THE UNIVERSITY OF CALGARY

The Economics of Extracting Ethane in Alberta Versus the US

by

Charlotte Raggett

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ABSTRACT

Natural gas produced in Alberta contains a small amount of natural gas liquids (NGLs). These liquids can be partially or entirely separated from the gas, during gas processing. This thesis attempts to determine the optimal location for the extraction of one of these liquids, ethane. Using a comparative cost analysis, the competitiveness of extracting ethane is examined at four locations, (northwest Alberta, Edmonton, Alberta, inland Texas and Chicago), and for four scenarios (a rich stream extracting 85% of the ethane, a lean gas stream extracting 85% of the ethane, a rich gas stream extracting 50% of the ethane and a lean gas stream extracting 50% of the ethane). Of course the costs associated with extraction depend not only on where extraction occurs, but also on the type of extraction process chosen, the nature of the gas to be processed and the destination of the product. A comparison of the costs involves determining capital and operating costs for the extraction facility, as well as downstream gathering, CO_2 removal, storage and transportation costs. Several market destinations are considered including Edmonton, Alberta, Chicago, Illinois, and the US Gulf Coast.

The results of the analysis indicate that the optimal location for the production of ethane destined for the US Gulf Coast market is inland Texas. For the Edmonton, Alberta market, ethane extracted at that location is the most competitive. Finally, for the north-western Illinois market Edmonton was the most competitive supply source for ethane.

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LIST OF ABREVIATIONS, SYMBOLS, NOMENCLATURE, AND ACRONYMS

CERI	Canadian Energy Research Institute
Bcf/d	Billion cubic feet per day
MMcf/d	Million cubic feet per day
C_2	Ethane
C_3	Propane
nC_4	normal butane
iC_4	isobutane
C_5+	pentanes plus
C_2+	ethane plus
C_3+	propane plus
LPGs	liquefied petroleum gases
Mb/d	thousand barrels per day
CO_2	carbon dioxide
H_2S	hydrogen sulphide
WCSB	Western Canadian sedimentary basin
MAPCO	Mid-America Pipeline Company
NGLs	natural gas liquids
ANG	Alberta Natural Gas Company Ltd
AEUB	Alberta Energy and Utilities Board
NEB	National Energy Board

Chapter 1

INTRODUCTION

1.1 Objectives of the Study

Natural gas is produced in a raw form containing methane and other hydrocarbons called natural gas liquids, hydrogen sulphide, water and carbon dioxide. Before natural gas can be delivered to residential, commercial and industrial consumers it must be processed to remove the majority of these components accepting only methane and some portion of the ethane. While mainly occurring to ready natural gas for downstream consumers, processing also serves another purpose: to produce the natural gas liquids present in the raw natural gas. This processing can occur in the field where the gas is produced, or at the entrance to transmission or delivery pipelines. Obviously the location where the processing takes places affects the cost of processing and the value of the natural gas liquids. This analysis examines the economics of such gas processing from the perspective of its purpose to produce ethane and other natural gas liquids. The analysis focuses on a specific example, that of the Alliance gas pipeline, a gas pipeline intended to deliver gas from Western Canada to Chicago. The unique ability of this pipeline to move either processed or unprocessed gas allows flexibility as to the location of the gas processing plant. Since the construction of the processing plant represents a significant sunk cost this analysis determines the optimal location for the processing plant in the context of an investment in capital.

The study in economics of capital investment has been ongoing since before even Adam Smith published the Wealth of Nations, where he popularised the concept that capital, labour, and land are factors of production. Of course Smith introduced the idea of capital accumulation as merely a default of not consuming income (Spiegel, 1983).

Today economic literature surrounding capital investment is innumerable. Several approaches to explain the accumulation of capital and capital investment decisions dominate the literature; these being the net present value approach and the real options approach. These approaches attempt to explain the addition of capital by firms through modifications to classical investment theory, where capital is added up to the point where its marginal revenue product is equal to the cost of capital, the prevailing interest rate (Lipsey, Purvis and Steiner, 1988). The need for a model which explains the addition of heterogeneous units of capital, which are non-productive until a certain amount of capital accumulation takes place is met by such approaches.

However, this analysis attempts to determine not whether to add capital but where to add capital. For this reason the approach used here is a simplification of the net present value approach, the comparative cost method, which compares the cost of producing a good using capital invested in one location versus capital invested at other locations.

1.2 Outline of the Study

Chapter 2 begins with a brief characterisation of the various markets for ethane and the structure of those markets, including the existing production and delivery infrastructure. The focus of the chapter is on the historical development of the ethane industry both within Alberta and in the U.S. as a whole. Following this, Chapter 3 reviews relevant literature, details the comparative cost method and its limitations, gives a brief review of the applications of this method, and discusses the various assumptions of the analysis. Chapter 4 quantifies the components of production and capital costs compared between the locations identified. Also, for each of the potential markets (Edmonton, Chicago, and the US Gulf Coast), Chapter 4 provides a comparison of the delivered costs from each supply source to each market. Chapter 5 summarises the effects on cost elements of non-quantifiable factors such as government policy and discusses the expectations of future values for cost inputs. Chapter 6 summarises the findings of the previous chapters and discusses the potential direction of further research.

1.3 Introduction

In the summer of 1994, the Canadian Energy Research Institute (CERI) with funding from government and industry undertook a study, the focus of which was the NGL industry in Canada. This thesis is an in-depth examination of one of the key issues addressed in the study, the cost of producing ethane in Alberta versus the US Gulf Coast.[1]

Since the study was completed, a project has been proposed which again brings the issue of Alberta's ethane industry to the spotlight. Alliance Pipeline L.P. has proposed the construction of a 1.25 billion cubic feet per day (Bcf/d) wet gas pipeline between northwest Alberta and Chicago, allowing ethane to flow to Chicago in the natural gas stream. Alliance plans to construct a gas processing plant in Chicago to extract ethane and other natural gas liquids (NGLs) and market them either in Chicago or the US Gulf Coast (Alliance Pipeline, 1996). The Alberta petrochemical industry and the Alberta government, fearing that this may result in a reduction of ethane supply for ethylene production within the province, have shown interest in relocating the plant to Edmonton or even farther upstream in northwest Alberta, as opposed to Chicago (West,

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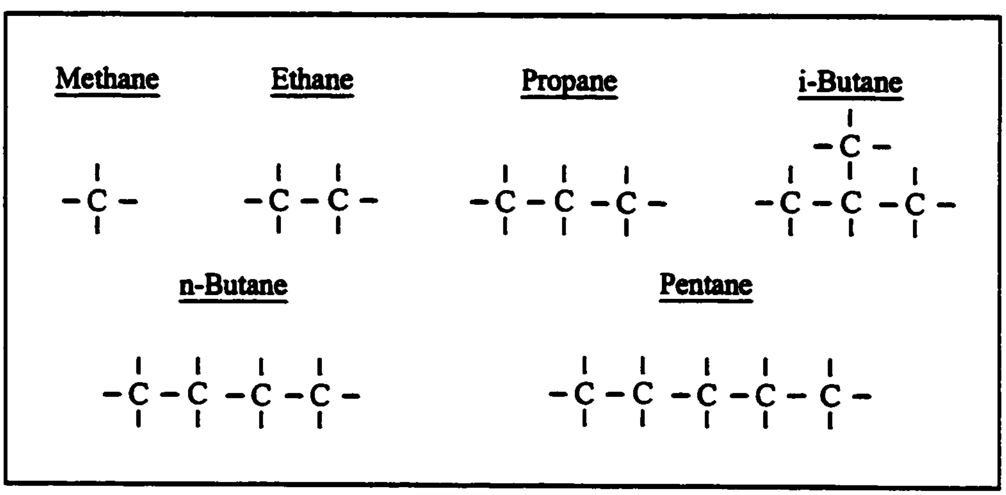
[1] As a member of the four person research team undertaking the analysis at the Institute, working for over a year, the data collection, industry contact, detailed analysis and written work done by this author for the CERI study, is the basis of this extended research. The study was published in August of 1995, and is the source of many facts and figures, prepared by this author for that study. Also, some information which was collected and analysis undertaken for the report, was never included in the final publication but has been used in this analysis.

1997). Therefore, this analysis examines the competitiveness of ethane extracted at these three locations versus ethane extracted in the largest supply region in the US, inland Texas.

The raw natural gas which emerges from producing wells consists mainly of methane (C_1), but also contains varying quantities of heavier hydrocarbons including ethane (C_2), propane (C_3), butane (C_4), and pentanes plus (C_5^+). Figure 1.1 shows the structure of the hydrocarbons; methane is called C_1 because it is a hydrocarbon containing one carbon atom surrounded by four hydrogen atoms. Butane itself can take one of two forms, either normal butane (n-C_4) or isobutane (i-C_4). These heavier products are collectively known as natural gas liquids (NGLs), with propane and butane often referred to as liquefied petroleum gases (LPGs). Natural gas which has a high NGL content is referred to as rich or wet gas, while dry or lean natural gas has a lower than average NGL content (Burdick and Leffler, 1983).

Figure 1.1
Structure of Hydrocarbons Present in Raw Natural Gas



Natural gas liquids mixtures are extracted from raw gas. For example, a C_2+ mix is comprised of C_2, C_3, C_4 and C_5^+, while a C_3^+ mix has all the NGL components except C_2. Further processing allows NGLs in a mix to be fractionated into "spec" (specification) products, in which an individual NGL component is isolated into a separate stream. With the exception of the use of NGLs in miscible floods which enhance oil recovery, all NGLs are used as specification products by final consumers. However, ethane and sometimes propane are left in the natural gas stream, where they capture heating or "shrinkage" value.

Canada is a major producer of NGLs, producing an estimated 207 thousand barrels per day (Mb/d) of ethane, 182 Mb/d of propane, 123 Mb/d of butanes, and 151 Mb/d of condensate or pentanes plus$^+$ in 1994 (Heath et al., 1995). The total NGL production of 663 Mb/d was roughly one third the volume of crude oil produced that year, and approximately 29 percent of comparable U.S. NGL production, making Canada the second largest producer of NGLs in the world (Heath, et al., 1995).

Some extraction of NGLs from natural gas is necessary in order to meet the quality specifications required for conventional gas pipeline transportation, although high-pressure pipelines such as Alliance have the ability to transport raw gas. However, the removal of various contaminants through dehydration (the removal of water vapour) and removal of gases such as carbon dioxide (CO_2) and hydrogen sulphide (H_2S) is required by all gas transmission and delivery pipelines (Leffler, 1987). In addition, gas delivered to the final residential, commercial or industrial consumer must meet strict quality specifications. The precise amount of processing necessary depends on the properties of the raw gas produced from reservoir; beyond that, it is up to the discretion of the producer as to whether the greater effort required to pull more NGLs, particularly ethane, out of the raw gas is economically justified by market demand for natural gas liquids. In fact, since ethane is so close in nature to methane, little ethane needs to be extracted to meet consumer quality specifications. Therefore, the decision to extract ethane is based mainly on whether the margin that is made by extracting it is greater than the next best alternative, leaving the ethane in the natural gas and receiving 'shrinkage' value.

There are approximately 630 natural gas processing plants in Western Canada, which can be categorised into field plants and straddle plants. Field plants, located near gas reservoirs, process raw natural gas to meet pipeline specifications for injection into the NOVA and Foothills systems. They are generally of a smaller scale than straddle plants, and depending on the nature of gas produced, cannot process up to consumer quality specifications. The liquids produced at field plants are trucked or pipelined in a mixed form to fractionation plants, where the mixes are separated into the individual NGL components. Some plants can fractionate, or separate, products and some produce only pentanes plus.

There are currently six straddle plants in Alberta, straddling major natural gas transmission pipelines downstream of the field plants. While much of the butane and condensate has been removed from the natural gas by the time it passes through a straddle plant, the sheer volume of gas processed by these plants allows them to be large producers of the remaining propane as well as ethane. The four straddle plants located at Empress and the one at Cochrane are the largest facilities of their kind in the world, processing between them the majority of the natural gas produced in Canada. They extract essentially all the residual C_3^+, and a large fraction of the ethane, from the gas prior to its leaving Alberta for natural gas markets within Canada and the U.S. A smaller plant is located near Edmonton.

NGLs which are recovered at field or straddle plants use an extensive infrastructure to transport, store, further process, and market the separate NGL components. Most plants have access to NGL pipelines either directly or by trucking. Most of these pipelines move either ethane plus or propane plus mixes but some move specification products.

One such pipeline, the Alberta Ethane Gathering System (AEGS) connects to the straddle plants at Empress and Cochrane, as well as a number of field plants including those at Jumping Pound, Bonnie Glen, and Waterton, transporting ethane from the producing plants to NOVA Chemical's petrochemical plants at Joffre, the new Dow cracker at Edmonton, as well as storage caverns in the Edmonton area.

The main NGL mix pipelines are the Amoco Cochrane to Edmonton (Co-Ed) pipeline, the Peace pipeline, and the Federated pipeline system. Smaller lines which carry NGLs include the Mitswan, Judy Creek, Dunvegan, and Rimbey pipelines. In addition, the Rangeland pipeline, which is primarily devoted to crude oil, transports batches of NGLs. These NGL pipelines form a web gathering propane plus, and ethane plus from all over Western Canada to the Fort Saskatchewan area, near Edmonton.

Once the NGL mix is delivered to the Fort Saskatchewan area, it can access underground storage caverns, surface storage, fractionators, and injection facilities for shipment on the Cochin and IPL NGL export pipelines. The fractionation units, operated by Chevron, Amoco, and Dow, have associated NGL storage. While the Chevron and Amoco facilities only separate propane plus, while the Dow facility handles ethane plus, the ethane from which is consumed by the Dow ethylene plant.

From the Fort Saskatchewan area, Cochin and IPL ship NGLs to Eastern Canada and the US mid-west. Ethane can only be shipped on Cochin; from the interconnection with Mapco East, ethane (blended with propane to form an 80:20 ethane/propane mix) can be shipped southward to the U.S. Midwest, and ultimately the Gulf Coast.

Ultimately, all of the ethane removed from the natural gas stream in Alberta is either consumed by petrochemical plants within the Province, used as a solvent in miscible flooding, or shipped to markets in Sarnia or the US (Conway or Mont Belvieu) for sale to petrochemical customers (Heath, et al., 1995).

1.4 Parameters of the Analysis

There are a number of variables which are examined in the analysis, which affect the results of the analysis, including the type of natural gas to be processed, the intended efficiency of the facility used for extraction, and the method used to transport the product both before and after extraction.

The type of natural gas processed is assumed to be either 'rich' gas or 'lean' gas. Typically, gas produced in the regions examined here contains anywhere from 5 to 20 (molecular) percent of ethane (Alberta Energy and Utilities Board, 1993). Based on the composition of gas processed at the straddle plants at Empress and Cochrane, a 'rich' gas stream is assumed to contain approximately 6.5 percent ethane, while the 'lean' gas stream contains around 4.7 percent ethane. The C_3^+ content of the gas is slightly lower for the lean gas than the rich gas processed.

The facilities examined are a 'deep cut' plant extracting 85% of the ethane contained in the gas stream and a 'lean-cut' plant extracting 50% of the ethane in the gas stream. Both types of plant are assumed to process 1.25 Bcf/d of natural gas using turbo-expander extraction technology. The turbo expander uses the cooling effect of lowering the pressure of the gas to condense the heavier hydrocarbons such as NGLs, thus separating them from the methane and ethane. In a similar second phase the ethane is separated from the methane. This technology is flexible, enabling plants to operate effectively even when gas throughputs and NGL recovery levels differ and is therefore, desirable for plants which extract ethane intermittently or which have seasonal variations in throughput.

The straddle plants are assumed to be located around the US and Canada. In the case of the straddle plant located in northwest Alberta, the plant is assumed to be situated along either the Federated or Peace C_2^+ gathering systems. The Edmonton plant is assumed to be located in close proximity to the Dow de-ethanizer. The plants in Alberta and at Chicago are assumed to straddle a proposed Canadian pipeline, Alliance, delivering rich gas to the Chicago market. The plant in inland Texas is assumed to be located along the Koch Chapparel and Seminole pipelines, connecting the western part of the state to the US Gulf Coast.

Chapter 2

HISTORICAL OVERVIEW OF THE ETHANE INDUSTRY

2.0 Introduction

There are three main issues which are particularly relevant to the development of the industry. These are: the requirement by the Government of Alberta to extract valuable natural gas liquids before gas export; the development of an Alberta petrochemical industry with the active participation of the Alberta government; and the emergence of an important miscible flood market for ethane, and its anticipated decline.

2.1 History [1]

2.1.1 The Rise of Gas Processing

The development of the gas processing industry in Alberta occurred later than similar development in the US, mainly because of the lag in the deployment of the area's natural gas basin. By exploring for crude oil in the Western Canadian Sedimentary Basin (WCSB), substantial reserves of natural gas were discovered, estimated to be almost 31 trillion cubic feet by 1960. However, development of these reserves was hampered by the difficulty of obtaining regulatory approval to export natural gas to lucrative markets outside of Alberta. As regulators eased up on export permits, several major pipelines were constructed moving natural gas from the basin to California, Ontario and the US Midwest. To move gas on these new pipelines and avoid condensation, increasing extraction of liquids became necessary, quickly outpacing available gas processing capacity. From 1960 to 1980 the total number of gas processing plants increased rapidly from 50 to almost 300, with marketed gas volumes rising by over 600 percent. Most of

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1 The following sections are based largely on research done by this author for the CERI Study (Heath, et al., 1995).

these plants removed pentanes plus and sulfur, but very few extracted propane and butane (Cannon, 1993).

In the ensuing years, the Alberta Energy and Utilities Board (AEUB) regulated increasing recovery of propane and butane for conservation purposes. Plants were converted to propane plus extraction, mostly using lean oil absorption units. The producers of large volumes of natural gas found themselves producing many barrels of LPGs as by-products which had limited local market opportunities. However, standing alone no one producer had sufficient volumes to invest in gathering, fractionation, storage and export facilities. One firm, Dome Petroleum, saw the advantages of aggregating volumes to justify the significant investment in marketing facilities necessary to make NGLs profitable. They began by constructing a C_3^+ pipeline from the Alberta Natural Gas straddle plant at Cochrane to Edmonton. To separate out spec products from this and other deliveries to Edmonton, fractionation facilities were built at Fort Saskatchewan. In addition, taking advantage of the Interprovincial Pipe Line from Edmonton to Sarnia, Dome built C_3^+ injection facilities and NGL product was moved to Sarnia to be fractionated at the Amoco facility and sold into the larger Eastern US and Ontario markets. However, it was the growth of the petrochemical sector in Alberta that spawned the further extraction of ethane at gas processing and straddle plants (Cannon, 1993).

2.1.2 Early Development: Ethane Extraction Investment

Several factors greatly enlarged the market potential of ethane. First, petrochemical development in both Alberta and Ontario provided a new market for NGLs. Second, a perceived shortage of US natural gas led to the development of synthetic natural gas production fed mainly by NGLs. A coordinated effort between the Alberta government, the petrochemical sector and NGL producers was instrumental in developing the ethane-ethylene industry in Alberta. On September 17th, 1975 Dow

Chemical of Canada Ltd., Dome Petroleum Ltd., the Alberta Gas Ethylene Company Ltd., and the Alberta Gas Trunk Line Company Ltd. sent a letter to the Minister of Business Development and Tourism requesting certain commitments from the Alberta government surrounding the pending development of Alberta's petrochemical sector. They stated that their intention was to build a petrochemical complex at Joffre and the related ethane supply infrastructure. The plants required would include ethane extraction units at both of the existing Empress straddle plants, the Cochrane plant and the straddle plant south of Edmonton. The proposed ethylene plant at Joffre would have a nameplate capacity of 1.2 billion pounds per year and another plant of the same size was intended to be constructed as soon as was needed after the first. The ethylene plant contracted to buy ethane and sell ethylene on a cost of service basis from the straddle plant system and to petrochemical upgraders such as Dow and later Celanese. Contractual agreements also required Dow and Dome to build the Cochin pipeline from Fort Saskatchewan to Sarnia to transport volumes of ethylene and Dome agreed to purchase any ethane surplus to the needs of the petrochemical sector and sell it to the Columbia LNG plants in Greensprings, Ohio or to other fuel markets. In the "Dowling letters" (AEUB, 1988), it was stated that,

> Dome will purchase from AGE for delivery at the western terminus of the Cochin pipeline ethane which is surplus to the requirements of the ethylene plants... Ethane sold to Dome for removal from Alberta will be transported in the Cochin pipeline and sold to Columbia LNG Corporation "Columbia" at the commodity price under the Dome/Columbia agreement or to other fuel markets outside of Alberta.

Dome possessed the only long-term ethane export permit, and under the agreements, the export of ethane from Alberta for use in petrochemical plants was thus ruled out.

However, the subsequent closure of the Columbia plant prompted ethane exporters to appeal the ban on exports to petrochemical markets outside the province. In recognition of this Minister Hugh Planche, in a letter dated Dec. 30, 1985, agreed to allow the export of ethane to petrochemical markets outside Canada, with the understanding that the original commitments contained in the Dowling letters remain in force (AEUB, 1988). The conditions placed on such sales were as follows:

a) Any such sale will proceed only if it will impose no material negative impact to the existing or prospective Alberta ethylene or ethylene derivatives industries;

b) Any such sale will only be of a short to medium term duration and will be subject to recall for use in any installed Alberta petrochemical facility;

c) Any such sale will be to supply only existing capacity and will not be used to supply expansions or new capacity additions; and

d) Any such sale will be concluded only where viable alternatives are available to the potential purchaser and where the terms of any such sale are competitive with such alternatives, and provided further that the price to the potential purchaser shall not be less than the cost of ethane purchased from the project's extraction system.

From the time of the initial agreements of the Dowling letters, ethane was extracted at the Empress plants owned by Petro-Canada, Dome and Alberta Natural Gas at Cochrane and shipped on a new specification ethane pipeline, the Alberta Ethane Gathering System (AEGS) connecting these locations to Joffre, the inlet to the Cochin pipeline, and ethane storage caverns at Fort Saskatchewan and Redwater. After the Planche letters were signed, excess ethane supplies from AEGS were shipped to various petrochemical markets in Canada and the U.S. However, an alternative market for ethane was beginning to develop within Alberta during the early part of the 1980's. Due to an introduction by the Alberta government of royalty relief for hydrocarbon miscible flooding (used to enhance the recovery of crude oil), flood projects began using ethane as a component for solvent. Since gas prices were low and regulated to remain so in comparison to crude oil this was an economical source of solvent. More than eight plants subsequently applied to construct ethane plus extraction facilities, to take a 'deeper cut' of the ethane in the raw gas produced, and a pipeline was constructed to move ethane plus to miscible floods further north of Edmonton (Heath, et al., 1995).

2.1.3 Alternative Market Development and Alberta's Ethane Policy

By the 1980's ethane extraction at field plants was a substantial portion of total Alberta ethane production. Upstream from the straddle plants on the gas gathering network, the field plants extracted a certain portion of the ethane in the natural gas stream before it reached Empress or Cochrane. The Alberta Ethane Policy was first developed by the Government of Alberta through the AEUB (then the Energy Resources Conservation Board) to resolve disputes between natural gas producers and field plant owners, straddle plant owners and the Alberta petrochemical sector. It was introduced in 1988 and will be in effect until 2004. The policy protects the supply of ethane to the "Project", Alberta's domestic straddle plant and petrochemical sector. The development of Alberta's petrochemical sector was predicated on availability of ethane as feedstock. This in turn depended on feedstock contracts with straddle plants extracting ethane from flows of natural gas past Empress, Edmonton and Cochrane. As gas processing plants with ethane extraction capacity were built upstream of these facilities, concerns were raised over the ethane content of natural gas as it reached the straddle plants. The straddle plant owners feared that field plants built upstream would make their facilities redundant and the petrochemical sector feared that ethane supplies would be too volatile if field plants were the sole supplier because of marginal ethane extraction economics at such facilities. The Alberta Government stepped in to protect the volume of ethane reaching the straddle plant systems, and thus the petrochemical sector, by enforcing the Ethane Policy (AEUB, 1988). The Policy has several criteria:

a) the policy dictates the threshold volume of ethane that must reach each straddle plant which produces ethane for the 'project';

b) all gas plants in ethane extraction mode at the time of implementation are exempt from the policy with the exception of incremental processing capacity;

c) processing plants applying for ethane extraction units will be subject to the policy and ethane extraction will not be approved unless the processor proves that the threshold volumes at the straddle plants will not be affected by the upstreaming;

d) currently operating processing plants that affect reductions in ethane volumes to below threshold volumes will be forced to re-inject the ethane; and

e) processing plants delivering solution gas recoveries to reservoir cycling schemes are exempt from the Policy until such time as they deliver the residue gas to the existing straddle plant system.

The effect of the policy has been to limit the number of upstream ethane extraction units approved by the AEUB to those that are ensured of having no impact on the supply of ethane to the existing straddle plants. However, ethane extraction at straddle plants has increased. Today the majority of ethane is extracted at the Empress, South Edmonton and Cochrane facilities. They process collectively almost three quarters of Canada's marketable gas production and produce approximately 137 thousand barrels per day of ethane. Field plants produce approximately 70 thousand barrels per day, of which only a tiny portion is produced outside of the province of Alberta (Heath, et al., 1995).

2.2 The Nature of Ethane Markets in the US and Canada

In general, the price of ethane is determined by the supply and demand for ethane, but is also influenced by the price of substitutes to petrochemical use such as naphtha and gas oil. If ethane is viewed as a by-product of natural gas production it has an inelastic supply curve. In reality, the degree to which ethane is extracted from raw natural gas can be affected by the technique used to process the gas; also once extracted a portion of the ethane can sometimes be re-injected into the gas stream. Therefore, between the quantity of ethane that must be extracted to meet consumer quality specifications and the quantity of ethane contained in the raw natural gas, the supply of ethane can be elastic. However, since the facilities capable of extracting ethane such as turbo expanders come in specific sizes, this elastic portion is also step-like. Also facilities sized to match gas throughput produce a fixed volume of ethane. Therefore, any contraction in the equilibrium quantity of ethane supply can only come about as the result of a particular facility or set of facilities running idle rather than each supplier slightly reducing production. And in the case of any particular facility the option to run idle may not exist if gas is flowing through the plant and must be processed to meet downstream natural gas demand. For this reason the timing of capital investment is crucial - the industry's ability to produce ethane must match to the best extent possible the current quantity of ethane demanded, while always fulfilling primary gas processing requirements.

The demand for ethane is driven by the demand for ethylene, while ethylene demand is driven by the economy's demand for goods such as plastics and synthetic fibres. As with gas processing plants, ethylene production facilities also enjoy significant economies of scale. Therefore, ethane demand is also step-like, each step mirroring the ethane required for an ethylene plant of minimum efficient scale. Another key factor affecting the demand for ethane, in particular in the US Gulf Coast, is the price of substitute feedstocks to ethylene, such as naphtha and gas oil.

In terms of equilibrium prices, the existence of step-like and relatively inelastic supply and demand curves tends to cause volatile ethane prices and often situations where the quantity of ethane produced does not balance with ethane consumed; thus the need for storage. In Alberta cost-of-service agreements between producers and petrochemical plants, tend to reduce the volatility of ethane prices, maintaining shrinkage plus processing cost as an equilibrium price for ethane. Since Alberta ethylene plants are not flexible in their choice of feedstocks the prices of crude oil derived substitutes have little influence on ethane prices.

However, in the Gulf Coast market, ethylene plants have more flexibility in their slate of feedstocks and a supply of naphtha and other products is necessary to satisfy total feedstock demand. Therefore, ethane prices have historically been more volatile.

In Alberta, the existence of Empress as a hub through which the majority of natural gas produced from the WCSB flows created an ideal location for large-scale ethane production. Since the bulk of this ethane has been contracted to NOVA Chemicals since production began the price of ethane is set at a cost-of-service which is approximately $1.00 per gigajoule above shrinkage value (Alberta Natural Gas, 1997). The only other buyer of note in Alberta is Dow Chemical. This ethylene producer has contracts with NGL producers to supply ethane plus to the fractionator and de-ethanizer located at Fort Saskatchewan. Both Dow and NOVA re-sell some of this ethane to miscible flood operators. Also, both ethylene producers have ethane shipping commitments on Cochin, an ex-Alberta NGL pipeline. The existence of only two main ethane buyers in the Alberta market, and the fact that the bulk of this ethane is sold on a shrinkage-plus-cost basis keeps ethane prices closer to shrinkage value than in the US.

The US ethane market is somewhat different. In contrast to Alberta, there are many more ethylene producers. On the US Gulf Coast alone there are over 30 different companies producing ethylene at over 50 ethylene plants the majority of which use ethane as a feedstock (Oil and Gas Journal, 1994). The supply side of the market is similar to Alberta. Any producer of natural gas will also produce ethane as a by-product. However, to extract ethane a producer must own or have access to gas processing infrastructure. Typically, the majority of gas producers have either equity processing capacity or process gas at a custom processor. Depending on the nature of the contract, these custom processing plants may contract with the gas producer to retain a share of the proceeds from the sale of the liquids, may take ownership of these liquids at the plant, or may process the liquids for a fee. In the US, since there is no single natural gas hub like Empress in Alberta, there are many ethane extraction units spread throughout the western part of country. The tendencies for these units to be of smaller scale than those in Alberta means that costs are generally higher per unit than plants in Alberta experience. Consequently, the nature of the market for ethane results in a higher price relative to shrinkage than that observed in Alberta.

Chapter 3

METHODOLOGY

3.0 Introduction

This chapter will introduce the Comparative Cost Method, the framework for determining the competitiveness of various locations for ethane production. The comparative cost method was first developed to allow for a static comparison between the costs faced by competing producers for a certain point in time (Isard, 1960). Application of this method will broadly follow an application done in 1984 which compared the costs of producing ethylene in Alberta to other producing regions such as the US Gulf Coast, Mexico and Saudi Arabia (Apuzzo, 1984). However, since this analysis is focused on ethane rather than ethylene, many of the components of total cost will differ.

In the following sections a description of the development of various methods for evaluating investment opportunities such as the net present value approach, and the option value approach, are presented, highlighting the benefits and drawbacks of their uses. Next a derivation of the comparative cost method from the more complex net present value method is presented detailing the limitations of this simplification. Then the parameters of the comparative cost analysis are outlined and any major assumptions are identified; the reason for making these assumptions are given. Next, a review of the use of this method and other work done relating to the economics of gas processing is presented, followed by a summary of the chapter.

3.1 Literature Overview

This section will present a historical development of the methods used to evaluate investment. It will include a brief summary of classical investment theory, net present value approaches, and option value approaches to evaluating investment opportunities.

The essence of the evaluation of an investment opportunity, in this case in several different locations, is the method used to value the investment. These methods have been developed over time, starting with the simplest model of classical investment theory, which simply states that the equilibrium stock of capital is such that the firm's marginal efficiency of capital equals the interest rate, where the marginal efficiency of capital equals the marginal revenue product of capital divided by the price of capital (Lipsey, Purvis and Steiner, 1988, p. 360).

$$MEC = \frac{MRP}{P} = i \tag{1}$$

However, this relates to homogenous, instantly productive units of capital. For investment where a significant sequential series of investments are required, and these units are only productive once the series is complete, this theory is not applicable. This theory also has little use when examining irreversible investment; nor does it address the risk surrounding future payouts associated with such a large-scale irreversible investment.

Traditionally, handling of large-scale project evaluations in business have been carried out using net present value analysis or variations on this theme. Using this approach, the value of the investment is simply the sum of discounted future payouts less the original cost of the project, Brealey, Myers, Sick and Giammarino (1992, p. 89)

$$NPV = C_0 + \frac{C_1}{(1+r_1)} + \frac{C_2}{(1+r_2)} + \ldots + \frac{C_t}{(1+r_t)}. \tag{2}$$

Here the irreversibility of the investment is incorporated through a requirement that the original sunk cost, C_0, is recouped via discounted future net payouts $(C_1..C_t)$, for t periods, the useful life of the asset. This assumes that the asset has no scrap value (that investment is irreversible). Here r_i, the discount rate, is representative of the cost of capital. However, this model has no mechanism, as is, to incorporate the risk inherent in the project.

Various methods have been put forward to incorporate risk into the net present value model. Since the cost of capital to a firm is an average of the required rate of return to investors and the firm cost of debt weighted by the firm's capital structure, firms have typically used this to discount cash flows on new projects. Therefore, firms involved in riskier industries would more heavily discount cash flows from new projects, than those involved in less risky industries. However, a weakness of this method is that it implicitly assumes that the risk associated with a new project mirrors the risk of the firm's existing operations, which is very rarely the case. Another method incorporates risk through the introduction of a risk premium which appropriately increases discount rates, r_i, the higher for the more uncertain future net payouts. However, since the choice of the risk premium is arbitrary the method does not accurately predict project NPVs, and is only useful in comparing projects where *relative* degrees of risk are known, Brealey, Myers, Sick and Giammarino (1992, pp. 201 - 236).

Instead firms have used the capital asset pricing model to estimate discount rates more accurately. The capital asset pricing model (CAPM) is essentially a series of assumptions of capital market theory which result in equilibrium conditions relating to investment behaviour. Therefore, CAPM can be used to determine a benchmark rate of return (or discount rate) when evaluating possible investments with uncertain payouts. CAPM involves the prediction of equilibrium expected returns on risky assets. Using simplifying assumptions;

1. There are many investors each with an endowment small in comparison to the total endowment;
2. All investors focus on a single holding period;
3. Investments are limited to publicly traded financial assets, and risk-free borrowing or lending;
4. There is no tax on investment income nor are there transaction costs; and
5. All investors are rational and all have equal access to information.

a basic version of the CAPM is discussed in Brealey, Myers, Sick and Giammarino (1992) and summarised here. The expected project return used in the net present value approach as a risk adjusted discount rate is:

$$r = r_f + \beta(r_m - r_f). \tag{3}$$

For specific investment opportunities the discount rate equals the risk-free interest rate plus the project's *beta* multiplied by the difference between the market rate of return and the risk-free rate of return. The project *beta* is defined as the covariance between the project's return and the market's return divided by the variance of the market's return. In practice the covariance between project and market return is often unknown. Therefore, for a specific project, the beta of a portfolio of firms in an industry closely related to that of the project and whose returns are known is substituted. The drawback of using CAPM includes the fact that beta will likely change over time; added to which it is often very difficult to estimate a beta for new projects, for instance those which are innovative or involve new technology.

Another limitation is that although the net present value using CAPM discount rates incorporates both irreversibility and risk it does not account for the fact that in reality expenditure patterns are not fixed. The flexibility that actually exists in project management indicates that traditional NPV approaches are missing important elements. For example, by exercising the option to invest the firm gives up the opportunity to wait for new information that may effect the timing and desirability of the project. This option has a value which is not incorporated into the traditional NPV approach. Both Pindyck (1988) and McDonald and Siegel (1986) show how with even moderate risk levels, ignoring this option value can lead to investment valuations that are erroneous.[1]

Development of this model by Stephen Nickell (1978) began with a simple alteration to the neo-classical model whereby the cost of capital increased as the rate of investment increased. However, this did not incorporate necessary factors such as the

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[1] It must be stressed that option values only exist when the firm can wait to invest. In addition, other options such as the option to cease plant operations when returns are not expected to cover variable costs, are only of value if the firm can actually cease operation. As will be shown later, in this case neither the construction of the gas processing plant, nor operation of the plant, can be postponed or stopped.

heterogeneity of capital into the model. The next major development was a model developed by Roberts and Weitzman (1981) which examines projects with a series of capital outlays but incorporates information gathering. In each period information is introduced reducing the uncertainty over the value of the entire project. Since the project can be stopped at any time before final completion, this means that it is more likely that projects which are rejected by simple NPV analysis might be approved using this model of project valuation. This model assumes that information is received as a result of a capital outlay, similar to that of research and development. However, capital outlays similar to the construction of a manufacturing facility do not result in greater information about project value. Instead, in this example, capital outlays and information are not related.

Therefore, Ben Bernanke (1981) and Alex Cukierman (1980) developed models in which information and capital outlays are independent of each other. These are both simple models which involve only a single irreversible expenditure with the option of postponing the expenditure until further information about the value of the project is received. They show that an "option value" exists even if the firm is risk neutral. However, this option value is the explicit value of waiting for more information. The option value of importance in this analysis is similar to a call option on a dividend-paying stock where the value of a future set of dividends are unknown. As the risk associated with the realisation of the dividends increases the value of the call option decreases. So the value of the call option fluctuates stochastically over time.

A model which analyses the value of such options was put forward by McDonald and Siegel in 1986. A derivation of this model is presented in Dixit and Pindyck (1994) and is summarised here. This simple model determines at what time it is optimal to pay a sunk cost, I, in return for a project with a value, V, where V evolves according to a pattern of geometric Brownian motion,

$$dV = \alpha V dt + \sigma V dz . \tag{4}$$

Here dz is the increment of a Wiener process, α represents growth or the expected rate of change of V, and σ is the degree of uncertainty. Brownian motion is a continuous-time stochastic process satisfying certain conditions. First it is a Markov process in that the probability distribution of all future values depends only on current values. Second, it has independent increments such that the probability distribution for one change is independent from another. Finally, changes in the process are normally distributed with variance equal to a linear function of the time interval. In other words the future values are lognormally distributed, and the variance of this distribution is linearly related to the time horizon. Thus although information arrives to enable a valuation in each period, future values are never known. Equation (4) is not representative of most projects where the option exists to temporarily or permanently shut-down the plant. However in the case of a gas processing plant, for example, where the plant cannot cease operations for any length of time, nor shut down, unless gas can be diverted to another facility Equation (4) is applicable; it is not applicable to gas processing in the sense that it assumes the capital outlay can be made at any time in the future, when in reality gas processing plant investments must be simultaneous with the production of the natural gas. As above, the decision to invest is synonymous with the decision to exercise a call option, where the option is the investment. In contrast, it can be considered a dynamic programming problem. Both approaches are presented here.

The value of the option to invest, denoted *F(V)*, is equal to the maximum of the expected present value at time *t* less the initial investment *I*:

$$F(V) = \max \mathcal{E}\left[(V_t - I)e^{-\rho T}\right], \tag{5}$$

where $\mathcal{E}$ denotes the expectation, *T* is time of the investment, ρ is the discount rate, and the maximisation is subject to Equation (4). To ensure that a solution exists it is necessary to assume that $\alpha<\rho$, otherwise the value of waiting would indefinitely outweigh the value of the project. When $\sigma>0$, there is uncertainty through the introduction of a Wiener process. Unlike a deterministic case, where there is no uncertainty, it is impossible to isolate a time, *T*, where it is optimal to invest. Therefore, the investment rule becomes instead an optimal value V^* where investment is warranted once $V \geq V^*$. There are essentially two approaches to solve this investment problem. The first uses dynamic programming and the second uses contingent claims analysis.[2]

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[2] Contingent claims analysis is a quantitative method used to determine the value of an investment option when the value of the option is dependent on one or more stochastic variables such as product prices and input costs.

Solution Using Dynamic Programming

The starting point for the dynamic programming solution involves identifying, using a Bellman equation, the values for V which are not optimal for investment. This equation,

$$\rho F dt = \mathcal{E}(dF), \tag{6}$$

is based on Bellman's Principle, which states that any optimal decision is based on an optimal outcome today and a subset of future choices that are also optimised. Ito's Lemma for a stochastic calculus case, Equation (7),

$$dF = F'(V)dV + \frac{1}{2}F''(V);\;\; F' = \frac{dF}{dV};\;\; F'' = \frac{d^2F}{dV^2}, \tag{7}$$

combined with Equation (4), results in

$$\mathcal{E}[dF] = \alpha VF'(V)dt + \frac{1}{2}\sigma^2 V^2 F''(V)dt. \tag{8}$$

Referring to Equation (6), and dividing through by dt, gives

$$\frac{1}{2}\sigma^2 V^2 F''(V) + \alpha VF'(V) - \rho F = 0. \tag{9}$$

By letting $\alpha = \rho - \delta$ (for ease of comparison with the contingent claims analysis solution) then Equation (9) can be rewritten as

$$\frac{1}{2}\sigma^2 V^2 F''(V) + (\rho - \delta)VF'(V) - \rho F = 0, \tag{10}$$

yielding the differential equation as shown. Several boundary conditions relate to this differential equation including

$$F(0) = 0; \tag{11}$$
$$V^* = I + F(V^*);. \tag{12}$$
$$F'(V^*) = 1. \tag{13}$$

While Equation (11) and Equation (12) are intuitively obvious (the value of the option for a project with no value is zero, and the optimal project value is equal to both the capital cost and the opportunity cost of undertaking the project) Equation (13) relates to the requirement that $F(V)$ be continuous at V^* or else V^* would not be optimal.

Since Equation (9) is a second-order homogeneous differential equation a solution of the form

$$F(V) = AV^{\beta_1} \tag{14}$$

can be surmised, where A is a constant and $\beta_1 > 1$ is a constant function of α, ρ, and δ. Using the other two boundary conditions and Equation (14) it is easy to show that

$$V^* = \left(\frac{\beta_1}{\beta_1 - 1}\right) I, \tag{15}$$

and

$$A = \frac{(V^* - I)}{(V^*)^{\beta_1}} = \frac{(\beta_1 - 1)^{\beta_1 - 1}}{\left[(\beta_1)^{\beta_1} I^{\beta_1 - 1}\right]}. \tag{16}$$

It becomes immediately apparent that the existence of uncertainty and the potential for the project to grow (i.e. α and σ are both >0) imply that $V^* \neq I$; in other words there is a value to waiting. Returning to the solution for the differential equation, by substituting Equation (14) into Equation (9) and dividing through by V^{β} and A yields the quadratic

$$\tfrac{1}{2}\sigma^2\beta(\beta-1)+(\rho-\delta)\beta-\rho=0, \tag{17}$$

with roots

$$\beta_1=\frac{1}{2}-\frac{(\rho-\delta)}{\sigma^2}+\sqrt{\left[(\rho-\delta))/\sigma^2-1/2\right]^2+2\rho/\sigma^2}>1, \tag{18}$$

and

$$\beta_2=\frac{1}{2}-\frac{(\rho-\delta)}{\sigma^2}+\sqrt{\left[(\rho-\delta))/\sigma^2-1/2\right]^2+2\rho/\sigma^2}<0. \tag{19}$$

As will be shown later, the use of a constant, arbitrary discount rate, ρ, is not necessarily a consistent reflection of the true market value of the option. This can be seen as a weakness of the dynamic programming approach. However, contingent claims analysis can be used to modify the model to reflect this market valuation.

Solution Using Contingent Claims Analysis

In order to solve the previous problem using contingent claims analysis, it is necessary to assume that there exists an asset or dynamic portfolio of assets that is perfectly correlated with the asset in question. In other words there already exists in the market an investment opportunity which mirrors the value of the project in question.[3] Here x is assumed to be the price of an asset which is perfectly correlated with V. This implies that the coefficient of correlation with the market in general for x is equal to that

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[3] In general this should hold, but in this analysis it might be difficult to identify a specific example.

of V, such that $\rho_{xm} = \rho_{Vm}$. Assuming neither V nor x pay dividends (as is the case with the investment opportunity in question in this analysis) then x evolves according to the equation

$$dx = \mu x dt + \sigma x dz, \tag{20}$$

where μ is the expected rate of return and σ is the variance parameter. As shown previously according to the Capital Asset Pricing Model (CAPM)

$$\mu = r + \beta(r_m - r); \tag{21}$$

so that

$$\mu = r + \rho_{xm}\sigma\phi; \text{ where } \phi = (r_m - r)/\sigma, \tag{22}$$

where r is the risk free interest rate, r_m is the expected return on the market, leaving ϕ to represent the market price of risk. Again, setting $\delta = \mu - \alpha$, for a solution to exist the model requires that δ be greater than zero or that the risk adjusted rate of return be greater than the rate of capital gain of V; if this were not the case the firm would never invest so δ represents an opportunity cost of waiting to proceed with the project while preserving the option value of the project. It is important to note that as δ approaches infinity the value of the option approaches zero because the risk adjusted rate of return for the project is so much higher than any capital gain of the project that it is never worth waiting to invest. In this case standard NPV analysis is applicable.

As in the dynamic programming solution, $F(V)$ is the value of the option to invest in the project. In this instance the portfolio considered includes the option valued at $F(V)$

and a put option for $n = F'(V)$ units of the project.[4] Then the value of the portfolio at any given time is

$$\Phi = F(V) - F'(V)V, \tag{23}$$

where the value of the option is $F(V)$ and the value of the put option to the buyer, or the cost to the seller, is the number of units held, $F'(V)$ times the value of those units, V. For a short time period, dt, a rational investor will only hold the put option if the pay out is $\delta VF'(V)$. This is because the asset pays dividends of δ and capital gains of α per unit V. Therefore, going short $F'(V)$ units requires a dividend pay out of $\delta VF'(V)$. Incorporating this into the previous equation, over a short time period, yields a value on the short term value of the portfolio of

$$dF - F'(V)dV - \delta VF'(V)dt. \tag{24}$$

Using Ito's Lemma to determine dF implies

$$dF = F'(V)dV + \tfrac{1}{2}F''(V)(dV)^2, \tag{25}$$

and substituting this into the previous result yields a short term return on the portfolio of

$$\tfrac{1}{2}F''(V)(dV)^2 - \delta VF'(V)dt. \tag{26}$$

As shown previously

$$dV = \alpha Vdt + \sigma Vdz, \tag{4}$$

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[4] A put option is defined as a an option contract that gives the holder the right to sell a certain quantity of an underlying security to the writer of the option, at a specified price (strike price) up to a specified date (expiration date). This is also called "going short".

which implies that

$$(dV)^2 = \sigma^2 V^2 dt. \tag{27}$$

Therefore the value of the portfolio in the short term becomes

$$\tfrac{1}{2}\sigma^2 V^2 F''(V)dt - \delta V F'(V)dt. \tag{28}$$

Since this value is not affected by risk and because arbitrage is possible, the value of the portfolio in the short term must be equal to the value of the return risk free such that

$$r\Phi dt = r[F - F'(V)V]dt = \tfrac{1}{2}\sigma^2 V^2 F''(V)dt - \delta V F'(V)dt, \tag{29}$$

which after manipulation derives the following differential equation

$$\tfrac{1}{2}\sigma^2 V^2 F''(V) + (r-\delta)VF'(V) - rF = 0. \tag{30}$$

This is identical to the differential equation from the dynamic programming solution except that this equation includes the risk-free interest rate, r, rather than the arbitrary discount rate, ρ. Solving in the same manner as before yields the same roots as before but in this instance r has replaced ρ. Therefore, the assumption of spanning has allowed for a solution which is not dependent on an arbitrary discount rate. Without spanning, the solutions are only equivalent under risk neutrality, where r is equal to ρ.

Interpreting the results, of interest are the relationships between r, δ, σ, and $F(V)$, V, and V^*. Dixit and Pindyck (1994) use a simple model to show some of these relationships. Recalling, for example, that

$$\beta_1 = \frac{1}{2} - \frac{(\rho-\delta)}{\sigma^2} + \sqrt{[(\rho-\delta))/\sigma^2 - 1/2]^2 + 2\rho/\sigma^2} > 1, \tag{18}$$

$$V* = \left(\frac{\beta_1}{\beta_1 - 1}\right)I, \tag{15}$$

and

$$F(V) = AV^{\beta_1}, \tag{14}$$

and assuming

$$I = 1$$
$$r = 0.04$$
$$\delta = 0.04$$
$$\sigma = 0.20,$$

then

$$\beta_1 = 2,$$
$$V* = 2,$$
$$F(V) = 1.$$

In this example the value of the project must be twice the size of the project cost before proceeding with the investment.

Now, to determine the relationship between $F(V)$ and σ, Figure 3.1 below depicts the change to $F(V)$ and V as σ is increased from 0 to 0.15. As shown, an increase in the volatility of project values increases the value of waiting to invest, the option value. Similarly an increase in the risk free discount rate increases the value of the option to wait to invest increases. In contrast, Figure 3.2 shows that the relationship between $F(V)$, V

and δ is negative; as the expected rate of growth of the project decreases (as α decreases), this causes δ to increase which in turn causes the expected increase in the value of the option to invest to decrease.

Figure 3.1
Impact on the Option Value of Increased Volatility in Project Values

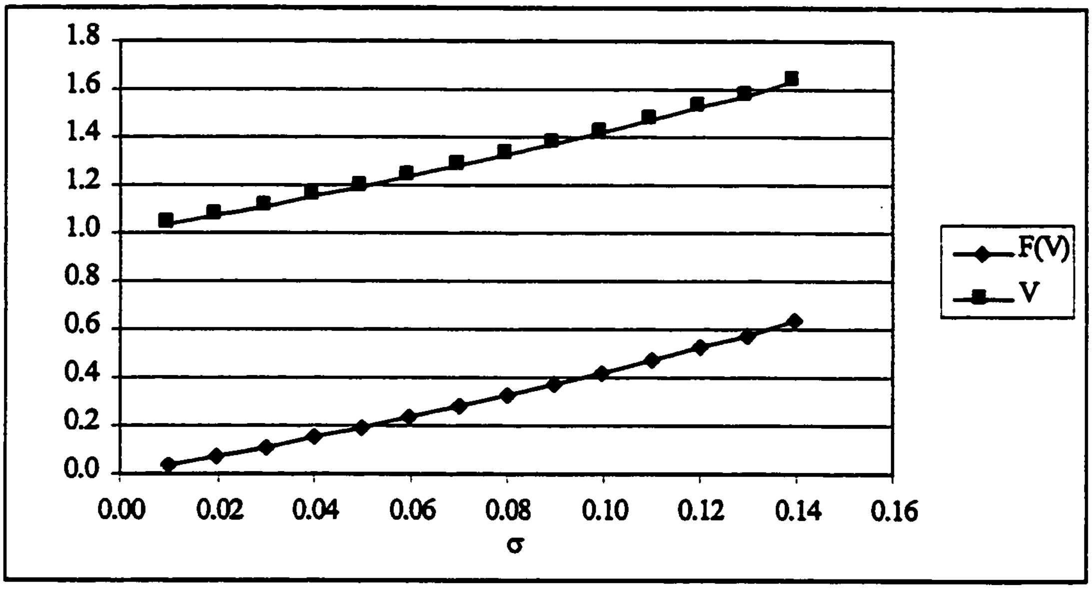
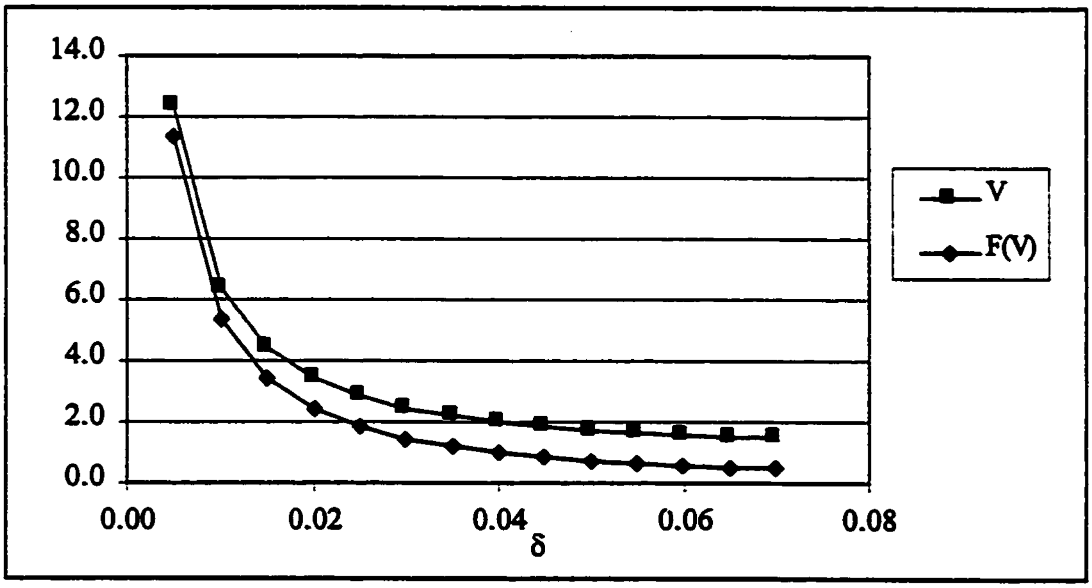


Figure 3.2
Impact on the Option Value of Increased δ in Project Values



Following on the heels of the McDonald and Siegel model (1986), Majd and Pindyck (1987) examined real options where investment decisions and cash outlays occur in sequence over time, capital outlays occur at a maximum rate (i.e. requiring time to build), and no returns are realised until all capital outlays are complete. Using contingent claims analysis they determine that evaluating such projects using traditional NPV rules can result in incorrect investment decisions. This is simply because NPV does not incorporate the flexibility of the sequential outlay of capital. They determine that the maximum effect on the investment decision of the time requirement to complete the series of capital expenditures occurs when there is the greatest level of uncertainty regarding future values, opportunity cost of delay is at a maximum, and when the maximum rate of construction is lowest.

In 1988 Pindyck again used contingent claims analysis to derive optimal decision rules for irreversible investments with flexible capacity. By incorporating the time required for construction, the opportunity cost of an investment (i.e. the irreversibility of investment) and uncertainty surrounding future value he showed how his model was superior to simple NPV models. Simple NPV rules suggest that capital should be expended as long as its value is at least as great as the cost of purchasing and installing the capital. However, Pindyck suggests that this is not strictly accurate. Rather, the value of the expenditure must exceed the cost of purchase and installation of the capital by the opportunity cost of the investment (i.e. the value of investing the capital elsewhere). This is where his model differs from those of Bernanke (1981) and Cukierman (1980) and is more similar to that of McDonald and Siegel (1986). He cites an example involving a numerical example from McDonald and Siegel (as shown above) where the opportunity cost is so large that the present value of the project must be at least double the direct cost (purchase and installation cost) of the project.

In 1995, Abel, Dixit, Eberly and Pindyck presented a working paper relating to capital investment decisions where the opportunity exists for future expansion or contraction of the capital stock. In this case they found that, in general, the option to expand reduces the incentive to invest while the opposite was true for the opportunity to contract. Different from previous literature, they show that it is not correct to conclude that the irreversibility of investment, the inability to contract capital, alone reduces the incentive to invest under uncertainty. Instead, they show that it is the existence of the option to expand the capital stock under irreversibility and uncertainty which reduces the overall incentive to invest. This counterintuitive result relates to the fact that while the option to later expand capital adds to current value, exercising the option nullifies this value.

Again in 1995, Abel and Eberly, established that the effect of an increase in uncertainty on capital stocks where a capital stock exposed to uncertainty and irreversibility already exist is ambiguous. In contrast, they show that changes to expected growth rates for demand, interest rates, price elasticity for demand and the share of capital in output have predictable and often intuitive impacts. While previous literature described the impact of irreversibility and uncertainty on a firm initially with zero capital, they assess the impact of further irreversibility and increased uncertainty on additional capital investment in the long run. They do so by analysing the interaction of two opposing effects: the "hangover" effect, which relates to the fact that, in response to positive conditions in the past, the firm may have a current capital stock which is too high; and the user-cost effect, which is that established by previous literature, that under uncertainty and irreversibility, the resulting higher user cost of capital results in lower capital investment than otherwise is optimal. Because the two effects conflict as to their impact on long-run capital stocks it is impossible to determine the impact of further irreversibility and increased uncertainty on additional capital investment. Further they determine that, under uncertainty and irreversibility, while a high growth rate for demand decreases the expected long-run stock of capital, high interest rates, a low elasticity of demand, and a low capital share in production have the opposite effect.

Real option approaches are for the most part still being integrated into corporate planning decisions such as asset acquisitions or competitor take-overs; analysis of real investment opportunities continues to be dominated by the net present value approach. In contrast the option value approach has risen to dominance in financial option pricing.

However, the real option value approach is limited to situations where the firm can delay investment. There are many situations where a firm may not be able to delay an investment. For example, Dixit and Pindyck (1994) identify a situation where strategic considerations make it necessary to invest to immediately pre-empt investment by existing or potential competitors. This analysis is another example of a situation where the real option approach is not applicable.

Since investment in gas processing facilities is a by-product of gas production, the incorporation of an option value is not possible since the firm has no option of waiting; as soon as the gas begins to flow it must be processed. In the example considered here the gas processing investment is a necessary part of a larger project and therefore must proceed if the overall project proceeds. [5] Therefore, the option value approach is not applicable since delay is not possible, and the only question to be addressed is where should the plant be located. To answer this question the comparative cost method is used.

3.2 The Comparative Cost Method and its Limitations

The comparative cost method is essentially a simplification of the net present value approach to of evaluating investment opportunities. Formally the Comparative Cost Method can be derived from a simple net present value approach as show; for location A to be a more desirable location than B,

$$NPV_A > NPV_B \tag{31}$$

such that the net present value of the project at location A must be higher than the net present value at location B. Then, the sum of discounted cash flows from location A must be higher than for location B as shown below, where n is the expected term of plant

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[5] A direct conclusion from this statement is that the evaluation of gas processing investment should be addressed as part of a larger evaluation of the gas exploration, development, production, gathering, processing, and delivery pipeline investment. Then the real option approach comes into play in that the whole product chain could be delayed including the development of the resource and the addition of gathering, transmission, storage and processing infrastructure if there was a value to waiting. However, analysis of this scale is outside the scope of this analysis.

operation, r is the appropriate discount rate in each period, and C is the cash flow for each period:

$$\sum_{i=0}^{n}\frac{C_i^A}{(1+r_i^A)^i} > \sum_{i=0}^{n}\frac{C_i^B}{(1+r_i^B)^i}. \tag{32}$$

Without forecasts of each element of cash flow such as input costs and output prices, the simplifying assumption is made that each period's cash flows will be identical to all others such that,

$$C_t^A = C_s^A; C_t^B = C_s^B; \forall s,t \in 0,..,n. \tag{33}$$

This assumption will be relaxed in later chapters through sensitivities performed to test the relative attractiveness of locations if specific cost inputs are allowed to vary. In this case cash flows are assumed to be expressed in real rather than nominal terms. Now Equation (32) can be rewritten as

$$C^A\left[\sum_{i=0}^{n}\left(\frac{1}{1+r_i^A}\right)^i\right] > C^B\left[\sum_{i=0}^{n}\left(\frac{1}{1+r_i^B}\right)^i\right]. \tag{34}$$

In this case the discount rates used for each location will reflect the risk associated with fluctuations in input costs and output prices for that location. In this analysis however, regardless of location, plants will sell product into identical markets, namely the US Gulf Coast and the US Mid-continent. In Alberta ethane prices previously based on a premium over gas prices are increasingly being sold at a price benchmarked to US Gulf Coast ethane prices. Therefore, output price risk is assumed to be identical. In addition, since the majority of inputs to production are sourced from identical suppliers regardless of location, with costs varying between regions solely as a result of differences in delivery costs, it is realistic to assume that input cost risk should also be identical. Finally since the firms user cost of capital should be the same regardless of location, overall discount rates should be similar between locations such that

$$r_i^A = r_i^B; \forall i \in 0,..,n. \tag{35}$$

This assumption would only be valid for locations with no significant differences to user costs of capital such as political risk and other elements difficult to quantify such as drastic climate changes, sudden changes in tax structure etc. Since Canada and the US have little social and political instability this assumption is valid here. Equation (34) can now be simplified to

$$C^A > C^B. \tag{36}$$

The resulting condition is stated in terms of accounting variables. Cash flow relates to economic variables in the following way: simply stated cash flow equals net income (revenues less costs) plus non-cash expenses (such as depreciation or amortisation) less non-cash revenues. Cash flows refer not only to cash items but also cash equivalent items including liquid assets such as bonds stocks and treasury bills. In this analysis we will assume that all costs and revenues are cash items, and that items such as depreciation and taxes are considered cash also.[6] Thus cash flow equates to net income or revenue minus cost. Then Equation (36) can be restated as

[6] The reason that depreciation (amortization) and taxes are non-cash items in reality is that firms often schedule tax and depreciation liabilities differently than government schedules such as the CCA. For

$$PQ - TC^A > PQ - TC^B. \tag{37}$$

where P is the price of the good, q, the quantity produced (neither of which will depend on location), and TC is the total cost of producing the good in the location. This implies that

$$TC^A < TC^B; or\ AC^A < AC^B, \tag{38}$$

which is the comparative cost method rule for determining an optimal location.

The methodology employed by the comparative cost method involves a totalling of the costs incurred by producing a good in each of the regions - in this case Chicago, inland Texas and various producing regions in Alberta - and transporting it to a variety of markets. The analysis is static in that the results are only valid for as long as the relative cost components do not change (Isard, 1960).

In the case of ethane, there are many inputs to production and the majority of these differ in cost between each of the regions. After totalling each of these costs for the region, the most attractive regions will obviously be those facing the lowest delivered costs (Isard, 1960).

The attractiveness of this method is its simplicity. However, various limitations of this method exist. First, there are many non-quantifiable factors which impact the competitiveness of the producing regions. Secondly, a static determination of a region's competitiveness does not aid a producer in a long-term locational decision without some

example, deferred taxes refer not to outstanding tax payments but a deemed liability by the firm to pay taxes in future. Therefore, in this analysis it is assumed that the firm matches depreciation schedules and prediction of future trends in cost components. Thirdly, the analysis assumes that the producer is a price-taker.

Non-quantifiable factors which impact the true competitiveness of a region include political instability and the regulatory environment. Even if a region is the most competitive, if a plant upgrade take years to obtain regulatory approval, or local residents constantly picket plant sites, a producer may feel unwilling to invest in a production facility in that region (Isard, 1960).

Over time cost components will likely change. However, of interest to producers are changes that are not in line with those of competing regions. For example, Alberta enjoys a significant natural gas feedstock cost advantage over other regions because of the low opportunity cost or shrinkage value of natural gas. If export pipeline capacity were to be expanded to profitable US markets, causing Alberta gas prices to increase relative to ethane producers in the US, the competitiveness of Alberta versus the US could decline over time. However, it is not within the scope of this analysis to forecast the prices of each input involved. This would seriously limit the scope of the conclusions if it was likely that input prices would be volatile both over time and between regions. However, with several notable exceptions, it is unlikely that this is the case. In addition, these notable exceptions dominate the array of inputs; these variables make up the majority of the cost of production. To determine the influence that these notable exceptions, such as natural gas prices and exchange rates, have on the value of the project between regions, sensitivities are performed. Since, the comparative cost method assumes

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tax payment schedules with government.

that all periods mirror the first period and is therefore, in essence, a one period, net present value analysis, where limitations surrounding the ability to accurately estimate future values are mitigated by sensitivity analyses.

In the case of North America, assuming ethane producers are price takers would not be inaccurate. For example there are over 1000 natural gas producers throughout Canada and the US with access to gas processing infrastructure where NGLs can be extracted (Cannon, 1993).

3.3 Location of the Plant

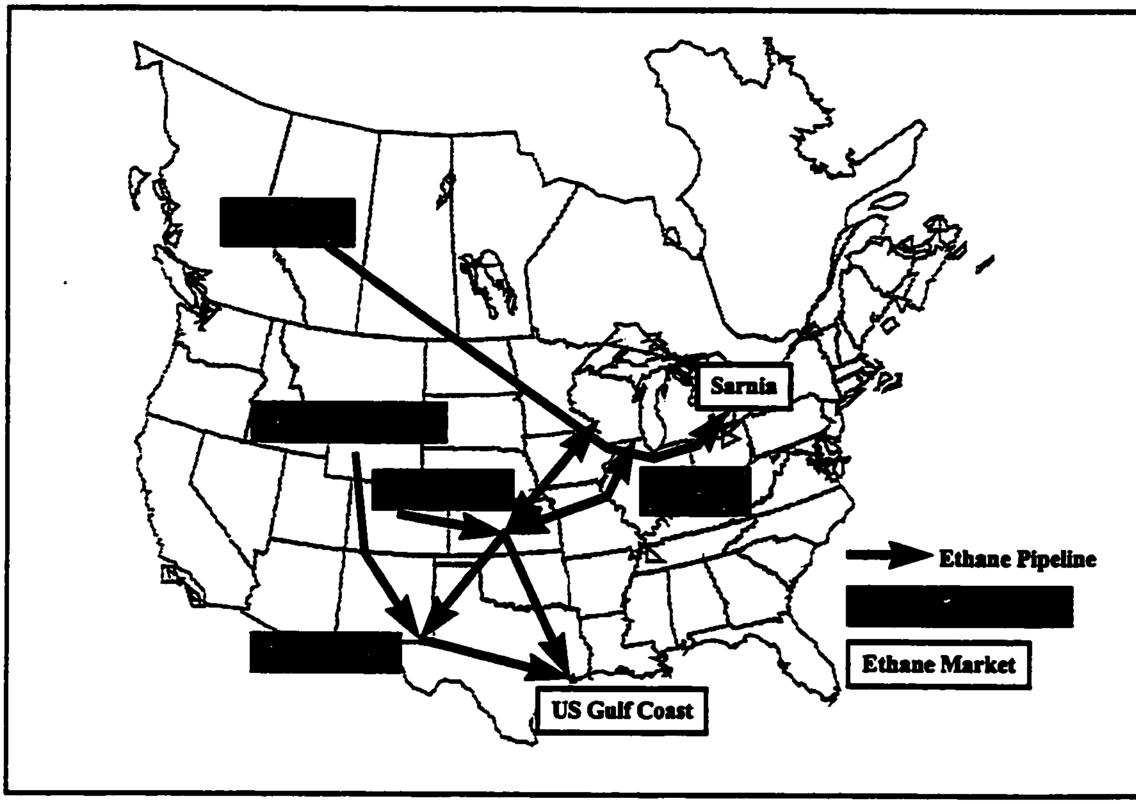
In this analysis the regions to be examined include north-western Alberta, Edmonton, Alberta, Chicago, Illinois, and inland Texas. The choice of locations to be compared is based on the potential locations for a plant to straddle the proposed Alliance gas export pipeline. Alberta gas producers are facing a time of change. Current export pipelines do not have capacity to transport the volumes of gas expected in the future. As a result, several new projects are planned to add export capacity to Eastern Canada and the US Midwest. One pipeline in particular is proposing to move rich (wet) gas from north-western Alberta through Edmonton to Chicago and build a large gas processing plant at the end of the pipeline. This proposal has brought forward the debate regarding the gas processing industry and markets they serve. The Alberta government has traditionally promoted the extraction of natural gas liquids within the province, thus encouraging economic diversification by attracting petrochemical producers who use these NGLs as feedstock; permits are required for the export of ethane from the province

(AEUB, 1988). In addition, the Alberta government has stated that in the future only ethane excess to the needs of the petrochemical sector will be granted export permits (West, 1997). However, since the pipeline project is offering lower transportation tolls to those who move wet gas (i.e. gas with a higher ethane content) producers are chafing against strict export guidelines for ethane (Alliance Pipeline, 1996). Therefore, part of the economic decision which must be made by potential shippers on the pipeline is the optimal location for ethane extraction, either Alberta or Chicago, and whether this ethane will be competitive with other producing regions such as inland Texas. For these reasons, the analysis focuses on the cost competitiveness of extracting ethane in north-west Alberta, Edmonton, Alberta, Chicago, Illinois, and inland Texas.

Typically, most industries locate either close to raw material supplies or close to end-use markets. The advantage of being close to gas supply is cheaper shrinkage cost and the advantage of locating next to markets is that delivery costs are reduced. Since most gas transmission systems are not equipped to move wet gas, extraction has predominantly occurred in areas of gas production and not ethane markets. The petrochemical industry consumes over 760 Mb/d of the 800 Mb/d of ethane produced in the US and Canada (Heath, et al., 1995). The main markets are in Sarnia, Ontario, Edmonton and Joffre, Alberta, Chicago, Illinois and the US Gulf Coast. **Figure 3.3** shows the main areas of production and transportation systems between supply regions and market centres (Heath, et al., 1995). Obviously the attractiveness of locating in Chicago (given a wet gas pipeline from Alberta) is that the plant would be close to both wet gas supply and an ethane market.

Not all locations serve all markets. An extraction facility in Chicago would most likely opt to move ethane plus to US ethylene plants, the closest markets for ethane. To do so, a connection with the Mapco system would be required, enabling ethane to move to ethylene plants in Chicago and the US Gulf Coast. Ethane from Chicago could not access Alberta markets. Similarly, plants in inland Texas which serve the USGC and Chicago markets do not have the ability to serve Alberta markets. Ethane produced in Alberta has the capability to reach all markets. Moving the ethane from Alberta via pipeline to Illinois, Conway or the US Gulf Coast involves shipment first along Cochin. At the junction with the Mapco pipeline which moves the ethane either to ethylene plants in Illinois or south to Conway and then to the US Gulf Coast, ethane must be blended with propane since the pipeline cannot carry product which is as volatile as ethane. Once the product reaches Conway, it can either be fractionated and sold as ethane and propane or it can continue on to the US Gulf Coast where there are both ethane and ethane-propane markets. In Illinois ethylene plants use ethane-propane mix directly and no fractionation is required.

Figure 3.3
Ethane Pipelines, Supply Regions and Market Centres



3.4 Characteristics of Locations Examined

For each region there are multiple components of total cost. Common to all regions include shrinkage, materials, utilities, labour and capital cost, gathering and fractionation fees, storage charges, CO_2 removal charges, transportation tolls and taxes. If these costs are significantly different from region to region they will affect inter-regional competitiveness. As will be shown, in most cases, there are significant disparities for all of these costs between regions.

Producing ethane and delivering it to market involves a number of processes. First the ethane and other liquids must be extracted from the natural gas stream. This involves the use of fuel (electricity and natural gas), cooling and process water, monoethanolamine and dessicant, a molecular sieve, for the ethane extraction process and the compensation to the natural gas producer for the energy content of the natural gas that is lost when ethane and other liquids are extracted. Plant capital and operating costs also include labour (including the control laboratory), maintenance, depreciation, insurance and property taxes. Secondly, the ethane that is extracted must be moved to the market via gathering and transportation pipelines.

In Alberta, at gas plants either the producer has negotiated with a gas plant owner for processing or the producer owns the gas plant. In either case the liquids extracted will detract from the energy content of the natural gas. This shrinkage, or heating value is then the cost of the ethane molecules to the producer. For the past several years there has been a positive differential between gas prices in Chicago and Texas and Alberta. Therefore, regions which are premium markets for natural gas, such as Chicago and Texas, experience higher shrinkage costs than regions like Alberta.

A utility bill for a gas processing plant is often the largest plant cost after ethane. Using a mixture of natural gas and electricity is often the most cost-effective way to fuel a plant. However, for both these forms of energy, their costs are significantly different than in the US. Since natural gas prices and electricity prices are generally lower in Alberta than most US basins, Alberta plants have historically enjoyed a cost advantage over their US counterparts.

Over labour costs there is some debate. Given the complexities of labour compensation, such as benefits, tax regimes, isolation pay, non-monetary compensation and other facets of employee/employer relations, there is great difficulty in determining actual labour costs for ethane extraction facilities. Also since many by-products of natural gas are stripped off at once the difficulty of apportioning labour and other costs between ethane and other products further complicates the debate.

Gathering fees vary widely not just between Alberta and US producers but also within the province itself. Naturally, a large determinant of gathering charges is distance travelled. In some cases pipelines charge a "postage stamp" tariff which is the same for all shippers regardless of distance shipped. However, for all ethane gathering systems in Alberta distance is a factor in tolling methodology. One exception is the Alberta Ethane Gathering System which is owned by three firms and connected to many ethane extraction plants, but on which only one company is a shipper of record. All ethane shipped on the line is owned by the shipper of record, in this case NOVA and therefore, there is no tariff as such but a compensation paid to the other owners of the pipeline for use. For ethane gathering systems in the US, there are many tolling methodologies. However, as **Table 3.1** shows, gathering charges (from Heath, et al., 1995) differ between region.

Table 3.1
Ethane Gathering Fees in the US and Canada

Region	**Gathering Fees** *(US cents/US gallon)*
Alberta	1.0 - 3.4
Mid-West	1.1
West Texas	0.5

Similarly, fractionation fees are different from region to region. The volume of ethane plus requiring fractionation and the availability of separation capacity are the two main determinants of fees. In Edmonton, Sarnia and the US Gulf Coast fractionators are operating at capacity and consequently have very similar fractionation charges. On the other hand the existence of almost 100 thousand barrels per day of spare fractionation capacity in the Conway area, has resulted in a charge per gallon of approximately 1 cent US/ US gallon lower for all the fractionators in this area.

In the case of storage, charges are very difficult to determine, since many of the facilities are privately owned and operated for proprietary volumes. Often fractionation fees include 30 days of free storage. However, it is likely that since all three main fractionation centres, Edmonton, Conway, Kansas and the US Gulf Coast, are situated above considerable salt cavern storage facilities, storage charges may not differ substantially between regions. Generally these charges are a very small portion of the total cost of producing and marketing ethane.

Transportation tolls are the main portion of total cost to move ethane to market. For ethane exported from Alberta, only one route is available: along the Cochin pipeline east to the junction with the MAPCO pipeline and then south to Conway and the US Gulf Coast. Some of the ethane currently exported to the US Gulf Coast does not physically get shipped all the way. At the MAPCO junction there are two large ethane crackers and a portion of Alberta ethane is moved to this location in trades or exchanges with US producers with product at Conway and the US Gulf Coast. However, conventional transportation along these two pipelines, given the distances involved, implies a much greater tariff than transportation from any US producing region.

3.5 Assumptions of the Analysis

The analysis is founded upon a series of assumptions which are either made to simplify the analysis or because necessary data were not available.

1. Ethane, the product to be compared, is homogenous, in that there are no significance differences in the nature and quality of the ethane produced at each of the regions.
2. Gas producers receive shrinkage value for ethane extracted at the gas processing plant in all regions. All ethane producers receive the same value for their product in a particular market.
3. Gas processing plants are configured the same (size, structure, technology etc.) from region to region. Gas throughputs, gas composition, and NGL production are also similar.
4. Plants and other factors of production (pipelines, fractionators, CO_2 removal units) are immobile.
5. The industry has no barriers to entry (although a minimum efficient scale exists).

3.6 A Review of the Related Literature

Two areas of study relate specifically to this thesis: previous application of the comparative cost method; and application of this method specific to the economic aspects of gas processing.

There are many applications of the comparative cost method related to the energy sector. However, those that are both publicly available and relating to ethane are extremely limited. These are focused on the production of ethylene from ethane, but many of the components of cost are similar between ethane and ethylene production, including plant construction and operating costs, and product delivery (both via high pressure pipeline). Two such analyses include a thesis done by A.M.R. Apuzzo (1984) and a study done for the Canadian Chemical Producers Association (CCPA) (1996). The work by A.M.R. Apuzzo uses the comparative cost method to determine the optimal location for the production of ethylene from ethane. Locations compared include Alberta, the US Gulf Coast, Mexico and Saudi Arabia. The conclusion reached is that the optimal location is one where ethane feedstock costs are low, and this advantage is not eroded by higher product delivery costs. The study finds that ethane feedstock costs are lower in Alberta as compared with the US Gulf Coast, because of lower natural gas shrinkage costs. The analysis done for the CCPA also uses the comparative cost method, but focuses on a comparison of the cost of constructing ethylene facilities in Alberta, Sarnia, and the US Gulf Coast. The inputs to plant construction such as fuel, labour, and materials are similar to those used in the construction of gas processing plants. The study concludes that overall, construction costs are the lowest in Alberta.

The majority of applications of the comparative cost method to determine the optimal location for NGL extraction in the US and Canada been done by economic consultants for businesses evaluating investment opportunities. Often these studies are sponsored by a group of clients, sometimes with the intention of making the results public to forward a government policy decision or industry development. The economics of NGL extraction are analysed regularly by US and Canadian consulting firms such as Purvin and Gertz (1993) and Chem Systems Inc. (1996). The results are occasionally presented at conferences, such as Tannerhill, Echterhoff and Trimble (1994). This analysis compared the economics of producing ethane and other liquids for eight US regions. The analysis found that the highest gross margins for ethane were found in the Permian and San Juan Basins, the Mid-Continent, Upper Texas and the Louisiana Gulf, while the Rocky Mountains and South Texas had small to negative margins.

This thesis follows an analysis of the cost of producing ethane done by the Stanford Research Institute for the Process Economics Program (SRI, 1994). The purpose of the SRI analysis was to determine the optimal configuration for extraction: either a deep or shallow cut of either rich or lean gas. The quantities of inputs such as natural gas, electricity, and labour are taken from the SRI analysis. However, the costs of these inputs are updated for this analysis. In addition, while the SRI analysis is based on one location, the US Gulf Coast (Texas), this thesis compares the total cost across regions.

3.7 Summary

The analysis will use the comparative cost method to determine which of the following locations, Chicago, inland Texas and various producing regions in Alberta, are most competitive in the Alberta, Illinois and Texas petrochemical feedstock markets. Each of the regions faces different production costs, mainly due to differences in gas and electricity prices between the regions. In order to allow for comparison purposes several assumptions are made regarding the costs and factors of production involved.

The ultimate goal of the analysis is to allow for a consistent comparison of the value of locating the processing plant at each of the locations identified. This will allow for conclusions to be drawn regarding the attractiveness of extracting ethane within Alberta versus at the other end of gas export pipelines in locations such as Chicago. How the Alberta gas processing and petrochemical sectors develop in the future will depend on the result of the comparison. It will also provide a measure of the competitiveness of Alberta ethane in US markets.

Chapter 4

EVALUATION OF LOCATIONS

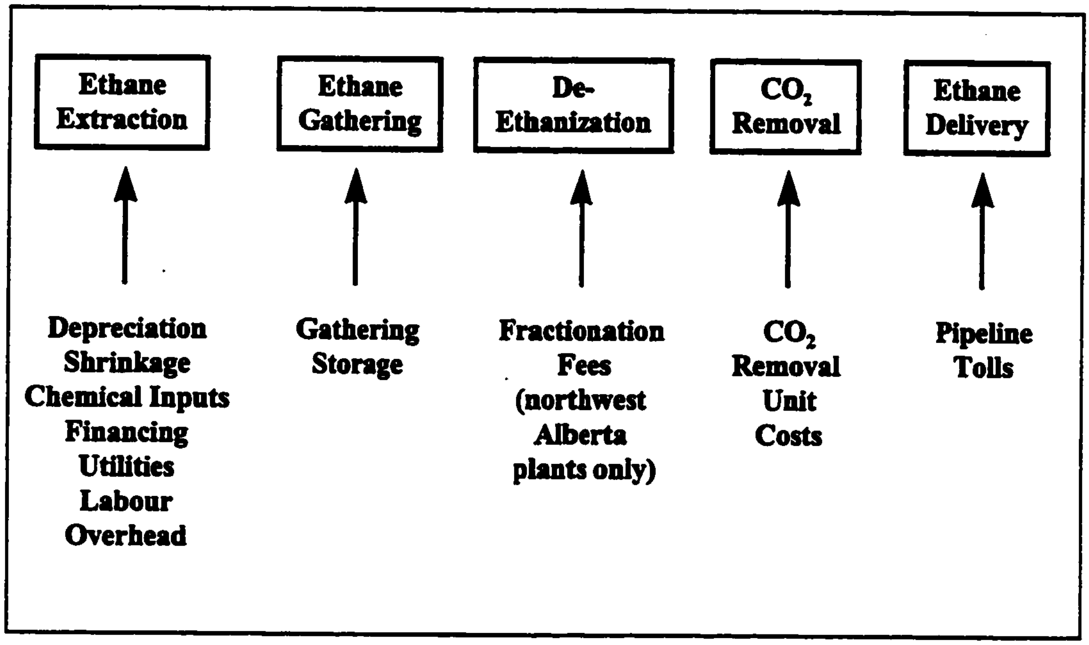
4.0 Introduction

This section will identify, using the methodology outlined in Chapter 3, a comparative cost of producing and moving ethane to market in either Edmonton, Chicago, or the US Gulf Coast, as compared to its shrinkage value. The analysis uses average costs for each input to production for the year 1995. While this allows conclusions to be drawn regarding the competitiveness of each region in 1995, it does not provide concrete conclusions for future years given that cost inputs may change over time. Projecting cost inputs into the future could provide insight into the competitiveness of regions past 1995. However, forecasting the prices of natural gas, electricity and other inputs is not within the scope of this study. Instead, Chapter 5 will provide a qualitative discussion of the expectation of cost inputs in the future. In addition, the chapter will examine some of the non-quantifiable factors affecting competitiveness between regions such as government policies, labour relations, and perceptions regarding future gas availability and quality.

4.1 Parameters of the Analysis

Given the infrastructure as it exists today, **Figure 4.1** shows the stages of production for ethane, including further processing either before or after delivery. For all locations examined cost inputs include labour, utilities, materials, depreciation, overhead, taxes and insurance.

Figure 4.1
Stages of Production for Ethane



Several inputs to the analysis are not direct costs associated with producing ethane, but impact the results. The first, the exchange rate, is assumed to be the average rate for 1995, $0.7285 US per dollar Canadian, taken from the Bank of Canada Review (1996). Second, the composition of natural gas to be processed is assumed to mirror the composition of natural gas gathered in Alberta. This gas either lean, the Empress composition, or rich, the Cochrane composition, are standard for gas pre-processed at field extraction plants to reach pipeline dew-point specifications. **Table 4.1** shows the assumed gas compositions in molecular percent taken from Heath, et al. (1995). This unit can be interpreted as the volume of the component present in a gaseous state in one unit of natural gas. Finally, the plant is configured to process 1.25 billion cubic feet (Bcf) of natural gas per day, extracting from either type of gas, a deep-cut, 85% of the ethane present, or a lean-cut, 50% of the ethane present. The volumes of extractable liquids are also shown in **Table 4.1** for both types of gas and extraction efficiency. It is important to point out that it is normal practice to spread the costs associated with extraction over the entire volume of natural gas liquids extracted (including ethane, propane, butane and pentanes plus). This can be done by a simple volumetric average or on the basis of the energy content of each component. Therefore, using the latter method, ethane produced is assigned a smaller portion of the total processing costs than using the former method since it has a lower energy content versus the other liquids. In this analysis, results from the former method are used.

Table 4.1
Gas Composition and Liquids Content

Component	Rich Gas (mole %)	Lean Gas (mole %)	Liquids Extracted A: Rich Gas, 85% C2 Recovery (Mb/d)	Liquids Extracted B: Rich Gas, 50% C2 Recovery (Mb/d)	Liquids Extracted C: Lean Gas, 85% C2 Recovery (Mb/d)	Liquids Extracted D: Lean Gas, 50% C2 Recovery (Mb/d)
Sales Gas	91.30%	93.60%	n/a	n/a	n/a	n/a
Ethane	6.50%	4.70%	44.39	25.81	32.10	18.66
Propane	1.20%	1.00%	9.81	9.81	8.09	7.77
i-Butane	0.13%	0.17%	1.26	1.26	1.63	1.62
n-Butane	0.18%	0.23%	1.68	1.68	2.13	2.11
Pentanes Plus	0.70%	0.30%	7.61	7.61	3.26	3.26

4.1.1 Plant Requirements

Before determining what each input to the production of ethane costs, it is necessary to detail exactly what inputs to production are required. Each configuration of straddle plant requires slightly different amounts of inputs. **Table 4.2** gives the requirement of inputs for the four cases: case A (rich inlet gas with extraction efficiency of 85%); case B (rich inlet gas with extraction efficiency of 50%); case C (lean inlet gas with extraction efficiency of 85%); case D (lean inlet gas with extraction efficiency of 50%). The data are taken from a study by the Stanford Research Institute (1994), and are scaled up from a 166.7 million cubic feet per day gas processing capacity to 1.25 billion cubic feet per day by a factor of approximately 7.5, in accordance with discussions with a straddle plant operator, Alberta Natural Gas Company Ltd. (ANG), which suggested that, with the exception of labour, variable costs are not significantly affected by plant size, but rather by gas composition and extraction efficiency.

Table 4.2
Inputs to NGL Extraction

Inputs	Units	Case A	Case B	Case C	Case D
Labour					
Operating	persons/8 hour shift	4	4	4	4
Maintenance	%/year of on-site cost	3%	3%	3%	3%
Control Laboratory	%/year of operating labour	20%	20%	20%	20%
Materials					
Gas Shrinkage	MMBtu/gallon of NGL	0.079	0.084	0.077	0.082
Monoethanolamine	lbs/gallon of NGL	0.001	0.001	0.001	0.001
Molecular Sieve	lbs/gallon of liquids	0.001	0.001	0.001	0.001
Maintenance	%/year of on-site cost	3%	3%	3%	3%
Operating	%/year of operating labour	10%	10%	10%	10%
Utilities					
Cooling Water	gallon of water/gallon of NGL	6.65	8.57	10.10	12.20
Process Water	gallon of water/gallon of NGL	0.015	0.020	0.041	0.050
Electricity	kWh/gallon of NGL	0.040	0.041	0.093	0.068
Natural Gas	million Btu/gallon of NGL	0.004	0.005	0.010	0.010
Other					
Plant Overhead	%/year of total labour	80%	80%	80%	80%
Taxes and Insurance	%/year of fixed capital	2%	2%	2%	2%
Depreciation	%/year of fixed capital	5%	5%	5%	5%
Interest on Working Capital	%/year of working capital	12%	12%	12%	12%

Labour requirements include the staff to operate the facility, 4 persons per 8 hour shift, labour incurred during maintenance of the facility estimated as a proportion of the construction cost of the plant, and the labour for the control laboratory assumed to be 20% of the total cost of operating labour.

Materials required by the plant include inputs which are related to the volume of NGLs being extracted such as monoethanolamine and dessicant, a molecular sieve. In addition the shrinkage value of the extracted liquids are included in this component of cost. Finally, the materials required for maintenance and the control laboratory such as computer systems, and parts are estimated as 3% of on-site costs and 10% of operating labour, respectively. It seems counter-intuitive that the 85% extraction cases have lower gas shrinkage, on an energy basis, than the 50% cases per gallon of liquids extracted. However, this follows from the fact that when less ethane is extracted relative to propane plus, then the energy content of an average gallon extracted is in fact higher, since ethane has less energy than propane plus.

Utilities such as fuel and water are required to power, heat, or cool plant operations. All these inputs are a function of the total liquids being extracted. The electricity and natural gas fuel requirements suggest that the facilities have fuel switching capabilities, but mainly depend on electric motors for power.

Other plant costs include overhead, taxes, insurance, depreciation, and interest on working capital. These costs are related to the initial cost of the plant, with the exception of overhead (mainly administrative expenses), which is based on labour costs.

4.2 Cost Inputs to NGL Extraction

4.2.1 Capital Costs

The two main components of capital include fixed and variable capital. Variable capital is the equipment required for the plant which can be relocated as desired for another extraction facility, in other words, the cost is not sunk. However, on-site and off-site costs are capital components which are sunk (fixed). As **Table 4.3** shows that both the fixed and variable capital costs, taken from SRI (1994) and scaled up in a similar fashion as the other inputs, are reduced as both extraction efficiency and/or NGL content is reduced. NGLs are removed from natural gas through turbo expansion. As the gas is expanded and therefore cooled, the liquids condense from the natural gas. This occurs in a tower similar to a fractionation column at a refinery, where lighter NGLs drop out the higher in the tower the gas reaches. Therefore, as NGL content increases and/or the required extraction efficiency is increased the tower must be larger and/or taller; hence, the capital costs increase.

Table 4.3
Straddle Plant Capital Costs
(million $CAD)

Component	Case A	Case B	Case C	Case D
Equipment	33.1	28.3	28.3	23.9
On-Site Costs	126.4	110.5	112.2	97.2
Off-Site Costs	48.6	38.9	35.4	30.9
Total Fixed Capital	175.0	149.4	147.6	128.2

NOTE: Total fixed capital for Case A is based on an internal evaluation by ANG, which estimated $C 233 million for a green-field plant extracting 85% of the ethane and 99% of the propane plus from a rich gas stream including a full range fractionator and CO_2 removal unit, and $C 175 million without these two units, but including a de-ethanizer. The relationship between capital requirements across the cases is taken from PEP and applied to the total cost estimated by ANG.

The capital costs shown in **Table 4.3** are for a typical Alberta plant. However, several factors would tend to lead to differences in capital costs between regions including differences in construction costs, design costs, project management costs, and materials costs. The comparison of costs between regions is based on work done with respect to ethylene plants. Although ethylene plants and gas processing plants are distinct facilities, many inputs associated with the design and construction of the facilities are identical, including labour, engineering, management, and materials (gravel, sand, concrete, steel etc.). Therefore, regional capital cost differences will be assumed to be similar to those of the ethylene industry.

The most important factor in determining the potential for differences in construction costs, design costs, and project management costs are wage rate disparities between regions. A recent analysis conducted by the Canadian Chemical Producers Association comparing wage costs for field labour, sub-contract labour, project management labour and design labour found that as compared to Alberta, projects in Texas and Sarnia would experience 7% and 4% higher labour costs, respectively. As the study noted labour cost differences are the "biggest single contributing factor to cost variations between the regions" (CCPA, 1996). In this analysis it is assumed that labour costs in Chicago are most similar to those in Sarnia. This reflects the similarities between cost of living, union structure, population density, and location (CCPA, 1996).

Differences in material costs are caused mainly by climate. For example, plants in Alberta and Chicago must equip for higher snow loading conditions, causing material costs to be between 1% and 5% higher than for the Texas plant. The price paid for materials may also cause differences in total material costs between regions. Although disparate sand, gravel and concrete prices may lead to differences, the bulk of materials are obtained in the global market. Thus, for these products only delivery charge differences between regions affect material costs. Analysis has indicated that for similar materials used to construct ethylene plants freight charge differences are not significant between regions (CCPA, 1996). Overall capital costs are assumed to be 3.7% and 6.7% higher in inland Texas and Chicago respectively (CCPA, 1996).

These costs are annualized using a depreciation rate of 5 percent per year. This rate is not taken from the SRI analysis (SRI, 1994), which uses 10 percent per year since this is too aggressive a rate considering that these facilities have a considerably longer life-span than 10 years.

4.2.2 Materials and Utilities

Natural gas prices are the basis of two cost components: shrinkage and fuel costs. In this analysis it is assumed that the processor compensates the natural gas producer for the removal of liquids based on the energy that is removed, valued at the price of natural gas (i.e. the opportunity cost of the energy). In the US this type of contractual relationship between producer and processor is called "keep-whole". With this type of contract the liquids become the property of the processor and the dry gas the producer. However, where several facilities are competing for extraction rights and excess processing capacity exists gas producers may be able to negotiate a price that is higher than shrinkage value for the liquids that are extracted. In fact some processors and producers have even negotiated profit-sharing contracts for the sale of the gas and liquids streams from the plant, in the US called "percent-of-proceeds" (CS First Boston, 1994). However, since this is not the standard for the industry, and in fact very rare in Alberta, the "percent-of-proceeds" contract will not be addressed in the numerical analysis.

The cost of shrinkage is incurred during the extraction of liquids at straddle plants. For gas producers, the opportunity cost of the ethane extracted is the energy value it would otherwise have captured by remaining in the natural gas. This value, called shrinkage value, is the energy value that the producers will ultimately receive for their natural gas. There are many factors which determine the actual price producers in Alberta receive for their natural gas, such as the ability of the producer to make long-term volume commitments, the location of the gas produced, the producer's ability to negotiate access to export pipeline, the volume of gas involved, whether or not the gas is first sold to marketer, or aggregator etc. Given these factors and the secrecy surrounding the prices involved in natural gas contracts, it would be almost impossible to determine the actual opportunity cost of the extracted ethane and other liquids extracted. However, simplifying assumptions are made.

To ensure a consistent comparison, shrinkage values are based on average 30 day spot natural gas prices and for all regions represent volumes traded at major market hubs. This avoids the inclusion of the mark-up made by local distribution companies when selling natural gas to industrial, residential or commercial consumers. In the case of northwest Alberta, natural gas prices are based on the value of the natural gas at the fieldgate, using the Alberta Reference Price from the Alberta Department of Energy. For the plant located in Edmonton the prices refer to natural gas located at the AECO C Hub, the intra-Alberta gas price benchmark. This price is similar to a fieldgate price plus an intra-Alberta delivery cost on the NOVA gathering system. For the plant in inland Texas, the closest gas trading hub is Henry Hub, Texas. Natural gas prices for this hub are used in the analysis. In Chicago, gas prices are based on the Henry Hub price plus an average transportation toll between Henry Hub and Chicago, in this case $US 0.05/MMBtu, for 1995. While cost-of-service tolls between the two markets are actually closer to $US 0.22/MMBtu, there is a large excess of capacity and according to discussions with TransCanada Pipelines, the tolls have been reduced to variable cost for the past several years. **Table 4.4** shows the monthly and annual averages of gas prices used for each location, taken from Brent Freidenberg Associates Ltd. (1996).

Table 4.4
Natural Gas Prices

Period	Northwest Alberta (1) $C/GJ	Edmonton (2) $C/GJ	Chicago (3) $C/GJ	Inland Texas (4) $C/GJ
January	1.05	1.18	2.32	2.26
February	0.79	0.91	2.01	1.95
March	0.79	0.91	1.92	1.85
April	0.90	1.02	2.00	1.94
May	1.09	1.22	2.22	2.16
June	1.10	1.23	2.26	2.20
July	0.92	1.05	2.26	2.19
August	0.87	0.98	2.02	1.96
September	0.92	1.03	2.04	1.97
October	0.99	1.11	2.23	2.16
November	1.09	1.21	2.37	2.30
December	1.13	1.24	2.55	2.48
1995 Average	0.97	1.09	2.18	2.12

NOTES:
(1) Alberta Department of Energy reference plantgate average 30 spot price;
(2) AECO C Hub average 30 day spot price;
(3) Henry Hub delivered month average 30 day spot price plus 5 cents US/MMBtu transportation toll from Henry Hub to Chicago;
(4) Henry Hub delivered month average 30 day spot price.

In this period, Alberta straddle plants would have experienced a shrinkage and fuel gas cost advantage over their US counterparts in Chicago and inland Texas.

Fuel costs represent the largest single portion of operating costs at gas plants. Energy in the form of natural gas and electricity is used to operate heaters, compressors, pumps, turbines and electrical monitoring equipment. When extracting ethane plus as compared with propane plus, additional energy is required to further cryogenically cool, or turbo-expand the natural gas. The most readily available form of energy is the raw natural gas feeding into the plants. Also, electricity is required to power certain systems and for electrical equipment. Most smaller gas plants in Alberta burn natural gas to power their operations, supplemented only by small amounts of electricity. Fuel switching capability between electricity and natural gas allows gas plants to take advantage of fluctuations in electricity and gas prices. Since straddle plants require much larger volumes of energy, they can re-coup the large capital cost required to install fuel switching equipment. The straddle plants at Empress, Alberta, the largest plants in North America, were provided with electricity from a dedicated coal-fired generator built by Trans Alta. This allows the plants to switch between the electricity from the grid and natural gas from the NOVA pipeline, and has led to much lower volume of intake gas consumption than most field plants. The prices for natural gas used as fuel are as shown in **Table 4.4**.

Estimating electricity prices is somewhat more complicated for several reasons. First, the structure of electricity pricing is dependent on the peak requirements of the facility which can fluctuate widely. Secondly, many large scale facilities may have co-generation capacity which can reduce electricity costs on average to levels below that charged by the electric utility. For this comparison electricity prices are taken as those charged to an industrial consumer from an electric utility with no co-generation capacity. **Table 4.5** shows the average annual electricity prices used in the analysis, obtained from TransAlta Utilities (1997), Alberta Power (1997), and the US Energy Information Administration (1995). As the table shows, Alberta extraction facilities have a significant advantage over the US facilities for electricity input.

Two other inputs to liquids extraction are monoethanolamine, used to remove H_2S and some portion of the CO_2 from the gas and liquids, and dessicant, which acts as a molecular sieve for gas and liquids de-hydrating (Oil and Gas Journal, 1992). In North

America there are only a handful of producers of these specialty chemicals including Dow Chemical (who sell to distributors) and Zeochem, located in the eastern US. **Table 4.6** presents estimates of monethanolamine and dessicant costs for 1995, obtained from local distributors of the products such as Travis Chemicals and Van Waters and Rogers. While Alberta processors have a slight cost advantage over US plants with respect to monoethanolamine, mainly because it is locally produced by Dow Chemical, they pay significantly more for dessicant, which comes from Louisville, Kentucky.

Table 4.5
1995 Electricity Prices

	Rural Alberta	Edmonton	Chicago	Inland Texas
Industrial User Electricity Price (¢ (Cdn.)/kWh)	2.8	2.9	7.3	5.5

NOTE: Rates for the Edmonton and northwest Alberta plants are calculated using demand and energy charges based on the electricity use for the plant as configured in Case A. Based on data from Alberta Power, the northwest Alberta rate is estimated as a 1.5% reduction of the Edmonton rate. The rates for Chicago and Texas are based on annual average state-wide industrial user rates.

Materials required for maintenance are estimated as 3% of on-site cost and 10% of operating labour cost respectively. Maintenance costs are related to original capital costs through the need for repair as facilities experience wear and tear. Operating materials such as staff buildings, computer systems, phone systems, and vehicles are obviously related to total labour requirements (SRI, 1994).

Table 4.6
Monethanolamine and Dessicant Costs
1995 Estimate ($C/lb)

	Alberta	Chicago	Inland Texas
Monethanolamine	0.89 (1)	0.93 (3)	0.95 (3)
Dessicant	2.49 (2)	1.54 (4)	1.54 (4)

NOTES:
(1) Bulk price for Alberta including freight;
(2) Bulk price for Alberta including freight;
(3) Large user price for over 12 drums (2.76 tons) per delivery, freight charge of 2 cents/lb for delivery to Texas, no charge to Chicago;
(4) Large user charge, includes 2 cents/lb freight charges for delivery within the US.

The final input associated with materials and utilities is that of water. Water is needed in the extraction process and to cool plant systems during extraction. For every region considered information on water costs is limited. Since the Edmonton plant is located within the jurisdiction of the City of Edmonton local water rates are used to estimate the cost of process water (City of Edmonton, 1996). The relative rates for inland Texas are based on a previous analysis on ethylene production costs, which found that process water cost approximately 15% more at the Gulf Coast versus Alberta (Apuzzo, 1984). For the cost of cooling water, a modest annual licensing fee is all that is required to use this water within Alberta. This means that cooling water is effectively almost free in Alberta (Alberta Environmental Protection, 1991). Using the same analysis for the relative costs of water in Texas, cooling water costs are estimated as almost double those in Alberta. Plants in Chicago facing similar availability of fresh water as in Alberta are assumed to face the same costs for both cooling and process water as Alberta. **Table 4.7** shows the estimated costs for water in each of the regions.

Table 4.7
Cooling and Process Water Costs
1995 Estimate ($C/m³)

	Alberta	Chicago	Inland Texas
Cooling Water	0.00005	0.00005	0.00006
Process Water	0.67	0.67	0.77

4.2.3 Labour Costs

The three main components of labour costs are operating labour, maintenance, and the control laboratory. As discussed in section 4.2.1, field labour wage rates including benefits and burdens are the higher in Alberta and Chicago than in Texas due to the existence of unions. For this analysis it is assumed that field labour wage rates are similar between the gas processing and ethylene industry. In fact the staff would have very similar roles, plant maintenance and equipment monitoring, and would likely be in a similar pay scale. Statistics Canada wage rate data is categorised by industry, chemical and oil and gas, but within the oil and gas sector only differentiates between workers on the basis of hourly, weekly, or salaried employees. This means that salaried gas plant employees and salaried oil company office employees are included in the same category. Therefore, using Statistics Canada data for gas plant employee wage rates would be misleading (Statistics Canada, 1995). Therefore, the labour wage rates used are from the ethylene competitiveness study previously mentioned (CCPA, 1996). As a result, labour costs in Alberta are $C 31.96 per hour, in Chicago are $C 38.06 per hour and $C 26.35 per hour in inland Texas (CCPA, 1996). These costs represent the labour on-site. Cost associated with off-site management is included in overhead, to be discussed later.

In the course of plant operations, special technicians are required for maintenance and to operate the control laboratory. These costs are estimated as 3% of the initial plant on-site fixed capital cost and 20% of operating labour cost respectively.

4.2.4 Other Costs

Other components of extraction cost include plant overhead, taxes, insurance, depreciation (or amortization) and interest on working capital. Plant overhead, estimated as 80% of total labour costs, includes administrative and other similar expenses not directly related to operations, such as legal fees, payroll costs, and corporate management. Taxes and insurance are estimated as 2% of fixed capital. This is a simplification which may obscure differences in regimes between regions. In reality, taxes are likely to be slightly higher in Alberta than in the US, while insurance costs are likely to be lower (Canada is generally a much less litigious society than the US). The plant is amortized at 10% of fixed capital per year. This allows for a faster write-off of the asset than may be accurate in practice. However, since the rate used is consistent between regions, this will not impact the conclusions. Interest on working capital (equity) is set at 12%; consistent with that of most corporate investments. The actual debt-equity ratio is heavily weighted to debt, reflecting the limited size of the project and current interest rates.

4.2.5 Total Extraction Costs

Total annual extraction costs are determined by multiplying the price of each input by the quantity of that input required per year. **Table 4.2** presented estimates of the required amounts of each input per gallon of liquids produced. **Table 4.8**, which is calculated based on the requirements from **Table 4.2**, shows the annual requirements of each input. Multiplying these input requirements by their respective prices yields **Tables**

4.9 to 4.12 for each of the plant configurations, cases A through D. (**Tables 4.9 (a)** through **4.12 (a)** give costs per gallon of liquids extracted). Finally, total production costs are divided by the annual liquids output to yield an average extraction cost per gallon of liquids.[1] Several conclusions are apparent from these tables. First, in all cases the locations that are most competitive are those with the lowest shrinkage values, since this represents by far the largest component of total cost. Second, the most cost-effective way to extract liquids from rich or lean gas is to configure the plant to extract 85% rather than only 50% of the ethane. The additional ethane recovered more than covers the additional capital cost required up-front. Third, the richer the gas the better for processing costs.

Table 4.8
Plant Requirements for Extraction

Inputs	Units	Case A	Case B	Case C	Case D
Labour					
Operating	hours per year	35,040	35,040	35,040	35,040
Maintenance	%/year of battery limits cost	3%	3%	3%	3%
Control Lab.	% of operating labour	20%	20%	20%	20%
Materials					
Shrinkage	GJ/year	82,218,339	62,429,540	59,070,254	44,214,152
Monoethanolamine	lb/year	992,763	707,892	723,855	512,277
Dessicant	lb/year	992,763	707,892	723,855	512,277
Maintenance	%/year of battery limits cost	3%	3%	3%	3%
Operating	% of operating labour	10%	10%	10%	10%
Utilities					
Cooling Water	m3/yr	24,978,532	22,953,451	27,661,331	23,646,385
Process Water	m3/yr	56,343	53,567	112,289	96,911
Electricity	kWh/year	39,710,502	29,023,591	67,318,552	34,834,851
Fuel Gas	GJ/year	4,187,870	3,732,717	7,633,779	5,402,476
Plant Overhead	% of total labour	80%	80%	80%	80%
Taxes and Insurance	%/year of fixed capital	2%	2%	2%	2%
Depreciation	%/year of fixed capital	5%	5%	5%	5%
Interest on Working Capital	%/year	12%	12%	12%	12%

[1] Costs are given in US cents per US gallons since this is standard unit used in the NGL business in both the US and Canada. Posted prices for NGLs are almost always listed in these units.

Table 4.9
Liquids Extraction Costs: Case A (85% extraction, rich gas)
(Canadian Dollars per Year)

Inputs	Northwest Alberta	Edmonton	Chicago	Inland Texas
Labour				
Operating	1,119,878	1,119,878	1,333,564	923,421
Maintenance	3,791,667	3,791,667	4,045,708	3,931,958
Control Lab.	223,976	223,976	266,713	184,684
Total Labour	5,135,521	5,135,521	5,645,985	5,040,063
Materials				
Shrinkage	79,751,789	89,686,505	179,552,545	174,201,712
Monoethanolamine	887,125	887,125	926,669	946,524
Dessicant	2,476,744	2,476,744	1,526,279	1,526,279
Maintenance	3,791,667	3,791,667	4,045,708	3,931,958
Operating	111,988	111,988	133,356	92,342
Total Materials	87,019,312	96,954,028	186,184,558	180,698,816
Utilities				
Cooling Water	1,275	1,275	1,275	1,466
Process Water	37,918	37,918	37,918	43,606
Electricity	1,125,844	1,142,988	2,889,028	2,180,398
Fuel Gas	4,062,233	4,568,268	9,145,680	8,873,131
Total Utilities	5,227,270	5,750,449	12,073,901	11,098,601
Total Direct Operating Costs	97,382,103	107,839,998	203,904,444	196,837,480
Plant Overhead	4,108,417	4,108,417	4,516,788	4,032,050
Taxes and Insurance	3,500,000	3,500,000	3,734,500	3,629,500
Depreciation	8,750,000	8,750,000	9,336,250	9,073,750
Interest on Working Capital	2,758,542	2,758,542	2,758,542	2,758,542
Total Production Cost	116,499,062	126,956,957	224,250,525	216,331,322
Average Product Value $/yr	116,499,062	126,956,957	224,250,525	216,331,322
Average Product Value $/m3	31.02	33.80	59.70	57.59
Average Product Value US¢/USg	8.55	9.32	16.46	15.87

Table 4.10
Liquids Extraction Costs: Case B (50% extraction, rich gas)
(Canadian Dollars per Year)

Inputs	Northwest Alberta	Edmonton	Chicago	Inland Texas
Labour				
Operating	1,119,878	1,119,878	1,333,564	923,421
Maintenance	3,314,394	3,314,394	3,156,566	3,156,566
Control Lab.	223,976	223,976	266,713	184,684
Total Labour	4,658,248	4,658,248	4,756,843	4,264,670
Materials				
Shrinkage	60,556,654	68,100,223	136,336,770	132,273,808
Monoethanolamine	632,567	632,567	660,764	674,922
Dessicant	1,766,050	1,766,050	1,088,318	1,088,318
Maintenance	3,314,394	3,314,394	3,156,566	3,156,566
Operating	111,988	111,988	133,356	92,342
Total Materials	66,381,653	73,925,222	141,375,774	137,285,955
Utilities				
Cooling Water	1,275	1,275	1,275	1,466
Process Water	37,918	37,918	37,918	43,606
Electricity	1,125,844	1,142,988	2,889,028	2,180,398
Fuel Gas	3,620,735	4,071,772	8,151,695	7,908,767
Total Utilities	4,785,772	5,253,953	11,079,916	10,134,237
Total Direct Operating Costs	75,825,673	83,837,423	157,212,533	151,684,863
Plant Overhead	3,726,598	3,726,598	3,805,474	3,411,736
Taxes and Insurance	2,987,374	2,987,374	2,845,118	2,845,118
Depreciation	7,468,434	7,468,434	7,112,795	7,112,795
Interest on Working Capital	2,264,475	2,264,475	2,264,475	2,264,475
Total Production Cost	92,272,554	100,284,305	173,240,394	167,318,987
Average Product Value \$/yr	92,272,554	100,284,305	173,240,394	167,318,987
Average Product Value \$/m3	34.45	37.44	64.68	62.47
Average Product Value US¢/USg	9.50	10.32	17.83	17.22

Table 4.11
Liquids Extraction Costs: Case C (85% extraction, lean gas)
(Canadian Dollars per Year)

Inputs	Northwest Alberta	Edmonton	Chicago	Inland Texas
Labour				
Operating	1,119,878	1,119,878	1,333,564	923,421
Maintenance	3,367,424	3,367,424	3,207,071	3,207,071
Control Lab.	223,976	223,976	266,713	184,684
Total Labour	4,711,278	4,711,278	4,807,348	4,315,175
Materials				
Shrinkage	57,476,791	64,636,700	129,402,791	125,546,467
Monoethanolamine	648,472	648,472	677,378	691,892
Dessicant	1,810,455	1,810,455	1,115,682	1,115,682
Maintenance	3,367,424	3,367,424	3,207,071	3,207,071
Operating	111,988	111,988	133,356	92,342
Total Materials	63,415,130	70,575,039	134,536,279	130,653,455
Utilities				
Cooling Water	1,275	1,275	1,275	1,466
Process Water	37,918	37,918	37,918	43,606
Electricity	1,125,844	1,142,988	2,889,028	2,180,398
Fuel Gas	7,423,548	8,348,303	16,713,317	16,215,245
Total Utilities	8,588,584	9,530,484	19,641,538	18,440,715
Total Direct Operating Costs	76,714,993	84,816,802	158,985,164	153,409,345
Plant Overhead	3,769,023	3,769,023	3,845,878	3,452,140
Taxes and Insurance	2,952,020	2,952,020	2,811,448	2,811,448
Depreciation	7,380,051	7,380,051	7,028,620	7,028,620
Interest on Working Capital	1,729,235	1,729,235	1,729,235	1,729,235
Total Production Cost	92,545,322	100,647,131	174,400,345	168,430,788
Average Product Value $/yr	92,545,322	100,647,131	174,400,345	168,430,788
Average Product Value $/m3	33.71	36.66	63.52	61.34
Average Product Value US¢/USg	9.29	10.10	17.51	16.91

Table 4.12
Liquids Extraction Costs: Case D (50% extraction, lean gas)
(Canadian Dollars per Year)

Inputs	Northwest Alberta	Edmonton	Chicago	Inland Texas
Labour				
Operating	1,119,878	1,119,878	1,333,564	923,421
Maintenance	2,916,667	2,916,667	2,777,778	2,777,778
Control Lab.	223,976	223,976	266,713	184,684
Total Labour	4,260,521	4,260,521	4,378,055	3,885,883
Materials				
Shrinkage	43,597,232	49,028,158	98,154,461	95,229,367
Monoethanolamine	464,407	464,407	485,109	495,503
Dessicant	1,296,569	1,296,569	799,003	799,003
Maintenance	2,916,667	2,916,667	2,777,778	2,777,778
Operating	111,988	111,988	133,356	92,342
Total Materials	48,386,862	53,817,789	102,349,707	99,393,993
Utilities				
Cooling Water	1,275	1,275	1,275	1,466
Process Water	37,918	37,918	37,918	43,606
Electricity	1,125,844	1,142,988	2,889,028	2,180,398
Fuel Gas	5,316,420	5,978,689	11,969,346	11,612,648
Total Utilities	6,481,457	7,160,870	14,897,567	13,838,119
Total Direct Operating Costs	59,128,839	65,239,180	121,625,329	117,117,994
Plant Overhead	3,408,417	3,408,417	3,502,444	3,108,706
Taxes and Insurance	2,563,131	2,563,131	2,441,077	2,441,077
Depreciation	6,407,828	6,407,828	6,102,694	6,102,694
Interest on Working Capital	1,482,202	1,482,202	1,482,202	1,482,202
Total Production Cost	72,990,417	79,100,758	135,153,745	130,252,673
Average Product Value $/yr	72,990,417	79,100,758	135,153,745	130,252,673
Average Product Value $/m3	37.12	40.23	68.73	66.24
Average Product Value US¢/USg	10.23	11.09	18.95	18.26

Table 4.9(a)
Liquids Extraction Costs: Case A (85% extraction, rich gas)
(US ¢/US gallon)

Inputs	Northwest Alberta	Edmonton	Chicago	Inland Texas
<u>Labour</u>				
Operating	0.08	0.08	0.10	0.07
Maintenance	0.28	0.28	0.30	0.29
Control Lab.	0.02	0.02	0.02	0.01
Total Labour	0.38	0.38	0.41	0.37
<u>Materials</u>				
Shrinkage	5.85	6.58	13.18	12.78
Monoethanolamine	0.07	0.07	0.07	0.07
Dessicant	0.18	0.18	0.11	0.11
Maintenance	0.28	0.28	0.30	0.29
Operating	0.01	0.01	0.01	0.01
Total Materials	6.39	7.11	13.66	13.26
<u>Utilities</u>				
Cooling Water	0.00	0.00	0.00	0.00
Process Water	0.00	0.00	0.00	0.00
Electricity	0.08	0.08	0.21	0.16
Fuel Gas	0.30	0.34	0.67	0.65
Total Utilities	0.38	0.42	0.89	0.81
Total Direct Operating Costs	7.15	7.91	14.96	14.44
Plant Overhead	0.30	0.30	0.33	0.30
Taxes and Insurance	0.26	0.26	0.27	0.27
Depreciation	0.64	0.64	0.69	0.67
Interest on Working Capital	0.20	0.20	0.20	0.20
Total Production Cost	8.55	9.32	16.46	15.87

Table 4.10(a)
Liquids Extraction Costs: Case B (50% extraction, rich gas)
(US ¢/US gallon)

Inputs	Northwest Alberta	Edmonton	Chicago	Inland Texas
<u>Labour</u>				
Operating	0.12	0.12	0.14	0.10
Maintenance	0.34	0.34	0.32	0.32
Control Lab.	0.02	0.02	0.03	0.02
Total Labour	0.48	0.48	0.49	0.44
<u>Materials</u>				
Shrinkage	6.23	7.01	14.03	13.61
Monoethanolamine	0.07	0.07	0.07	0.07
Dessicant	0.18	0.18	0.11	0.11
Maintenance	0.34	0.34	0.32	0.32
Operating	0.01	0.01	0.01	0.01
Total Materials	6.83	7.61	14.55	14.13
<u>Utilities</u>				
Cooling Water	0.00	0.00	0.00	0.00
Process Water	0.00	0.00	0.00	0.00
Electricity	0.12	0.12	0.30	0.22
Fuel Gas	0.37	0.42	0.84	0.81
Total Utilities	0.49	0.54	1.14	1.04
Total Direct Operating Costs	7.80	8.63	16.18	15.61
Plant Overhead	0.38	0.38	0.39	0.35
Taxes and Insurance	0.31	0.31	0.29	0.29
Depreciation	0.77	0.77	0.73	0.73
Interest on Working Capital	0.23	0.23	0.23	0.23
Total Production Cost	9.50	10.32	17.83	17.22

Table 4.11(a)
Liquids Extraction Costs: Case C (85% extraction, lean gas)
(US ¢/US gallon)

Inputs	Northwest Alberta	Edmonton	Chicago	Inland Texas
Labour				
Operating	0.11	0.11	0.13	0.09
Maintenance	0.34	0.34	0.32	0.32
Control Lab.	0.02	0.02	0.03	0.02
Total Labour	0.47	0.47	0.48	0.43
Materials				
Shrinkage	5.77	6.49	12.99	12.60
Monoethanolamine	0.07	0.07	0.07	0.07
Dessicant	0.18	0.18	0.11	0.11
Maintenance	0.34	0.34	0.32	0.32
Operating	0.01	0.01	0.01	0.01
Total Materials	6.37	7.08	13.51	13.12
Utilities				
Cooling Water	0.00	0.00	0.00	0.00
Process Water	0.00	0.00	0.00	0.00
Electricity	0.11	0.11	0.29	0.22
Fuel Gas	0.75	0.84	1.68	1.63
Total Utilities	0.86	0.96	1.97	1.85
Total Direct Operating Costs	7.70	8.51	15.96	15.40
Plant Overhead	0.38	0.38	0.39	0.35
Taxes and Insurance	0.30	0.30	0.28	0.28
Depreciation	0.74	0.74	0.71	0.71
Interest on Working Capital	0.17	0.17	0.17	0.17
Total Production Cost	9.29	10.10	17.51	16.91

Table 4.12(a)
Liquids Extraction Costs: Case D (50% extraction, lean gas)
(US ¢/US gallon)

Inputs	Northwest Alberta	Edmonton	Chicago	Inland Texas
Labour				
Operating	0.16	0.16	0.19	0.13
Maintenance	0.41	0.41	0.39	0.39
Control Lab.	0.03	0.03	0.04	0.03
Total Labour	0.60	0.60	0.61	0.54
Materials				
Shrinkage	6.11	6.87	13.76	13.35
Monoethanolamine	0.07	0.07	0.07	0.07
Dessicant	0.18	0.18	0.11	0.11
Maintenance	0.41	0.41	0.39	0.39
Operating	0.02	0.02	0.02	0.01
Total Materials	6.78	7.54	14.35	13.93
Utilities				
Cooling Water	0.00	0.00	0.00	0.00
Process Water	0.01	0.01	0.01	0.01
Electricity	0.16	0.16	0.40	0.31
Fuel Gas	0.75	0.84	1.68	1.63
Total Utilities	0.91	1.00	2.09	1.94
Total Direct Operating Costs	8.29	9.14	17.05	16.42
Plant Overhead	0.48	0.48	0.49	0.44
Taxes and Insurance	0.36	0.36	0.34	0.34
Depreciation	0.90	0.90	0.86	0.86
Interest on Working Capital	0.21	0.21	0.21	0.21
Total Production Cost	10.23	11.09	18.95	18.26

4.3 Delivery, Storage and CO_2 Removal Costs

While Alberta plants seem for the most part to have an extraction cost advantage over similar US facilities, mainly due to lower shrinkage costs, US plants have a definite advantage in transportation cost because of their closer proximity to ethane markets. **Figure 4.2** shows the average cost of moving ethane on various gathering and delivery systems in Canada and the US.

4.3.1 Gathering Costs in Alberta

The tariff on a gathering system generally depends on the size of the pipeline, the original cost of construction, the maximum operating pressure (necessarily higher for lighter hydrocarbons), the geography of the region, the percentage of capacity in use, regulations and contractual agreements between shippers and operators of the pipeline. These factors vary considerably for the two main ethane plus gathering systems in Alberta.

The two ethane plus gathering systems, are the Federated and Peace pipelines. These pipelines gather ethane from northern and western Alberta and deliver it to Edmonton. The Peace pipeline runs from western Alberta, close to the BC border, and connects many gas processing plants including large ethane producers such as the Elmworth and Kaybob South plants, to Fort Saskatchewan and the Dow fractionator. While the pipeline was originally designed to carry crude oil it has been fitted to batch ethane plus, propane plus, crude oil, and condensates. The Federated system has a northern leg bringing NGLs from miscible flood projects at Swan Hills and Judy Creek north to Fort Saskatchewan and a southern leg collecting NGLs from gas plants in the West Pembina and Brazeau River areas. In the last few years the pipeline has been expanded to collect ethane plus from the Caroline field, a large new sour gas field close to Calgary. The Caroline sour gas plant, operated by Shell, produces 25 thousand barrels per day of ethane plus mix and almost 18 thousand barrels per day of condensate (AEUB, 1995). All legs of the Federated pipeline are dedicated to gathering solely NGLs.

While Federated is a private pipeline and does not make its point-to-point tolls public, the Peace system publishes tariffs for delivery from a range of locations to the Fort Saskatchewan hub. **Table 4.13** shows the 1995 tariffs, obtained from the pipeline operator, for both major ethane producers and other smaller NGL producers on the Peace pipeline system. These are incentive tolls for ethane plus, and range from 1.0 to 3.4 US cents per gallon. The Peace pipeline has avoided using the 'postage stamp' tariff methodology in favour of a system involving cost-of-service calculations. However, tariff incentives have been given in the recent past to producers of ethane in an attempt to boost shipments. Strong gas prices in 1993 and the beginning of 1994 caused a significant decline in ethane shipments, as the price ethane was fetching at Edmonton for petrochemical use was unable to compete with ethane's shrinkage value in natural gas. Alarmed by this drop in ethane volumes on the pipeline, Peace offered ethane shippers an incentive tariff. Since then, there has been a subsequent plunge downwards in gas prices and the opening of Dow's fractionator, to which many Alberta ethane producers have made volume commitments, including some located along the Peace pipeline. Because ethane moved on Peace or Federated must be transported in a mix with other liquids, the mix must be fractionated at Edmonton.[2] Fractionation charges in Edmonton for 1995 are estimated at 2.3 US cents per US gallon (Heath, et al., 1995).

4.3.2 Delivery Pipeline Costs

In the US and Canada there are three main ethane gathering and transportation systems: the Koch system, the Mid-America Pipeline Company (Mapco) and the Cochin

[2] Ethane from the other plants in Edmonton, Chicago and inland Texas is moved in either a spec or ethane-propane mix form. At the destination, ethane-propane mix need not be fractionated for sale to petrochemical users.

system. Gathering charges and pipeline charges are shown in **Figure 4.2**. Included in the figure are the total transportation costs when delivering from the producing regions to the three main markets: Edmonton, Chicago and the US Gulf Coast. As the data shows, transportation cost is fundamentally a function of distance.

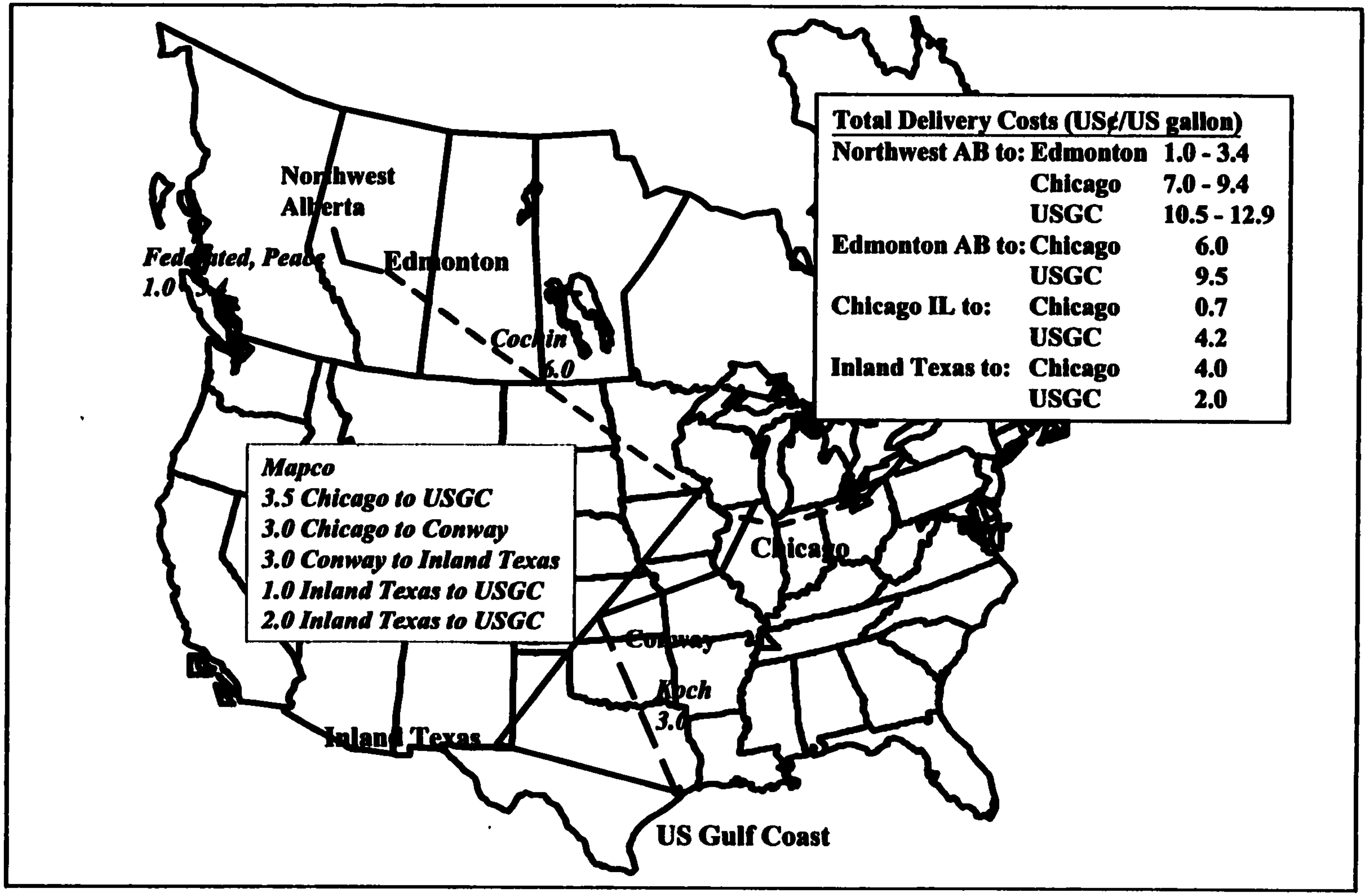
Table 4.13
Peace Pipeline Tariffs
(US ¢/US gallon)

Delivery Location	Tariff
Wapiti	3.4
Elmworth	2.3
Kakwa	2.5
Karr	1.0
Ante Creek	1.2
Kaybob South	0.8
Hope Creek	0.6
Carson Creek	1.9
Greencourt	1.9

4.3.3 Storage and CO_2 Removal Costs

For the most part, storage of ethane is only necessary because volumes are waiting to be fractionated, pipelined, purchased or used. In Alberta, ethane storage caverns exist mainly at Fort Saskatchewan. At this location AEGS, Cochin, and Procor all have salt caverns which can store ethane and/or ethane plus. Breakout storage also exists at the Junction with the Mapco system and in Conway and the US Gulf Coast the fractionation facilities all have significant storage caverns for ethane, ethane plus and ethane-propane mix. Following the progress of ethane from production to market highlights locations where storage is required. After field plant ethane is separated from heavier NGLs at Fort Saskatchewan, ethane is aggregated in Cochin storage caverns to await transport on the

Figure 4.2
Gathering and Delivery Costs



pipeline. It is co-mingled there with straddle plant ethane production from AEGS until there is enough to make up a batch for Cochin. The storage costs are absorbed in the pipeline tariff on Cochin. At the junction with the Mapco system, ethane is moved into breakout storage, also included in the shipping cost on Cochin, and from there it is blended with propane and moved into the Mapco system. At either Conway or the US Gulf Coast the ethane exits the pipeline, where it is moved either to market as ethane-propane mix or to a fractionator for separation from the propane. At any of these stages ethane slow to move will be charged for additional storage time. However, storage fees for ethane average at only 0.5 cents US per US gallon. It is assumed that for both US and Canadian producers there is one-time cost of 0.5 cents US per US gallon for ethane storage (Heath, et al., 1995).

CO_2 removal is required for two reasons: it is potentially corrosive to ethylene facilities; and pipelines in the US require a certain ethane quality since volumes are co-mingled. As with storage costs, charges differ little between the US and Canada; apparently one CO_2 removal unit is much like any other. The estimate of CO_2 removal cost used in this analysis is 1.4 US cents per US gallon (Heath, et al., 1995).

4.4 Total Delivered Costs

With the above data for production costs and additional costs such as gathering, delivery, CO_2 removal, fractionation and storage, delivered costs can be determined for each market and each plant configuration. **Figures 4.3, 4.4, and 4.5** show the results of the analysis for each of the markets.

For the Edmonton market, not surprisingly, the most competitive supply source is the Edmonton plant, mainly because even though shrinkage costs are slightly higher, neither gathering nor fractionation charges are incurred. Similarly, for the Chicago market Edmonton is the lowest cost supply source since the shrinkage cost advantage

Figure 4.3
Delivered Costs to Edmonton

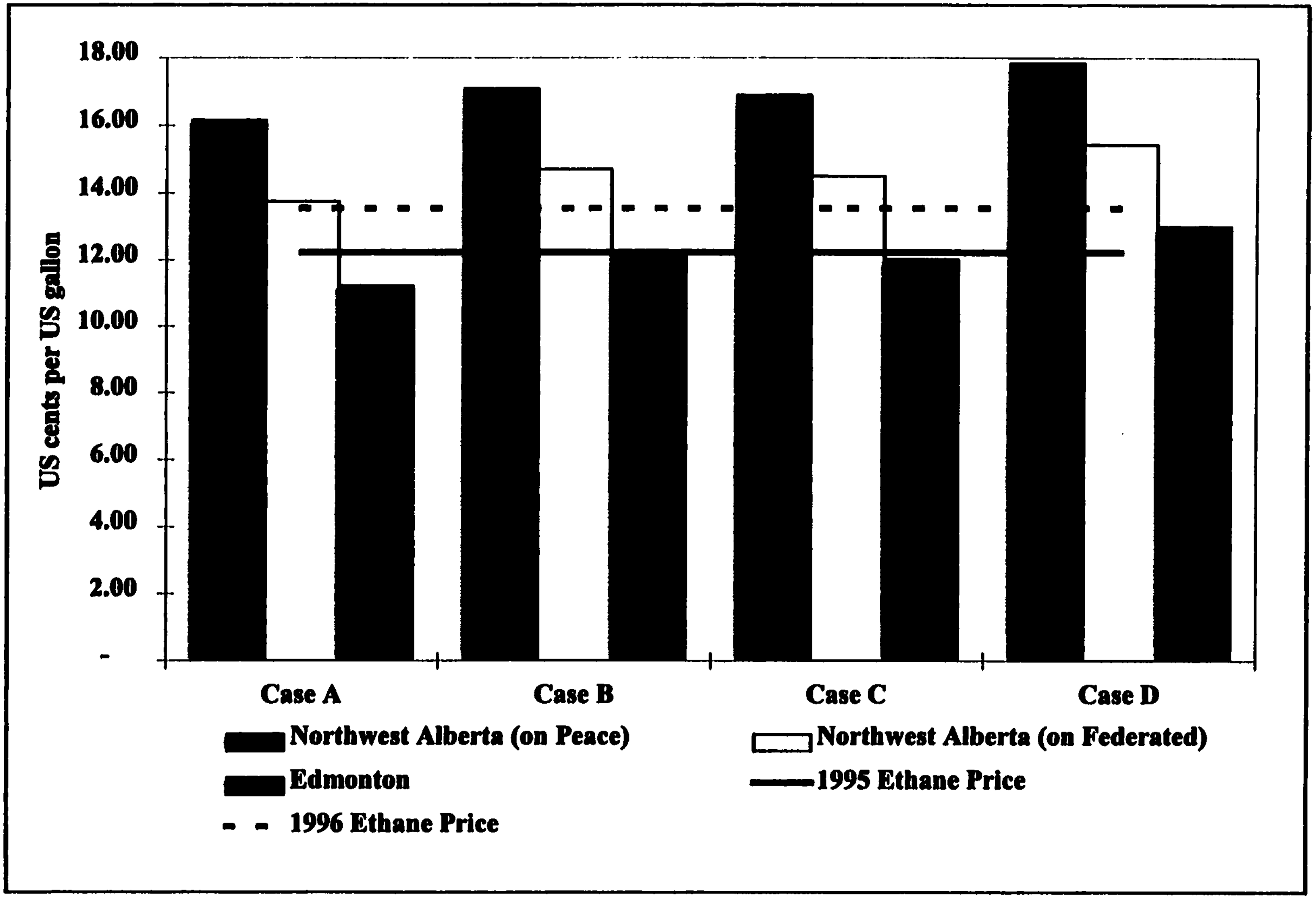


Figure 4.4
Delivered Costs to Chicago

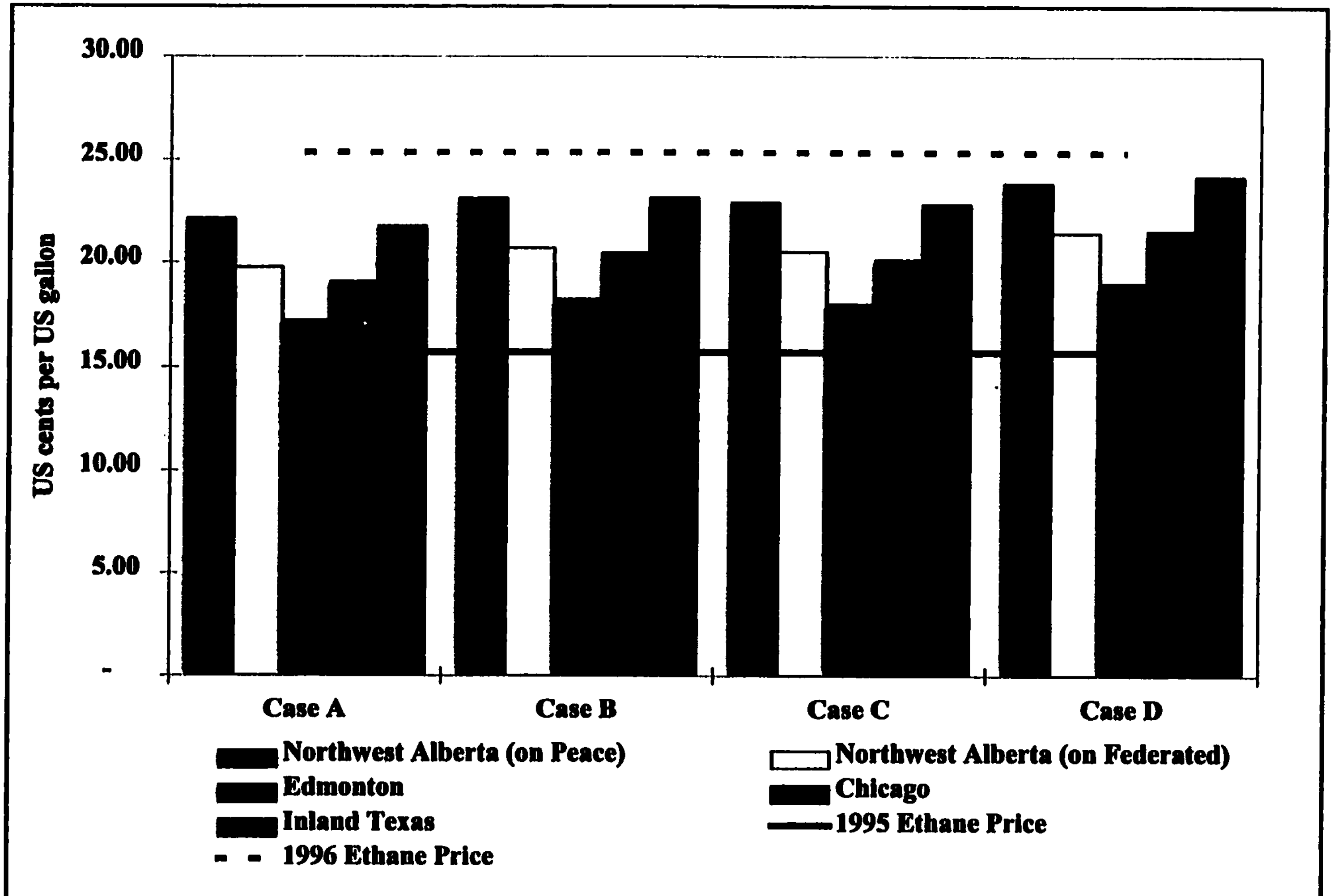
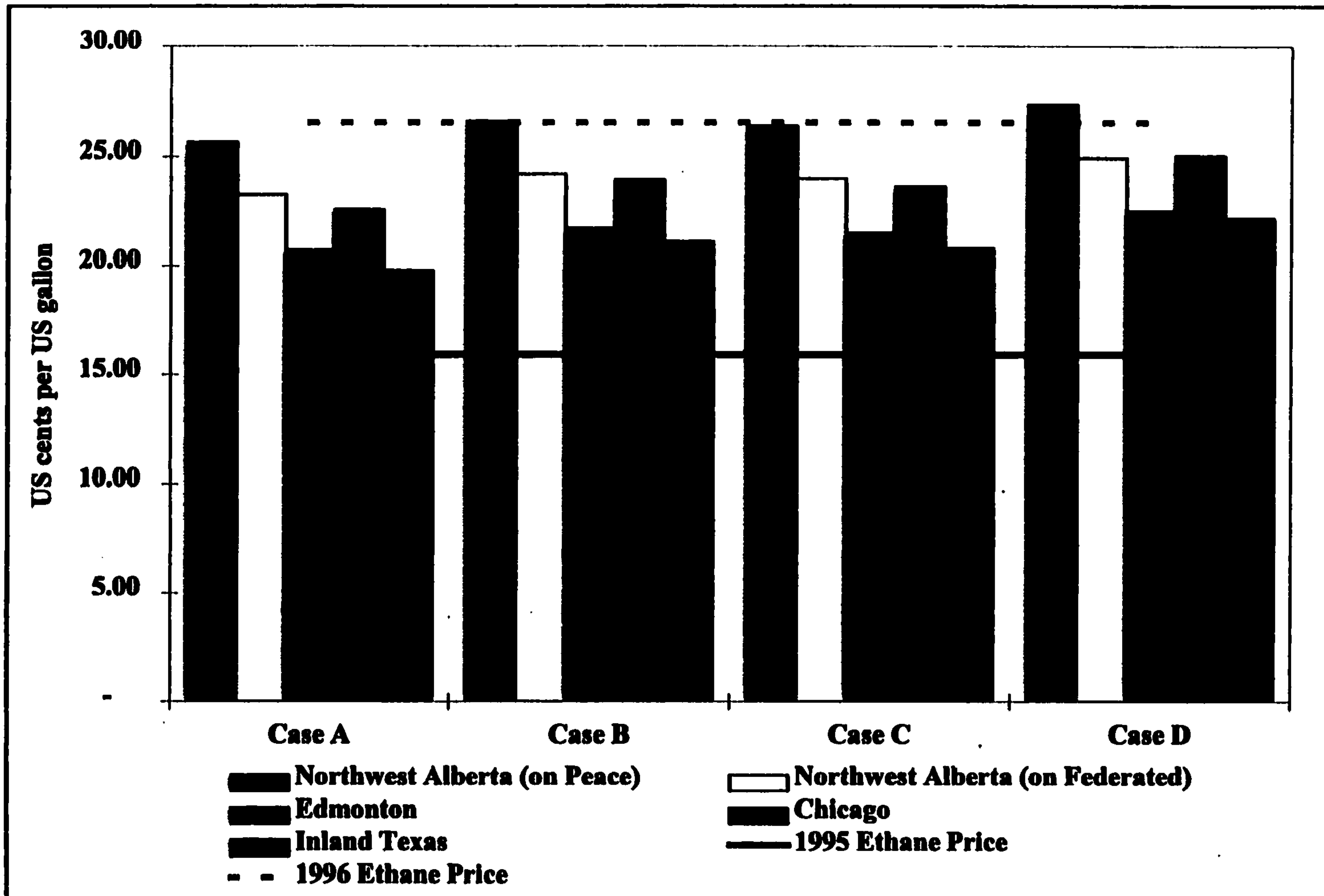


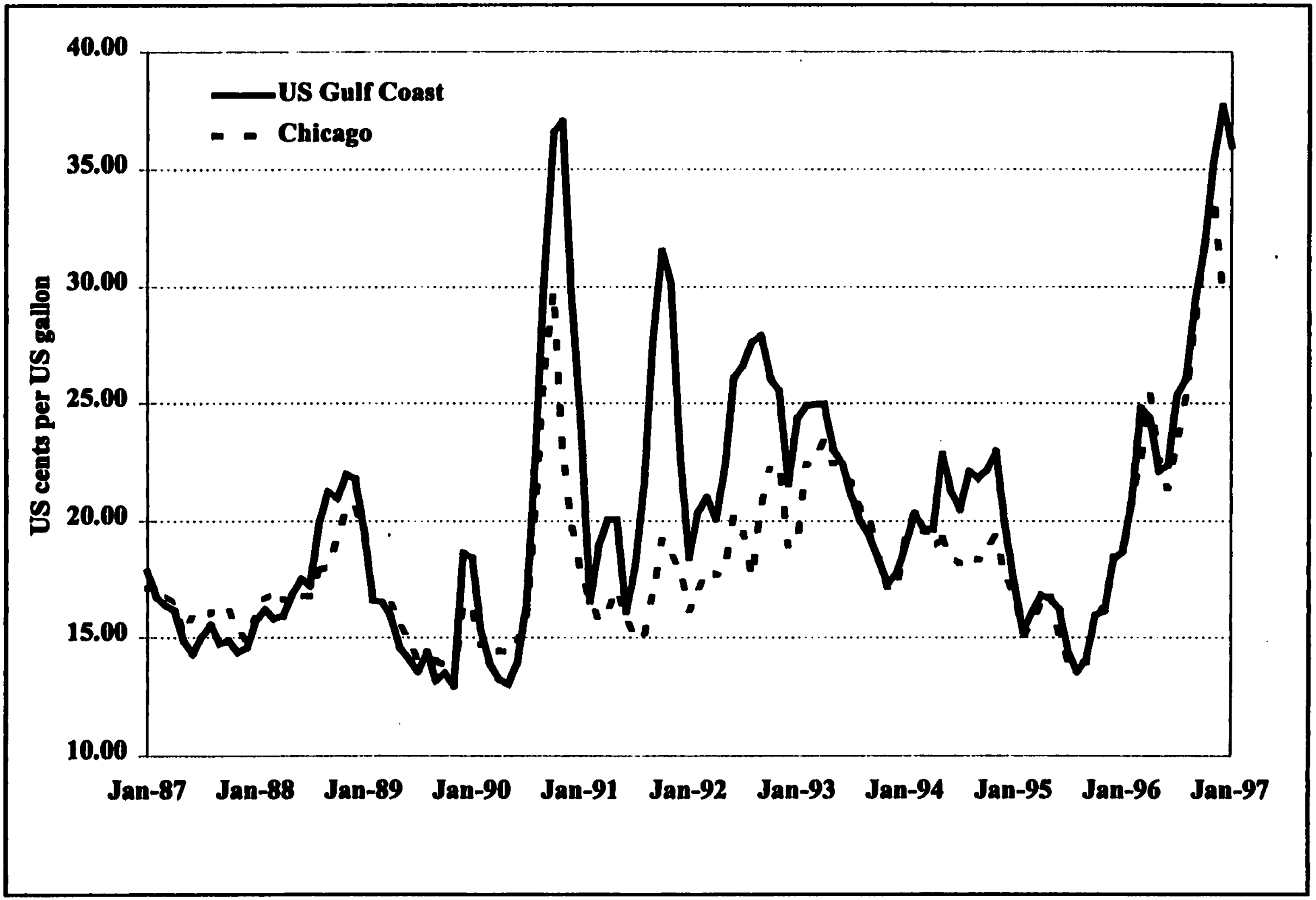
Figure 4.5
Delivered Costs to the US Gulf Coast



outweighs the transportation cost between Edmonton and Chicago. Again, in the US Gulf Coast market Edmonton ethane is very competitive. However, ethane from inland Texas has a lower delivered cost due to its proximity to the market area.

Also included in the graphs are estimated annual average ethane prices for 1995 and 1996 (Alberta Department of Energy, 1995, and Oil Price Information Service, 1997). The years 1995 and 1996 are chosen since they represent respectively the lowest and highest ethane prices in recent history. Clearly, extracting ethane is a risky business since prices would not have covered costs in 1995. This would be a daunting conclusion for processors if ethane was the only liquid extracted. However, while the delivered costs for other liquids such as propane and butane mirror those for ethane, prices in all markets are much higher. The question then is why would processors wish to remove ethane? Happily, ethane prices have not always been as low as in 1995. **Figure 4.6** shows historical ethane prices at the US Gulf Coast and Chicago. Over the period shown prices have averaged 20.71 cents at the US Gulf Coast and 18.71 cents US per US gallon at Chicago (Oil Price Information Service, 1997).

Figure 4.6
Ethane Prices at the US Gulf Coast and Chicago



Chapter 5
EXPECTED FUTURE TRENDS

5.0 Introduction

The intent of this chapter is to provide a brief discussion of some of the factors which influence the competitiveness of the regions which are either not directly quantifiable or are likely to change over time. With respect to factors which may change over time, some discussion of future trends is presented based on available forecasts or projections. With respect to non-quantifiable factors, the potential for these to impact competitiveness and the direction of the impact is given.

5.1 Expected Changes in Components of Delivered Cost

Total delivered costs include extraction costs and other costs involved with purifying the ethane and moving it to market. The components of cost are affected by the prices of the inputs to extraction. These inputs include labour, natural gas, electricity, capital (affected mainly by labour, materials, interest rates and required returns on equity), monoethanolamine, and dessicant. In addition further costs for CO_2 removal, storage, fractionation and delivery are incurred and these are also affected by various market forces. **Figures 5.1** through **5.3** show the components of delivered cost for each of the markets examined assuming a Case A plant configuration. As the figures show, the largest components of delivered cost are attributed to natural gas inputs, capital costs, CO_2 removal, fractionation fees, and delivery charges. However, only natural gas input

Figure 5.1
A Breakdown of the Delivered Cost to Edmonton

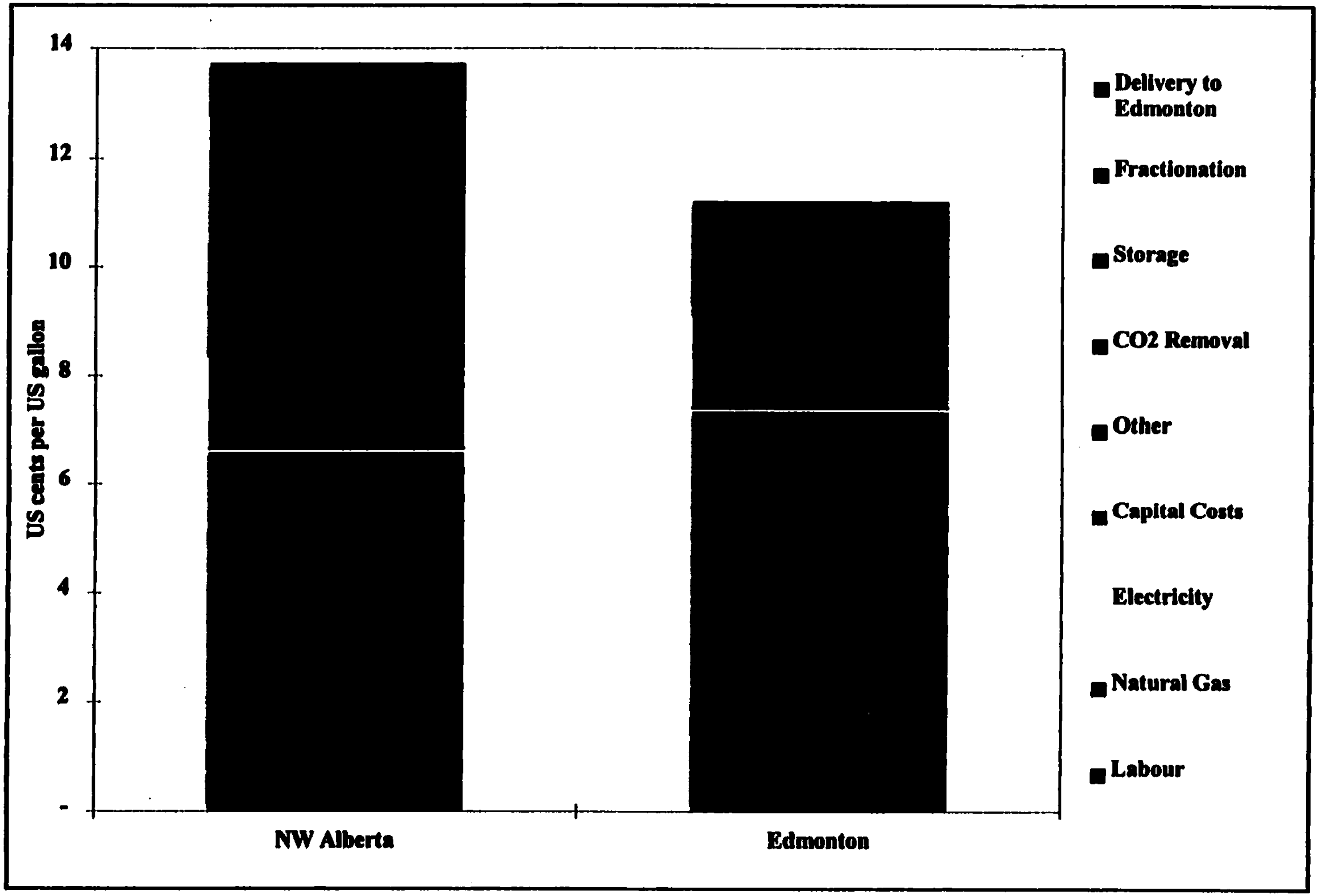


Figure 5.2
A Breakdown of the Delivered Cost to Chicago

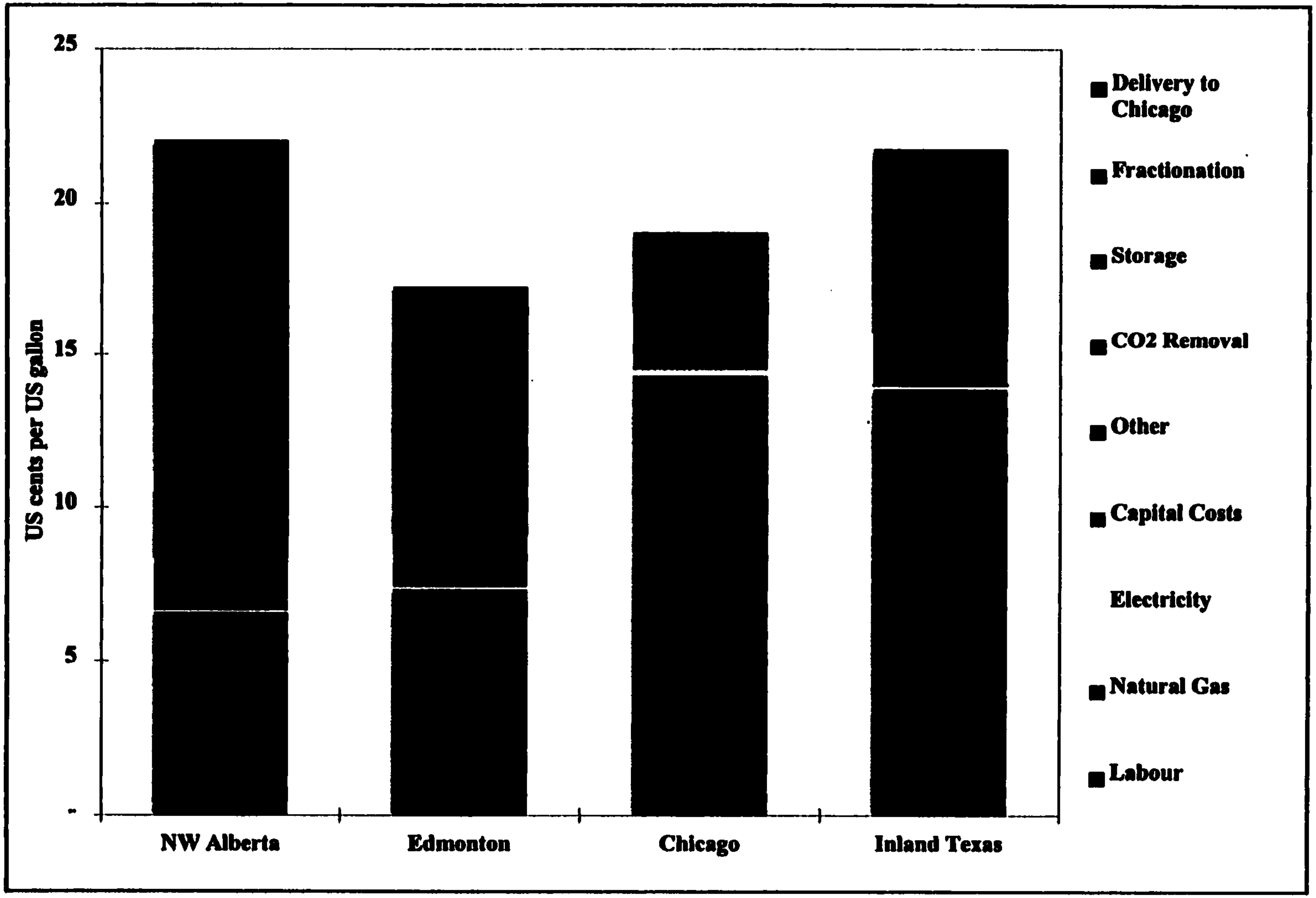
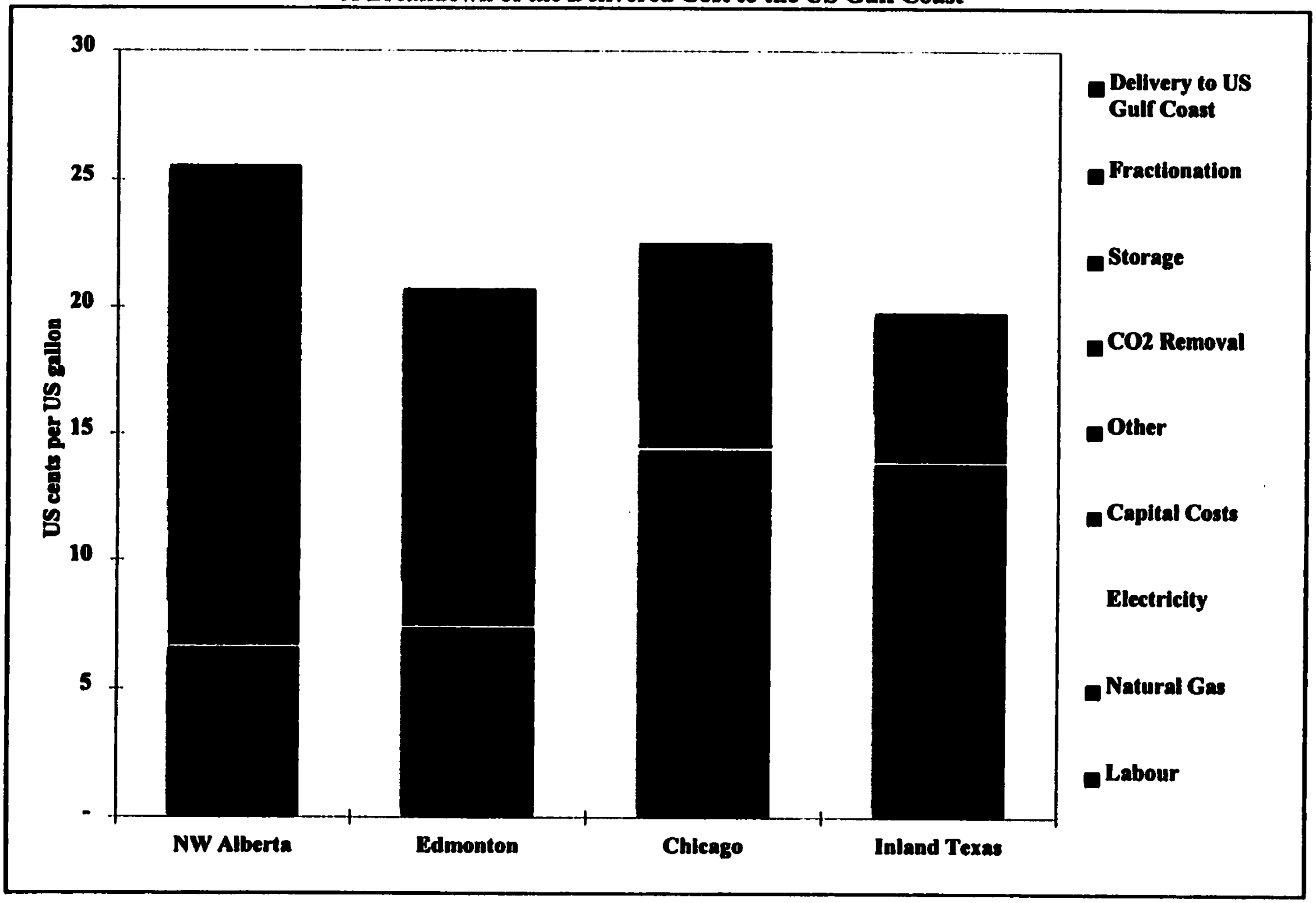


Figure 5.3
A Breakdown of the Delivered Cost to the US Gulf Coast



costs, fractionation fees, and delivery costs differ significantly between locations. Since these costs are the most variable and have the greatest influence on competitiveness between locations the discussion of future relative costs will be limited to these inputs. Relative changes in the prices of other inputs will likely not be significant enough to change the relative competitiveness of the regions being compared. For example, electricity prices in Alberta would have to be 25 times higher than current levels for Chicago to a be lower cost supply source for the Chicago market than Edmonton.

The next sections will discuss the potential for future relative prices of natural gas, fractionation fees, and delivery costs to alter from current levels. In addition a factor which has an impact on many of the cost inputs is the exchange rate between the US and Canadian dollar. The impact of an upper and lower estimate of the exchange rate is also a sensitivity presented below.

5.1.1 Natural Gas Prices

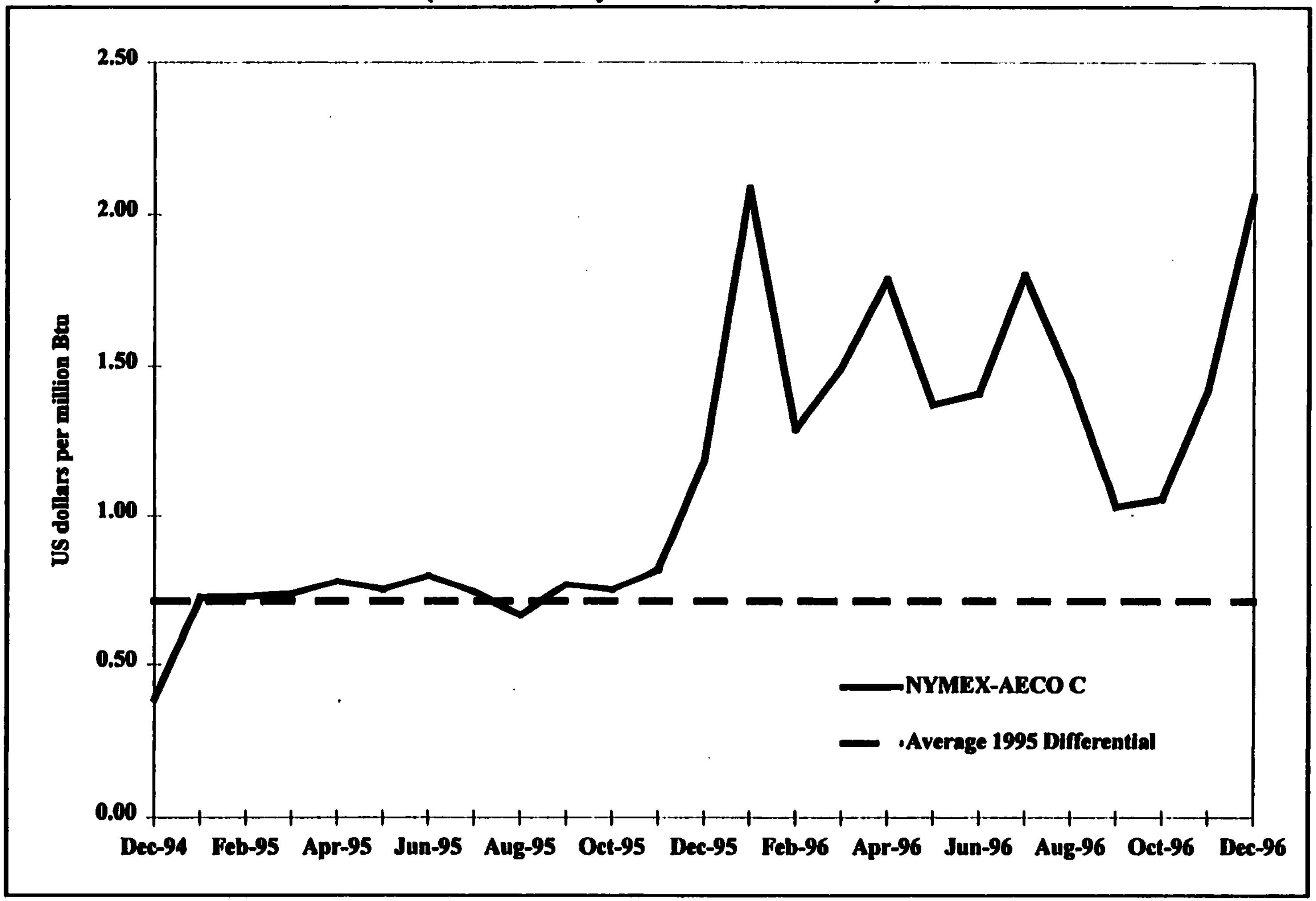
The competitiveness of each region is essentially a function of the cost of natural gas. Therefore of most interest to the issue of competitiveness is the future direction of relative prices. The motivation for this analysis was the proposal of a wet gas pipeline between Alberta and Chicago, Alliance Pipeline, when several large scale export pipelines had already or were subsequently announced. The mandate of the Alliance project is to reduce the gas price basin differential between the US Gulf Coast and Alberta to $US 0.55 per million Btu (interestingly this implies a differential between

Chicago and Alberta that is less than the cost of transportation on the proposed pipeline). **Figure 5.4** shows the differential has historically averaged between $US 0.70 to 0.80 cents per million Btu, and this analysis uses a differential of $US 0.72 cents per million Btu (Brent Friedenberg Associates, 1997). However, in 1996 this differential has risen as gas trapped in Alberta through a lack of export pipeline capacity forced local prices down relative to US markets. Therefore, for producers without space on export pipelines revenues from the sale of natural gas have been significantly lower than could be realised with more capacity. The way Alliance intends to ensure a lower level of basin differential will be through the availability of a significant volume of cheap pipeline expandability which can be brought into use at the sign of increasing differentials.

Thus a sensitivity is run where Canadian gas prices are only 55 cents US per million Btu lower than those in the US Gulf Coast and only 65 cents US per million Btu than those in Chicago. In this environment shrinkage advantages enjoyed by Alberta processors would be significantly eroded, resulting in an extraction cost advantage of 3 rather almost 7 cents US per US gallon between Edmonton and Chicago. As Chapter 4 concluded, the shrinkage advantage is necessary to compensate Alberta processors for the extra transportation costs incurred when moving to premium ethane markets in the US. The results of the sensitivity are shown in **Table 5.1**.

However, the Alberta gas market does not exist in isolation. As with Alberta, gas producers in the US Gulf are expecting large increases in regional gas production within the next several years. With a jump in gas from Canada into US markets through export

Figure 5.4
Gas Price Basis Differential
(NYMEX Henry Hub less AECO C Hub)



pipeline expansions, and a similar jump in domestic supplies, a downward pressure on gas prices is likely. Overall, it is likely that gas prices will be weakened as markets absorb a supply shock; however, it is difficult to predict the effect on relative prices across regions. One thing does seem certain, that the differential which existed in 1996 of $US 1.52 US per million Btu will cause the construction of at least one large new export pipeline (Brent Friedenberg Associates, 1997). In which case it is likely that gas prices in Alberta relative to Chicago and inland Texas will either remain constant or strengthen in the future.

Table 5.1
Gas Price Differential Sensitivity Results
Case A Delivered Costs (US cents per US gallon)

	Northwest Alberta (on Peace)	Northwest Alberta (on Federated)	Edmonton	Chicago	Inland Texas
		Sensitivity Results			
To Edmonton	18.20	15.80	13.19	n/a	n/a
To Chicago	24.20	21.80	19.19	19.06	21.77
To USGC	27.70	25.30	22.69	22.56	19.77
		Original Results			
To Edmonton	16.15	13.75	11.22	n/a	n/a
To Chicago	22.15	19.75	17.22	19.06	21.77
To USGC	25.65	23.25	20.72	22.56	19.77

5.1.2 Fractionation Fees

Fractionation fees are incurred only for liquids produced in northwest Alberta. The reason the product needs to be fractionated is that the liquids gathering systems, Peace and Federated pipelines, move only mixed NGLs to Edmonton. If specification ethane could be moved from northwestern Alberta to Edmonton this would result in a significant reduction in delivered cost. It is technically difficult to convert pipelines which move mixed product to carry spec products. First to accommodate a variety of products batching capability is necessary. Second, since ethane is a very light hydrocarbon a high pressure system is required to transport it in a specification form. Neither Peace nor Federated has the ability to move volumes at the pressures required. Therefore, it is unlikely that a plant in this location would be able to avoid incurring this cost in the future.

5.1.3 Delivery Costs

The future direction of delivery costs depends on a variety of factors including the volume of product to be moved versus the pipeline's capacity, and the construction of new, or mothballing of old, systems.

The cost of moving liquids on the gathering systems moving liquids from northwestern Alberta to Edmonton are most likely to be altered in the future. Several projects have recently been approved by the Alberta Energy and Utilities Board (AEUB) which will move product from this region to Edmonton. These include an expansion of the Peace pipeline system, the construction of a connector leg by Novagas Clearinghouse Ltd. (NCL) into northeastern BC through northwestern Alberta connecting into the Peace pipeline systems and the construction of an entirely new line by Federated connecting the same area to Edmonton. All three pipelines would then be connected to plants in northwestern Alberta with the ability to move product to Edmonton. The increased competition for product to fill these pipelines is likely to reduce gathering costs for plants in this region of Alberta. Therefore, the current range of tolls from 1.0 to 3.4 cents US per US gallon depending on proximity to Edmonton, is likely to be decreased.

The pipeline connecting Alberta processing plants to the Chicago market, Cochin pipeline, is currently moving volumes at close to capacity. However, in the future the pipeline may see a reduction in volumes being transported. This is due to several factors. First, the current volume of ethane flowing on the pipeline is as a result of ship or pay contracts between the pipeline and NOVA Chemical and Dow Chemical Canada. The two companies ship almost 40 thousand barrels per day of ethane to Sarnia and the Mapco interconnect near Chicago. In 1998, these contracts expire exposing Cochin to a potential reduction in throughput of almost 35 percent (Heath et al., 1995). Second, access to a competing pipeline, Interprovincial Pipeline Ltd. (IPL), moving propane plus to eastern Canada has recently been expanded. PanCanadian Petroleum Ltd., recently applied to the National Energy Board to require IPL, which moves around 150 thousand barrels per day of propane plus to eastern Canada, to provide shippers with access to injection facilities and breakout storage. The Board found that IPL had not met common carrier requirements to provide shippers with access to these facilities. Once access to this pipeline, which has lower transportation tolls than Cochin to similar destinations, has been increased Cochin could see a drop in the volume of propane moving on the pipeline. This could result in one of two outcomes; either tolls are reduced in an effort to encourage liquid volumes back to the pipeline or tolls are increased as costs are spread over lower volumes. The former outcome seems more likely since the pipeline is over ten years old and a large proportion of the initial capital outlay has been recovered to date.

The cost of moving product on the Mapco system, which is bi-directional depends on the demand for movements north versus south. In all likelihood, the demand for movements north relative to south will increase. Large wet gas finds off the Gulf Coast will result in a significant increase in the production of NGLs in the Texas and Louisiana area (Mortensen, George and Peacey, 1996). The attractiveness of the propane market in the US Midwest is greater than that of the petrochemical market at the US Gulf Coast in the winter. As a result large volumes of propane move north and this volume will only increase in the future. Consequently, the incentive for Mapco to reverse the pipeline and ship NGLs south must be higher than the current tolls.

5.1.4 Exchange Rates

This analysis assumes an exchange rate of 72.85 cents US per Canadian dollar. However, exchange rates fluctuate and have been as low as 67 cents and as high as 85 cents US per Canadian dollar in last few years. With a devaluation in the Canadian dollar prices of inputs paid for in Canadian dollars relate to a lower cost in terms of US dollars. The reverse is true for an increase in the value of the Canadian dollar versus the US dollar. This sensitivity calculates the impact on the delivered cost (in US cents per US gallon) of both a devaluation and an increase in the value of the Canadian dollar as it relates to the US dollar. **Table 5.2** presents the results of the sensitivity for exchange rates of 65 cents US per Canadian dollar and 85 cents US per Canadian dollar.

Table 5.2
Exchange Rate Sensitivity Results
Case A Delivered Costs (US cents per US gallon)

	Northwest Alberta (on Peace)	Northwest Alberta (on Federated)	Edmonton	Chicago	Inland Texas
Sensitivity Results ($0.65 US per Canadian $)					
To Edmonton	15.25	12.85	10.23	n/a	n/a
To Chicago	21.25	18.85	16.23	19.06	21.77
To USGC	24.75	22.35	19.73	22.56	19.77
Sensitivity Results ($0.85 US per Canadian $)					
To Edmonton	17.54	15.14	12.74	n/a	n/a
To Chicago	23.54	21.14	18.74	19.06	21.77
To USGC	27.04	24.64	22.24	22.56	19.77
Original Results					
To Edmonton	16.15	13.75	11.22	n/a	n/a
To Chicago	22.15	19.75	17.22	19.06	21.77
To USGC	25.65	23.25	20.72	22.56	19.77

Naturally, a devaluation of the Canadian dollar implies that Canadian imports are more competitive with ethane produced in the US. However, the decline in delivered costs for Canadian exports is not simply calculated as the percentage difference in the new and old exchange rates. This is because costs paid in US dollars for factor inputs such as dessicant and monoethanolamine are not impacted by exchange rate differences. Conversely, an increase in the exchange rate to 85 cents US per Canadian dollar, implies that Canadian imports become less competitive versus US production.

5.2 Non-Quantifiable Factors Influencing Competitiveness

Although there are many non-quantifiable factors affecting the costs involved with producing and delivering ethane to market few have the potential to affect the relative competitiveness of the regions. Two factors are discussed here: the affect of government policy and the affect of the quantity and quality of gas to be processed.

5.2.1 Government Policy

The Government of Alberta has traditionally been involved in the ethane extraction business as it relates to the provincial petrochemical sector and hence economic diversification. Since the ethylene sector uses ethane as a feedstock, when ethane prices are low (as a result of depressed gas prices) feedstock prices are also lower resulting in greater profits for the sector. Therefore, although gas and NGL royalties are lower, petrochemical sector taxes for the government are increased; the petrochemical sector is a government revenue hedge against low energy prices. For this reason the government has been very protective of threats to the viability of the petrochemical industry in Alberta. In fact, ethane exports require a permit from the Alberta Department of Energy through the Albert Energy and Utilities Board. In the future it is uncertain how restrictive the government will be regarding ethane exports. Both ethylene producers are planning to increase output requiring a commensurate increase in ethane feedstocks. In addition, several parties are examining the possibility of constructing a third plant, including Shell Canada and Imperial Oil Ltd (AEUB, 1997). This could affect the competitiveness of ethane produced in Alberta by simply restricting ethane from flowing out of the province or creating the image of the region as an unreliable supply source because of the uncertainty surrounding the ability of producers to obtain export permits.

5.2.2 Gas Availability and Composition

Since these plants are hypothetical in nature, the actual volume of gas processed and its NGL content remain to be seen. In this analysis it is assumed that the plants process the same volume of gas and receive gas of the same composition. In reality this is unlikely. If plants are sized the same and have contracted supply then all facilities could in theory have similar throughput. However, over time producing gas wells experience unpredictable decline rates, and new gas volumes must be contracted to the facility, making it likely that over time throughput is variable. Also, since new gas is constantly replacing old the composition is likely to change over time. For example, the ethane content of gas processed at straddle plants at Empress, Alberta ranges anywhere from 3.5 to 5.0 mole percent (AEUB, 1997). As this analysis shows the cost of extraction is significantly affected by the richness of the gas being processed. The Geological Survey of Canada predicts that gas from the Western Canadian Sedimentary will become richer over time as deeper (and wetter) wells are drilled (CERI, 1997). In contrast, gas processed in inland Texas could become drier as a result of the increased production of coal-bed methane (a very dry gas). Therefore, the composition of the gas at each location is likely to vary in the future, with the potential for plants in Alberta and Chicago (since it would straddle a Canadian gas export pipeline) to become more competitive than the plant in inland Texas as the relative NGL content of the gas increases.

5.3 Conclusions

The overall effect of future changes in cost inputs is summarised in **Table 5.3.** As a whole the effect of these changes on relative competitiveness is uncertain since the potential changes are not quantifiable, and tend to affect costs in opposite directions.

Table 5.3
A Summary of the Effect of Future Changes in Cost Inputs on Delivered Cost

Input	Northwest Alberta	Edmonton	Chicago	Inland Texas
Decrease of Gas Price Differentials	Increase Cost	Increase Cost	No Change	No Change
Increase in Fractionation Fees	Increase Cost	No Change	No Change	No Change
Decrease in Alberta Gathering Costs	Decrease Cost	No Change	No Change	No Change
Increase in Tolls on Cochin	Increase Cost	Increase Cost	No Change	No Change
Increase in Tolls on MAPCO	Increase Cost	Increase Cost	Increase Cost	No Change
Government Restricts Ethane Exports	Increase Cost	Increase Cost	No Change	No Change
Gas Richer in Alberta, Leaner in Texas	Decrease Cost	Decrease Cost	Decrease Cost	Increase Cost
Exchange Rates Drop to $0.65US/C$	Decrease Cost	Decrease Cost	No Change	No Change
Exchange Rates Increase to $0.85US/C$	Increase Cost	Increase Cost	No Change	No Change

Chapter 6
CONCLUSIONS

6.0 Summary and Conclusions

This intent of this analysis was to determine the optimal location for an ethane extraction facility along a proposed wet gas export pipeline from Alberta to Chicago, and the competitiveness of such as facility a compared to the largest ethane producing region in the US. Using a comparative cost approach, the various components of extraction cost were identified and quantified. In addition, the cost of purifying and delivering ethane produced in northwest Alberta, Edmonton, Chicago and inland Texas to several markets including Edmonton, Chicago and the US Gulf Coast were determined. Since the comparative cost approach was used for a certain period in time, a discussion of the likely changes to cost over time was included as well as the impact of non-quantifiable factors on elements of cost.

The results of the analysis indicate that the optimal location for the production of ethane destined for the US Gulf Coast market is inland Texas. For the Edmonton, Alberta market, ethane extracted at that location is the most competitive. Finally, for ethane delivered to the north-western Illinois market, Edmonton was the optimal location for extraction. These results could be of interest to the National Energy Board and the US Federal Energy Regulatory Committee because both are currently considering applications filed by Alliance for the construction of a wet gas pipeline from Alberta to Chicago. From the perspective of liquids extraction, it would preferable for Alliance to locate liquids extraction infrastructure in Alberta rather than Chicago. The issue of ethane export is also of interest to the Alberta government, which grants ethane export permits even if the ethane is contained in a wet gas pipeline. If it is more economic to extract ethane in Alberta, as this analysis suggests, then granting export permits to Alliance pipeline may not be justified.

6.1 Weaknesses of the Analysis

There are several weaknesses surrounding the analysis. The first involves the determination of capital costs. The analysis uses capital costs for a plant in Alberta and adjusts upwards or downwards the costs for competing regions based on the differences in regional costs for the construction of an ethylene plant. It would be more accurate to use estimates of capital costs of gas processing plants for each region. However, the body of literature on the subject is limited.

The second weakness of the analysis is the fact that the results are static. Since the life of gas processing facilities is greater than 20 years, decisions regarding the location of such facilities need to be based on the results of a comparison of costs over time. This could be accomplished by estimating costs over time and using these to calculate a net present value for each region. The accuracy of these results would be limited by the accuracy of the forecasts of cost inputs, but they could provide insight into future regional competitiveness. In addition, the sensitivity of changes in cost inputs over time could be of interest.

Finally, as indicated in the literature review, evaluating investment opportunities is more accurately performed using a real options approach. It would be more accurate to evaluate the investment in the processing plant in the greater context of the option to produce natural gas and all its components, through exploration, development, gathering, processing, transmission and delivery. However, since the choice to produce gas once taken implies that the option to process has already been exercised the comparative cost method was used.

6.2 Potential for Further Research

Drawing from the previous section, further analysis is required to determine actual capital cost differences between regions for the construction of gas processing plants. Also, based on forecasts of the cost of each input to extraction the analysis needs to be expanded to reflect competitiveness of each region over time. In addition, the incorporation of analysis of the competitiveness of varying sizes of facility would be useful.

The most useful area of suggested further research relates to the application of the real options approach. This approach incorporates the inherent value in the option to invest in a facility as part of the value foregone when investment finally takes place (Dixit and Pindyck, 19943). However, a firm may for strategic reasons also consider that entering or exiting an industry has value (Tirole, 1988). There seems to be little consideration in the prevailing literature of how these values compare, and how these considerations may work together to propel firms to choose to invest. In reality, it is likely that a combination of the strategic value of investing (or not) and the real option value of investing are both considered (although perhaps not quantified) when firms make such investment decisions.

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TEST TARGET (QA-3)

150mm

6"

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Phone: 716/482-0300
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