differences between the different regions

Therefore, it is concluded that the cost overrun rates of all cost components show significant differences between regions, and compressor station location matters for cost overruns in all cost components

7.8 Cost overruns over time

Forty seven megaprojects constructed between the mid 1960s and 1984 were reported with an average cost overrun of 88% (Merrow, 1988) More than 1,000 World Bank projects between 1947 and 1987 had cost estimating errors (Pohl and Mihaljek, 1992) Fifty five percent of all INDOT projects between 1996 and 2001 experienced cost overruns (Bordat et al, 2004) Cost overrun is constant for a more than 70 year period between 1910 and 1998 for 208 transportation projects in 14 nations on five continents (Flyvbjerg et al , 2003) An analysis of 412 pipelines constructed between 1992 and 2008 shows that only the ROW cost t overrun rates of pipeline projects decreases over time, but cost overrun rates of labor, material, miscellaneous and total costs did not show any decrease over time (Rui et al , 2012) All the literatures show that the cost estimating errors persist over time in many different types of projects But is there any improvement in pipeline compressor station cost estimation over time? This section attempts to discover whether the cost estimating performance of compressor station projects has improved over the years Improved performance of cost estimating is normally expected with experience

Table 7 5 Average cost overrun rates for dıfferent regıons

Components	Regıons	Average	SD	S	K	Mın	Max	N
Materıal	Northeast	-0 03	0 32	0 81	9 18	-1 00	1 40	61
	Central	0 05	0 29	0 99	4 26	-0 55	0 94	46
	Mıdwest	-0 02	0 22	0 24	2 88	-0 39	0 43	17
	Southeast	0 01	0 24	-1 26	9 71	-0 95	0 61	32
	Southwest	0 00	0 21	0 12	2 05	-0 40	0 39	33
	Western	0 23	0 54	1 55	5 20	-0 59	1 78	29
Labor	Northeast	0 46	0 84	1 81	10 79	-0 99	4 54	59
	Central	0 49	0 90	1 28	3 95	-0 63	3 17	45
	Mıdwest	0 66	1 25	2 74	10 38	-0 40	5 05	17
	Southeast	0 40	0 90	1 19	3 74	-0 89	2 72	32
	Southwest	0 96	1 34	2 49	9 20	-0 09	6 25	33
	Western	0 85	1 19	1 34	4 44	-0 72	4 05	29
Mıscellaneous	Northeast	0 04	0 78	3 60	19 11	-0 85	4 36	60
	Central	0 16	1 35	4 80	27 91	-0 72	8 11	46
	Mıdwest	-0 09	0 46	1 86	6 78	-0 56	1 37	17
	Southeast	-0 11	0 41	1 31	5 90	-0 84	1 29	32
	Southwest	-0 09	0 50	1 72	6 12	-0 71	1 65	32
	Western	-0 13	0 36	0 35	2 22	-0 68	0 58	29
Land	Northeast	0 09	1 72	2 04	6 59	-1 00	5 20	14
	Central	-0 06	1 63	4 25	21 26	-1 00	7 86	28
	Mıdwest	0 10	0 99	0 76	2 55	-1 00	2 00	14
	Southeast	0 35	0 61	-0 16	1 75	-0 40	1 04	4
	Southwest	-0 35	0 99	2 24	7 35	-1 00	2 62	13
	Western	-0 66	0 82	2 89	10 46	-1 00	2 20	16
Total	Northeast	0 11	0 35	2 06	13 97	-0 82	1 93	61
	Central	0 11	0 42	2 55	11 39	-0 54	2 01	46
	Mıdwest	0 05	0 25	1 35	5 79	-0 38	0 80	17
	Southeast	0 05	0 26	2 04	8 24	-0 30	1 05	32
	Southwest	0 10	0 31	2 19	7 72	-0 19	1 16	33
	Western	0 23	0 47	1 16	4 30	-0 60	1 48	29

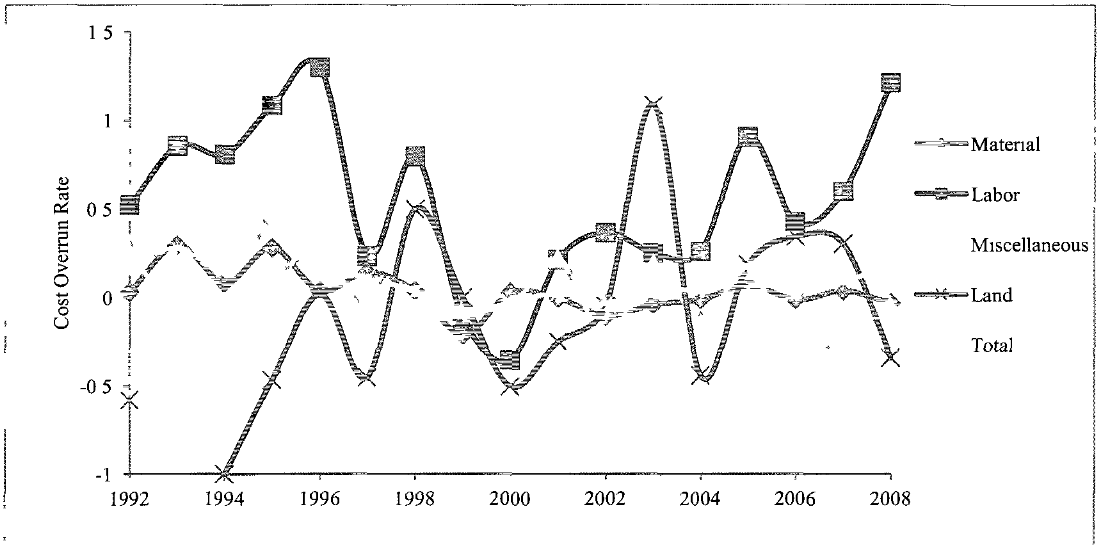

Figure 7.7 Annual average cost overrun rates of cost components

Average cost overrun rates of compressor station construction components between 1992 and 2008 are displayed in Figure 7.7. Cost overrun rates of labor and land costs fluctuate widely. But cost overrun rates of material, miscellaneous, and total costs change more gradually, tending to decrease over time.

The length of the construction phase influences cost overrun rates, so it is better to use the planning year as a time measurement (Flyvbjerg et al., 2003). But the data of the year of building and construction period are not publicly available. Therefore, the year of completion is used as a measure of the time which may cause bias. The nonparametric Nptrend test is conducted to see whether there is a changing trend in cost overrun rates over the years. All results of the Nptrend test show that cost overrun rates of compressor station cost components decreases over time except for the labor costs (p=0.51 for labor cost). Therefore, based on the available data, it is concluded that cost estimating of compressor station construction cost components has improved over time except for labor cost.

7.9 Conclusions and future work

This paper statistically analyzes the cost estimating performance of individual pipeline compressor station construction components by using a dataset containing 220 compressor station projects. The trend and distribution of all 220 compressor station construction cost component estimation errors over the 1992-2008 period are analyzed Overall, average cost overrun rates of the material, labor, miscellaneous, land, and total costs are 0 03 (SD=0 33), 0 60 (SD=1 04), 0 02 (SD=0 94), -0 14 (SD=1 30), and 0 11 (SD=0 36), respectively Labor costs have much larger cost overruns compared to other cost components Statistical test results show that cost estimating for all cost components is biased except for the material cost And the magnitude of the cost underestimating error is generally larger than the overestimating error

Results of statistical tests show that cost overrun rates of all construction cost components are not significantly influenced by project size or project capacity at a 95% confidence level However, the cost overruns of all construction cost components are significantly different in different regions, and all compressor station construction cost component estimation has improved over the 1992-2008 period except for the labor cost

Weather, soil, terrain conditions, cost of living, population density, economies of scale, prime mover, and distances from supplies are suggested as factors for accurate cost estimation difficulties

Based on the analysis of historical pipeline compressor station cost estimating errors, Table 7 6 provides some proposed guidelines for compressor station project cost estimators It is considered that individual cost components should receive varying degrees of attention under different conditions in order to make cost estimation efficient and reliable A four-level scale maximum attention, moderate attention, less attention, and minimum attention, allows the estimators to consider how much attention and effort should be paid to individual component cost analysis, depending on project size, capacity, and location

To the best of the author's knowledge, this paper is the first in-depth analysis of pipeline compressor station construction component cost overruns Suggested future work may include the following

- Lack of good quality data is a major difficulty for more in-depth investigation for compressor station cost overrun, so collecting more accurate detailed information on the compressor station construction period, ownership of projects, type of compressor and movers, and whether or not it is a Greenfield project is a major part of future work

- Results of these analyses ın thıs study should be applıed to the future compressor statıon project cost estımatıons, such as compressor statıon cost overrun dıstrıbutıon and average cost overrun rate for dıfferent groups
- A set of recommendatıons should be developed to help managers and engıneers to better estımate compressor statıon projects and mınımıze the cost estımatıng errors

Table 7 6 Proposed guıdelınes for compressor statıon cost estımatıon

Category	Sub-category	Materıal	Labor	Mıscellaneous	Land	Total
Project Sıze	Small	C	A	D	D	B
	Medıum	D	A	D	D	C
	Large	D	A	D	D	B
Capacıty	Small	C	A	C	D	B
	Medıum	D	A	D	D	C
	Large	D	A	D	B	C
Regıon	Northeast	D	A	D	C	B
	Central	C	A	B	D	B
	Mıdwest	D	A	D	B	C
	Southeast	D	A	D	A	C
	Southwest	D	A	D	D	C
	Western	A	A	D	D	A

Note A=Maxımum attentıon, B=Moderate attentıon, C= Less attentıon, D= Mınımum attentıon

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CHAPTER 8 ALASKA IN-STATE GAS PIPELINE

8.1 Abstract

Comprehensive analyses of historical cost data for pipelines and compressor stations generate valuable information and references for pipeline cost estimation, and provide a solid foundation for analysis of the feasibility of an Alaska in-state gas pipeline This chapter describes the background and market for an Alaska in-state gas pipeline, and discusses parameters, assumptions, and methodologies for models of the Alaska in-state gas pipelines Monte Carlo simulation models are developed and simulated to evaluate the feasibility of an Alaska in-state gas pipeline by assigning triangular distribution of the values of economic parameters The simulated results of models for an Alaska in-state gas pipeline under different flow rate scenarios are analyzed and compared Analysis of simulated results shows that the construction of an Alaska in-state natural gas pipeline is feasible at three scenarios of 500 mmcfd, 750 mmcfd, and 1000 mmcfd

8.2 Overview of pipeline route

An Alaska in-state gas pipeline system is proposed to transport a conditioned natural gas from ANS to Southcentral Alaska A map of the proposed gas pipeline is shown in Figure 8 1 The system includes a 737-mile-long, 24-inch-diameter mainline pipeline that runs from Prudhoe Bay to Livengood, and then heads south and joins the Parks Highway corridor From there, the mainline pipeline continues south and terminates at milepost (MP) 737, connecting to the Beluga pipeline at MP39 near Big Lake A lateral 35-mile-long, 10-inch-dimater pipeline takes off from the main pipeline a few miles north of Nenana near Dunbar and travels to the northeast of Fairbanks (AGDC, 2011a) For the purposes of this study, "Pipeline A" refers to that section of the system between Prudhoe Bay and Dunbar station, "Pipeline B" is the section of the system between Dunbar station and Beluga, and "Pipeline C" refers to the section of the system between the Dunbar station and Fairbanks The maximum allowable pressure for the pipeline is 2,500 pounds per square inch (psi) (AGDC, 2011a) The number of compressor stations along the pipeline depends on pipeline flow rates and distances The potential number of compressor stations for the Alaska in-state gas pipeline in shown in Table 8 1 In addition to pipeline sections, this study examines a GTP to be built at ANS to remove contaminants such as carbon dioxide, water vapor, and hydrogen sulfide, and a LNG plant to be built at the tidewater sites in Southcentral Alaska to manage seasonal fluctuations in demand and to export LNG to the Pacific Rim market Six potential tidewater site options for LNG plant are Nikiski, Port Mackenzie, Seward Marine Industrial Center, Port of Anchorage, Western Kenai Peninsula, and Homer (AGDC, 2011b)

Table 8 1 Number of compressor stations in different segments by flow rate (ACDC, 2011c)

Segments	500 mmcfd	750 mmcfd	1000 mmcfd
Pipeline A	1	3	7
Pipeline B	1	2	4

8.3 Alaska natural gas supply and demand

Cook Inlet has supplied low cost natural gas to South-central Alaska since 1963, however, after 2002, the lack of natural gas production in Cook Inlet led to the closure of the Kenai Agrium plant in 2007 and the closure of the Kenai LNG plant and export facility in 2011(Agrium, 2007, Petroleum News, 2011)

Forecasted Cook Inlet natural gas production by Hart et al (2009) is shown in Figure 8 2 This figure shows that natural gas production from Cook Inlet will continue to decline significantly without new investment in natural gas exploration and developments Average annual production will be less than 100 mmcfd (36 5 bf/yr) after 2015 According to the best-assumption projections, natural gas production can remain constant at 250 mmcfd (91 25 bf/yr) through 2019 In the long terms, the Cook Inlet Basin, therefore, cannot provide sufficient natural gas for Southcentral Alaska and other Alaskan markets The data shows the need for a gas pipeline for transporting natural gas from ANS to markets in Southcentral Alaska

Alaska natural gas demand has a significant seasonal variation characteristic An analysis of the Alaska natural gas production history from 1990 to 2006 was conducted by Thomas et al (2007), providing a long term perspective of the monthly variation in gas demand (industrial, residential/commercial, electricity production, field operations, etc) (Figure 8 3) Average peak monthly production during this period is 610 mmcfd (18 5 bcf/month) The difference between the average peak month and average monthly average is 87 mmcfd Overall, for Alaska in-state gas consumption (excluding LNG plant consumption) between 2002 and 2008, July accounts for only 7% of the yearly consumption, while January accounts for 9 6% of the yearly consumption (EIA, 2011) The data indicates a significant seasonal variation in Alaskan gas demand A storage facility or LNG plant, therefore, would have to be built to store or process the gas remaining after in-state needs are met

Potential natural gas demand for an Alaska in-state gas pipeline is based on the report "In-State Demand Study" conducted by Northern Economics, Inc (2010) Estimated potential natural gas demand for each sector is shown in Table 8 2 This potential natural gas demand is used as the in-state natural gas market for an Alaska in-state gas pipeline in this study

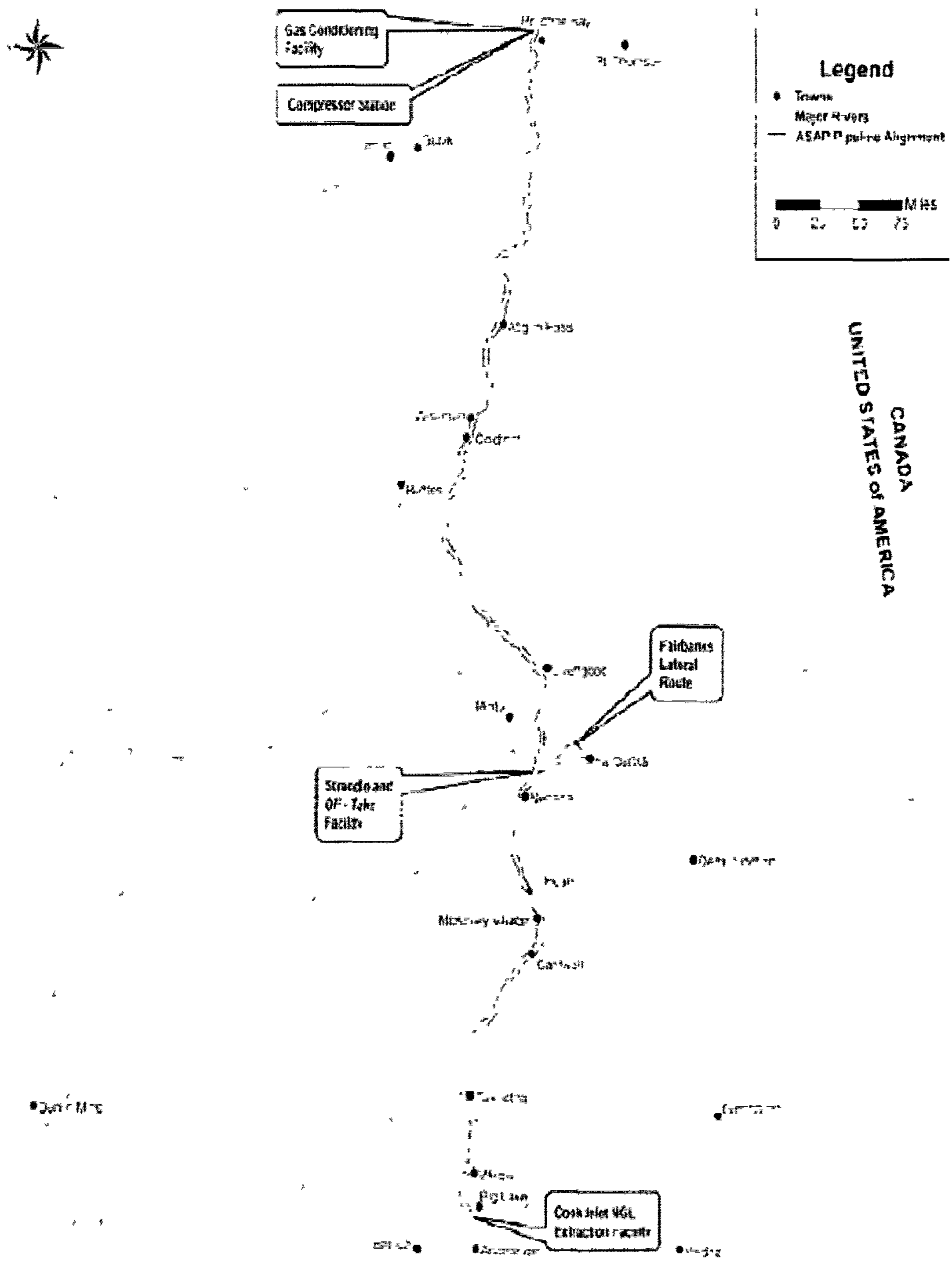


Figure 8 1 Alaska in-state gas pipeline route map and major facilities (AGDC, 2011a)

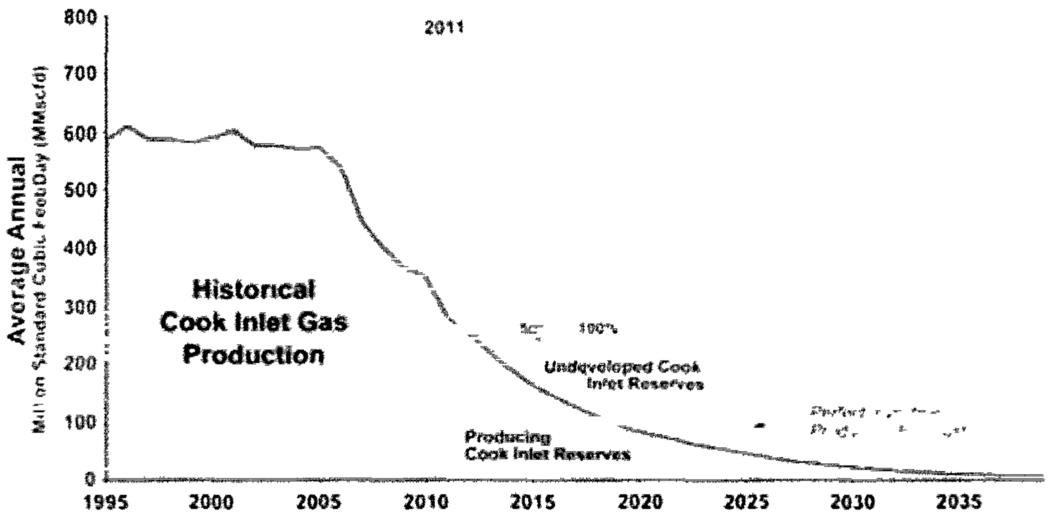


Figure 8 2 Cook Inlet natural gas production history and projection (Hartz et al , 2009)

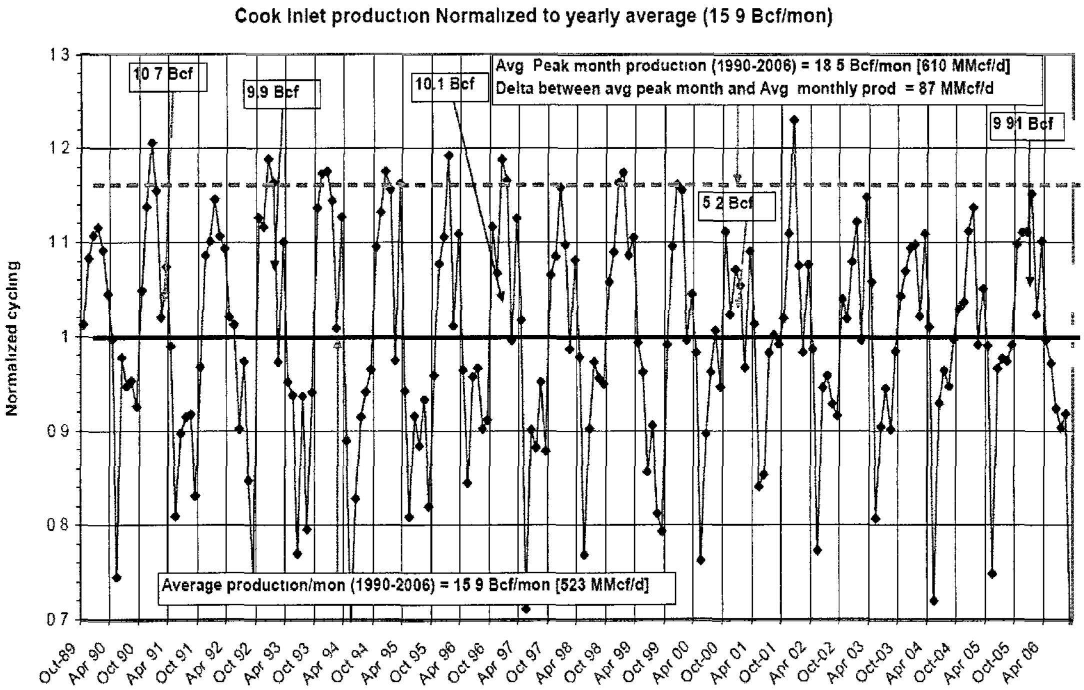


Figure 8 3 Normalized Cook Inlet productions between 1990 and 2006 (Thomas et al , 2007)

Table 8 2 Potential natural gas demand for an Alaska in-state gas pipeline

Regions	Sectors	mmcf/day	bcf/year
Northern Railbelt region	Residential	18 4	6 7
	Commercial	9 3	3 4
	Flint Hills	12 3	4 5
	Petro-star	0 9	0 3
	Livengood Gold Mine	9 0	3 3
	Power sector	29 0	10 6
	Eielson Air Force	7 7	2 8
	Fort Wainwright	8 3	3 0
	Subtotal	95 0	34 7
Southern Railbelt region	Residential	96 8	35 3
	Commercial	51 2	18 7
	Power Sector	70 3	25 7
	Fort Greeley	0 9	0 3
	Mines	30 0	11 0
	Subtotal	249 2	91 0
	Total	344 2	125 6

8.4 Natural gas price

This section discusses historical Alaska gas prices, Alaska wellhead gas prices, U S Henry Hub prices, forecasted U S wellhead gas prices, and forecasted U S Henry Hub gas prices

Since 1963, nearly 70% of Alaskans have depended on low cost natural gas from Cook Inlet The delivered natural gas price by ENSTAR between 1996 and 2009 is shown in Figure 8 4 The average price of Cook Inlet gas has been 30% to 50% below prices in other states between 1996 and 2019 (ENSTAR, 2011) Natural gas prices in Southcentral Alaska sharply increased in 2005 due to the soaring costs of natural gas, and continued to rise sharply, especially in 2007 and 2009 However, natural gas prices in Southcentral Alaska in 2009 are still lower than those in other states (Figure 8 5)

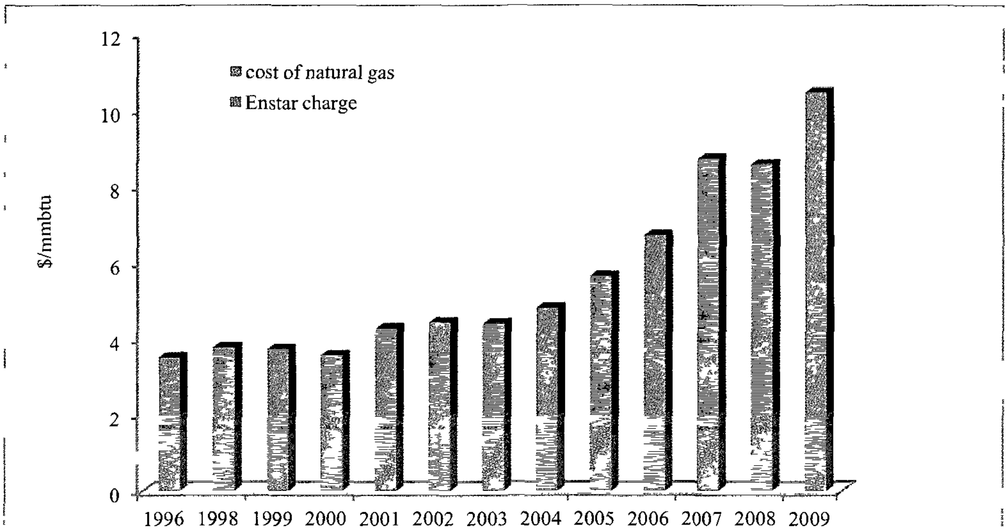


Figure 8.4 Natural gas prices of ENSTAR - delivered (ENSTAR, 2011)

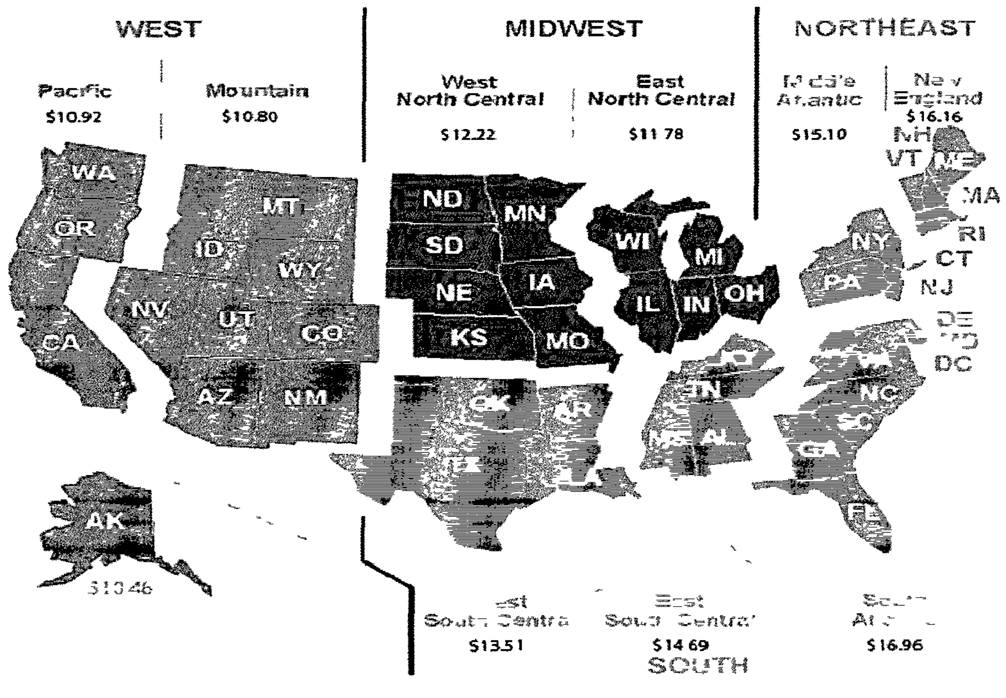


Figure 8.5 2009 Regional average natural gas prices - delivered (ENSTAR, 2011)

The Henry Hub is the largest centralized point for natural gas spots and futures trading in the U S The New York Mercantile Exchange uses the Henry Hub price for its natural gas futures contract, and almost 50% of U S wellhead production occurs near or passes by the Henry Hub on the way to market The Henry Hub spot price refers to natural gas sales contracted for next day delivery and title transfer at the Henry Hub In addition, the Henry Hub price measures gas without gas liquids (EIA, 2011) U S wellhead price is the price received by natural gas producers for marketed gas The wellhead price includes the value of natural gas liquids and is influenced by all transactions occurring in the U S (EIA, 2011)

Figure 8 6 presents the historical nominal prices of the Henry Hub, Alaska wellhead, and U S average wellhead, while Figure 8 7 shows the real price of the Henry Hub, Alaska wellhead, and U S average wellhead In these two figures, the three curves trend up The Henry Hub price is the highest, while the Alaska wellhead price is the lowest The changing trend of the Henry Hub price is almost the same as the U S average wellhead price, though the Henry Hub price is a little higher than the U S average wellhead price about $ 0 6/mcf The peak of the Henry Hub price was $10/mcf in 2005 As seen in Figure 8 6, Alaska wellhead price has been much lower than the Henry Hub and U S wellhead prices in the past, with a difference of $1 83/mcf The low Alaska wellhead price is a major factor for inexpensive natural gas in Southcentral Alaska

The projected annual average Henry Hub and Lower 48 wellhead gas prices between 2010 and 2035 is shown in Figure 8 The Henry Hub price for the next 25 year starts at $4 43/mmbtu in 2010 with an annual average growth rate of about 2% The Lower 48 wellhead gas price begins at $3 98 /mmbtu in 2010 with an annual average growth rate of about 2% (EIA, 2011)

8.5 LNG price in the Pacific Rim import market

The LNG option was analyzed in "Greenfield liquefied natural gas economic feasibility study" conducted by AGDC (2011b) The Pacific Rim market is the most promising potential market for Alaska natural gas because China, Japan, and South Korea lack indigenous energy supplies and have a high dependence on fuel energy They also are located at a relatively short geographic distance from Alaska LNG price in Japan is tied to Japanese Customs Cleared (JCC) price, as shown in the formula below (AGDC, 2011b)

$$\text{LNG price} = \text{Base price} - \text{Slope} * \text{JCC} \qquad \text{Equation 8.1}$$

However, in recent years, China and India have used long-term contracts to get low LNG prices through negotiation. The LNG price for the Alaska LNG export scenario forecasted for by AGDC (2011b) is :

$$\text{LNG price} = 0.6675 + 0.1515 * \text{WTI} \qquad \text{Equation 8.2}$$

The West Texas Intermediate (WTI) oil price in 2018 is forecasted at about $103/barrel (2008 dollars), then with a 1% to 3% annual growth rate through 2035 (EIA, 2011). Based on the forecasted WTI oil price and Equation 8.2, the LNG price will be $16.3/mmbtu in Japan in 2018. This report also estimated LNG shipping costs from Alaska to the Pacific Rim/Indian Ocean by LNG volume (Figure 8.9). In addition, regasification costs are in the range of $0.5 to $1.00 /mmbtu plus a $0.25 to $0.50/mmbtu connection fee (2011 dollars).

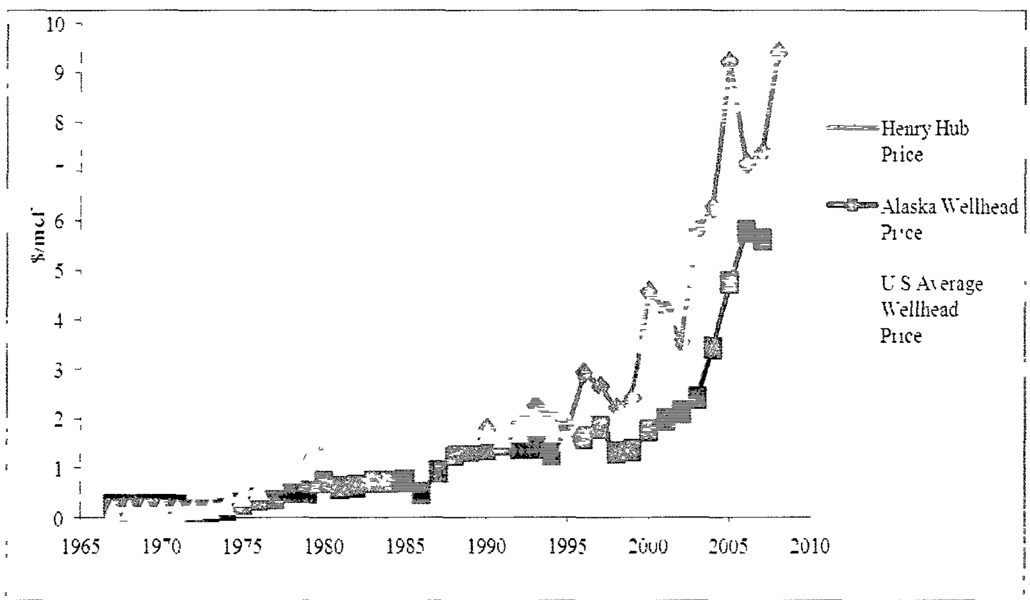


Figure 8.6 Historical nominal prices of Henry Hub, Alaska wellhead, and U.S. average wellhead (EIA)

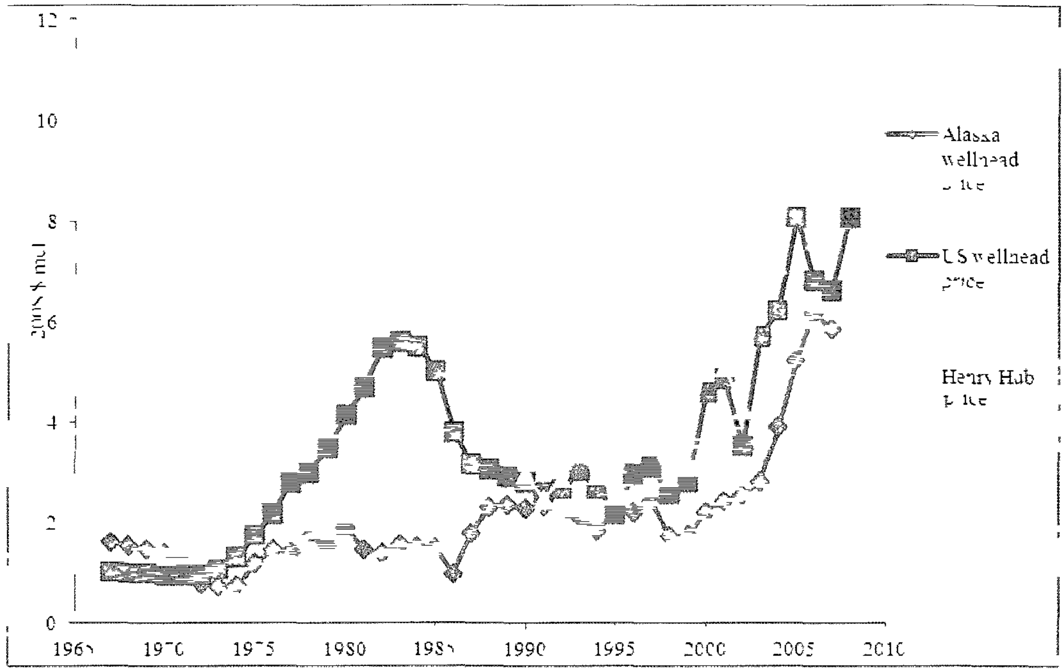


Figure 8 7 Historical real prices of Henry Hub, Alaska wellhead, and U S average wellhead (EIA)

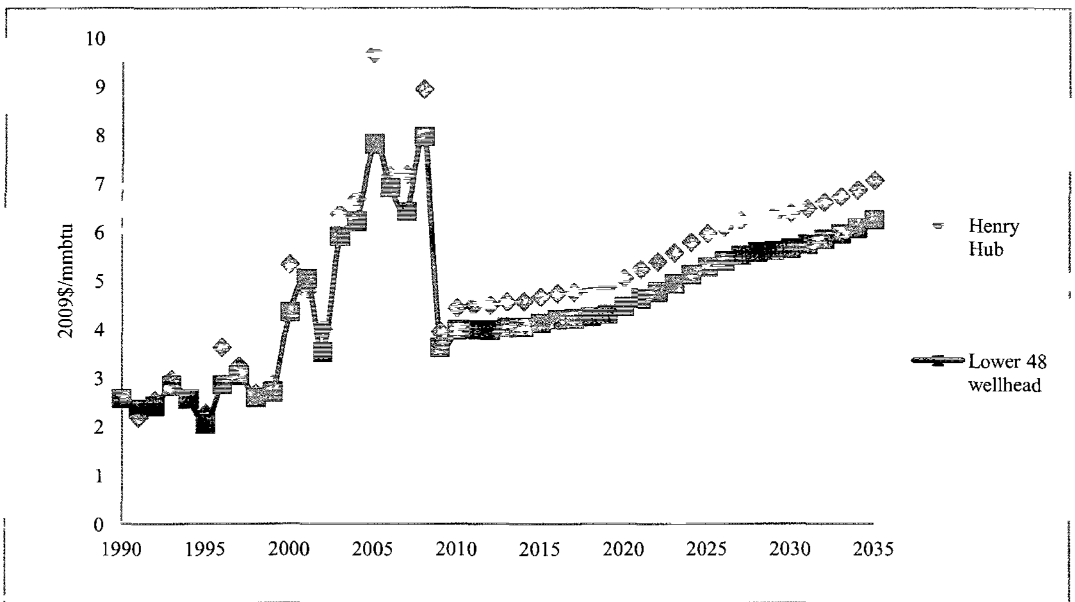


Figure 8 8 Annual average Lower 48 wellhead and Henry Hub prices for natural gas (EIA)

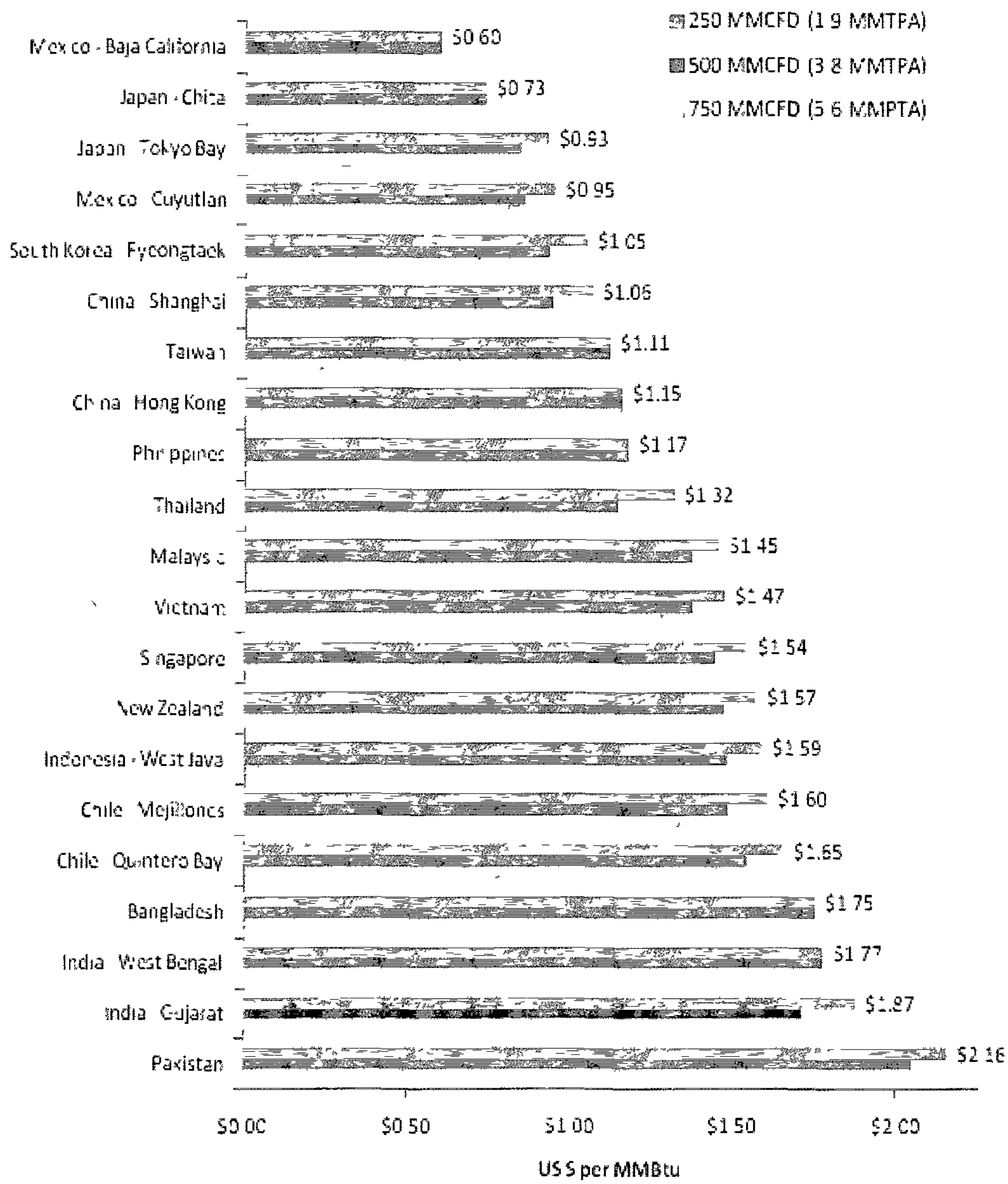


Figure 8.9 Estimated LNG shipping costs from Alaska to the Pacific Rim/Indian Ocean regasification import markets by LNG volume, 2010 $/mmbtu (AGDC, 2011b)

8.6 Assumptions and economic parameters

Economic parameters for building Alaska in-state gas pipeline models include rate of return, unit cost of capital and operation, fuel loss, tax rate, depreciation, debt-to-equity ratio, inflation rate, capital and cost escalation rate, construction pattern, project lifetime, and location cost factors. All these parameters ınfluence the feasıbılıty of buıldıng an Alaska ın-state gas pıpelıne These assumptıons are made based on comprehensıve analyses of hıstorıcal pıpelıne and compressor statıon costs, and other hıstorıcal and empırıcal data

8 6 1 Rate of return

Rate of return, also known as return on ınvestment (ROI), ıs a measure for evaluatıng the effıcıency of an ınvestment or comparıng the effıcıency of a number of dıfferent ınvestments The general formula for calculatıng ROI ıs (Investpedıa, 2011)

$$\mathrm{ROI} = \frac{(\text{Gain from investment} - \text{Cost of investment})}{\text{Cost of investment}} \qquad \text{Equation 8 3}$$

The hıgher the ROI, the more profitable the project Mınımum acceptable rate of return, also called hurdle rate, ıs the mınımum rate of return on an ınvestment If an ınvestment has an expected ROI hıgher than the hurdle rate, ıt ıs usually a reasonable ınvestment, otherwıse ıt ıs consıdered ınfeasıble project In general terms, the hurdle rate determınes feasıbılıty

The weıghted average cost of capıtal (WACC) ıs a practıcal way to approxımately measure a firm's ınternal hurdle rate for financıng decısıons The WACC ıs computed usıng the followıng equatıon (Reynolds, 2003)

$$\mathrm{WACC} = \frac{\text{Equity}}{\text{Equity+Debt}}(\text{Market rate}) * (\text{Risk premium}) + \frac{\text{Debt}}{\text{Equity+Debt}} * (\text{Debt rate} * (1 - \text{Tax rate})) \qquad \text{Equation 8 4}$$

The approprıate hurdle rate for the Alaskan gas project ıs ın the range of 10% to 15% (NERA, 2002) The overall requıred rate of return for an Alaska ın-state gas pıpelıne ın thıs study ıs assumed to be 10% ın thıs study

8 6 2 Capıtal cost and operatıon cost

The capıtal cost ın thıs model ıncludes

- GTP at the ANS,
- Pıpelıne A, Pıpelıne B, and Pıpelıne C,
- Lıquefied natural gas plants (LNGP) at Cook Inlet regıon

The capıtal cost ın thıs model does not ınclude

- Pıpelıne support ınfrastructure and joınt facılıtıes at ANS,
- Faırbanks straddle and off-take facılıty,
- Fınancıal cost

The capıtal cost for each of these projects varıes dependıng on locatıon and flow rate Pıpelıne costs ın the south of Faırbanks are lower than ın the north of Faırbanks These cost models are developed based on NERA's model (NERA, 2002), usıng dollars-per-ınch-per-mıle for the pıpelıne cost estımatıon, whıch contaıns compressor statıon costs The values of pıpelıne unıt cost are derıved from analysıs of hıstorıcal pıpelıne and compressor statıon costs The sources of GTP and LNGP costs are referenced from reports of Energy Project Consultant, LLC (2008) and ADGC (2011b), respectıvely Table 8 3 shows the assumptıons of breakdown capıtal cost

Table 8 3 Assumptıons of capıtal costs of each segment

Segments	500 mmcfd			750 mmcfd			1000 mmcfd		
	Mın	Lıkelıest	Max	Mın	Lıkelıest	Max	Mın	Lıkelıest	Max
GTP($mıllıon)	1100	1375	1650	1568	1959	2351	1980	2475	2970
Pıpelıne A ($/ınch/mıle)	81139	101423	121708	89512	111890	134268	102072	127590	153108
Pıpelıne B ($/ınch/mıle)	46500	58900	71300	54703	69291	83878	62906	79681	96456
Pıpelıne C($/ınch/mıle)	56000	70000	84000	56000	70000	84000	56000	70000	84000
LNGP ($/ton)	550	688	825	495	619	743	440	550	660

Operatıng costs are descrıbed as a percentage of capıtal cost The assumed operatıng cost of each segment ıs shown ın Table 8 4

8 6 3 Fuel use and loss

Fuel use or loss ıs the amount of natural gas consumed by operatıons of pıpelıne transportatıon, GTP, and LNGP Normally, fuel use or losses are set as a percentage of the total volume of natural gas Overall fuel use reduces the fınal quantıty delıvered, thus reducıng revenue and ıncreasıng unıt costs and tarıffs Table 8 5 shows the assumptıons made on fuel loss for each process

Table 8 4 Assumptions of operating costs (Eke, 2006)

Segments	% of capital cost		
	Min	Likeliest	Max
GTP	3%	4 00%	5%
LNGP	3%	4 00%	5%
Pipeline	1%	1 50%	2%

Table 8 5 Fuel use and loss for the model (Eke, 2006)

Segments	Fuel Loss
GTP	4%
Pipeline	2% per 1000 miles
LNGP	10%

8 6 4 Tax and depreciation

Income tax and property tax rates depend on the regions Since an Alaska in-state gas pipeline would be located in the State of Alaska, typical Alaska tax rates are used Table 8 6 shows a list of potential taxes for the Alaska in-state gas pipeline models Capital cost is depreciated using the Modified Accelerated Capital Recovery System (MACRS)

Table 8 6 Tax rates (Eke, 2006)

Taxes	Rate
Federal income tax	35 00%
Alaska income tax	9 40%
Alaska property tax	2 00%

8 6 5 Financing structure

Financing structure includes overall rate of return, debt-to-equity ratio, inflation rate, and capital and operation cost escalation Detailed information is shown in Table 8 7

8 6 6 Constructions pattern

This study assumes project construction will begin in 2015 and reach completion in three years The project will operate for 30 years

Table 8 7 Assumptions of financing structure

Financial assumptions	Rate
Overall rate of return	10%
Debt-to-equity ratio	70/30
Inflation rate	2 50%
Capital and operation cost escalation	3%

8 6 7 Location cost factors

Pipeline and compressor station costs are significantly different by regions Pipeline unit total costs in the Southeast region are 2 6 times those in Canada and 1 8 times those in the Central Region (Rui et al , 2011) Compressor station unit total costs in the Western region are 34% higher than those in the Northeast Region (Rui et al , 2012) Natural gas pipeline and compressor station costs in Alaska are expected to be much higher than those in Lower 48 states, however, actual costs for an Alaska in-state gas pipeline are not publicly available

Alaska is a unique state due to its geographic, climatic, economic, social, cultural, and lifestyle diversity Transportation linkages and market size efficiencies strongly influence the price of the same item in different locations (McDoweLL Group, 2009) Importation of labor, severe climatic conditions, lower labor and machine efficiency, the large volumes of fill required, and the transportation cost for supplies and materials are most likely the mam reasons for railroad construction costs being higher in the Northern region of Alaska (Clark, 1973)

In addition, permafrost in Alaska is a major difficulty in pipeline construction Approximately 75% of the proposed gas pipeline passes through continuous permafrost zones from ANS to the Brooks Range, and then crosses discontinuous and sporadic zones before reaching Southcentral Alaska (Figure 8 10) Permafrost normally causes three problems frost-heaving, frost jacking, and thaw settlement Three major design modes are chosen for building a gas pipeline in Alaska above-ground pipeline, below-ground pipeline with conventional burial, and below-ground pipeline with special burial (Alyeska Pipeline Service Company, 2011) Construction costs in permafrost zones were three to four times higher than under usual conditions, and operation costs increase accordingly (Porfiryev and Porjhayev, 1963) The 800-mile-long, 48-inch-diameter Trans Alaska Pipeline System, moving oil from ANS to Valdez, was constructed between

March 27, 1975 and May 31, 1977 (Alyeska Pipeline Service Company, 2011). The total cost was $9 billion in 1977 dollars, with 4.53 times the growth of cost compared to the budget (Merrow, 1988; Cole et al., 1998). Approximately $800 million was spent to elevate the 400-mile segment above the permafrost (Henry et al., 1998).

Some of the few available references for Alaska location cost factors mentioned by different organizations are shown in Table 8.8. Based on these available references, location cost factors used for the Alaska in-state gas pipeline in this study are determined and shown in Table 8.9.

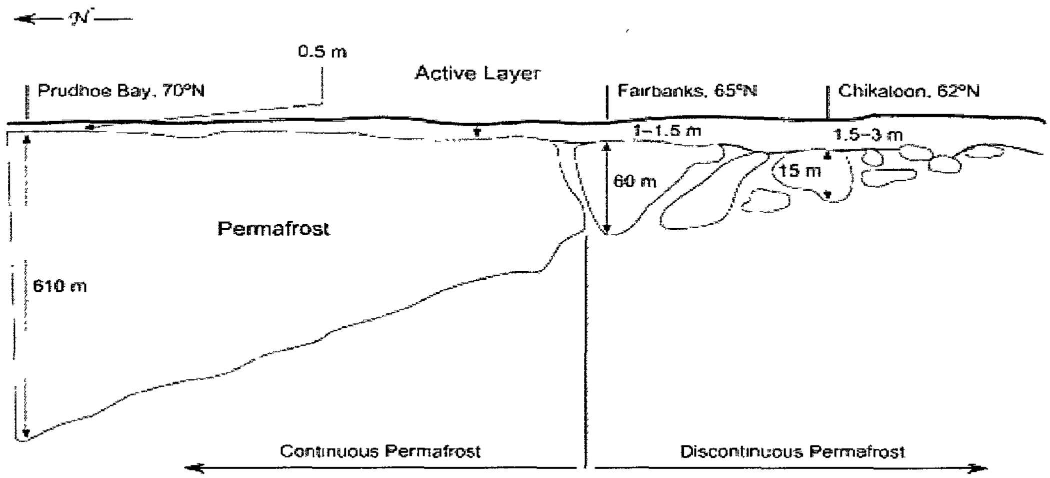


Figure 8.10 Latitudinal profile through permafrost zones in Alaska (U.S. Arctic Research Commission, 2003)

Table 8.8 Reference for Alaska location cost factors

Sources	Benchmark	Alaska	Anchorage	Fairbanks	Arctic	Barrow	ANS
US Army Corps of Engineers(2010)	U.S.average	1.78	1.67	1.89	N/A	N/A	N/A
McDowell Group (2008)	U.S.average	1.26	1.2	1.3	1.87	1.89	N/A
Idaho National Laboratory (Thomas, et al., 1996)	Gulf of Mexico	N/A	N/A	N/A	N/A	N/A	1.5-2

Table 8.9 Location cost factors for Alaska in-state gas pipeline

Segments	Benchmark	Minimum	Likeliest	Maximum
Pipeline A	U.S. average	1.9	2.3	2.6
Pipeline B	U.S. average	1.3	1.7	2.0
Pipeline C	U.S. average	1.9	2.3	2.6

8.7 Methodology and software for Alaska in-state gas pipeline models

The NERA model is a levelized tariff models shown in Equation 8.4 (NERA, 2002). Based on NERA's model, Alaska in-state gas pipeline models are developed with Monte Carlo simulations and new assumptions. The relationship between input variables and output results is developed by using a combination of function, formula, and data. Economic models are developed to comparatively analyze three possible flow rate scenarios (500 mmcfd, 750 mmcfd, and 1,000 mmcfd) by assessing tariffs, capital costs, and taxes. Capital costs, tariffs, and taxes will change automatically by changing gas input quantity. Forecasted results immediately demonstrate the differences between projects of varying flow rates.

$$\text{Tariff}_t = \frac{\Sigma(\text{Operation cost}_t + \text{Depreciation}_t + \text{CapitalR}_t + \text{Income Tax}_t + \text{Property Tax}_t}{Q_t} \qquad \text{Equation 8.5}$$

where CapitalR_t: regulatory return on the installed capital cost, Q_t: annual transported natural gas volume, t: year.

For simplicity, this model uses the 100% equity to evaluate the project. This assumption is different from most real project financing. Since different investors have different financings, and each financing has different impacts on evaluating projects, it is much simpler to use a common figure to compare the projects at 100 % equity.

The Monte Carlo simulations are realized by using the *Crystal Ball* software and Excel *Crystal Ball* is an analytical tool for Monte Carlo simulations (ORACLE, 2011). Each uncertain input variable in a simulation is assigned a probability distribution. A simulation calculates the numerous scenarios of a model by randomly using values from the probability distribution of uncertain input variables. Distributions and associated scenario of input variables are called assumptions (ORACLE, 2011). Major distribution types of assumptions in *Crystal Ball* software are shown in Figure 8.11.

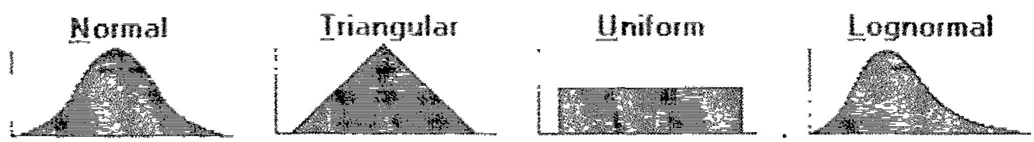
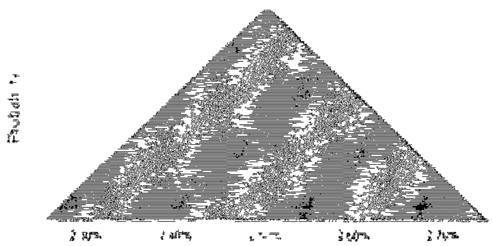


Figure 8.11 Major assumptions of input variables in *Crystal Ball* software (ORACLE, 2011)

The type of distribution selected is based on the historical distribution of variables. Based on analysis of cost overruns for historical pipeline and compressor station costs, the triangular distribution is selected for this simulation for this model.

An example of typical probability distributions of the input variables is shown in Figure 8.12. The base represents the possible range of values, while the height of the triangle represents the probability of the value actually happening. The highest point of the triangle is the likeliest value. Accordingly, probability distributions of output variables are forecasted. Variables associated with their distribution in Table 8.3 and Table 8.4 are input for Monte Carlo simulation models. Capital costs, taxes, and tariffs are forecasted output.



Typical triangular distribution with variables

Minimum	2.25%
Likeliest	2.50%
Maximum	2.75%

Figure 8.12 Typical triangular distribution assumption of the input variable

8.8 Results and analysis

The three flow rate scenarios are evaluated by their taxes, tariffs, and capital costs. The probabilistic values of taxes, tariff, and capital cost are estimated with Monte Carlo simulation, and are shown in Appendices A through C. The base case (likeliest value) of estimated values of capital cost, tariff, and tax is selected for the comparison.

8.8.1 Capital cost

Capital costs are costs related to the initial establishment of the facility. Capital costs are how much investor or owners have to invest in projects at the beginning. This is a very important criterion in the economic analysis of any project, especially for project requiring intensive capital. Capital costs of each segment for different flow rates are tabulated in Table 8.10. Detailed distribution results of capital costs are shown in Appendix A.

Capıtal costs of the project ıncreases wıth the ınput quantıty of gas For base case, the whole project capıtal cost ıncreases from $3,590 mıllıon to $6,879 mıllıon as the quantıty of gas ıncreases from 500 mmcfd to 1,000 mmcfd The unıt cost per mmbtu natural gas decreases wıth flow rates (Table 8 12), but pıpelıne capıtal costs ıncreases wıth flow rates

Table 8 10 Estımated capıtal cost range of each segment by dıfferent flow rates

	500 mmcfd			750 mmcfd			1000 mmcfd		
Capıtal cost ($ mıllıon)	Mın	**Lıkeliest**	Max	Mın	**Likeliest**	Max	Mın	**Likeliest**	Max
GTP	1105	**1375**	1647	1572	**1959**	2342	1984	**2475**	2967
Pıpelıne A	858	**1017**	1174	901	**1122**	1344	1027	**1280**	1531
Pıpelıne B	357	**452**	546	421	**532**	644	484	**612**	740
Pıpelıne C	19	**23**	28	19	**23**	28	19	**23**	28
LNGP	579	**722**	865	1384	**1725**	2063	1993	**2489**	2984
Total Pıpelınes	1227	**1493**	1772	1374	**1678**	1973	1555	**1915**	2268
Whole Project	3039	**3590**	4131	4559	**5362**	6148	5806	**6879**	7888

8 8 2 Tax

Total taxes for an Alaska ın-state gas pıpelıne ıncludes Alaska state and U S federal taxes Total tax amount recovered from the pıpelıne ıs shown ın Table 8 11 Detaıled dıstrıbutıon results of taxes are shown ın Appendıx B The taxes for Alaska and the U S both show an ıncrease trend wıth ıncreased quantıtıes of ınput gas From thıs ıllustratıon, for the base case, the 1,000 mmcfd pıpelıne shows the hıghest tax amount of $3,869 mıllıon accruable from the project The larger flow rate case produces more tax revenue for government, whıch causes larger tax costs for pıpelıne project ınvestors or operators From the government perceptıve, the 1,000 mmcfd project should be the best optıon wıth the hıghest tax revenue

Table 8 11 Estımated tax of Alaska and U S by flow rates

	500 mmcfd			750 mmcfd			1000 mcfd		
Tax ($ mıllıons)	Mın	**Likeliest**	Max	Mın	**Likeliest**	Max	Mm	**Likeliest**	Max
Alaska tax	759	**897**	1932	1138	**1338**	1535	1450	**1716.96**	1970
U S tax	953	**1126**	1295	1427	**1678**	1924	1819	**2151.5**	2468

8 8 3 Tarıff

Pıpelıne tarıffs are the transportatıon costs for delıverıng natural gas to customers and paıd by the consumer of the natural gas Pıpelıne tarıffs ın the U S are regulated by the Federal Energy Regulatory

Commission, so tariffs on the pipeline project are estimated based on the cost of the project and regulated rate of return Tariff is the critical parameter for determining the natural gas market for an Alaska in-state gas pipeline and the feasibility for a pipeline project For the Alaska in-state gas pipeline project in this study, the tariff is evenly distributed over 30 years The estimated nominal tariff for each segment by different flow rates is shown in Table 8 12 and Figure 8 13 Table 8 13 and Figure 8 14 demonstrate real tariffs for each segment in 2008 dollars (base case) The tariff of each segment decreases with increasing throughout The lowest tariff case is considered the best choice for customers Detailed distribution results of tariffs are shown in Appendix C The results show three flow rate scenarios all produce reasonable prices for each take-off location

The 1,000 mmcfd flow rate (base case) is used as an example Assumed wellhead gas price is \$2/mmbtu and assumed local distribution charges \$2/mmbtu (AGDC, 2011a) The Fairbanks straddle and off-take facility cost may cause extra tariffs for Fairbanks natural gas, about \$1 9 /mmbtu (AGDC, 2011a) The estimated cost of natural gas to Fairbanks customers is \$7 54/mmbtu, and the estimated cost of natural gas to Anchorage customers is \$5 80 /mmbtu Therefore, the price of gas from an in-state natural gas pipeline for Fairbanks and Anchorage customers is significantly lower than what they pay now The estimated export price for LNG is \$7 55/mmbtu LNG shipping cost to Asia is approximately \$0 80 to \$1 40/mmbtu (AGDC, 2011b) Regasification cost is in the range of \$0 5 to \$1 00 /mmbtu and plus a \$0 25 to \$0 50/mmbtu connection fee The final total price for exported LNG to Asian is approximately \$9 3 to \$10 65/mmbtu which is a strong competitive price advantage compared to forecasted LNG prices in Asian market of approximately \$16 3/mmbtu (2008 dollars)

The cases of 750 mmcfd and 1,000 mmcfd may be eliminated by the Alaska Gasline Inducement Act (AGIA), passed by the Alaska Legislature in 2007 The State of Alaska provided \$500 million financial inducement to a licensee to offset some initial financial risk In addition, the maximum flow rate for the in-state gasline is limited to 500 mmcfd (Alaska Gas Pipeline Project Office, 2011) If this limitation is eliminated, the in-state gas pipeline will become more feasible The \$500 million financial inducement may add extra cost to the in-state gas pipelines, but the extra levelized tariff is only \$0 06/mmbtu for the 750 mmcfd case and \$0 05/mmbtu for the 1,000 mmcfd case With this extra tariff, the 750 mmcfd and 1,000 mmcfd cases still show significantly lower tariffs than the 500 mmcfd case From a tariff perspective, the 1,000 mmcfd case is the most valuable option for customers

Table 8 12 Estimated nominal tariffs of each segment by different flow rates

	500 mmcfd			750 mmcfd			1000 mmcfd		
Tariffs ($/mmbtu)	Min	**Likeliest**	Max	Min	**Likeliest**	Max	Min	**Likeliest**	Max
GTP	1 45	**1.91**	2 39	1 39	**1.81**	2 29	1 32	**1.72**	2 14
Pipeline A	0 94	**1.20**	1 47	0 69	**0.88**	1 07	0 58	**0.75**	0 92
Pipeline B	0 51	**0.66**	0 81	0 37	**0.48**	0 59	0 31	**0.40**	0 49
Pipeline C	0 11	**0.14**	0 17	0 11	**0.14**	0 17	0 11	**0.14**	0 18
LNGP	2 55	**3.23**	3 94	2 37	**3.07**	3 83	2 13	**2.78**	3 47
Total Tariff at Fairbanks	2 65	**3.25**	3 90	2 32	**2.84**	3 39	2 11	**2.61**	3 13
Total Tariff at Big Lake	3 16	**3.77**	4 43	2 63	**3.18**	3 73	2 36	**2.87**	3 47
Total Tariff for Exporting LNG	5 95	**7.00**	8 15	5 29	**6.25**	7 29	4 63	**5.65**	6 68

Table 8 13 Estimated real tariffs of each segment by different flow rates (base case)

Tariffs ($/mmbtu)	500 mmcfd	750 mmcfd	1000 mmcfd
GTP	1 20	1 14	1 08
Pipeline A	0 75	0 55	0 47
Pipeline B	0 42	0 30	0 25
Pipeline C	0 09	0 09	0 09
LNGP	2 03	1 93	1 74
Total tariff at Fairbanks	2 04	1 78	1 64
Total tariff at Big Lake	2 37	1 99	1 80
Total tariff for exporting LNG	4 39	3 92	3 55

8 8 4 Discussion

ENSTAR and AGDC estimated capital cost of Alaska in-state gas pipelines For 500 mmcfd flow rate case, ENSTAR (2009) estimated capital cost of the gas pipeline ranging between $3,830 million and $ 4,570 million (2009 dollars) AGDC (2011a) estimated capital cost of the pipeline sections at about $4,590 million with an uncertainty range of ±30% (2011dollars) The estimated capital costs of pipeline sections in this study range from $ 1,227 to $1,772 million (2008 dollars) The consumer price index difference between 2011 and 2008 is only about 5% (Bureau of Labor Statistics, 2011) Therefore, there is a significant difference on the estimated capital costs of an m-state gas pipeline among different studies It is, however, difficult to draw any conclusion on which estimated costs are more accurate The estimated capital costs of gas pipeline in this study is based on unit cost estimated from historical cost data for 412 pipelines and 220 compressor stations as well as assumed location cost factors In this dataset, the unit cost of pipelines with lengths between 100 miles and 713 miles ranges from 20,569 \$/inch/mile to 91,000 \$/inch/miles, with average unit cost of 36,000 \$/inch/miles If the location cost factor is 2 for Alaska gas pipelines which is the highest reference number from available literatures, the estimated capital costs of an Alaska in-state gas pipeline will range from \$745million to \$3,222 million, which is still lower than ENSTAR and AGDC's estimated cost However, the cost sources of the ENSTAR and AGDC's estimated capital costs are not publicly available Therefore, the cost differences cannot be directly examined and investigated

There are some factors that may explain some of these differences Permafrost and remote issues in Alaska causes higher costs in pipeline construction In this dataset, none of the 412 historical pipelines and 220 compressors was constructed in Alaska, and there is no information shows that any of these pipelines and compressor stations was built on permafrost ENSTAR and AGDC may have some cost data about pipelines built on permafrost The selection of a different location cost factors may significantly change the total capital costs of pipeline projects The selection of location cost factor in this study may or may not be suitable Future work, therefore, may need to concentrate on collecting more pipelines data on the permafrost and remote sites in Alaska

8.9 Conclusions

Analysis of Alaska natural gas supply and demand indicates that an Alaska in-state gas pipeline is critically needed The LNGP is necessary for the Alaska in-state gas pipeline project to accommodate the strong seasonal swings of Alaska natural gas demand Based on forecasted results from the simulation models, three flow rate scenarios all produce reasonable low cost natural gas for Fairbanks, Anchorage, and exports The comparisons of the three flow rate scenarios in terms of capital cost, tax, tariff, and AGIA issue are shown in Table 8 14 From the customers' perspective, the 1,000 mmcfd case provides the lowest cost natural gas to customers without considering AGIA and capital requirements In terms of AGIA issues and capital costs, the 500 mmcfd case is the most applicable and lowest capital cost project From the governments' perceptive, the 1,000 mmcfd project should be the best option with the highest tax revenues and lowest tariffs. Therefore, Selection of flow rates depends on specific conditions and perspectives, but the results of this study show that building of an Alaska in-state gas pipeline project for all three flow rates is reasonable with assuming 30-year operations.

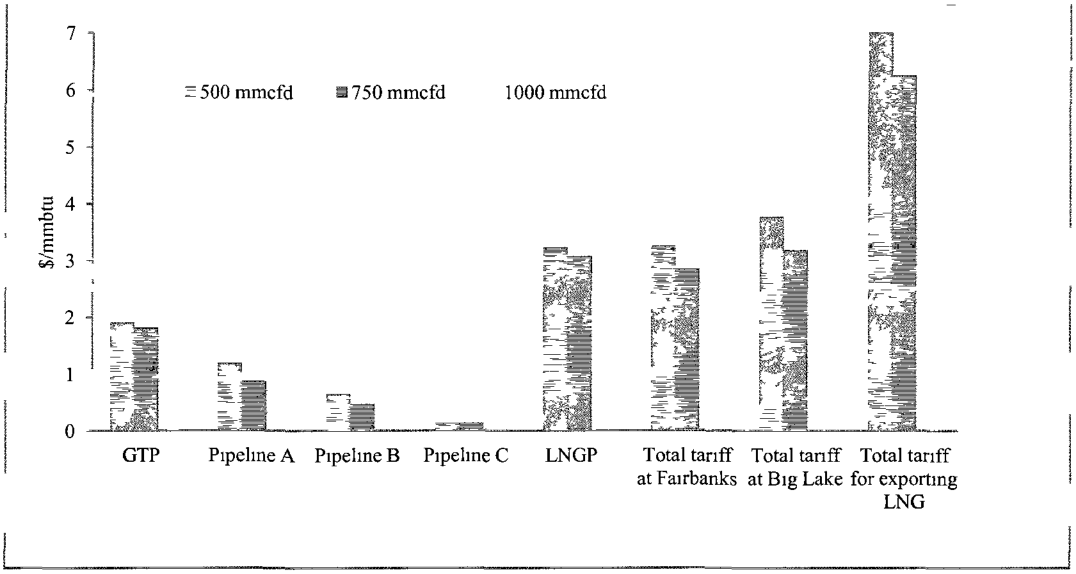


Figure 8.13 Estimated nominal tariffs of each segment by different flow rates (base case)

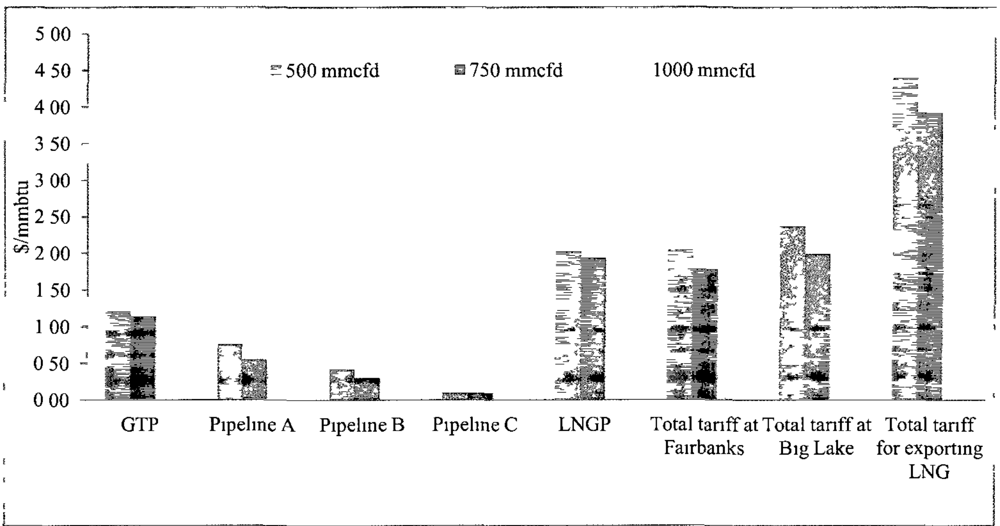


Figure 8.14 Estimated real tariffs of each segment by different flow rates (base case)

Table 8 14 Comparisons of three scenarios by criteria (base case)

Criteria	500 mmcfd	750 mmcfd	1000 mmcfd
Capital cost	Best	Medium	Worst
Tax	Worst	Medium	Best
Tariff	Worst	Medium	Best
AGIA	Applicable	Eliminated	Eliminated

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CHAPTER 9 SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

9.1 Summary

This study collected historical cost data of 412 pipelines and 220 compressor stations from *Oil & Gas Journal* to investigate pipeline and compressor station costs and build the foundation for an analysis of an Alaska in-state gas pipeline Monte Carlo simulation models of the Alaska in-state gas pipeline are developed by using *Crystal Ball* software All costs are adjusted to 2008 dollars using the CE index

Different analyses are conducted based on historical pipeline costs in terms of diameter, length, capacity, year, and location Multiple nonlinear regression models are developed to estimate pipeline costs for different pipeline cross-sectional area, lengths, and locations A comprehensive analysis of inaccuracies in pipeline construction component cost estimation is investigated in terms of diameter, length, capacity, year, and location

Different analyses are also conducted based on historical compressor station costs in terms of capacity, year, and location Multiple nonlinear regressions are built to estimate compressor station cost for different capacities and locations A comprehensive analysis of inaccuracies in compressor station construction component cost estimation is also investigated in terms of capacities and locations

With historical data regarding Alaska natural gas demand, the market for an in-state gas pipelines is analyzed and forecasted Based on forecasted unit costs of pipelines and compressor stations from regression models and the distribution of pipeline and compressor station cost overruns, the Monte Carlo simulation models of Alaska in-state gas pipeline for three different flow rate scenarios are developed Stimulated capital costs, tariffs, and taxes from Monte Carlo models are compared and analyzed

9.2 Conclusions

The major findings of this study are listed below

- Number of pipelines in the U S is unevenly distributed in terms of pipeline diameter, length, volume, and location
- Expectation of increased pipeline construction induces an increase in current unit costs
- Average share of pipeline material, labor, miscellaneous, and ROW costs is 31%, 40%, 23%, and 7%, respectively

- Shares of pipeline cost components vary by diameters, lengths, and regions
- Average learning rate for pipeline material costs and labor costs is 6 10% and 12 40%, respectively
- Learning rates for pipeline material costs and labor costs vary by diameter, length and region
- There is not sufficient evidence to indicate that gas and oil prices changes directly influence pipeline construction costs
- Developmental stages of pipeline technology, site characteristics, economies of scale, learning rates, and market conditions are factors influencing pipeline construction cost differences
- Multiple nonlinear regression models of pipeline cost components are developed and verified by statistical tests
- There are significant pipeline cost differences between different regions
- Economies of concentration play an important role in pipeline construction costs
- Unit costs of pipeline construction components fall with increasing pipeline cross-sectional area and length, except for ROW costs which only decreases with increasing cross-sectional area
- Overrun rates of pipeline material, labor, miscellaneous, and ROW costs are 0 049, 0 224, -0 009, 0 091, and 0 065, respectively
- Cost estimations of pipeline cost components are biased, except for the total cost estimations
- Cost errors of underestimated pipeline construction components are generally larger than those of overestimated pipeline construction components, except for total costs
- Project size significantly influences cost overruns for the total cost, but not for other individual cost components
- Pipeline diameter influences overruns of pipeline labor and miscellaneous costs
- Pipeline length does not influence any component cost overruns
- Pipeline capacity influences material cost overruns
- Pipeline location influences cost overruns for all cost components
- ROW cost estimates have improved over time, but other component cost estimations have not

- Guidelines for pipeline cost estimators are proposed
- Compressor stations are unevenly constructed across the U S
- Material costs have the highest average share of 50 6% of the total costs, followed by the labor cost of 27 2%, miscellaneous cost of 21 5%, and land cost of 0 8%
- Shares of compressor station component costs vary by regions, but not capacity
- Overall learning rates of material and labor costs for compressor stations are 12 1% and 7 5%, respectively
- Learning rates vary by different capacity and location
- There is insufficient evidence to indicate that changes in gas or oil prices cause the changes to pipeline compressor station construction unit costs
- Developmental stages of technology, geographic and environmental conditions, economies of scale, learning rates, and market situations influence compressor station costs
- Multiple nonlinear regression models of compressor station cost components are developed and validated by different statistical tests
- There are significant compressor station cost differences in different regions
- Economies of concentration play an important role in compressor station construction costs
- Unit costs of compressor station construction components fall with increasing horsepower due to economies of scale
- Overall average cost overrun rates of pipeline compressor station material, labor, miscellaneous, land, and total costs are 0 03, 0 60, 0 02, -0 14, and 0 11, respectively
- Cost estimates for compressor station construction components are biased except for material cost
- Cost estimation errors of underestimated compressor station construction components are generally larger than those of overestimated compressor station construction cost components
- Cost overruns of all cost components are not significantly different by project size or capacity
- Cost overrun rates of all cost components show significant differences between different regions

- Cost estimating of compressor station construction components has improved over time except for the labor cost
- Guidelines for compressor station cost estimators are proposed
- Alaska gas demand has strong seasonal characteristics
- Three flow rate scenarios for an Alaska in-state gas pipeline indicate all will provide low cost natural gas for Fairbanks, Anchorage, and LNG exporting The1,000 mmcfd flow rate scenario create the lowest cost, followed by 750 mmcfd and 500 mmcfd scenarios
- Building an Alaska in-state gas pipeline project for any of the three flow rates is reasonable with assumption a 30-years operational life, however, the selection of flow rates depends on specific conditions and perspectives

9.3 Recommendations

Although this paper uses data from 412 pipelines and 220 compressor stations completed between 1992 and 2008, there are limitations to the dataset and analyses First, the distribution of pipelines and compressor station costs are uneven For example, 40% of U S pipelines are in the Northeast region, while only 7 5% of U S pipelines are in the Southwest region The uneven data distribution may cause estimation or analysis bias Second, there is a lack of detailed information for some variables For example, the cost data do not provide starting year or the construction period, which causes biased when adjusting with CE index Third, some important variables should be included, such as pipeline wall thickness, steel grade, maximum allowable operating pressure, terrain along the route, and ownership, which produces significant cost differences and influences the fitness of the regression models

Future work should include collecting more data for pipelines and compressor stations regarding the above mentioned limitations, applying the results of analysis from pipeline and compressor station projects in future pipeline project cost estimations, developing a set of recommendations to aid managers and estimators to better estimate pipeline and compressor station costs and minimize errors, and collecting and analyzing more pipeline data about permafrost conditions and remote locations for an Alaska in-state gas pipeline

GLOSSARY

AGIA	Alaska Gasline Inducement Act
AGDC	Alaska Gasline Development Corporation
ANS	Alaska North Slope
bcf	billion cubic feet
BP	Breusch-Pagan test
CE Index	Chemical Engineering Plant Cost Index
DOE	Department of Energy
ENSTAR	ENSTAR Natural Gas Company
FERC	Federal Energy Regulatory Commission
GTL	gas to liquid
GTP	Gas treatment plant
Hp	horsepower
IEA	International Energy Administration
INDOT	Indiana Department of Transportation
INGAA	Interstate Natural Gas Association of America
KW	Kruskal-Wallis test
LNG	liquefied natural gas
LNGP	liquefied natural gas plant
JCC	Japanese Customs Cleared
MACRS	Modified Accelerated Capital Recovery System
MARR	minimum acceptable rate of return
mcf	thousand cubic feet
mmcf	million cubic feet
mmcfd	million cubic feet per day
mmbtu	million British thermal unit
NE	Northern Economics, Inc

ROW	right of way
WACC	Weight average cost of capital
WTI	West Texas Intermediate
SD	Standard deviation
SW	Shapiro-Wilk test
Tcf	Trillion cubic feet

Appendix A: Estimated capital costs

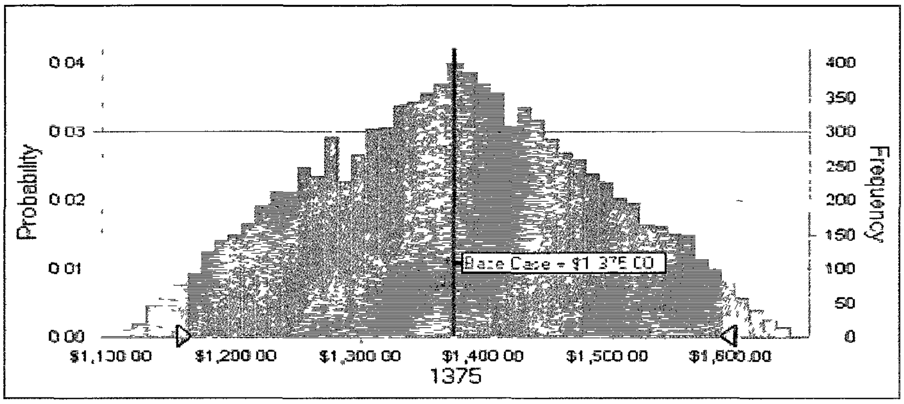

Figure A.1 Capital cost of GTP (500 mmcfd)

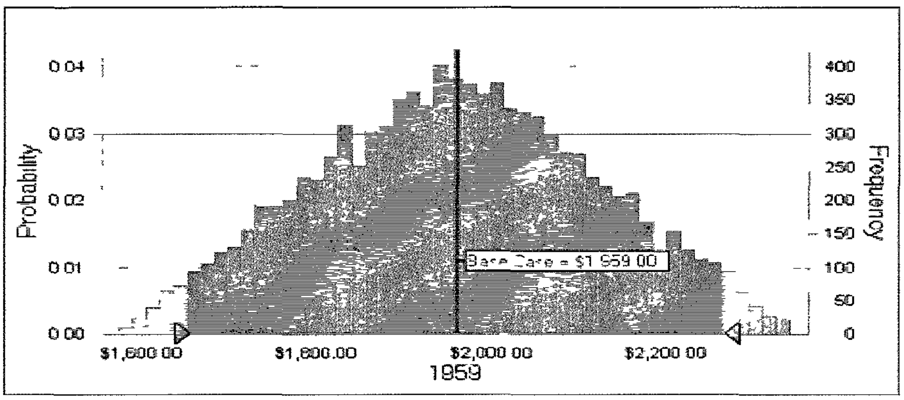

Figure A.2 Capital cost of GTP (750 mmcfd)

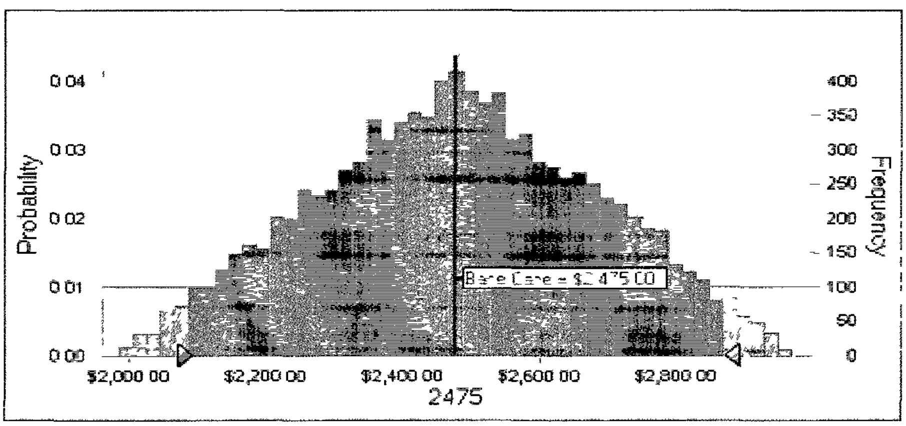

Figure A.3 Capital cost of GTP (1,000 mmcfd)

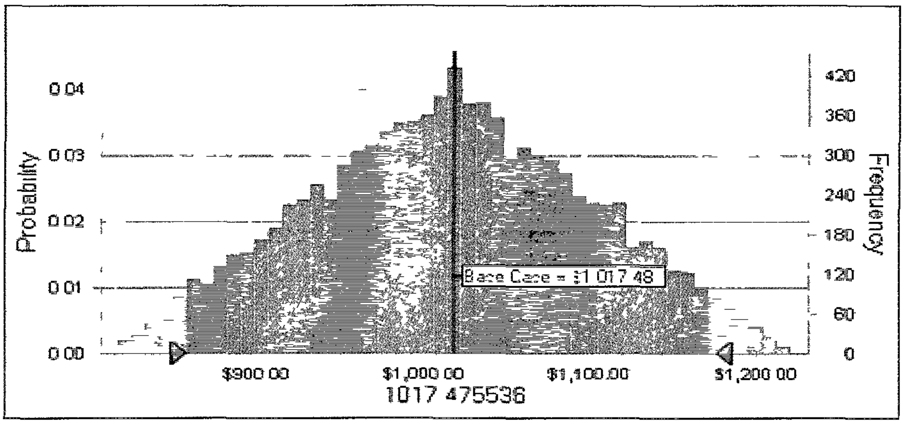

Figure A.4 Capital cost of Pipeline A (500 mmcfd)

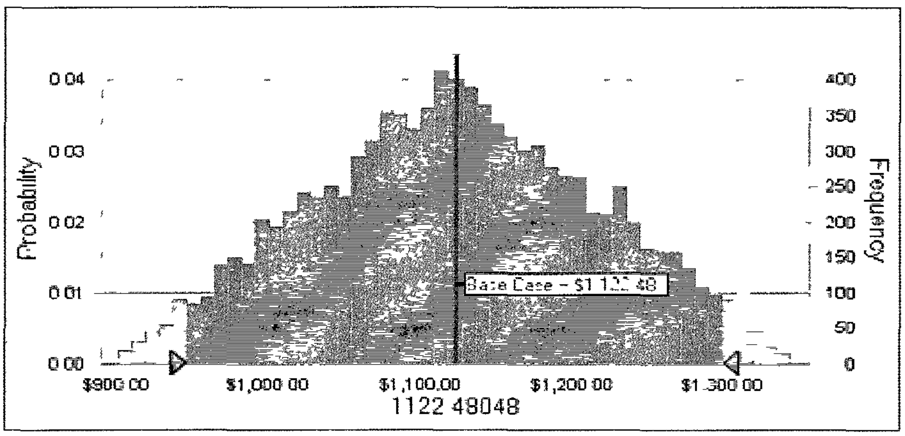

Figure A.5 Capital cost of Pipeline A (750 mmcfd)

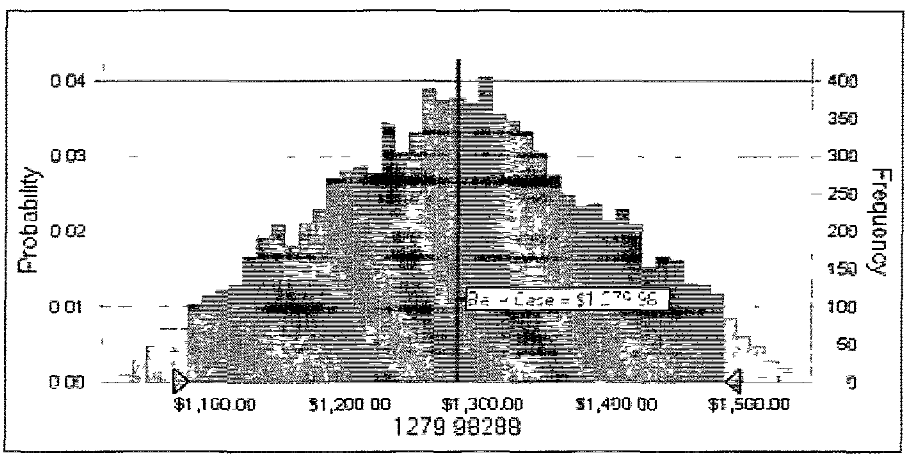

Figure A.6 Capital cost of Pipeline A (1,000 mmcfd)

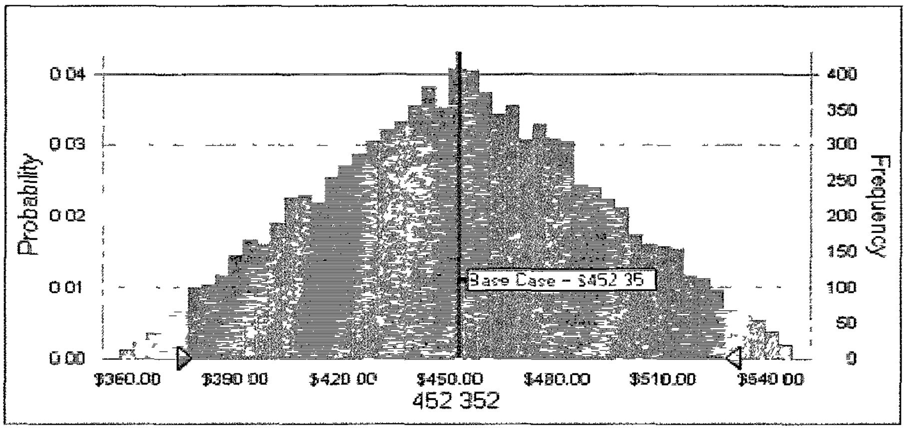

Figure A.7 Capital cost of Pipeline B (500 mmcfd)

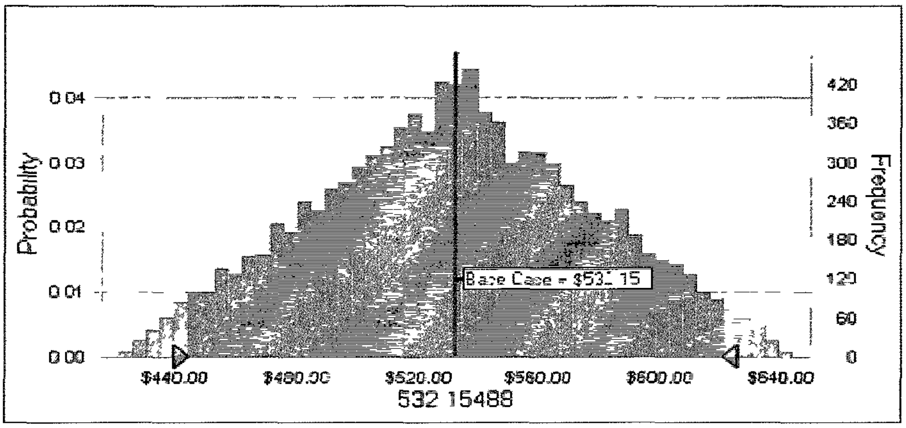

Figure A.8 Capital cost of Pipeline B (750 mmcfd)

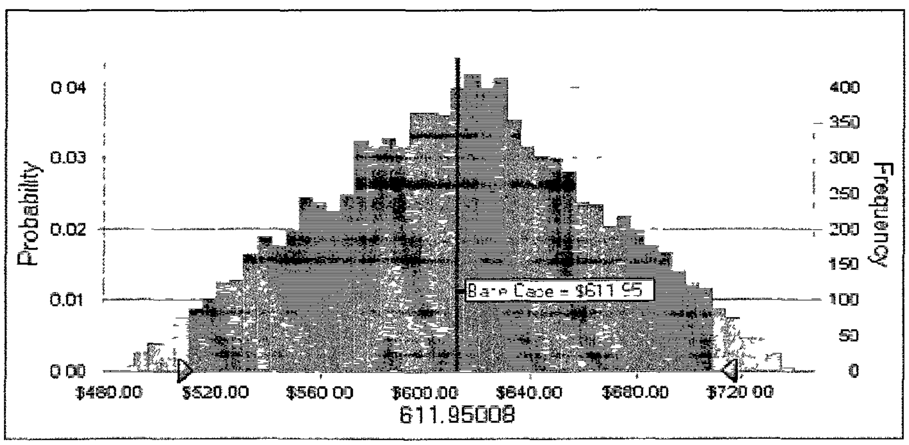

Figure A.9 Capital cost of Pipeline B (1,000 mmcfd)

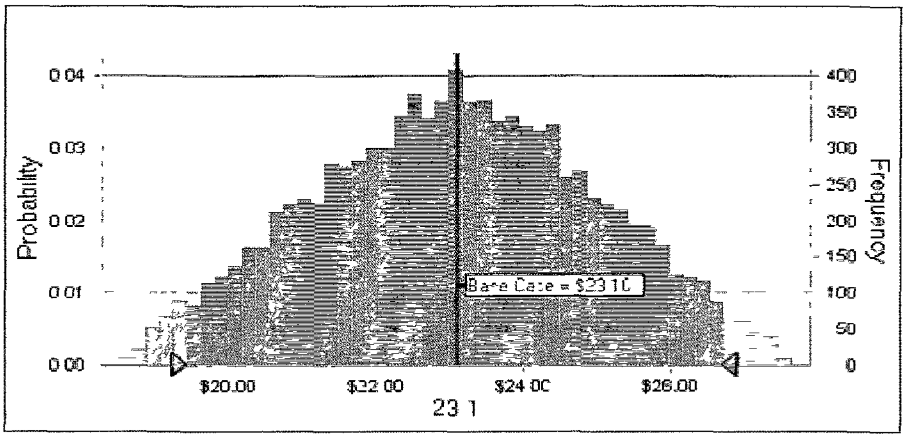

Figure A.10 Capital cost of Pipeline C (500 mmcfd)

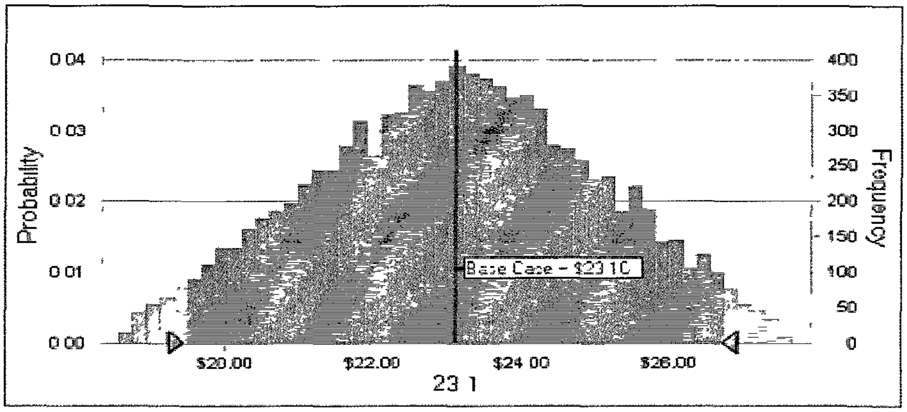

Figure A.11 Capital cost of Pipeline C (750 mmcfd)

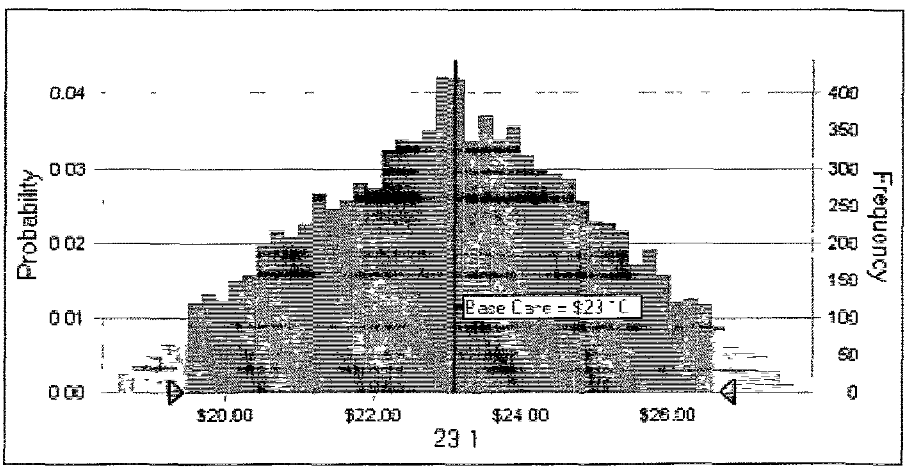

Figure A.12 Capital cost of Pipeline C (1,000 mmcfd)

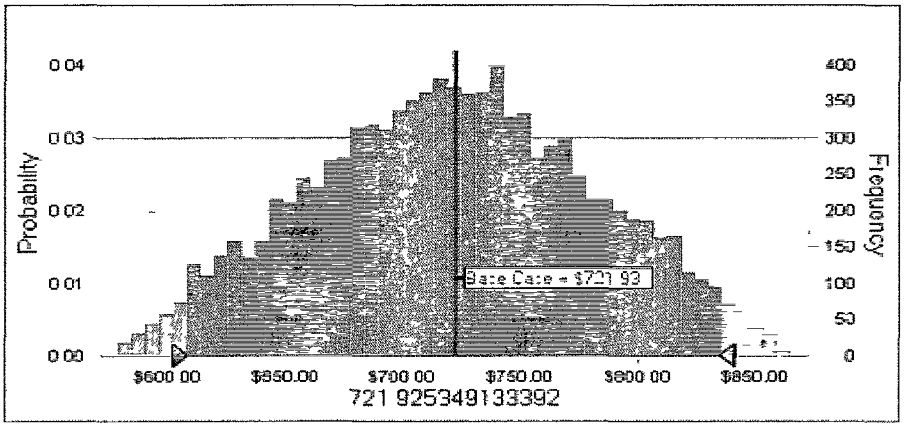

Figure A.13 Capital cost of LNGP (500 mmcfd)

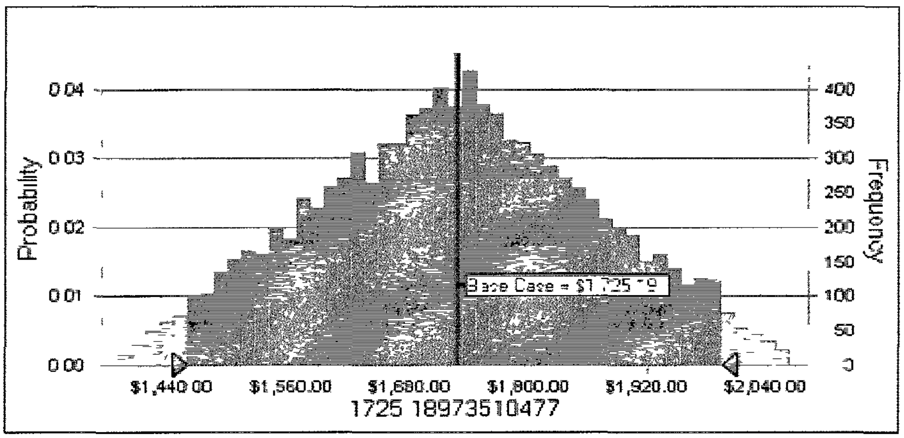

Figure A.14 Capital cost of LNGP (750 mmcfd)

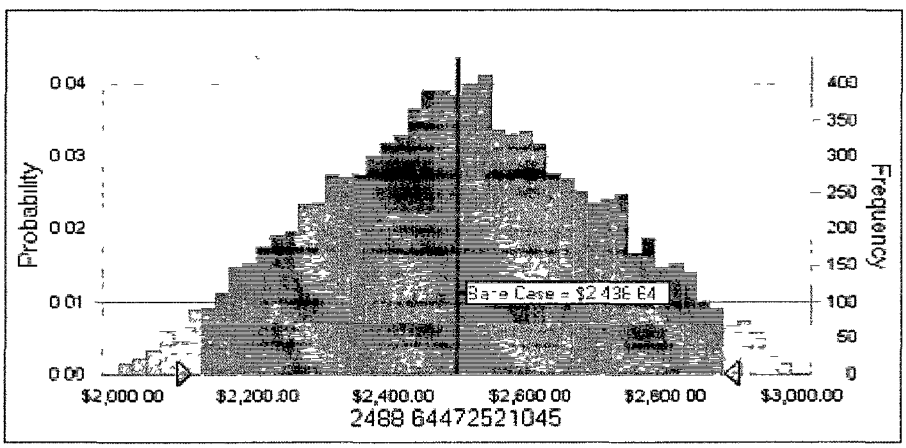

Figure A.15 Capital cost of LNGP (1,000 mmcfd)

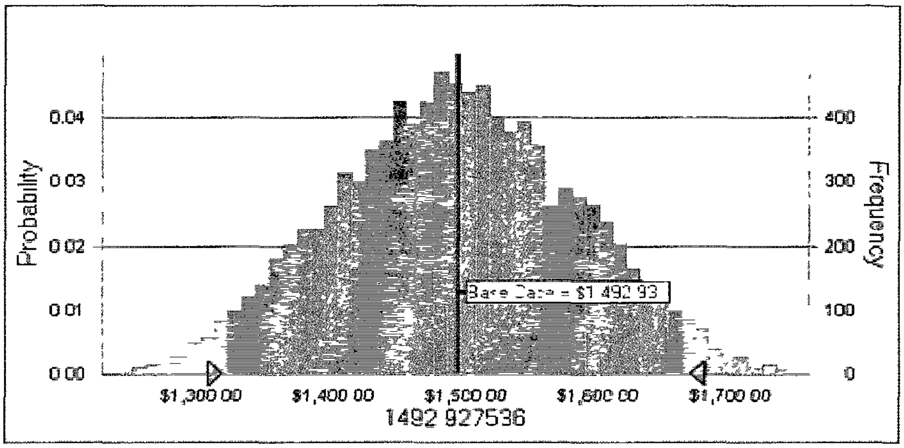

Figure A.16 Capital cost of total three pipeline sections (500 mmcfd)

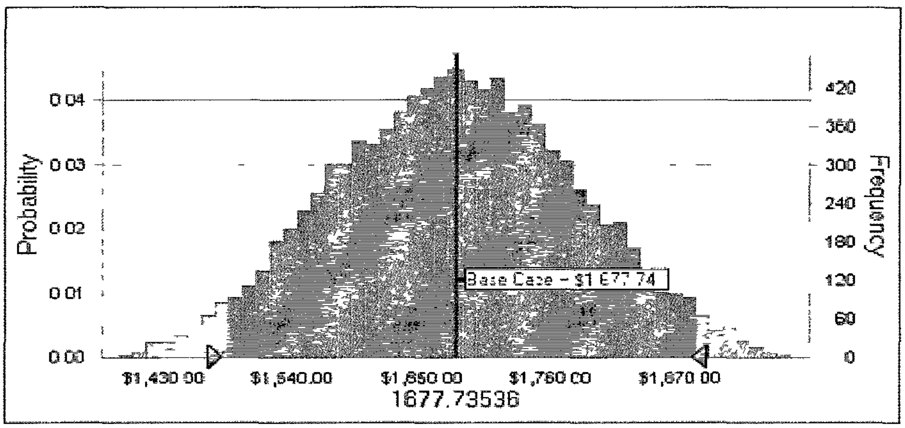

Figure A.17 Capital cost of total three pipeline sections (750 mmcfd)

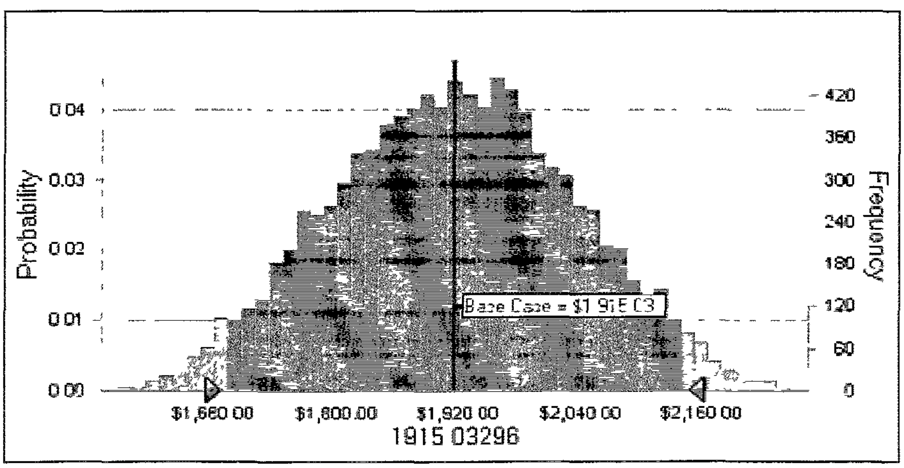

Figure A.18 Capital cost of total three pipeline sections (1,000 mmcfd)

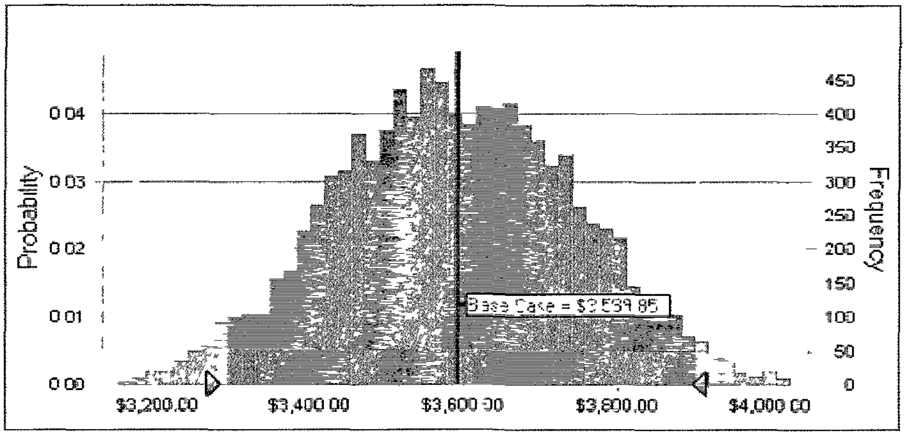

Figure A.19 Capital cost of whole project (500 mmcfd)

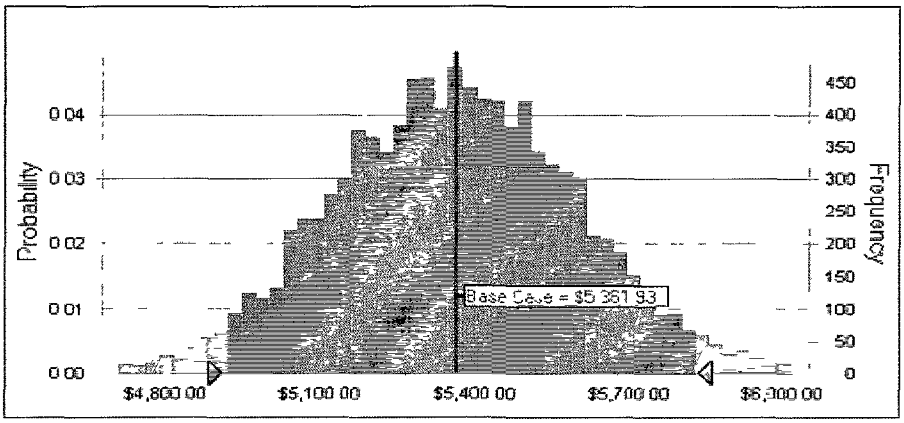

Figure A.20 Capital cost of whole project (750 mmcfd)

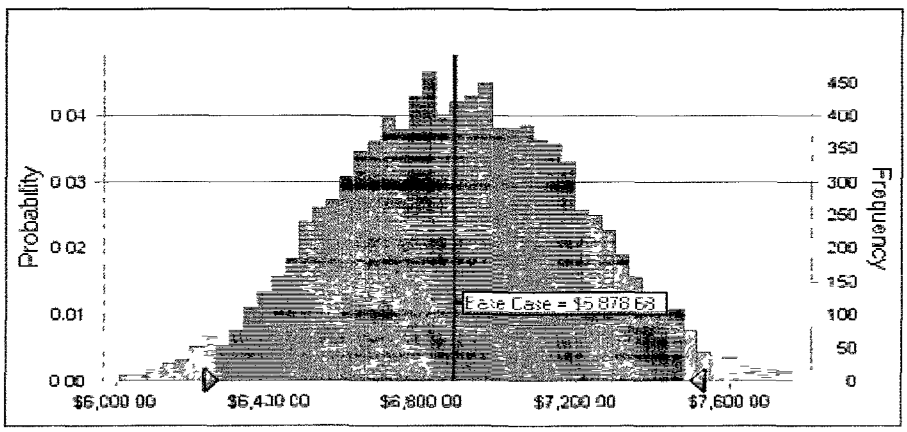

Figure A.21 Capital cost of whole project (1,000 mmcfd)

Appendix B: Estimated tax

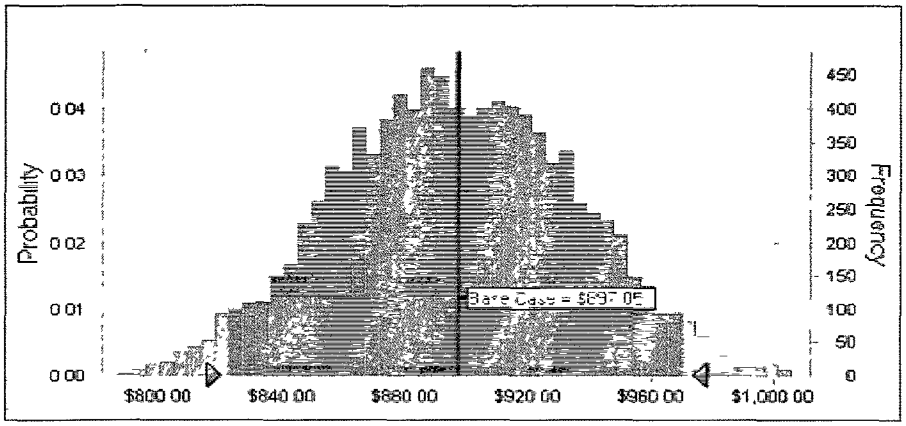

Figure B.1 Tax of Alaska Government (500mmcfd)

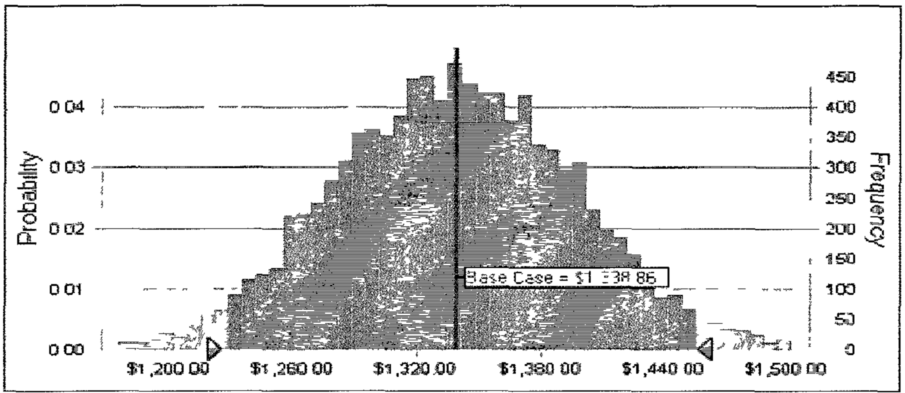

Figure B.2 Tax of Alaska Government (750mmcfd)

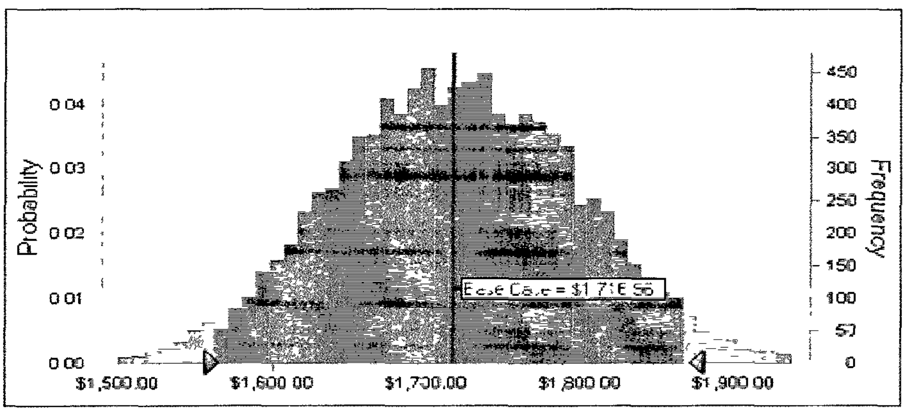

Figure B.3 Tax of Alaska Government (1,000mmcfd)

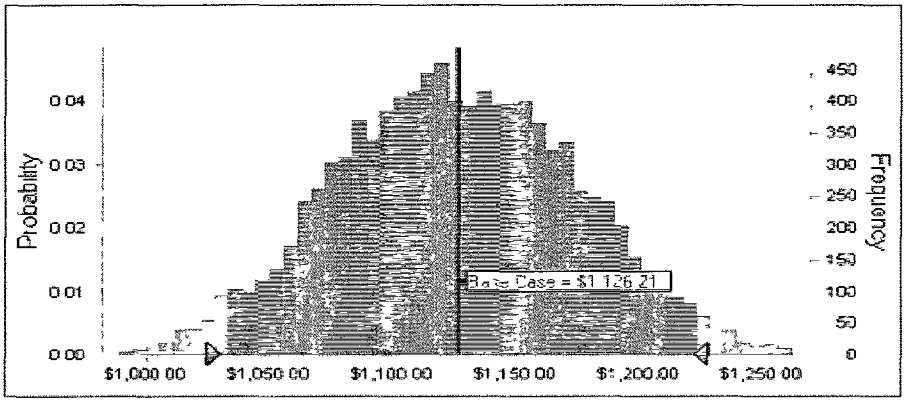

Figure B.4 Tax of U.S. Federal Government (500mmcfd)

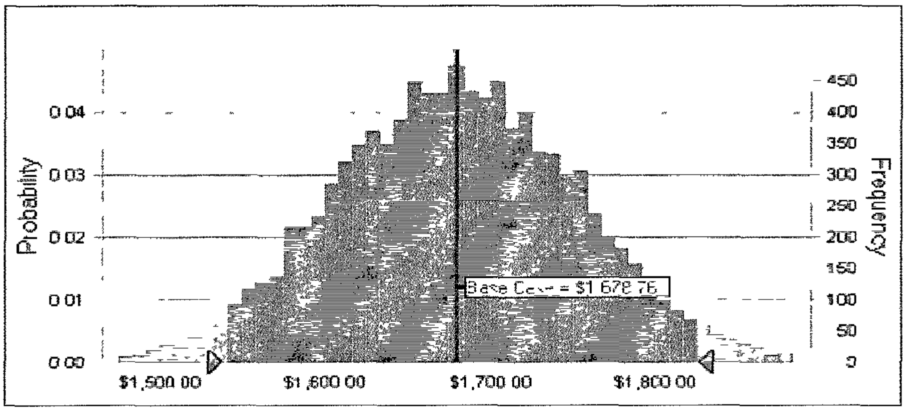

Figure B.5 Tax of U.S. Federal Government (750mmcfd)

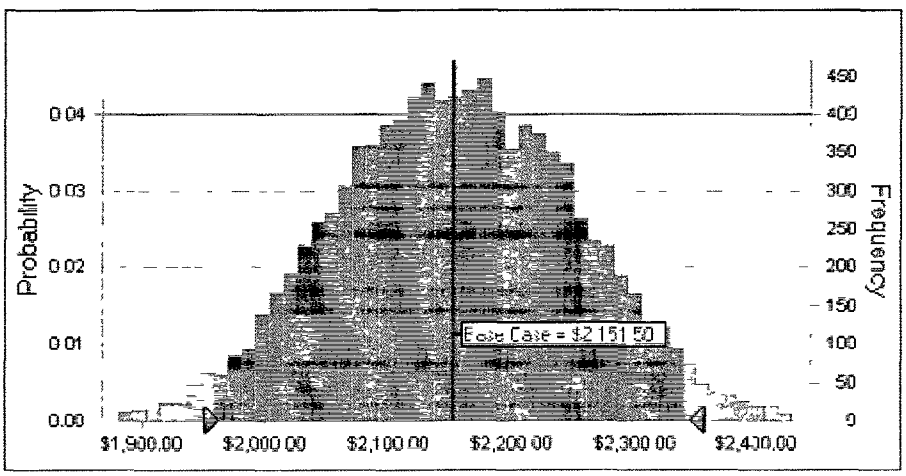

Figure B.6 Tax of U.S. Federal Government (1,000 mmcfd)

Appendix C: Tariff

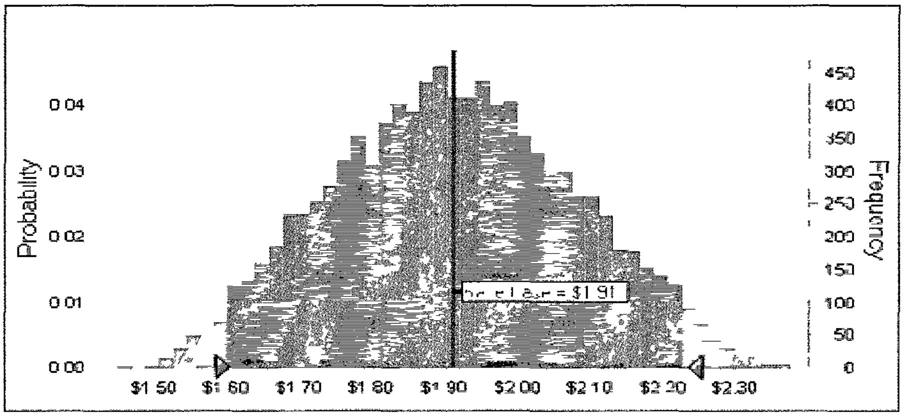

Figure C 1 Tariff of GTP (500 mmcfd)

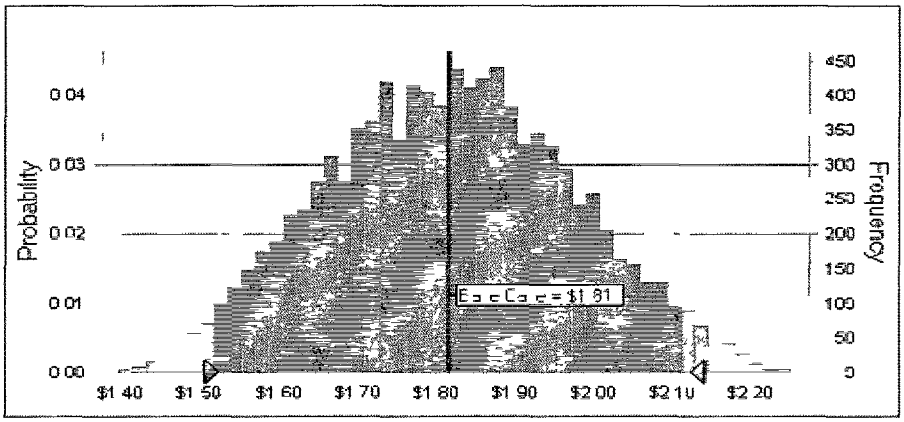

Figure C 2 Tariff of GTP (750 mmcfd)

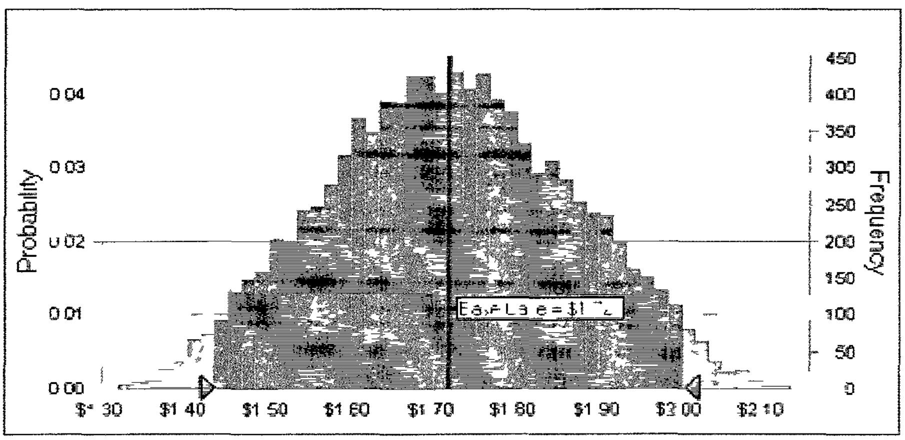

Figure C 3 Tariff of GTP (1,000 mmcfd)

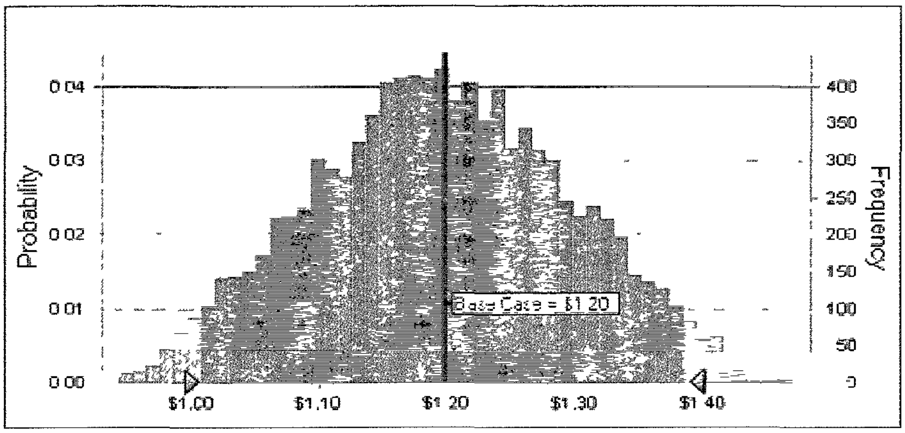

Figure C.4 Tariff of Pipeline A (500 mmcfd)

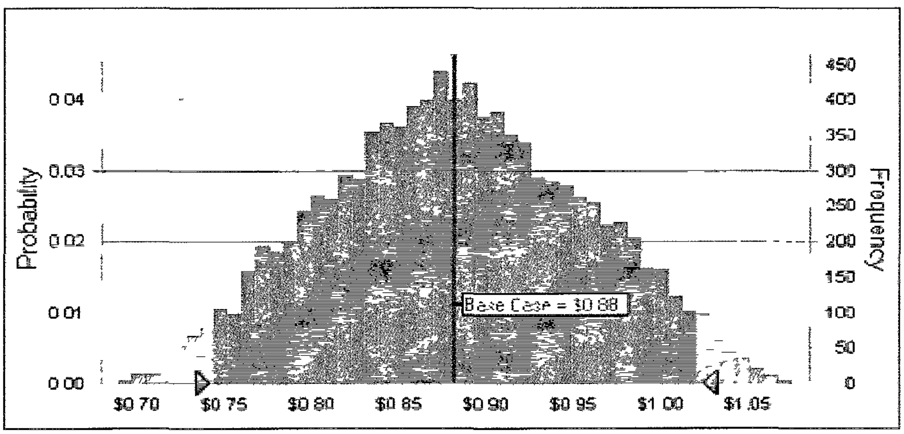

Figure C.5 Tariff of Pipelme A (750 mmcfd)

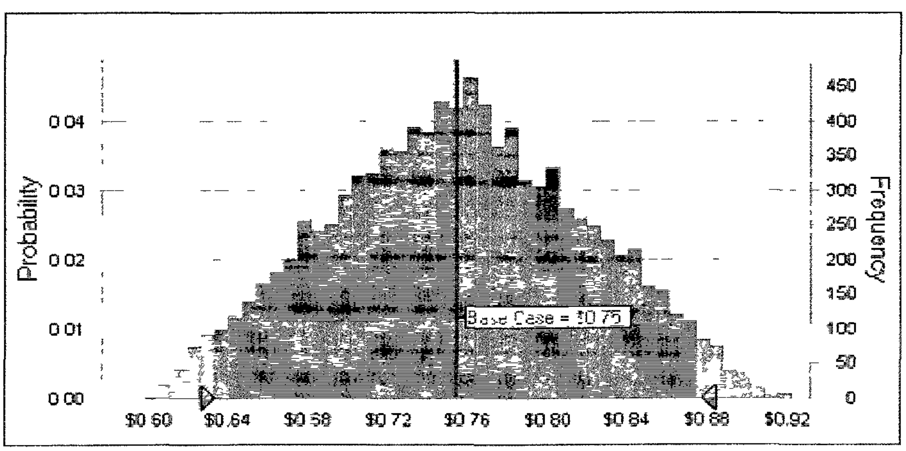

Figure C.6 Tariff of Pipeline A (1,000 mmcfd)

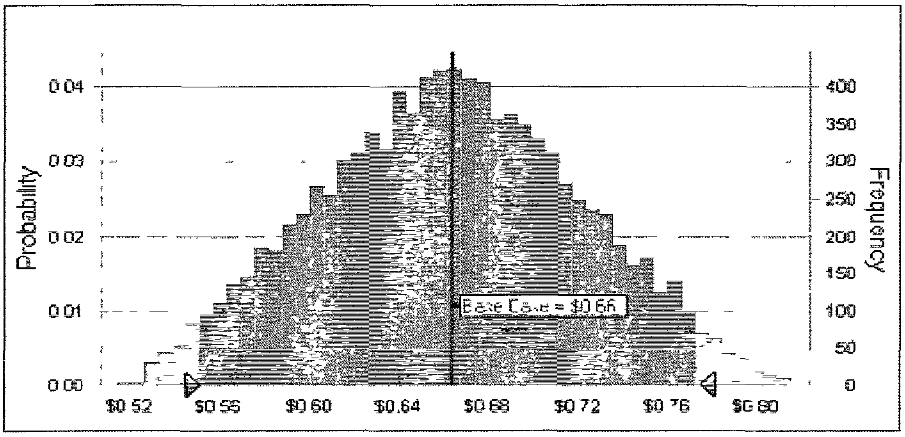

Figure C.7 Tariff of Pipelıne B (500 mmcfd)

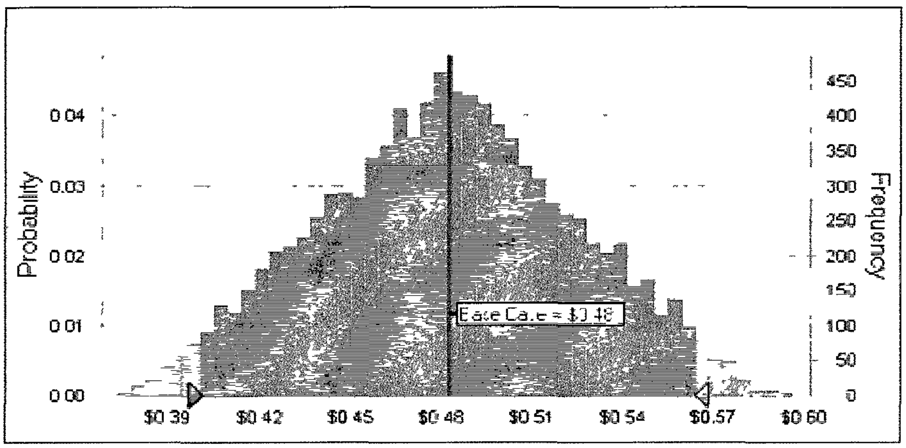

Figure C.8 Tariff of Pipeline B (750 mmcfd)

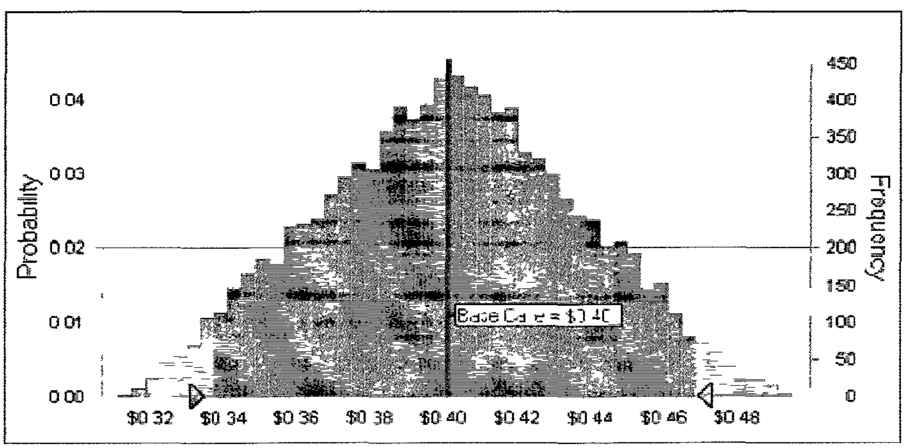

Fıgure C.9 Tariff of Pipeline B (1,000 mmcfd)

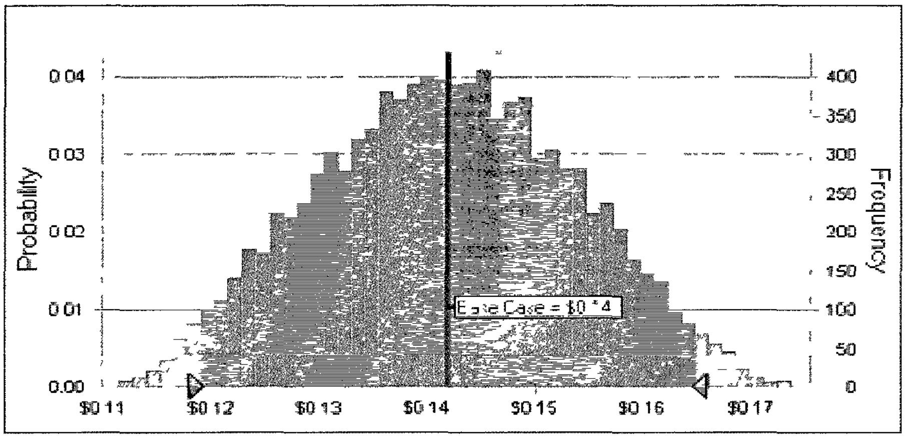

Figure C.10 Tariff of Pipeline C (500 mmcfd)

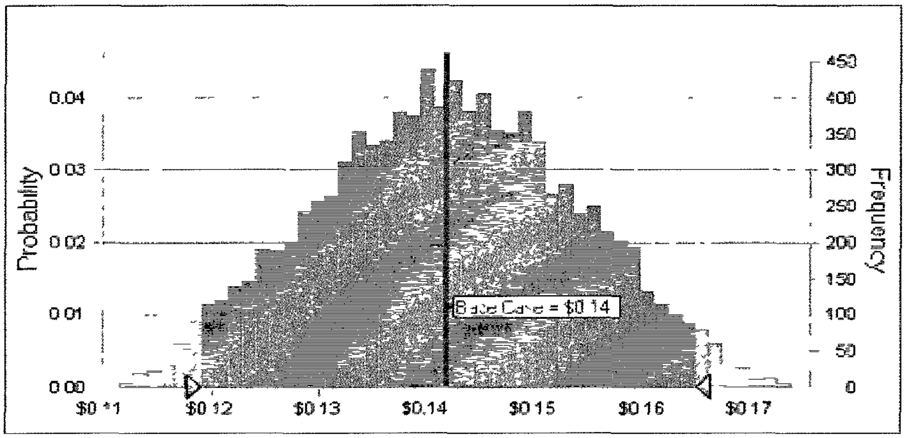

Figure C.11 Tariff of Pipeline C (750 mmcfd)

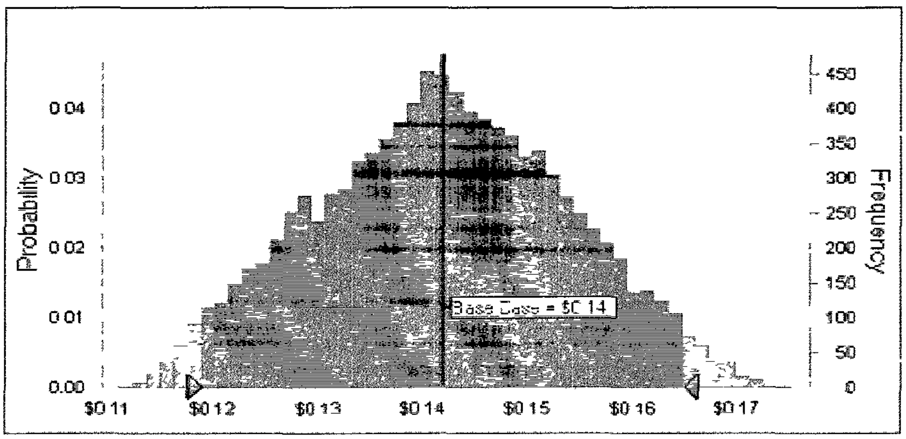

Figure C.12 Tariff of Pipeline C (1,000 mmcfd)

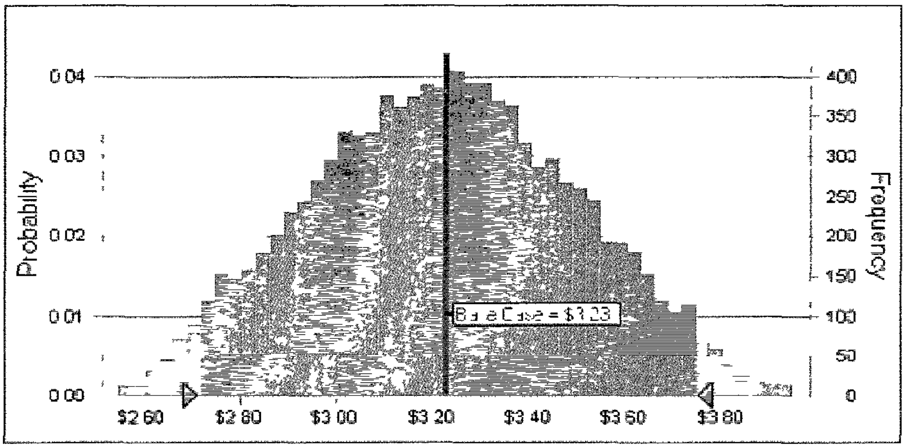

Figure C.13 Tariff of LNGP (500 mmcfd)

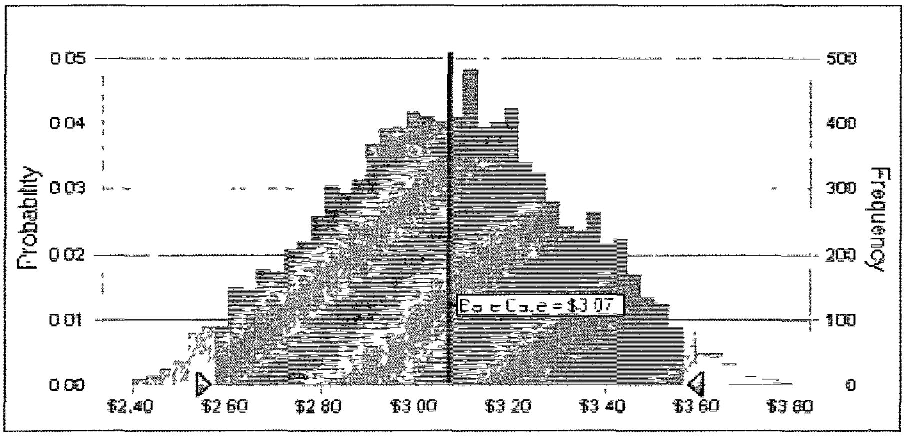

Figure C.14 Tariff of LNGP (750 mmcfd)

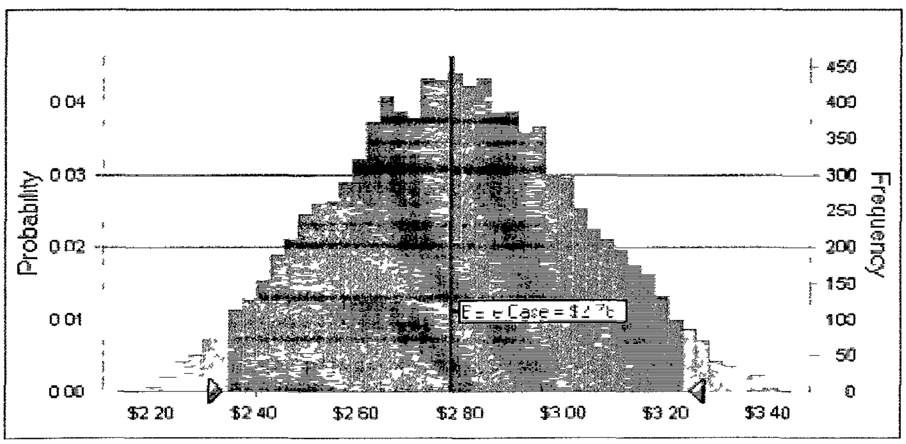

Figure C.15 Tariff of LNGP (1,000 mmcfd)

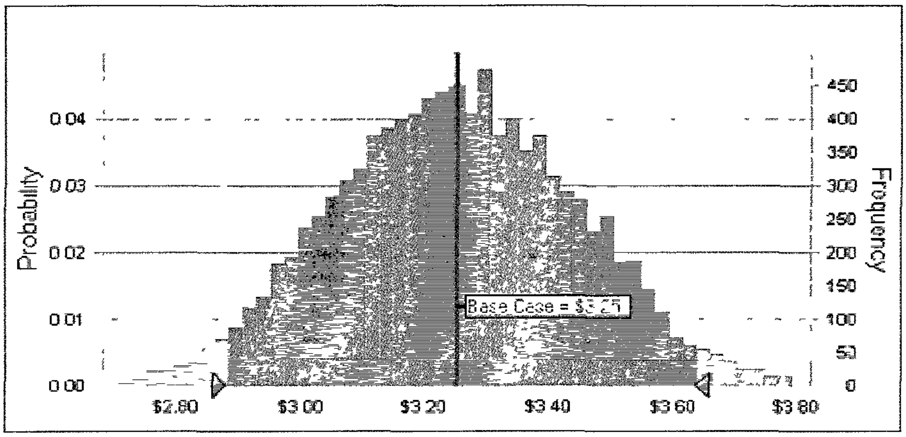

Figure C.16 Total tariff at Fairbanks (500 mmcfd)

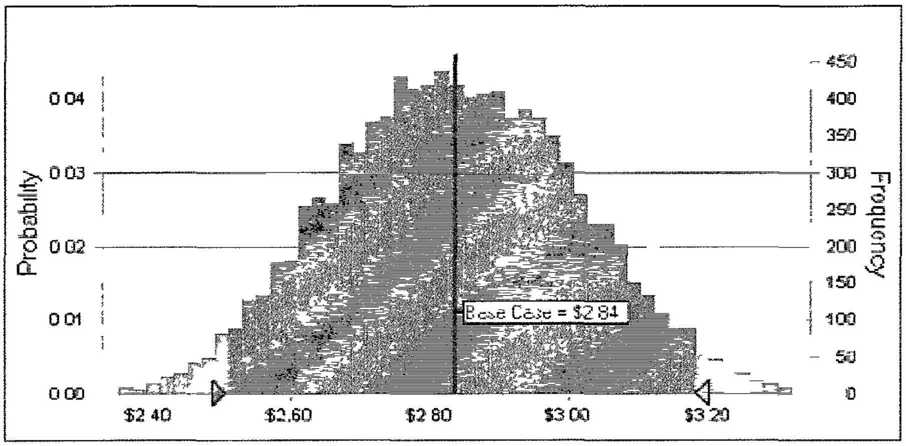

Figure C.17 Total tariff at Fairbanks (750 mmcfd)

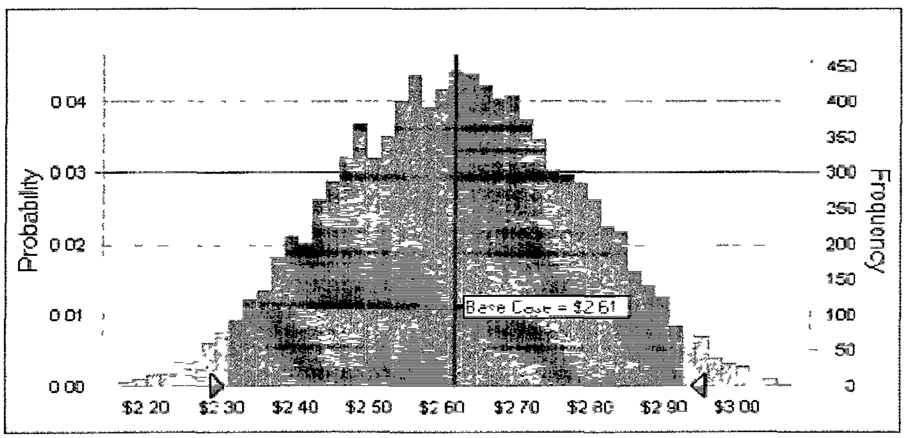

Figure C.18 Total tariff at Fairbanks (1,000 mmcfd)

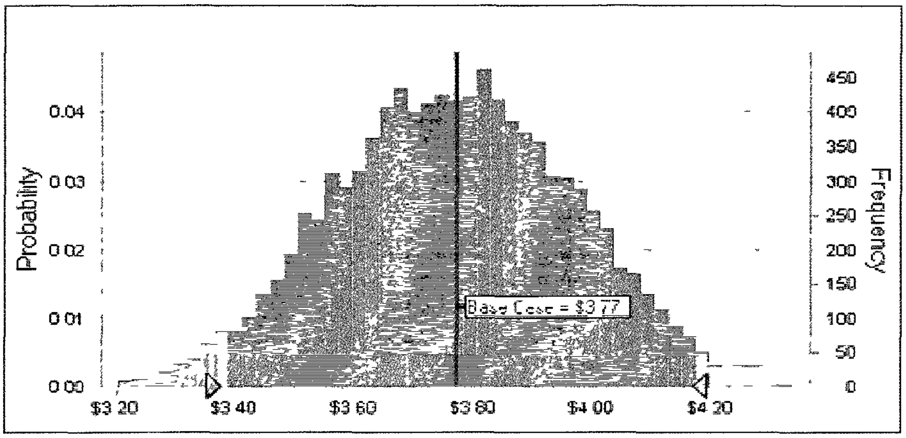

Figure C.19 Total Tariff at Big Lake (500 mmcfd)

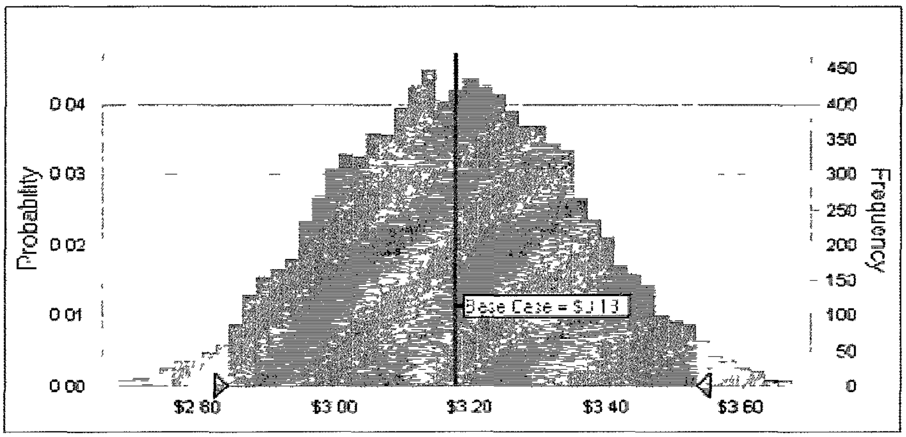

Figure C.20 Total Tariff at Big Lake (750 mmcfd)

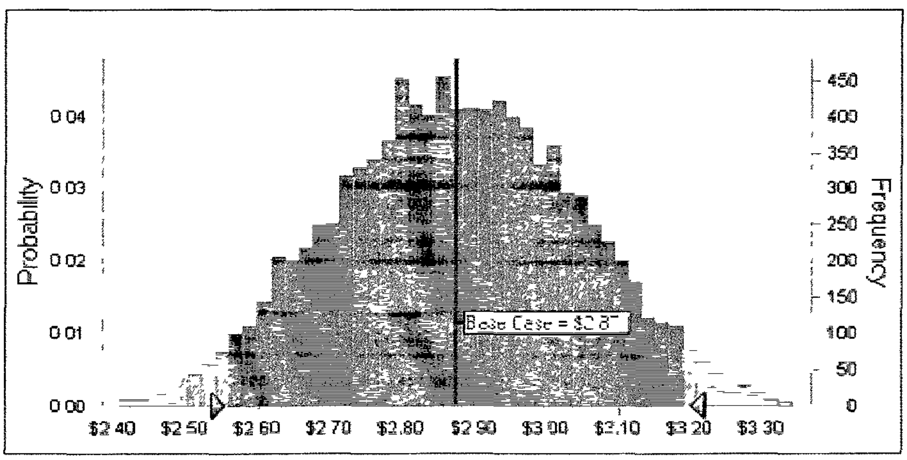

Figure C.21 Total Tariff at Big Lake (1,000 mmcfd)

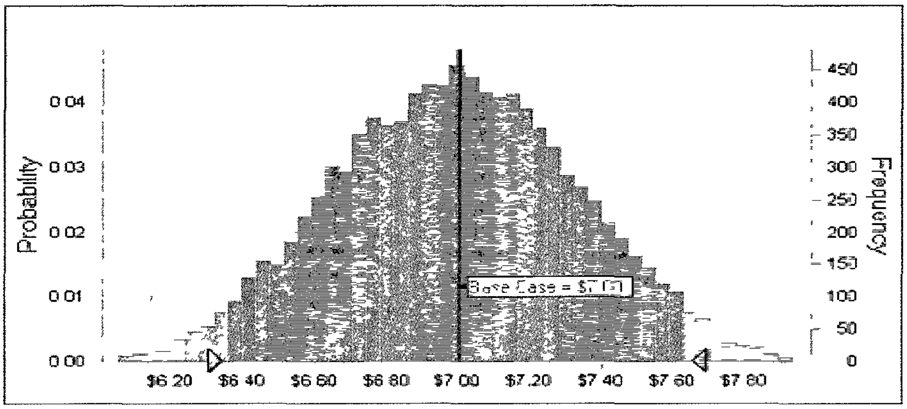

Figure C.22 Total Tariff for exporting LNG (500 mmcfd)

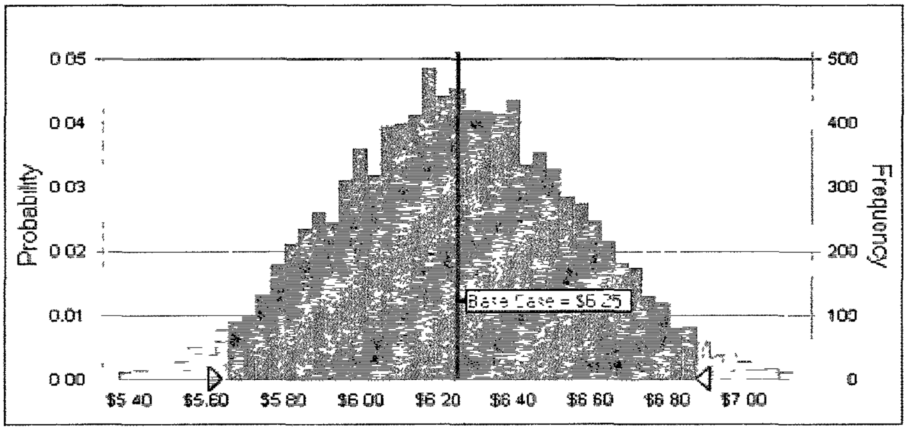

Figure C.23 Total Tariff for exporting LNG (750 mmcfd)

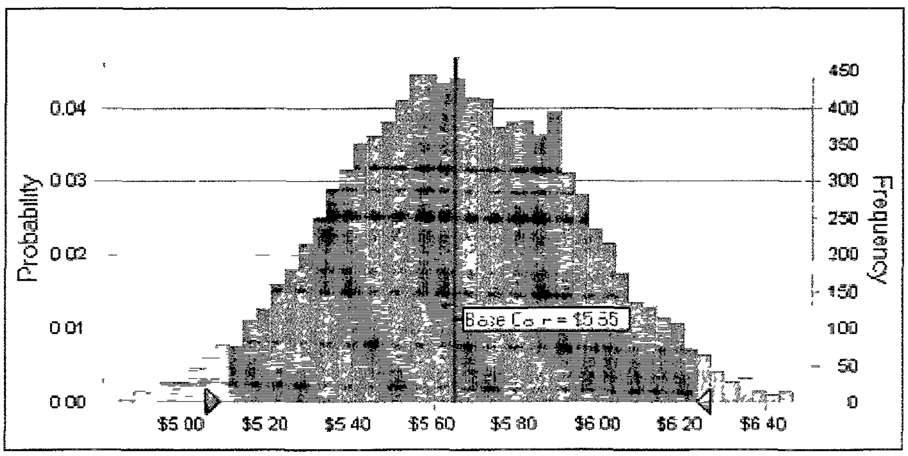

Figure C.24 Total Tariff for exporting LNG (1,000 mmcfd)